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PSEG
Services Corporation

February 1, 2022

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of Changes it its Electric Conservation
Incentive Program
(2022 PSE&G Electric CIP Rate Filing)

BPU Docket No. __________________

VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL

Aida Camacho-Welch, Secretary
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing on behalf of petitioner Public Service Electric and Gas Company is the Petition, Testimony of Michael McFadden, Karen Reif, Stephen Swetz, and Supporting Schedules in the above-referenced proceeding.

Please be advised that Attachment A - Schedule 6 is confidential and will be provided to the parties upon receipt of the Non-Disclosure Agreement, which is enclosed here.

Consistent with the Order issued by the Board in connection with In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being filed electronically with the Secretary of the Board and the New Jersey Division of Rate Counsel. No paper copies will follow.

Very truly yours,

C Attached service list (via e-mail)

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF CHANGES IN ITS ELECTRIC CONSERVATION INCENTIVE PROGRAM (2022 PSE&G ELECTRIC CIP RATE FILING)	**)**	**BPU DOCKET NO. __________**

VERIFIED PETITION

Public Service Electric and Gas Company ("PSE&G," "the Company," or "Petitioner"), a corporation of the State of New Jersey, having its principal offices at 80 Park Plaza, Newark, New Jersey, respectfully petitions the New Jersey Board of Public Utilities ("Board" or "BPU") pursuant to *N.J.S.A.* 48: 2-21, or any other statute the Board deems applicable, as follows:

INTRODUCTION AND OVERVIEW OF THE FILING

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service ("BGS"), and distribution of gas and the provision of Basic Gas Supply Service ("BGSS"), for residential, commercial and industrial customers within the State of New Jersey. PSE&G provides service to approximately 2.2 million electric and 1.8 million gas customers in an area having a population in excess of 6.2 million persons and that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton, and south to Camden, New Jersey.

2. Petitioner is subject to Board regulation for the purposes of setting its retail distribution rates and to assure safe, adequate, and reliable electric distribution and natural gas distribution service pursuant to *N.J.S.A.* 48:2-21 *et seq*.

3. PSE&G is filing this Petition seeking Board approval for a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer. The Clean Energy Future – Energy Efficiency Program ("CEF-EE") was approved in a Board Order dated September 23, 2020 in BPU Docket Nos. EO10121113 and GO18101112 ("CEF-EE Order"). In this Order, the Board approved a Conservation Incentive Program ("CIP") that allows the Company to account for lost sales revenue resulting from the decrease in customer energy usage. The CEF-EE Order approved a Stipulation that explicitly authorizes this electric CIP ("ECIP") cost recovery filing by February 1, 2022, for new rates effective June 1, 2022. Stipulation, paragraph 39.

BACKGROUND

4. On January 13, 2008, L. 2007, c. 340 ("RGGI Law") was signed into law and pronounced that EE and conservation measures must be essential elements of the State's energy future. The Legislature also found that public utility involvement and competition in the conservation and EE industries are essential to maximize efficiencies. N.J.S.A. 26:2C-45. Pursuant to Section 13 of the RGGI Law, codified in part as N.J.S.A. 48:3-98.1(a)(1), an electric or gas public utility may, among other things, provide and invest in EE and conservation programs in its service territory on a regulated basis.

5. An electric or gas public utility's investment in EE and conservation programs is eligible for rate treatment approved by the Board, including a return on equity, or other incentives or rate mechanisms. N.J.S.A. 48:3-98.1(b).

6. On May 23, 2018, Governor Murphy signed the Clean Energy Act ("CEA") into law. The CEA builds upon the RGGI Law by employing clean energy strategies and establishing

aggressive energy reduction requirements with the goal of improving public health by ensuring a cleaner environment for current and future New Jersey residents. Specifically, the CEA requires that each utility implement EE measures that "achieve annual reductions in the use of electricity of two percent of the average annual usage in the prior three years within five years of implementation of its electric energy efficiency program" and "annual reductions in the use of natural gas of 0.75 percent of the average annual usage in the prior three years within five years of implementation of its gas energy efficiency program."[1] The CEA emphasizes the importance of EE and peak demand reduction ("PDR") and calls upon New Jersey's electric and gas public utilities to play an increased role in delivering EE and PDR programs to customers, with the aim to achieve the State's goal of 100% clean energy by 2050.

7. The CEA required the Board to complete a study to determine energy savings targets for each utility to achieve the full economic, cost effective potential for energy usage reductions and the timeframe to achieve those reductions. It also required the Board to adopt quantitative performance indicators ("QPIs") to establish utility targets for energy usage reduction and PDR, and to establish a stakeholder process to evaluate the economically achievable EE and PDR requirements, rate adjustments, QPIs, and the process for evaluating, measuring, and verifying energy usage reductions and peak demand reductions by the public utilities.

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[1] *P.L. 2018, c. 17, § 3(a) and (e)(1).*

CEF-EE PROGRAM

8. PSE&G filed for approval of its CEF-EE Program pursuant to Section 13 of the RGGI Law on October 11, 2018 (“CEF-EE Petition” or “Petition”). In accordance with the RGGI Law, the Company met with Board Staff and Rate Counsel on May 3, 2018 for a pre-filing meeting to discuss: (a) the nature of the EE program; (b) the program cost recovery mechanism to be proposed in the Petition; and (c) the minimum filing requirements (“MFRs”) to be submitted along with the Petition.

9. On November 14, 2018, Staff informed the Company that it found the CEF-EE Petition to be administratively deficient with respect to the MFRs for EE, renewable energy, and conservation programs ("Deficiency Letter"). In response to Staff's Deficiency Letter, the Company filed supplemental information on January 4, 2019 (“Supplemental Filing”). On January 9, 2019, Board Staff notified the Company that it reviewed the Petition for completeness and determined the Petition administratively complete, thereby establishing the Board’s 180-day review period. Accordingly, the Board’s 180-day review period under N.J.S.A. 48:3-98.1 commenced on January 7, 2019, with an expiration date of July 6, 2019.

10. The CEF-EE Program filing consisted of 22 sub-programs, including seven (7) residential subprograms, seven (7) commercial and industrial (“C&I”) sub-programs, and eight (8) pilot subprograms. The CEF-EE residential sub-programs were proposed to, among other initiatives, promote the purchase and installation of high-efficiency appliances through rebates and on-bill incentives; provide customers with energy audits and installation of EE measures; educate residential builders and developers on energy efficient home design and construction; and educate kindergarten through 12th grade students on EE. These residential sub-programs

were proposed to work together to upgrade efficiency in homes throughout PSE&G's service territory. The CEF-EE C&I sub-programs were proposed to, among other things, promote the installation of energy efficient equipment; advance efficient design and equipment installation for new buildings; optimize energy consumption in existing buildings; and upgrade all of PSE&G's existing high-pressure sodium cobra head streetlights to more efficient light emitting diode ("LED") streetlights. Lastly, the CEF-EE pilot sub-programs were proposed to implement and manage select, advanced approaches to EE that, after the conclusion of the pilot phase, may support future EE programs in New Jersey.

11. The total proposed investment for the CEF-EE Program was approximately $2.8 billion, including $2.5 billion for investment—including $86.2 million for information technology ("IT") investments—and approximately $283 million in administrative costs, including $28.9 million for IT run costs, over the proposed six (6) year term of the Program, with a proposed 15-year amortization period for residential and C&I program investments.

12. PSE&G proposed that the costs be recovered via a new CEF-EE Program component ("CEF-EEC") of the Company's electric and gas Green Programs Recovery Charge ("GPRC") that would be filed annually. PSE&G proposed to earn a return on its net investment based on its most recent weighted average cost of capital ("WACC").

13. Additionally, the Company requested Board approval of a decoupling mechanism for recovering lost revenues, the Green Enabling Mechanism ("GEM"), which would provide for the recovery or refund of the difference between actual revenue and the level of "allowed" revenue per customer established in the most recently completed base rate case.

14. Public notice was provided, and six (6) public hearings were held on the CEF-EE Program on the following dates at three (3) locations in PSE&G's service territory: two (2) hearings on March 13, 2019 in New Brunswick, New Jersey; two (2) hearings on March 18, 2019 in Mt. Holly, New Jersey; and two (2) hearings on March 21, 2019 in Hackensack, New Jersey.

15. The Company, Rate Counsel, and the Environmental Advocates pre-filed direct and rebuttal testimony of their witnesses, and discovery was conducted.

16. Evidentiary hearings were conducted on May 1 and 2, 2019 before Commissioner Diane Solomon.

17. Several stipulations were approved by Commissioner Solomon to extend the 180-day period for decision pursuant to N.J.S.A. 48:3-98.1: (a) by Order dated June 27, 2019—extending the period from July 6, 2019 until August 19, 2019; (b) by Order dated August 12, 2019—extending the period from August 19, 2019 until September 18, 2019; (c) by Order dated September 11, 2019—extending the 180-day period for Board action on the Company's CEF-EE Program from September 18, 2019 until March 16, 2020 and authorizing PSE&G to extend four (4) of the five (5) then-current EE 2017 sub-programs for one (1) year, with an additional $32.995 million of expenditures to be added to the existing EE 2017 component of the GPRC ("EE 2017 Extension I").

18. The Parties held settlement meetings on January 14, 29, February 5, 7, and 11, 2020, which culminated in an interim settlement and further extension. A fully executed stipulation was submitted to the BPU: 1) providing an extension of time for BPU action on the CEF-EE Petition until September 30, 2020; and 2) allowing the Company to continue all five (5) existing EE sub-programs through September 30, 2020, with an additional $111 million of program investment and

an additional $19 million for the Fixed Administrative Allowance and evaluation by outside contractors, to be recovered through the EE 2017 component of the Company's annual GPRC filing ("EE 2017 Extension II"). The Board approved that stipulation by Order dated February 19, 2020.

19. Pursuant to the requirements of the CEA, the Board undertook a process to develop a framework for establishing EE and PDR programs to reduce the use of electricity and natural gas in New Jersey.

20. As part of the Board's separate EE transition process applicable to all utility and State administered EE programs implemented pursuant to the CEA, the Board also established a stakeholder process to evaluate the economically achievable EE and PDR requirements, rate adjustments, QPIs, and the process for evaluating, measuring, and verifying energy usage reductions and peak demand reductions by the public utilities.

21. Following several stakeholder meetings regarding the EE Potential Study, the Board adopted the energy savings targets and QPIs as preliminary and approved establishment of an Energy Efficiency Advisory Group to participate in the ongoing EE transition stakeholder process related to the development of EE and PDR programs in New Jersey.

22. Board Staff considered and incorporated public comments and technical data received throughout the EE transition process in the refinement of a framework for EE and PDR programs. Staff also released proposals for comment on program administration and cost recovery and, ultimately, following the submission of comments, on March 20, 2020 issued the full Energy Efficiency Transition Straw Proposal.

23. Public comments were again considered prior to submission to the Board for approval, and on June 10, 2020, the Board accepted Staff's proposed framework ("Framework Order") for the performance targets, program administration, cost recovery (including lost revenue treatment), evaluation, measurement, verification ("EM&V"), and filing and reporting standards for implementation of New Jersey's EE and PDR programs.

24. The Framework Order allowed utilities the option of seeking a lost revenue adjustment mechanism ("LRAM") or the Conservation Incentive Program to address lost revenue recovery as called for in the CEA. With regard to the Conservation Incentive Program, the Framework Order states:

> ***Conservation Incentive Program ("CIP")***
> As an alternative to the LRAM, Staff recommends that utilities continue to be able to utilize or propose participation in the Conservation Incentive Program ("CIP"). The Board approved the current CIP in 2014 for NJNG and SJG, and it includes the following protections: (1) an earnings test, (2) rate caps on surcharges, (3) a Basic Gas Supply Service ("BGSS") Savings Test, and (4) required shareholder contributions.
>
> Staff recommends the following adjustments designed to make the CIP applicable to both gas and electric public utilities:
>
> - Removal of the BGSS Savings Test – which realizes savings as a result of contract Restructurings, contract terminations, reductions of capacity for periods of at least one year, and other gas procurement strategies designed to benefit customers – and incorporation of an alternative test, which may include a cost-effectiveness test. The BGSS Savings Test could not apply to electric public utilities due to the Basic Generation Service ("BGS") auction process and to the other non-participating gas public utilities since they do not manage their natural gas capacity portfolios.
>
> - Requirement that the utility calculate the difference between its baseline revenue per applicable customer, determined by the utility's most recent base rate case, and the actual revenue per applicable customer on a monthly basis. Staff recommends that the difference between the monthly baseline and actual revenue amount be tracked in a deferral account and be subject to review during an annual cost recovery true-up filing.

- Requirement that the utility file a base rate case no later than five years after commencement of an approved EE program in order to reset the baseline revenue per applicable customer, with the five year requirement satisfied if the utility has another base rate filing obligation.

As part of the modified CIP, the following protections would remain in place: (1) an earnings test, (2) rate caps on surcharges, (3) some form of a shareholder contribution; and (4) incorporation of an alternative to the BGSS Savings Test.

25. Following the Board's issuance of the Framework Order, the Parties recommenced settlement discussions concerning PSE&G's CEF-EE proposal.

26. The Company, Board Staff, Rate Counsel, and the intervening parties reached an agreement resolving all issues in the CEF-EE proceeding as guided by the principles set forth in the Framework Order and by the Joint Utility Working Group and the Utility Program Working Groups formed in connection with the EE transition process.

27. Following discovery, the filing of testimony, evidentiary hearings and several settlement conferences as described above, the Parties executed a stipulation of settlement ("Stipulation") resolving the CEF-EE matter on September 22, 2020.

28. The CEF-EE Order approved the CIP mechanism that is the subject of this proceeding consistent with Staff's recommendation of the CIP in the Framework Order as outlined in Paragraph 24.

<u>THE CIP</u>

29. The Stipulation, approved by the CEF-EE Order dated September 23, 2020, provided for the recovery of fixed costs and the potential for decline in revenue to account for lost sales revenue resulting from the decrease in customer energy usage. The recovery of lost revenues will be made via a CIP based on the methodology outlined below and detailed in the schedule for

electric, as noted in Attachments 6E to the Stipulation. As set forth fully in the Stipulation and its attachments, with respect to the CIP mechanism, the Company agreed as follows:

Shareholder Contribution

30. To implement initiatives to further customer conservation efforts, providing a funding amount ("shareholder contribution") of $3.3 million per year as long as the CIP remains in place, commencing with the start of the CIP deferrals, as defined below. All shareholder contribution expenditures will be allocated 55% to electric distribution (or approximately $1.8 million) and 45% to gas distribution (or approximately $1.5 million). Any under-spend in a year will be factored into the following year's spending amount. The shareholder contribution will not be included in customer rates. The shareholder contribution will support initiatives designed to aid customers in reducing their costs of natural gas and electricity and to reduce each utility's peak demand.

Filing/Tariff Details

31. In light of the COVID-19 pandemic, the parties to the CEF-EE Stipulation agreed that PSE&G would submit its first electric CIP cost recovery filing by February 1, 2022, for new rates effective June 1, 2022, based on an initial deferral period of June 1, 2021 through May 31, 2022 and that it would not book any ECIP deferral prior to June 1, 2021. The ECIP will be adjusted annually thereafter. The filings will document actual results, perform the required ECIP collection test described in more hereinafter, and

propose the new ECIP rate. Any variances from the annual filing will be trued-up in the subsequent year.

CIP Methodology

32. The monthly CIP deferrals will be calculated by way of the approved methodology as reflected in Attachments 5 and 6E to the Stipulation. For the ECIP, the baseline revenue per customer is based on the billing determinants from the 2018 base rate case and the latest variable margin rates per rate schedule, including any IIP rate adjustments. The baseline usage and margin rates will be updated with each subsequent base rate case or IIP rate adjustment.

33. For purposes of determining recovery eligibility for CIP accruals, the margin impact of changes in customer usage will be segregated into weather-related and non-weather-related components. The non-weather-related components will be limited by eligibility tests described in more detail below. The weather-related component will not be subject to those limitations.

34. The non-weather component will be calculated by first deducting the weather component. For electric, the weather impact will be calculated in a manner consistent with the methodology used for gas. PSE&G will establish sales coefficients based on 20 years of weather history of sales for residential customers only. The weather will be measured by the impacts on sales and associated distribution revenue of heating degree days ("HDD") for winter weather and the temperature humidity index ("THI") for

summer weather. The average of the 20 years of data for HDD and THI will be considered normal. The difference in actual and normal HDD and THI will be multiplied by the sales coefficients to establish sales impacts. The sales impacts will be multiplied by the current tariff rates to derive the revenue impact. The weather normalization methodology is detailed in Schedule 4 of Attachments 6E.

35. Recovery of non-weather related electric CIP impacts shall be subject to the application of two eligibility tests: a BGS Savings Test and a Variable Margin Test. In order to be eligible for recovery, non-weather related CIP impacts must pass both cost recovery tests. A description of the eligibility tests is provided in the testimony of Stephen Swetz (BGS Savings Test) and Michael McFadden (Variable Margin Test).

36. The dual cost recovery tests set forth above shall operate in conjunction with each other so that the total non-weather recoverable amount is limited to the smaller of the two (2) recoverable amounts allowed under the separate BGS Savings Test and Variable Margin Test for Electric. Any amounts that exceed the BGS Savings Test and/or Variable Margin Test may be deferred for future recovery subject to the earnings test described below. The Company has agreed to not seek recovery of interest on any deferred carry-forward amount.

Earnings Test

37. The parties to the CEF-EE stipulation agreed to include an earnings test, through which actual ROE shall be determined based on the actual net income of the utility for the most recent 12-month period divided by the average of the beginning and ending common equity balances for the corresponding period. The timing of the earnings test and definitions of Net Income and Common Equity are specified in the ECIP Tariffs provided in Attachment 5. The earnings test will be applicable to the total CIP deferral, including weather and non-weather components. If the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period and shall not be carried over to subsequent filing periods.

REQUEST FOR COST RECOVERY

38. Consistent with the CEF-EE Order, PSE&G is seeking BPU approval to implement a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer.

39. Per the CEF-EE Order, the electric baseline revenue per customer is based on the billing determinants from the 2018 base rate case and the latest variable margin rates per rate schedule, including any Infrastructure Investment Program ("IIP") rate adjustments. The latest variable margin revenue for this filing is based on the Energy Strong II rate adjustment approved on April 27, 2021 for new rates effective May 1, 2021 in Docket No. ER20120736.

40. Attachment B is the testimony of Michael P. McFadden, PSE&G's Director of Sales and Revenue Forecasting, providing an overview of the CIP mechanism, the calculation of weather impacts for the current CIP period from June 1, 2021 – May 31, 2022, and the calculation of the Variable Margin Test. Attachment C is the testimony of Karen B. Reif, PSE&G's Vice President of Renewables and Energy Solutions, providing the spending activity related to the CIP Shareholder Contribution ("SC") over the past several months, an update on the SC expenditures to date, and an explanation of how the Company plans to show the SC spending for both its natural gas and electric CIP. Attachment D is the testimony of Steven Swetz, Senior Director of Corporate Rates and Revenue Requirements for PSEG Services Corporation supporting the rate calculation for the current CIP period.

41. The CIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline revenue per customer from the actual revenue per customer and multiplying the resulting revenue per customer by the actual number of customers for the month.

42. The Company's total deferral for the electric CIP ("ECIP") is $51,551,188, representing $72,568,455 of non-weather related electric distribution margin deficiencies partially offset by a refund due to customers of $21,017,267 related to weather related electric distribution margin.

43. As required by the CEF-EE Order and Stipulation, the proposed electric rate adjustment is limited by a Variable Margin Test. *See* the testimony of Michael P. McFadden for a description and the results of the Variable Margin Test at Attachment A, Schedule 5.

44. The application of the Variable Margin Test resulted in the Company's ECIP recovery of non-weather related distribution margin deficiencies totaling $72,568,455 being limited to $38,767,864.

45. The net ECIP amounts to $17,750,598—representing $38,767,864 of allowed margin recovery partially offset by weather related refunds to residential customers totaling $21,017,267. As a result of the limitation on allowed margin revenue recovery a remaining $33,800,591 of distribution margin deficiency will be deferred for recovery in a future CIP period

46. The ECIP rates are summarized below:

		ECIP Rates Without SUT	**ECIP Rates with SUT**	
Group I	RS & RHS	($0.001108)	($0.001181)	Per kilowatt-hour
Group Ia	RLM	($0.000598)	($0.000638)	Per kilowatt-hour
Group II	GLP	$0.6371	$0.6793	Per kilowatt of monthly peak demand
Group III	LPL-S	$0.6108	$0.6513	Per kilowatt of monthly peak demand

See, Attachment D Schedule SS-ECIP-2.

47. Based upon rates effective February 1, 2022, the annual average bill impacts of the rates requested are set forth in Schedule SS-ECIP-3.

48. The annual impact of the proposed rates to the typical residential electric customer using 740 kWh in a summer month and 6,920 kWh annually would be a decrease in the annual bill from $1,279.64 to $1,271.52 or $8.12, or approximately 0.63% (based upon Delivery Rates and BGS-RSCP charges in effect February 1, 2022 and assuming that the customer receives BGS-RSCP service from PSE&G).

49. Attachment E is a draft Form of Notice of Filing and of Public Hearings (Form of Notice). This Form of Notice will be placed in newspapers having a circulation within the Company's electric service territory upon scheduling of public hearing dates. A Notice will be served on the County Executives and Clerks of all municipalities within the Company's electric service territory upon scheduling of public hearing dates.

50. In accordance with the Board's recent Covid-19 order, [2] notice of this filing, the Petition, testimony, and schedules will be served upon the Division of Law, Public Utilities Section, R.J. Hughes Justice Complex, 25 Market St. 7th Floor West, PO Box 112, Trenton, NJ 08625and upon the Director, Division of Rate Counsel, 140 East Front Street 4th Floor, Trenton, N.J. 08625 by electronic mail. Electronic copies of the Petition, testimony, and schedules will also be sent to the persons identified on the service list provided with this filing.

51. PSE&G requests that the Board find the proposed rates show in the tariff sheets included herein at Attachment D, Schedule SS-ECIP-4, are just and reasonable and PSE&G should be authorized to implement the proposed rates as set forth herein, on a provisional basis effective June 1, 2022 per the CEF-EE Stipulation, upon issuance of a written BPU order.

52. Any final rate relief found by the Board to be just and reasonable may be allocated by the Board for consistency with the provisions of *N.J.S.A.* 48:2-21 and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the average percentage changes in final rates may increase or decrease compared to the proposed rates based upon the Board's decision.

[2] *See In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic for a Temporary Waiver of the Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, dated March 19, 2020.

COMMUNICATIONS

53. Communications and correspondence related to the Petition should be sent as follows:

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CONCLUSION AND REQUESTS FOR APPROVAL

For all the foregoing reasons, PSE&G respectfully requests that the Board retain jurisdiction of this matter and review and expeditiously issue an order approving this Petition specifically finding that:

1. PSE&G is authorized to receive the ECIP rate adjustment associated with the CIP period from June 1, 2021 – May 31, 2022, as reflected in this Petition and accompanying materials, along with anticipated updates of data; and

2. The rates shown in the tariff sheets included herein Attachment D, Schedule SS-ECIP-4, are just and reasonable and PSE&G should be authorized to implement the proposed rates as set forth herein, on a provisional basis effective June 1, 2022 per the CEF-EE Stipulation, upon issuance of a written BPU order.

3. Any amount not recovered in the current ECIP period will be deferred for recovery in a subsequent ECIP proceeding.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By ______________________________

Danielle Lopez
Assistant Counsel - Regulatory
PSEG Services Corp.
80 Park Plaza, T10
P. O. Box 570
Newark, New Jersey 07102

DATED: February 1, 2022

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF	**)**	
PUBLIC SERVICE ELECTRIC AND GAS	**)**	
COMPANY FOR APPROVAL OF CHANGES	**)**	**BPU DOCKET NO. __________**
IN ITS ELECTRIC CONSERVATION	**)**	
INCENTIVE PROGRAM	**)**	
(2022 PSE&G ELECTRIC CIP RATE	**)**	
FILING)	**)**	

CERTIFICATION

I, Michael P. McFadden, of full age, certifies as follows:

1. I am Director of Sales and Revenue Forecasting for PSEG Services Corporation.

2. I have read the contents of the foregoing Petition, and the information contained therein are true and correct to the best of my knowledge, information, and belief.

BY: ________________________________
Michael P. McFadden

Electric Conservation Incentive Program (CIP)

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Public Service Electric and Gas
Conservation Incentive Program
Group I: Residential Service RS and RHS

Customer Class (a)	Actual/ Estimate	Actual per Books[1] Total Class Variable Revenues (b)	Number of Customers (c)	Actual Avg. Revenue / Cust. (d) = (b) / (c)	Baseline Revenue / Cust.[2] (e)	Difference (f) = (d) - (e)	Margin Variance (g) = (c) * (f)
Residential							
Jun-21	Act	59,756,285	1,947,048	30.7	30.3	0.4	$828,108
Jul-21	Act	73,547,682	1,958,721	37.6	37.6	(0.1)	($189,163)
Aug-21	Act	72,204,852	1,951,294	37.0	34.8	2.2	$4,274,562
Sep-21	Act	42,040,513	1,956,381	21.5	21.4	0.1	$233,212
Oct-21	Act	28,458,218	1,958,765	14.5	13.8	0.7	$1,459,206
Nov-21	Act	29,285,891	1,960,821	14.9	15.0	(0.0)	($80,905)
Dec-21	Est	33,814,923	1,965,332	17.2	18.6	(1.4)	($2,677,637)
Jan-22	Est	42,274,779	1,952,094	21.7	20.6	1.059	$2,067,071
Feb-22	Est	34,241,932	1,951,155	17.6	17.1	0.5	$964,572
Mar-22	Est	32,131,115	1,950,776	16.5	16.4	0.1	$160,962
Apr-22	Est	27,228,015	1,953,517	13.9	14.0	(0.0)	($72,981)
May-22	Est	31,966,661	1,954,346	16.4	15.4	0.9	$1,821,310
Total		506,950,866		259.4	254.9	4.5	$8,788,316

Margin Deficiency/ (Credit)	$	(8,788,316)
Prior Period (Over) / Under Recovery[3]	$	-
Total Deficiency/(Credit)	$	(8,788,316)
Projected Residential kWh Use		12,980,585,338
Pre-tax CIP Charge/(Credit) per kWh	$	(0.0007)
BPU/RC Assessment Factor		1.002700
CIP Charge/(Credit) including assessments	$	(0.000679)
6.625% Sales Tax	$	(0.000045)
Proposed After-tax CIP Charge/(Credit) per kWh	**$**	**(0.000724)**
Current After-tax CIP Charge/(Credit) per kWh	$	-
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kWh	$	(0.000724)

[1] Per Exhibit C, Schedule 1, Page 2
[2] From latest base rate adjustment from Energy Strong II divided by billing determinants approved in the 2018 Base Rate Case
[3] Per Exhibit C, Schedule 1, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group I: Residential Service RS and RHS

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Act Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Est May-22	
Customers													
Service Charge Revenues	9,034,303	9,088,464	9,054,003	9,077,609	9,088,671	9,098,211	9,119,142	9,057,716	9,053,359	9,051,601	9,064,319	9,068,165	
Service Charge Rate (pre-tax)	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	
Total Customers	1,947,048	1,958,721	1,951,294	1,956,381	1,958,765	1,960,821	1,965,332	1,952,094	1,951,155	1,950,776	1,953,517	1,954,346	1,955,021
Volumes													
RS kWh	1,430,197,558	1,758,678,770	1,732,596,405	1,103,208,144	857,015,021	873,988,571	1,008,338,487	1,258,473,622	1,019,359,232	957,273,899	812,688,296	852,199,217	
RHS kWh	5,803,568	6,091,808	6,362,276	4,676,703	4,369,179	8,072,184	9,449,354	15,738,517	12,053,826	9,468,294	4,973,881	3,447,503	
Total Volumes	1,436,001,125	1,764,770,579	1,738,958,681	1,107,884,847	861,384,201	882,060,755	1,017,787,842	1,274,212,139	1,031,413,058	966,742,193	817,662,177	855,646,720	7,372,846,904

ILLUSTRATIVE PURPOSES ONLY

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group I: Residential Service RS and RHS
June 2021 - May 2022

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Est Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Act May-22	TOTAL
Beginning Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
kWh Sales	1,436,001,125	1,764,770,579	1,738,958,681	1,107,884,847	861,384,201	882,060,755	1,017,787,842	1,274,212,139	1,031,413,058	966,742,193	817,662,177	855,646,720	13,754,524,315
Pre-tax Recovery Rate per kWh[1]	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0

[1] Pre-tax Recovery Rate per therm excluding BPU and RC assessments.

Public Service Electric and Gas
Conservation Incentive Program
Group Ia: Residential Load Management (RLM)
June 2021 - May 2022

		Actual per Books[1]					
	Actual/	Total Class	Number of	Actual Avg.	Baseline		Margin
Customer Class	Estimate	Revenues	Customers	Revenue / Cust.	Revenue / Cust.[2]	Difference	Variance
(a)		(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	
Residential Load Management							
Jun-21	Act	914,413	11,766	77.7	87.9	(10.2)	($119,982)
Jul-21	Act	1,089,419	11,434	95.3	99.6	(4.3)	($48,978)
Aug-21	Act	1,145,188	11,880	96.4	93.4	2.9	$34,991
Sep-21	Act	489,140	11,610	42.1	42.7	(0.6)	($6,487)
Oct-21	Act	171,538	11,609	14.8	16.9	(2.1)	($24,331)
Nov-21	Act	176,841	11,481	15.4	15.5	(0.1)	($616)
Dec-21	Est	208,706	11,513	18.1	19.9	(1.8)	($20,424)
Jan-22	Est	256,855	11,600	22.1	21.7	0.5	$5,459
Feb-22	Est	223,212	11,788	18.9	18.9	0.1	$816
Mar-22	Est	214,888	11,848	18.1	18.1	0.0	$494
Apr-22	Est	178,638	11,668	15.3	14.3	1.0	$11,691
May-22	Est	314,774	11,432	27.5	18.5	9.1	$103,718
Total		5,383,611		461.9	467.3	(5.4)	($63,650)

Margin Deficiency/ (Credit)	$ 63,650
Prior Period (Over) / Under Recovery[3]	$ -
Total Deficiency/(Credit)	$ 63,650
Projected Residential kWh Use	181,822,367
Pre-tax CIP Charge/(Credit) per kWh	$ 0.0004
BPU/RC Assessment Factor	1.002700
CIP Charge/(Credit) including assessments	$ 0.000351
6.625% Sales Tax	$ 0.000023
Proposed After-tax CIP Charge/(Credit) per kWh	**$ 0.0004**
Current After-tax CIP Charge/(Credit) per kWh	$ -
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kWh	$ 0.0004

[1] Per Exhibit C, Schedule 1a, Page 2
[2] From latest base rate adjustment from Energy Strong II divided by billing determinants approved in the 2018 Base Rate Case
[3] Per Exhibit C, Schedule 1, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group Ia: RLM

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Act Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Est May-22	
Customers													
Service Charge Revenues	153,778	149,439	155,274	151,745	151,732	150,057	150,470	151,612	154,069	154,853	152,501	149,416	
Service Charge Rate (pre-tax)	13.07	13.07	13.07	13.07	13.07	13.07	13.07	13.07	13.07	13.07	13.07	13.07	
Total Customers	11,766	11,434	11,880	11,610	11,609	11,481	11,513	11,600	11,788	11,848	11,668	11,432	
Volumes													
RLM kWh	22,335,584	25,883,670	25,987,127	16,567,192	11,952,148	11,831,865	13,974,247	17,115,663	14,873,874	14,319,211	11,903,672	12,273,210	
Total Volumes	22,335,584	25,883,670	25,987,127	16,567,192	11,952,148	11,831,865	13,974,247	17,115,663	14,873,874	14,319,211	11,903,672	12,273,210	199,017,462

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group Ia: Residential Load Management (RLM)
June 2021 - May 2022

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Est Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Act May-22	TOTAL
Beginning Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
kWh Sales	25,883,670	25,987,127	16,567,192	11,952,148	11,831,865	13,974,247	17,115,663	14,873,874	14,319,211	11,903,672	12,273,210	22,335,584	199,017,462
Pre-tax Recovery Rate per kWh[1]	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0

[1] Pre-tax Recovery Rate per therm excluding BPU and RC assessments.

Public Service Electric and Gas
Conservation Incentive Program
Group II: General Power & Light (GLP)
June 2021 - May 2022

Customer Class	Actual/ Estimate	Actual per Books[1] Total Class Revenues	Number of Customers	Actual Avg. Revenue / Cust.	Baseline Revenue / Cust.[2]	Difference	Margin Variance
(a)		(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	
General Power & Light							
Jun-21	Act	32,195,639	274,238	117	130	(12.1)	($3,327,034)
Jul-21	Act	35,976,484	276,160	130	149	(19.0)	($5,259,709)
Aug-21	Act	35,077,383	277,516	126	145	(18.1)	($5,029,930)
Sep-21	Act	24,375,723	275,424	89	90	(1.7)	($480,661)
Oct-21	Act	13,191,029	275,088	48	54	(6.4)	($1,755,954)
Nov-21	Act	11,201,355	276,222	41	48	(7.9)	($2,186,202)
Dec-21	Est	11,342,061	275,719	41	48	(7.2)	($1,998,312)
Jan-22	Est	12,473,641	276,334	45	52	(6.7)	($1,843,233)
Feb-22	Est	11,745,717	276,283	43	49	(7.0)	($1,922,560)
Mar-22	Est	12,230,056	277,629	44	50	(5.5)	($1,521,729)
Apr-22	Est	11,450,856	283,966	40	49	(8.7)	($2,482,254)
May-22	Est	20,682,200	280,204	74	87	(13.5)	($3,785,133)
Total		231,942,144		838	952	(114.0)	($31,592,710)

Margin Deficiency/ (Credit)	$ 31,592,710
Prior Period (Over) / Under Recovery[3]	$ -
Total Deficiency/(Credit)	$ 31,592,710
Projected GLP Annual kW Use	26,561,410
Pre-tax CIP Charge/(Credit) per kW	$ 1.1894
BPU/RC Assessment Factor	1.002700
CIP Charge/(Credit) including assessments	$ 1.1926
6.625% Sales Tax	$ 0.0790
Proposed After-tax CIP Charge/(Credit) per kW	**$ 1.2716**
Current After-tax CIP Charge/(Credit) per kW	$ -
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kW	$ 1.2716

[1] Per Exhibit C, Schedule 2, Page 2
[2] From latest base rate adjustment from Energy Strong II divided by billing determinants approved in the 2018 Base Rate Case
[3] Per Exhibit C, Schedule 2, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group II: General Power & Light (GLP)

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Act Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Est May-22	
Customers													
Service Charge Revenues	1,241,797	1,250,358	1,260,650	1,244,787	1,245,421	1,252,532	1,257,976	1,264,641	1,265,196	1,269,650	1,299,401	1,309,163	
Service Charge Rate (pre-tax)	4.53	4.53	4.54	4.52	4.53	4.53	4.56	4.58	4.58	4.57	4.58	4.67	
Total Customers	274,238	276,160	277,516	275,424	275,088	276,222	275,719	276,334	276,283	277,629	283,966	280,204	
Demand													
GLP Annual kW	2,284,480	2,530,972	2,554,753	2,347,867	2,226,903	2,039,340	2,013,801	2,046,179	1,966,865	2,061,325	1,979,287	2,273,971	
Total Demand	2,284,480	2,530,972	2,554,753	2,347,867	2,226,903	2,039,340	2,013,801	2,046,179	1,966,865	2,061,325	1,979,287	2,273,971	26,325,743

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group II: General Power & Light (GLP)
June 2021 - May 2022

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Est Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Act May-22	TOTAL
Beginning Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
kW Demand	2,530,972	2,554,753	2,347,867	2,226,903	2,039,340	2,013,801	2,046,179	1,966,865	2,061,325	1,979,287	2,273,971	2,284,480	26,325,743
Pre-tax Recovery Rate per kW[1]	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0

[1] Pre-tax Recovery Rate per therm excluding BPU and RC assessments.

Public Service Electric and Gas
Conservation Incentive Program
Group III: Large Power & Light - Seconday (LPLS)
June 2021 - May 2022

		Actual per Books[1]					
Customer Class	Actual/ Estimate	Total Class Therms	Number of Customers	Actual Avg. Use / Cust.	Baseline Use / Cust.[2]	Difference	Margin Variance
(a)		(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	
Large Power & Light - Secondary							
Jun-21	Act	25,501,665	9,087	2,806	2,670	137	$1,243,447
Jul-21	Act	29,156,481	9,391	3,105	3,911	(807)	($7,574,398)
Aug-21	Act	30,684,967	9,364	3,277	3,949	(671)	($6,287,434)
Sep-21	Act	20,855,103	9,325	2,236	2,218	19	$172,796
Oct-21	Act	10,381,252	9,190	1,130	1,611	(481)	($4,419,189)
Nov-21	Act	7,648,978	9,310	822	1,001	(179)	($1,666,857)
Dec-21	Est	7,336,849	9,330	786	857	(70)	($656,630)
Jan-22	Est	6,883,596	9,336	737	919	(181)	($1,692,219)
Feb-22	Est	6,809,477	9,516	716	921	(205)	($1,954,736)
Mar-22	Est	7,236,266	9,557	757	922	(165)	($1,580,029)
Apr-22	Est	6,826,913	9,499	719	879	(160)	($1,521,648)
May-22	Est	13,555,073	9,547	1,420	1,707	(288)	($2,746,247)
Total		172,876,620		18,511	21,564	(3,053)	($28,683,145)

Margin Deficiency/ (Credit)	$ 28,683,145
Prior Period (Over) / Under Recovery[3]	$ -
Total Deficiency/(Credit)	$ 28,683,145
Projected LPLS Annual kW Use	25,153,822
Pre-tax CIP Charge/(Credit) per kW	$ 1.1403
BPU/RC Assessment Factor	1.002700
CIP Charge/(Credit) including assessments	$ 1.1434
6.625% Sales Tax	$ 0.0758
Proposed After-tax CIP Charge/(Credit) per kW	**$ 1.2192**
Current After-tax CIP Charge/(Credit) per kW	$ -
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kW	$ 1.2192

[1] Per Exhibit C, Schedule 3, Page 2
[2] From latest base rate adjustment from Energy Strong II divided by billing determinants approved in the 2018 Base Rate Case
[3] Per Exhibit C, Schedule 3, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group III: LPLS

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Act Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Est May-22	
Customers													
Service Charge Revenues	3,160,107	3,265,995	3,256,379	3,242,980	3,195,918	3,237,690	3,244,593	3,246,781	3,309,379	3,323,638	3,303,467	3,320,160	
Service Charge Rate (pre-tax)	348	348	348	348	348	348	348	348	348	348	348	348	
Total Customers	9,087	9,391	9,364	9,325	9,190	9,310	9,330	9,336	9,516	9,557	9,499	9,547	
Demand													
LPLS kW	2,309,065	2,470,399	2,527,955	2,382,609	2,266,377	1,994,922	2,024,471	1,938,986	1,918,108	2,038,327	1,923,020	2,141,258	
Total Demand	2,309,065	2,470,399	2,527,955	2,382,609	2,266,377	1,994,922	2,024,471	1,938,986	1,918,108	2,038,327	1,923,020	2,141,258	25,935,498

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group III: Large Power & Light - Seconday (LPLS)
June 2021 - May 2022

	Act Jun-21	Act Jul-21	Act Aug-21	Act Sep-21	Act Oct-21	Act Nov-21	Est Dec-21	Est Jan-22	Est Feb-22	Est Mar-22	Est Apr-22	Act May-22	TOTAL
Beginning Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
kW Demand	2,470,399	2,527,955	2,382,609	2,266,377	1,994,922	2,024,471	1,938,986	1,918,108	2,038,327	1,923,020	2,141,258	2,309,065	25,935,498
Pre-tax Recovery Rate per kW[1]	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Under/(Over) Recovery $	0	0	0	0	0	0	0	0	0	0	0	0	0

[1] Pre-tax Recovery Rate per therm excluding BPU and RC assessments.

Attachment A
Schedule 4

Public Service Electric and Gas
Conservation Incentive Program
Weather Normalization Calculation

Group I
RS

		DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	DEGREE DAYS VARIANCE	HDD CONSUMPTION FACTOR	DEGREE DAYS kWh	THI NORMAL	THI ACTUAL	THI VARIANCE	THI CONSUMPTION FACTOR	THI kWh	TOTAL kWh	MARGIN FACTOR[2]	MARGIN IMPACT
Jun-21	Act	0	0	0	455,913	0	2,993	4,364	1,371	154,354	211,648,898	211,648,898	$0.0413	$8,746,146
Jul-21	Act	0	0	0	458,664	0	5,507	5,796	289	155,285	44,880,556	44,880,556	$0.0413	$1,854,637
Aug-21	Act	0	0	0	456,939	0	4,847	6,238	1,391	154,701	215,121,421	215,121,421	$0.0413	$8,889,644
Sep-21	Act	0	0	0	458,141	0	2,174	2,845	671	155,108	104,040,567	104,040,567	$0.0413	$4,299,356
Oct-21	Act	236	80	(156)	458,714	(71,366,713)	391	811	420	155,302	65,172,638	(6,194,075)	$0.0333	($206,535)
Nov-21	Act	516	521	5	459,202	2,204,170	0	0	0	155,468	0	2,204,170	$0.0333	$73,496
Dec-21	Est	818	629	(189)	460,274	(87,203,534)	0	0	0	155,831	0	(87,203,534)	$0.0333	($2,907,715)
Jan-22	Est	992	992	0	475,206	0	0	0	0	154,756	0	0	$0.0333	$0
Feb-22	Est	833	833	0	474,987	0	0	0	0	154,685	0	0	$0.0333	$0
Mar-22	Est	693	693	0	474,902	0	0	0	0	154,657	0	0	$0.0333	$0
Apr-22	Est	357	357	0	475,583	0	189	189	0	154,879	0	0	$0.0333	$0
May-22	Est	128	128	0	475,790	0	926	926	0	154,946	0	0	$0.0333	$0
TOTAL		4,573	4,233	-340		-156,366,078	17,027	21,169	4,141		640,864,079	484,498,002		$20,749,029

Group I
RHS

		DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	DEGREE DAYS VARIANCE	HDD CONSUMPTION FACTOR	DEGREE DAYS kWh	THI NORMAL	THI ACTUAL	THI VARIANCE	THI CONSUMPTION FACTOR	THI kWh	TOTAL kWh	MARGIN FACTOR[2]	MARGIN IMPACT
Jun-21	Act	0	0	0	12,929	0	2,993	4,364	1,371	514	704,935	704,935	$0.0513	$36,130
Jul-21	Act	0	0	0	12,881	0	5,507	5,796	289	512	148,031	148,031	$0.0513	$7,587
Aug-21	Act	0	0	0	12,728	0	4,847	6,238	1,391	506	703,740	703,740	$0.0513	$36,069
Sep-21	Act	0	0	0	12,676	0	2,174	2,845	671	504	338,095	338,095	$0.0513	$17,329
Oct-21	Act	236	80	(156)	12,586	(1,958,078)	391	811	420	500	210,010	(1,748,068)	$0.0332	($58,095)
Nov-21	Act	516	521	5	12,550	60,241	0	0	0	499	0	60,241	$0.0332	$2,002
Dec-21	Est	818	629	(189)	12,461	(2,360,916)	0	0	0	495	0	(2,360,916)	$0.0332	($78,463)
Jan-22	Est	992	992	0	12,919	0	0	0	0	514	0	0	$0.0332	$0
Feb-22	Est	833	833	0	12,843	0	0	0	0	511	0	0	$0.0332	$0
Mar-22	Est	693	693	0	12,787	0	0	0	0	508	0	0	$0.0332	$0
Apr-22	Est	357	357	0	12,712	0	189	189	0	505	0	0	$0.0332	$0
May-22	Est	128	128	0	12,681	0	926	926	0	504	0	0	$0.0332	$0
TOTAL		4,573	4,233	-340		-4,258,753	17,027	21,169	4,141		2,104,811	(2,153,942)		($37,441)

Group Ia
RLM

		DEGREE DAYS NORMAL	DEGREE DAYS ACTUAL	DEGREE DAYS VARIANCE	HDD CONSUMPTION FACTOR	DEGREE DAYS kWh	THI NORMAL	THI ACTUAL	THI VARIANCE	THI CONSUMPTION FACTOR	THI kWh	TOTAL kWh	MARGIN FACTOR[2]	MARGIN IMPACT
Jun-21	Act	0	0	0	6,365	0	2,993	4,364	1,371	2,070	2,838,769	2,838,769	$0.0422	$119,761
Jul-21	Act	0	0	0	6,185	0	5,507	5,796	289	2,012	581,474	581,474	$0.0422	$24,531
Aug-21	Act	0	0	0	6,427	0	4,847	6,238	1,391	2,090	2,906,877	2,906,877	$0.0422	$122,635
Sep-21	Act	0	0	0	6,281	0	2,174	2,845	671	2,043	1,370,314	1,370,314	$0.0422	$57,810
Oct-21	Act	236	80	(156)	6,280	(977,074)	391	811	420	2,043	857,238	(119,835)	$0.0150	($1,798)
Nov-21	Act	516	521	5	6,211	29,812	0	0	0	2,020	0	29,812	$0.0150	$447
Dec-21	Est	818	629	(189)	6,228	(1,179,953)	0	0	0	2,026	0	(1,179,953)	$0.0150	($17,708)
Jan-22	Est	992	992	0	6,275	0	0	0	0	2,041	0	0	$0.0150	$0
Feb-22	Est	833	833	0	6,377	0	0	0	0	2,074	0	0	$0.0150	$0
Mar-22	Est	693	693	0	6,409	0	0	0	0	2,085	0	0	$0.0150	$0
Apr-22	Est	357	357	0	6,312	0	189	189	0	2,053	0	0	$0.0150	$0
May-22	Est	128	128	0	6,184	0	926	926	0	2,012	0	0	$0.0150	$0
TOTAL		4,573	4,233	-340		-2,127,214	17,027	21,169	4,141		8,554,672	6,427,458		$305,679

Total
All Groups

		TOTAL kWh	MARGIN IMPACT
Jun-21	Act	215,192,602	8,902,037
Jul-21	Act	45,610,061	1,886,755
Aug-21	Act	218,732,038	9,048,347
Sep-21	Act	105,748,976	4,374,495
Oct-21	Act	(8,061,979)	(266,429)
Nov-21	Act	2,294,223	75,945
Dec-21	Est	(90,744,403)	(3,003,885)
Jan-22	Est	0	0
Feb-22	Est	0	0
Mar-22	Est	0	0
Apr-22	Est	0	0
May-22	Est	0	0
TOTAL		488,771,517	$21,017,267

Public Service Electric and Gas
Conservation Incentive Program Filing
June 2021 - May 2022
CIP Recovery Tests
Summary

Determine Weather and Non-Weather CIP Impacts

	Weather	Non-Weather	Total
CIP Group I RS RHS	$ (20,711,587)	$ 11,923,271	$ (8,788,316)
CIP Group II RLM	$ (305,679)	$ 369,329	$ 63,650
CIP Group III GLP	$ -	$ 31,592,710	$ 31,592,710
CIP Group IV LPLS	$ -	$ 28,683,145	$ 28,683,145
Total Deficiency/(Credit)	$ (21,017,267)	$ 72,568,455	$ 51,551,188

Step 2: Apply Modified BGS Savings Test

A. Non-weather Impact Subject to Modified BGS Savings Test

Non-Weather Impact	$ 72,568,455
75% Factor	75%
Subtotal	$ 54,426,341
Prior Year Carry-Forward (Modified BGS Savings Test)	$ -
Non-weather Impact Subject to Test	**$ 54,426,341**

B. BGS Savings

Permanent Capacity Savings (Exhibit C, Schedule 6, Page 3)	$ 64,505,906
Additional Capacity BGS Savings (Exhibit C, Schedule 6, Page 3)	$ 22,874,564
Avoided Cost BGS Savings (Exhibit C, Schedule 6, Page 4)	$ 35,300,907
Total BGS Savings	**$ 122,681,377**

C. Results

Non-Weather Impacts Passing Test (current accrual)	**$ 72,568,455**
Non-Weather Impacts Passing Test (prior year carry-forward)	**$ -**
Non-Weather Impacts Exceeding Test	**$ -**

Public Service Electric and Gas
Conservation Incentive Program Filing
June 2021 - May 2022
CIP Recovery Tests
Summary

Step 3: Apply Variable Margin Revenue Test

A. Non-weather Impact Subject to Variable Margin Revenue Test		
Non-Weather Impact	$ 72,568,455	
Prior Year Carry-Forward (Variable Margin Revenue Test)	$ -	
Non-weather Impact Subject to Test	**$ 72,568,455**	
B. Variable Margin Revenues		
Variable Margin Revenues (Exhibit C, Schedule 6, Page 5)	$ 969,196,611	
Factor	4.0%	
Total Fixed Recovery Cap	**$ 38,767,864**	
C. Results		
Non-Weather Impacts Passing Test (current accrual)	**$ 38,767,864**	
Non-Weather Impacts Passing Test (prior year carry-forward)	**$ -**	
Non-Weather Impacts Exceeding Test	**$ 33,800,591**	

Step 4: Determine Recoverable Non-Weather CIP Impacts

A. Current Year Accrual Recoverable Non-Weather Impacts		
Amount Passing Modified BGSS Savings Test	$ 72,568,455	
Amount Passing Variable Margin Revenue Test	$ 38,767,864	
Recoverable Amount		**$ 38,767,864**
B. Previous Carry-Forward Recoverable Amounts		
Amount Passing Modified BGSS Savings Test		**$ -**
Amount Passing Variable Margin Revenue Test	$ -	
Deduction for any amount also included in above	$ -	
		$ -
Total Non-Weather Recoverable CIP Amount		**$ 38,767,864**

Public Service Electric and Gas
CIP Recovery Tests
CIP BGS Savings

I. Permanent BGS Savings

Year	WN Summer Peak	Final Zonal UCAP Obligation	PS Zonal Net Load Price $/MW-Day	PS Zonal Net Load Price $/kW-yr
2011/2012	10,340	12,333	$116.15	$42.42
2012/2013	10,150	11,645	$157.73	$57.61
2013/2014	10,100	11,629	$248.30	$90.69
2014/2015	10,120	11,564	$170.95	$62.44
2015/2016	10,160	11,398	$166.29	$60.74
2016/2017	9,490	11,043	$224.70	$82.07
2017/2018	9,530	10,932	$208.59	$76.19
2018/2019	9,450	11,272	$218.96	$79.97
2019/2020	9,370	11,281	$115.83	$42.31
2020/2021	9,480	11,320	$174.32	$63.67

Permanent Capacity Savings	1,013
2021 PS Zonal Net Load Capacity Cost per kW-year	$63.67

Total Permanent Reductions **$64,505,906**

II. Additional Capacity BGS Savings

CIP Recovery

Year	WN Summer Peak	Final Zona lUCAP Obligation	PS Zonal Net Load Price $/MW-Day
2020/2021	9,480	11,320	$63.67
2021/2022*	9,410	10,987	$68.84

Incremental Capacity Savings*	332
PS Zonal Net Load Capacity Cost per kW-year	$68.84

Total Additional Capacity Reductions **$ 22,874,564**

* Due to the potential for Peak increases due to Electric Vehicles and Electrification, incremental savings is set as a minimum of the incremental obligation savings or zero

III. Avoided Capacity

CIP Recovery Year	Annual $
2021/2022	**$ 35,300,907**

VI. Total of all Savings

CIP Recovery Year	Permanent Capacity Savings	Additional Capacity BGSS Savings	Avoided Cost BGSS Savings	Annual $
2021/2022	$ 64,505,906	$ 22,874,564	$ 35,300,907	**$ 122,681,377**

Public Service Electric and Gas
CIP Recovery Tests
Avoided Capacity Cost BGS Savings

Month (a)	Base Year Customer Count (b)	Current Year Customer Count (c)	Net Increase/ (Decrease) Customer Count (d) = (b) / (c)	Base Year Unforced Capacity / Customer (kW) (e)	Current Year Capacity Rate / Cust. ($/kW) (f)	Avoided Capacity (g) = (d) * (e) * (f)
Group 1: RS						
June	1,882,438	1,947,048	70,987	2.4	$5.65	953,125
July	1,876,061	1,958,721	93,218	2.4	$5.84	1,297,743
August	1,865,502	1,951,294	78,791	2.4	$5.84	1,103,101
September	1,872,503	1,956,381	83,213	2.4	$5.65	1,123,215
October	1,873,168	1,958,765	85,900	2.4	$5.84	1,197,707
November	1,872,865	1,960,821	74,273	2.4	$5.65	1,002,349
December	1,886,548	1,965,332	74,738	2.4	$5.84	1,034,681
January	1,890,595	1,952,094	72,006	2.4	$5.84	994,725
February	1,880,088	1,951,155	98,783	2.4	$5.28	1,239,462
March	1,852,372	1,950,776	32,412	2.4	$5.84	457,001
April	1,918,364	1,953,517	89,441	2.3	$5.65	1,178,427
May	1,864,076	1,954,346	76,464	2.4	$5.84	1,071,346
Subtotal	1,877,882	1,955,021	77,519			$12,652,882
Group 2: RLM						
June	12,114	11,766	(632)	7.1	$5.65	(25,198)
July	12,213	11,434	(680)	7.0	$5.84	(27,822)
August	11,549	11,880	(333)	7.4	$5.84	(14,392)
September	12,247	11,610	61	7.0	$5.65	2,419
October	12,179	11,609	(638)	7.0	$5.84	(26,146)
November	12,329	11,481	(698)	6.9	$5.65	(27,370)
December	12,188	11,513	(817)	7.0	$5.84	(33,468)
January	12,017	11,600	(588)	7.1	$5.84	(24,456)
February	12,039	11,788	(229)	7.1	$5.28	(8,584)
March	12,316	11,848	(191)	6.9	$5.84	(7,738)
April	12,310	11,668	(648)	6.9	$5.65	(25,426)
May	12,397	11,432	(878)	6.9	$5.84	(35,370)
Subtotal	12,158	11,636	(523)			($253,550)
Group 3: GLP						
June	269,005	274,238	9,478	8.9	$5.65	478,344
July	264,759	276,160	16,809	9.4	$5.84	923,205
August	259,351	277,516	12,978	8.6	$5.84	648,310
September	264,539	275,424	27,775	8.8	$5.65	1,376,371
October	247,648	275,088	16,409	9.0	$5.84	864,341
November	258,679	276,222	9,547	8.9	$5.65	479,030
December	266,675	275,719	14,615	8.9	$5.84	764,136
January	261,105	276,334	13,359	8.9	$5.84	695,162
February	262,975	276,283	19,728	9.3	$5.28	966,467
March	256,555	277,629	10,205	8.6	$5.84	515,384
April	267,424	283,966	19,325	8.9	$5.65	970,509
May	264,641	280,204	11,199	8.8	$5.84	577,356
Subtotal	261,946	277,065	15,119			$9,258,614
Group 4: LPLS						
June	8,883	9,087	231	267.1	$5.65	348,353
July	8,727	9,391	508	270.0	$5.84	801,842
August	8,370	9,364	636	270.9	$5.84	1,006,964
September	8,140	9,325	955	277.3	$5.65	1,497,621
October	9,014	9,190	1,049	273.8	$5.84	1,678,506
November	7,780	9,310	295	267.6	$5.65	446,874
December	8,886	9,330	1,550	276.8	$5.84	2,506,491
January	8,481	9,336	450	266.5	$5.84	700,340
February	8,891	9,516	1,035	287.4	$5.28	1,570,119
March	8,867	9,557	666	251.7	$5.84	979,160
April	8,846	9,499	632	275.2	$5.65	983,839
May	8,856	9,547	701	274.0	$5.84	1,122,854
Subtotal	8,645	9,371	726			$13,642,961
					Total Avoided Capacity Cost BGS Savings	$35,300,907

Notes:
(1) Base Year Customer Count is equal to the test year customer count used to set base rates in a base rate case

(2) Current Year Customer Count is equal to the customer count in the CIP accrual year.

(3) Base Year Unforced capacity is equal to the 2017/2018 Unforced capacity from PJM by rate schedule divided by number of customers

(4) Current Year Capacity rate is the current year PS Zonal Net Load Price $/kW-yr divided by 12

Public Service Electric and Gas
CIP Recovery Tests
Allowed Margin

Group I (RS)	$498,223,122
Group II (RLM)	$5,422,536
Group III (GLP)	$263,918,315
Group IV	$201,632,637
Total Variable Margin	$969,196,611

Customer Class	Actual/ Estimate	Number of Customers	Baseline Revenue / Cust.	Variable Revenue
Group I: Residential Service RS and RHS				
Jun-21	Act	1,947,048	37.6	$73,299,689
Jul-21	Act	1,958,721	34.8	$68,181,834
Aug-21	Act	1,951,294	21.4	$41,700,698
Sep-21	Act	1,956,381	13.8	$26,968,789
Oct-21	Act	1,958,765	15.0	$29,344,773
Nov-21	Act	1,960,821	18.6	$36,417,226
Dec-21	Est	1,965,332	20.6	$40,488,008
Jan-22	Est	1,952,094	17.1	$33,294,214
Feb-22	Est	1,951,155	16.4	$31,974,529
Mar-22	Est	1,950,776	14.0	$27,266,696
Apr-22	Est	1,953,517	15.4	$30,139,001
May-22	Est	1,954,346	30.3	$59,147,667
Total			254.9	$498,223,122
Group Ia: Residential Load Management (RLM)				
Jun-21	Act	11,766	99.6	$1,171,438
Jul-21	Act	11,434	93.4	$1,068,423
Aug-21	Act	11,880	42.7	$507,150
Sep-21	Act	11,610	16.9	$195,931
Oct-21	Act	11,609	15.5	$179,404
Nov-21	Act	11,481	19.9	$228,519
Dec-21	Est	11,513	21.7	$249,471
Jan-22	Est	11,600	18.9	$218,901
Feb-22	Est	11,788	18.1	$213,343
Mar-22	Est	11,848	14.3	$169,522
Apr-22	Est	11,668	18.5	$215,361
May-22	Est	11,432	87.9	$1,005,074
Total			467.3	$5,422,536
Group II: General Power & Light (GLP)				
Jun-21	Act	274,238	149.3	$40,948,032
Jul-21	Act	276,160	144.5	$39,912,024
Aug-21	Act	277,516	90.2	$25,044,520
Sep-21	Act	275,424	54.3	$14,964,660
Oct-21	Act	275,088	48.5	$13,332,043
Nov-21	Act	276,222	48.4	$13,365,733
Dec-21	Est	275,719	51.8	$14,285,095
Jan-22	Est	276,334	49.5	$13,669,883
Feb-22	Est	276,283	49.5	$13,684,599
Mar-22	Est	277,629	49.1	$13,620,869
Apr-22	Est	283,966	87.3	$24,795,452
May-22	Est	280,204	129.5	$36,295,406
Total			952.0	$263,918,315
Group III: Large Power & Light - Seconday (LPLS)				
Jun-21	Act	9,087	3,911.2	$35,539,981
Jul-21	Act	9,391	3,948.5	$37,081,599
Aug-21	Act	9,364	2,217.9	$20,767,713
Sep-21	Act	9,325	1,610.5	$15,018,426
Oct-21	Act	9,190	1,000.6	$9,195,648
Nov-21	Act	9,310	856.8	$7,976,506
Dec-21	Est	9,330	918.6	$8,570,060
Jan-22	Est	9,336	921.0	$8,598,416
Feb-22	Est	9,516	922.5	$8,778,481
Mar-22	Est	9,557	878.9	$8,399,555
Apr-22	Est	9,499	1,707.5	$16,219,404
May-22	Est	9,547	2,669.6	$25,486,848
Total			21,563.7	$201,632,637

ATTACHMENT B

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of Changes in its Electric Conservation
Incentive Program
(2022 PSE&G Electric Conservation Incentive Program)

BPU Docket No. ______________

DIRECT TESTIMONY

OF

MICHAEL P. MCFADDEN
DIRECTOR – SALES AND REVENUE FORECASTING

February 1, 2022

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL P. MCFADDEN
DIRECTOR – SALES AND REVENUE FORECASTING

Q. Please state your name, affiliation and business address.

A. My name is Mike McFadden, and I am the Director of Sales and Revenue Forecasting for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102.

Q. Please describe your education and business experience.

A. I received a Bachelor's of Science degree in Finance from the Rutgers School of Business and a Masters of Business Administration from Excelsior College. I have over 15 years' experience in rates, revenue requirements, and financial analysis. I started my career as an analyst in the Bureau of Rates and Tariffs for the New Jersey Board of Public Utilities ("Board") before joining Public Service Electric and Gas ("PSE&G", or "the Company") as a Senior Regulatory Analyst in 2008. In 2014, I was promoted to Manager of Revenue Requirements where I managed over 20 annual regulatory filings with the Board, including the Clean Energy Future – Energy Efficiency filing, which resulted in Board approval of the Conservation Incentive Program ("CIP"). In June 2021, I was promoted to my current position of Director of Sales and Revenue Forecasting for PSEG Services Corporation.

Q. Please describe your responsibilities as Director of Sales and Revenue Forecasting for PSEG Services Corporation.

A. I am responsible for overseeing the development of the Company's electric and gas sales and revenue forecast, including the forecasted electric and gas CIP accrual, and supervising the development of the weather impacts on the sales and revenue forecast.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of this testimony is to provide:

- An overview of the electric CIP mechanism ("ECIP"), including the monthly baseline revenue per customer for each applicable ECIP customer group;
- The calculation of the weather impacts for the current proceeding of June 1, 2021 – May 31, 2022 ("ECIP Period"); and
- The calculation of the Variable Margin ECIP savings test. Note that the BGS Savings Test and the Earnings Test described in the Petition are discussed in the testimony of Mr. Stephen Swetz, submitted herewith.

Q. Does your testimony include any schedules?

A. Yes. My testimony includes schedules that were prepared by me or under my direction and supervision. These schedules are as follows:

- Schedule MPM-ECIP-1 shows the development of the monthly HDD and THI consumption factors used to calculate the actual weather impact on sales from June 1, 2021 through December 31, 2021. Schedule MPM-ECIP-1 also includes a forecast of the consumption factors for the remaining forecast period of January 1, 2022 through the May 31, 2022; and

- Schedule MPM-ECIP-2 contains the Electric Sales Forecast Model, which explains the derivation of the weather coefficients and the data values used in the generation of the HDD and THI consumption factors in Schedule MPM-ECIP-1.

Q. What is the ECIP mechanism?

A. The ECIP mechanism was approved by the Board in the Clean Energy Future – Energy Efficiency matter on September 23, 2020 in Dockets Nos. GO18101112 and EO18101113 ("CEF-EE Order"). The ECIP rate mechanism provides a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer, removing the disincentive for the Company to encourage customers to conserve energy. The ECIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline revenue per customer from the actual revenue per customer and multiplying the resulting revenue per customer by the actual number of customers for the month.

Q. What rate schedules are included in the ECIP?

A. The ECIP is applicable to each of the following customer groups:

- Group 1 – Residential Service ("RS") and Residential Heating Service ("RHS")
- Group 1a – Residential Load Management ("RLM")
- Group 2 – General Lighting & Power ("GLP")
- Group III – Large Power & Light – Secondary Service ("LPLS")

Q. How is the baseline revenue per customer determined?

A. Per the CEF-EE Order, the electric baseline revenue per customer is based on the billing determinants from PSE&G's 2018 base rate case and the latest variable margin rates per rate schedule, including any Infrastructure Investment Program ("IIP") rate adjustments. The latest variable margin revenue for this filing is based on the Energy Strong II rate adjustment approved on April 27, 2021 for new rates effective May 1, 2021 in Docket No. ER20120736. Please see the table below for the baseline revenue per customer for each rate schedule based on the approved Energy Strong II filing.

Month	RS & RHS	RLM	GLP	LPLS
Jun	$30.26	$87.92	$129.53	$2,669.62
Jul	$37.65	$99.56	$149.32	$3,911.18
Aug	$34.81	$93.44	$144.52	$3,948.53
Sep	$21.37	$42.69	$90.25	$2,217.92
Oct	$13.79	$16.88	$54.33	$1,610.54
Nov	$14.98	$15.45	$48.46	$1,000.64
Dec	$18.57	$19.90	$48.39	$856.78
Jan	$20.60	$21.67	$51.81	$918.58
Feb	$17.06	$18.87	$49.47	$921.00
Mar	$16.39	$18.10	$49.53	$922.50
Apr	$13.98	$14.31	$49.06	$878.89
May	$15.43	$18.46	$87.32	$1,707.49
TOTAL ANNUAL	**$254.88**	**$467.25**	**$951.99**	**$21,563.65**

Q. How is the actual revenue per customer determined?

A. The actual revenue per customer is the variable margin per applicable rate schedule for the month divided by the number of customers for the month. For the residential rate schedules, RS, RHS and RLM, this is the margin from the volumetric kWh charge. For rate schedule GLP, this is the margin from the volumetric kWh charge and the annual and summer demand. Finally, for rate schedule LPLS, the variable margin is the annual and summer demand. Per the CEF-EE Order, the number of customers is calculated as the actual monthly service charge revenue divided by the service charge rate.

Q. Where are the calculations of the ECIP Margin Excess or Deficiency for this proceeding?

A. Please see Attachment A, Schedules 1 through 3 to the Petition for the June 1, 2021 through May 31, 2022 results based on actual data from June 1, 2021 through November 30, 2021 and a forecast for the remaining months from December 1, 2021 through May 31, 2022. Attachment A is the same template as Exhibit 6E of the Stipulation approved by the Board in the CEF-EE matter. Schedule 1 shows the results for rate schedules RS & RHS, Schedule 1a shows the results for rate schedule RLM, Schedule 2 shows the results for rate schedule GLP and Schedule 3 shows the results for rate schedule LPL-S. In each schedule, page 1 shows the calculation of the monthly margin variance for the ECIP period, page 2 shows details supporting the calculation, and page 3 shows the current period over or under-collection (zero for all rate schedules for this filing as there is no existing rate).

Q. Please describe the ECIP recovery tests?

A. Pursuant to the CEF-EE Order, recovery of a margin deficiency associated with non-weather related changes in customer usage is subject to the lesser of the outcomes of a BGS Savings Test and a Variable Margin Test. In order to recover the ECIP non-weather related margin deficiency: (1) the Company must have BGS savings of at least 75 percent of the non-weather related margin deficiency; and (2) the non-weather related margin deficiency must be less than or equal to 6.5% of aggregate variable margins (4% for this initial ECIP filing). Any amount that exceeds these limitations may be deferred for future recovery and will be subject to the recovery tests in that future period.

Q. How did you calculate the non-weather related ECIP margin?

A. The non-weather related ECIP margin is calculated as the total ECIP margin deficiency less the weather related margin deficiency. In accordance with the CEF-EE Order, the impact of weather for the ECIP period is calculated for the Residential customer classes only in a manner consistent with the existing gas Weather Normalization Charge and is shown in Attachment A, Schedule 4. The weather effect will be measured by the impacts on sales and associated distribution revenue of HDD and THI. As shown in Attachment A, Schedule 4, the margin impact is determined by calculating the total kWh impact of weather in the month and multiplying it by a margin factor for each residential rate schedule. The margin factor is the average kWh distribution rate for each rate schedule used to calculate the variable distribution revenue impact of weather.

Q. How is the kWh impact of weather determined?

A. As described in the CEF-EE Order and shown in Attachment A, Schedule 4, weather will be calculated as the difference in the actual and normal HDD and THI multiplied by the sales coefficients to establish sales impacts. The sales impacts will be multiplied by a margin factor based on the latest tariff rates to derive the revenue impact of weather. The sales coefficients used to calculate the monthly consumption factors by rate schedule are based on 20-years of weather history and shown in Schedule MPM-ECIP-1. The calculation reflects actual customers from June 2021 – December 2021 and a forecast for January 2022 – May 2022. The forecasted number of customers will be trued-up with the actual number of customers once the actual data is available.

Q. How are the monthly HDD and THI consumption factors developed?

A. Schedule MPM-ECIP-1 shows the calculation of the monthly HDD and THI consumption factors, which are the estimated sales impact per HDD and THI. The consumption factors multiplied by the variance of HDD and THI to normal calculates the weather impact on sales. The calculation is based on the estimated HDD and THI weather coefficients from the Company's econometric sales forecasting models. This is multiplied by the number of customers since the models, as a result of the coefficients, are based on sales per customer. For the rate schedule RS consumption factors, other variables that are interactive with weather, such as economic/demographic variables, are also incorporated into the calculation. The forecast models and methodology employed are described in detail in Schedule MPM-ECIP-2.

Q. How is the normal HDD and THI determined?

A. The base level of normal HDD and THI for the period of June 2021 – May 2023 have been calculated based on the 20-year period weather history ending December 2020 in accordance with the CEF-EE Order and are shown in Attachment A, Schedule 4.

Q. How is the margin factor for each rate schedule determined?

A. The margin factor is the weighted average of the latest kWh distribution rates in the Company's tariff and the approved kWh billing determinants from the last base rate case.

Q. What is the ECIP non-weather margin?

A. The total weather impact from June 2021 – December 2021 is an over-collection of $21 million from the warmer than normal weather as shown in Attachment A, Schedule 4. The total deferral as calculated in Attachment A, Schedule 1 – 4 for the ECIP period is estimated at $52 million. As a result, the non-weather ECIP deferral subject to the ECIP savings test is $73 million as shown in Attachment A, Schedule 5.

Q. What are the results of the ECIP savings tests?

A. The ECIP savings tests are the lesser of a modified BGS Savings Test and a Variable Margin Revenue Test. As shown in Attachment A, Schedule 5, there is no limit in the ECIP recovery for the BGS Savings Test, but the Variable Margin test is forecasted to limit the non-weather recovery at $39 million. The difference between the actual deferral and the non-weather recovery cap will be carried-forward to the next ECIP recovery period.

Q. Please describe the BGS Savings Test.

A. Please see the testimony of Stephen Swetz for the calculation of the BGS savings test, which is shown in Attachment A, Schedule 5, pages 3 and 4.

Q. Please describe the Variable Margin Test.

A. As shown in Attachment A, Schedule 5, page 5, the Variable Margin test is calculated as the actual number of customers multiplied by the baseline revenue per customer and then the allowed percentage of variable margin, which is 6.5%, except for this initial ECIP period where the rate is 4.0%. Based on actual results from June 2021 through November 2021 and a forecast from December 2021 – May 2022, total variable margin is $969 million, resulting, after applying the 4% rate, in a variable margin cap of $39 million.

Q. Is there an additional ECIP Recovery Test?

A. Yes. In addition to the BGS and Variable Margin non-weather recovery caps, the Company must pass an earnings test as shown in Attachment A, Schedule 6. Please see the testimony of Mr. Swetz for the calculation of the earnings test.

Q. Has the impact of the ECIP margin excess and margin deficiency been calculated by customer group?

A. Yes. Please see the testimony of Mr. Swetz for the proposed rates for each customer group and the associated impact on a typical or class average customer.

Q. Does this conclude your testimony at this time?

A. Yes.

Rate RS Weather Consumption Factor Calculation

	Heating Degree Days						Temperature/Humidity Index		
Month	HDDxWage Coefficient	HDD x Price Coefficient	Value: Real Price	Value: Wage	Customers	HDD Consumption Factor	THI	Customers	THI Consumption Factor
Jun-21	0.8326	(0.0203)	0.7530	0.3006	1,939,610	455,913	0.07958	1,939,610	154,354
Jul-21	0.8326	(0.0203)	0.7530	0.3006	1,951,311	458,664	0.07958	1,951,311	155,285
Aug-21	0.8326	(0.0203)	0.7530	0.3006	1,943,972	456,939	0.07958	1,943,972	154,701
Sep-21	0.8326	(0.0203)	0.7530	0.3006	1,949,089	458,141	0.07958	1,949,089	155,108
Oct-21	0.8326	(0.0203)	0.7530	0.3006	1,951,525	458,714	0.07958	1,951,525	155,302
Nov-21	0.8326	(0.0203)	0.7530	0.3006	1,953,601	459,202	0.07958	1,953,601	155,468
Dec-21	0.8326	(0.0203)	0.7530	0.3006	1,958,163	460,274	0.07958	1,958,163	155,831
Jan-22	0.8326	(0.0203)	0.7640	0.3121	1,944,661	475,206	0.07958	1,944,661	154,756
Feb-22	0.8326	(0.0203)	0.7640	0.3121	1,943,766	474,987	0.07958	1,943,766	154,685
Mar-22	0.8326	(0.0203)	0.7640	0.3121	1,943,419	474,902	0.07958	1,943,419	154,657
Apr-22	0.8326	(0.0203)	0.7640	0.3121	1,946,203	475,583	0.07958	1,946,203	154,879
May-22	0.8326	(0.0203)	0.7640	0.3121	1,947,050	475,790	0.07958	1,947,050	154,946

Reflects actual customers through December 2021 and a forecast thereafter.

Rate RHS Weather Consumption Factor Calculation

	Heating Degree Days			Temperature/Humidity Index		
Month	HDD	Customers	HDD Consumption Factor	THI	Customers	THI Consumption Factor
Jun-21	1.7381	7,439	12,929	0.06911	7,439	514
Jul-21	1.7381	7,411	12,881	0.06911	7,411	512
Aug-21	1.7381	7,323	12,728	0.06911	7,323	506
Sep-21	1.7381	7,293	12,676	0.06911	7,293	504
Oct-21	1.7381	7,241	12,586	0.06911	7,241	500
Nov-21	1.7381	7,221	12,550	0.06911	7,221	499
Dec-21	1.7381	7,170	12,461	0.06911	7,170	495
Jan-22	1.7381	7,433	12,919	0.06911	7,433	514
Feb-22	1.7381	7,389	12,843	0.06911	7,389	511
Mar-22	1.7381	7,357	12,787	0.06911	7,357	508
Apr-22	1.7381	7,314	12,712	0.06911	7,314	505
May-22	1.7381	7,296	12,681	0.06911	7,296	504

Reflects actual customers through December 2021 and a forecast thereafter.

Rate RLM Weather Consumption Factor Calculation

	Heating Degree Days			Temperature/Humidity Index		
Month	HDD	Customers	HDD Consumption Factor	THI	Customers	THI Consumption Factor
Jun-21	0.5410	11,766	6,365	0.17596	11,766	2,070
Jul-21	0.5410	11,434	6,185	0.17596	11,434	2,012
Aug-21	0.5410	11,880	6,427	0.17596	11,880	2,090
Sep-21	0.5410	11,610	6,281	0.17596	11,610	2,043
Oct-21	0.5410	11,609	6,280	0.17596	11,609	2,043
Nov-21	0.5410	11,481	6,211	0.17596	11,481	2,020
Dec-21	0.5410	11,513	6,228	0.17596	11,513	2,026
Jan-22	0.5410	11,600	6,275	0.17596	11,600	2,041
Feb-22	0.5410	11,788	6,377	0.17596	11,788	2,074
Mar-22	0.5410	11,848	6,409	0.17596	11,848	2,085
Apr-22	0.5410	11,668	6,312	0.17596	11,668	2,053
May-22	0.5410	11,432	6,184	0.17596	11,432	2,012

Reflects actual customers through December 2021 and a forecast thereafter.

DRAFT

Electricity Sales and Billed Demand Forecast - 2022

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

December 2021

Contents

Introduction

The electricity sales and billed demand forecast has a key role in both the operating and financial planning processes of Public Service Electric & Gas (PSE&G).

The sales forecast serves as the basis for the electric revenue forecast that is a key parameter in PSE&G's financial planning process. This includes not only the budgeting process but also the regulatory process.

The purpose of this document is to describe the current forecast methodology, forecast assumptions that serve as the basis of the 2021 electricity sales and billed demand forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the billed demand models.. An appendix contains detailed information on the billing period to calendar-month conversion.

I Energy Model Specification and Estimation

Residential Model

Residential electricity sales are determined by the number of residential customers and the amount of electricity that each of these customers uses. As a result, the modeling of residential sales is disaggregated into two components: the projection of the number of customers and the estimate of what, on average, each of these customers will use. While the projection of the number of residential electricity customers can be based on historical trends and expected demographic trends in the service area, the models utilized to develop the average use forecast are more complicated and are described below.

The demand for energy is a derived demand from the demand for the services that the energy provides. In the case of electricity, this is for a multitude of uses ranging from heating and cooling to cell phone chargers. Standard microeconomic theory suggests that the demand for these electricity-fueled end-uses is a function of the real, i.e. inflation adjusted, price of electricity, and the income of the household. In addition, since space heating, water heating, and space cooling are affected by the weather, both winter and summer weather need to be included in the model specification, i.e.

KWH/CUST = *f*(PRICEELEC, INCOME, WEATHER) [1]

where:

KWH/CUST	= Average electricity sales per customer,
PRICEELEC	= Real price of electricity,
INCOME	= Measure of customer income,
WEATHER	= Billing-month weather.

While information on individual appliance ownership and consumption is not available, PSE&G does have separate rates for Residential customers that have electric space heating (RHS), those that have opted for the Load Management Service rate (RLM) and the standard Residential Service rate (RS). In addition, data is available for customers taking service under rate WH, those Residential customers with a separately metered water heater. As a result, separate models estimating the average gas sales for each of these rates were developed.

Winter weather is incorporated into the models using billing-month heating degree days (HDD). Summer weather is measured by the billing-month temperature-humidity index.

The real price of electricity is defined as the annual average revenue per kWh divided by the Consumers' Price Index –All Urban Consumers. However the majority of the discretionary use of electricity is related to cooling. As a result, this variable was incorporated as an interactive variable with the THI to create the effect that a change in price will air conditioning use. Electricity sales are also affected by winter weather. For those customers with electric space heating, an interactive variable consisting of the product of the electricity price and HDD was used. For those customers without electric space heating, it is assumed that heating use is a function of the price of natural gas and that this variable drives the implicit demand for electricity use by furnace fans and boiler pumps. The real price of gas is defined as the annual average revenue per therm by PSE&G's residential space heating customers divided by the Consumers' Price Index –All Urban Consumers

Income is defined as the total real wages and salary disbursements per household for New Jersey from the U.S. Department of Commerce, Bureau of Economic Analysis. This is a narrower measure than personal income, omitting for example dividends, interest and rental income, and, as a result, is assumed to more accurately reflect the economic well-being of the majority of our customers. This variable was also incorporated into the specification as an interactive variable with weather for the same reason as the price variable. In the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior.

In recent years, new technologies and programs have had significant impacts on residential electricity consumption that are not captured by the standard set of economic variables. Each of these technologies/programs is handled in one of two ways.

The first methodology is incorporating a measure of the technology/program directly into the estimation equation. This methodology is used for efficient lighting for rates RS and RLM. It was not used for rate RHS efficient lighting since lighting effects are highly correlated with other conservation effects, notably heating efficiencies, resulting in an unreasonably high estimated coefficient.

The second methodology is removing the estimated impact of the technology/program from the historical data series prior to the model estimation. The impact of this technology/program, both historically and projected, is then added to the data series to produce a forecast. This methodology was used for net metered solar since the number of net metered solar installations has grown significantly since 2008. This trend in solar installations makes the Inclusion of the estimated impact of solar as an explanatory variable not feasible since the installed solar kW is highly correlated with the economic downturn resulting in much of the economic impact on consumption being captured by the solar variable. This methodology was also used for energy efficiency programs and electric vehicles since these programs are not the result of economic factors. It was also, as discussed above, used for rate RHS efficient lighting.

As a result, the final functional form of the model that was estimated is:

$$KWH/CUST_t = f(HDD_t \times PRICEFUEL_{a-1}, THI_t \times PRICEELEC_{a-1}, HDD_t \times \overline{INCOME}_{a-1}, HDD_t \times INCOME_{a-1}, CFL_t, \overline{MONTH}_{a-1},) \qquad [2]$$

where:

KWH/CUST	= Average electricity sales per customer less the impact of net metered solar,
PRICEELEC	= Real price of electricity,
PRICEELEC	= Real price of heating fuel,
INCOME	= Real Wage and Salary Disbursements per household,
HDD	= Heating degree days,
THI	= Temperature-humidity index,
CFL	= Estimated impact of CFLs on average use per customer (n/a to Rate RHS),
$\overline{\text{MONTH}}$	= Vector of binary variables for each month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The models were estimated using monthly data from the pre-COVID period, January 2010-February 2020, (excluding data from 2009 due to distortions resulting from the implementation of a new billing system.)The results of the OLS estimation procedure are summarized in Table 1 and Figures 1 and 2.

As Figures 1 -3 illustrate, the high values of the coefficients of determination of all of the models of residential customer usage explain an extremely high proportion of the variation from the mean values. The estimates of the individual coefficients of the models' estimations are what one would expect given the characteristics of residential electricity consumption. The key predictor of electricity sales to this sector is weather with the winter weather having a greater impact on those customers with electric space heating and summer weather has a greater impact on the load management customers. Price is a factor for residential customers during the winter months but, its impact is relatively small.

The electricity price elasticity estimates were not measurable. This most likely was due to the impacts of the relatively stable electricity price being dwarfed by the changing lighting technology, energy efficiency programs, and net metered solar.

Figure 1

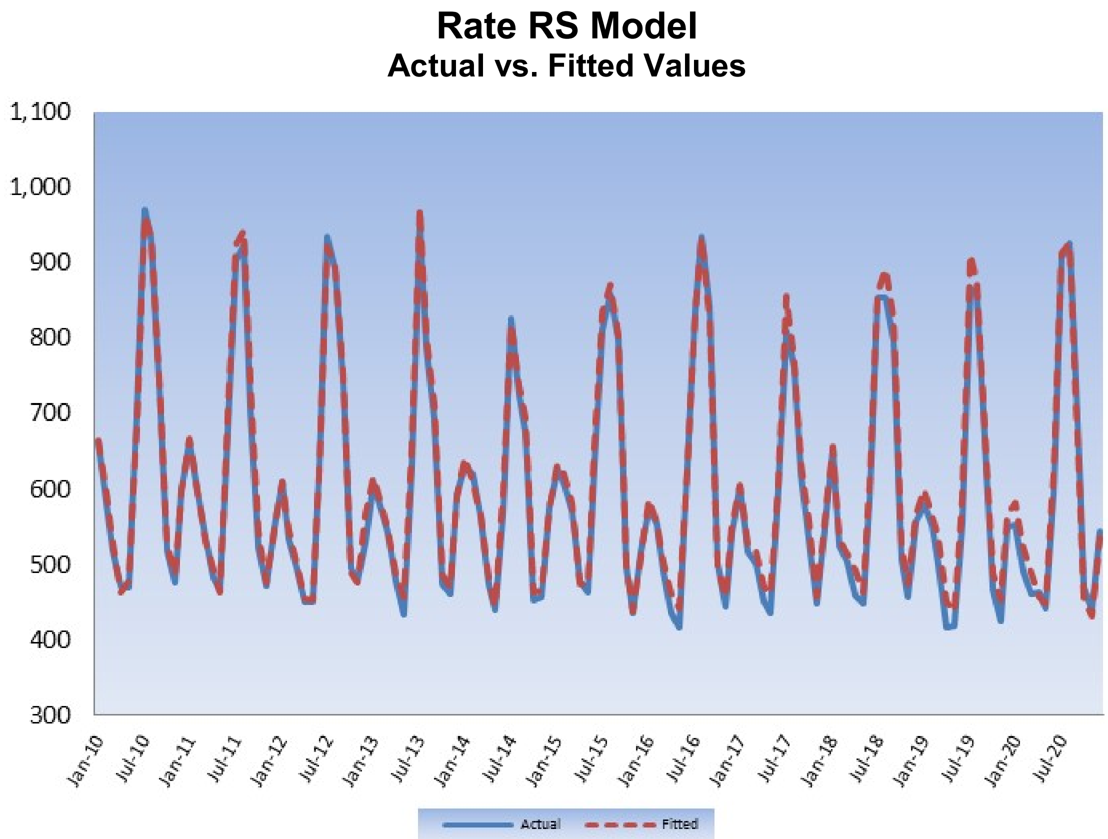
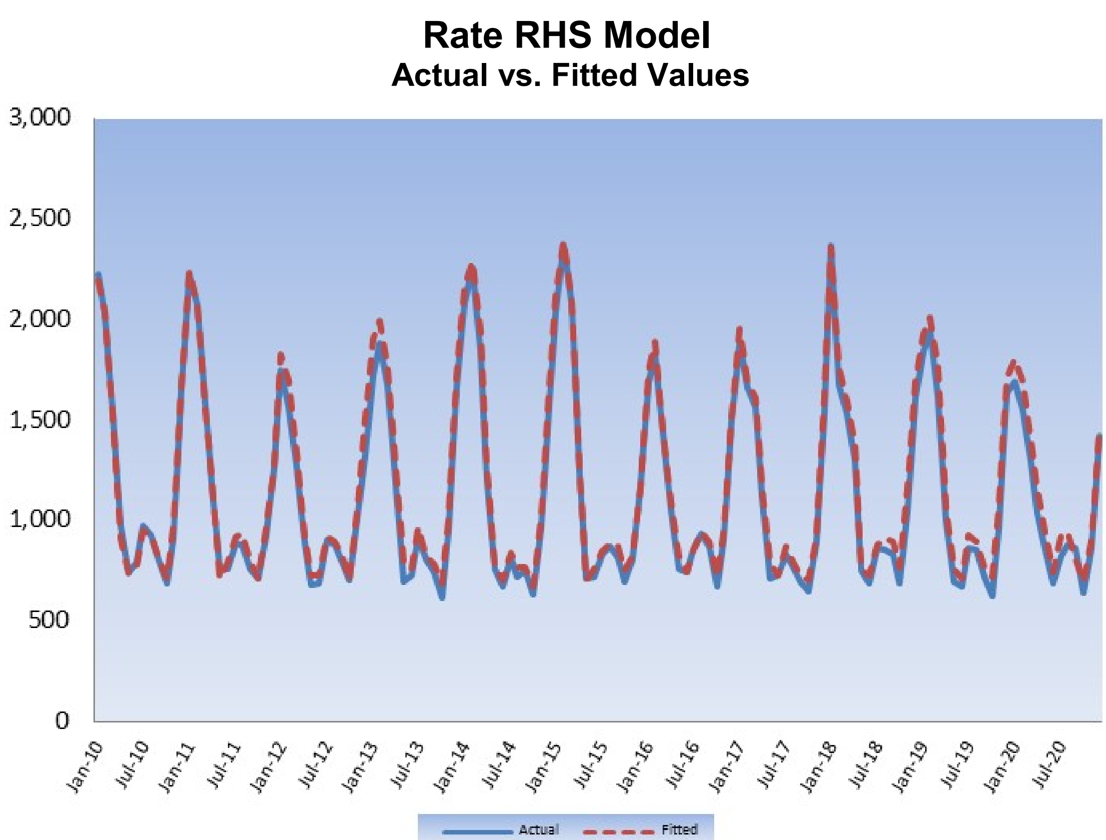


Figure 2



.Figure 3

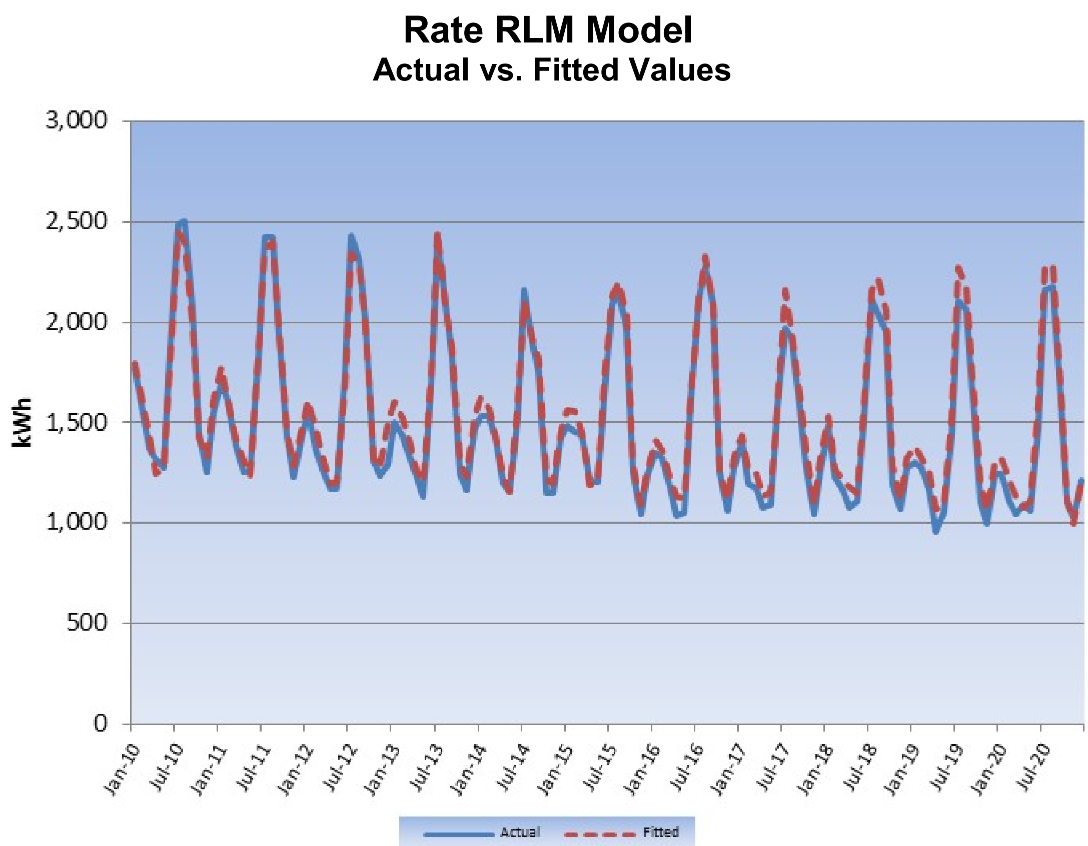


Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

Rate	HDDxGAS PRICE	HDDxWAGE	HDD	THI	CFL	R2	n
RS	-0.0203	0.8326		0.8326	-0.9724	0.99	122
	(0.0135)	(0.064)		(0.064)	(0.1178)		
RHS			1.7381	0.0691		0.99	122
			(0.0479)	(0.0089)			
RLM			0.5410	0.1760	-5.3792	0.98	122
			(0.0597)	(0.0111)	(0.2985)		
WH				0.0020		0.5071	122
				(0.0028)			

The key forecast assumption in the current residential forecast that is not incorporated directly into the models is the estimation of the impacts of the current pandemic.

Direct estimation of the impacts of COVID on residential sales is not possible because of the large percentage of COVID-induced estimated bills in 2020. As a result, the models were estimated through February 2020, the pre-COVID era, and the deviation of the "business as usual" forecasted values were compared to 2021 actual values – a period of estimated bills at a more normal level. Based on this analysis, the residential forecast was adjusted to, in general, increase sales reflecting the increased working from home. The estimated current impact, assumed to be in effect until June 2022, was then assumed to be cut in half thereafter as working from home was reduced but remained as a permanent change for some employees. The impacts are summarized in the table below.

Table 2

COVID Sales Impacts in the Residential Forecasts

	January 2021-June 2022			After June 2022		
Season	**RS**	**RHS**	**RLM**	**RS**	**RHS**	**RLM**
JAN-MAR	9.6%	-0.8%	17.0%	4.8%	-0.4%	8.5%
NOV-DEC	2.2%	0.2%	7.8%	1.1%	0.1%	3.9%
MAY-OCT	0.7%	-2.8%	1.0%	0.4%	-1.4%	0.5%

The second key element of the residential forecast is the projection of the number of residential natural gas customers. This forecast is based on historical trends between customer growth and residential construction activity in the service area and is discussed in the Forecast Assumptions section.

Commercial

The demand for electricity by the non-residential sector, as with any other factor of production, is a function of the input's price, the price of substitutes (if any) and the level of production. This implies that electricity sales to the commercial sector is a function of the real price of electricity and the level of "output" of the commercial sector in PSE&G's service territory, i.e. Again, since electricity is used for HVAC purposes, weather needs to be included in the specification resulting in the following: In addition, there have been numerous efficiency improvements in the end-uses of the commercial sector. To capture this, an index of appliance efficiency for the commercial sector based on the use per square foot of non-HVAC appliances in the commercial sector incorporated in the EIA's Annual Energy Outlook 2020 is also included in the models.

KWH = *f*(PRICEELEC, OUTPUT, WEATHER, EFFICIENCY) [3]

where:

KWH	= Electricity Sales,
PRICEELEC	= Real price of electricity,
OUTPUT	= Commercial sector output,
WEATHER	= Billing-month weather
EFFICIENCY	= Appliance efficiency index.

The problem with this specification is that there is not a good measure of output for the local commercial sector. However, if it is assumed that the demand for local commercial output is a function of the local economic and demographic factors, i.e., how many households there are (HSH) and how much money do they have to spend (INCOME), commercial output can then be defined as:

OUTPUT = *f*(INCOME, HSH) [4]

Substituting [4] into [3] yields:

KWH = *f*(PRICEELEC, INCOME, HSH, WEATHER, EFFICIENCY) [5]

The secondary customers in this class whose billed demand does not exceed 150 kW in any month are served under rate GLP. Customers that take service under the closed Heating Service rate are served under rate HS. As like the residential rates, these customers had a large number of estimated bills in 2020. As a result, this model was estimated for customers in these rates in the commercial sector using monthly billing data from the January 2006-February 2020 period (again, excluding 2009).

Historical annual household estimates for New Jersey is available from the U.S. Bureau of the Census. As with the residential models, seasonality associated with commercial electricity sales dictates that the economic/demographic variables can be used in the model directly but, needed, in some cases, to be used as interactive variables with weather. In addition, in the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior.

Direct estimation of the impacts of COVID on small and medium commercial sales is not possible because of the large percentage of COVID-induced estimated bills in 2020. As a result, these models were estimated through February 2020, the pre-COVID era. The large commercial customers, rates LPL and HTS did not have an issue with estimated bills and binary variables for the pandemic period were incorporated into the LPL-S equation. As a result, the functional form that was estimated for each of the three groups of commercial customers is[1]:

$$KWH_t = f(HDD_t \times PRICEELEC_{a-1}, THI_t \times PRICEELEC_{a-1}, HDD_t \times ECON_{a-1}, THI_t \times INCOME_{a-1}, HDD_t \times HSH_{a-1}, THI_t \times HSH_{a-1}, MONTH, EFFICIENCY, COVID) \quad [6]$$

where:

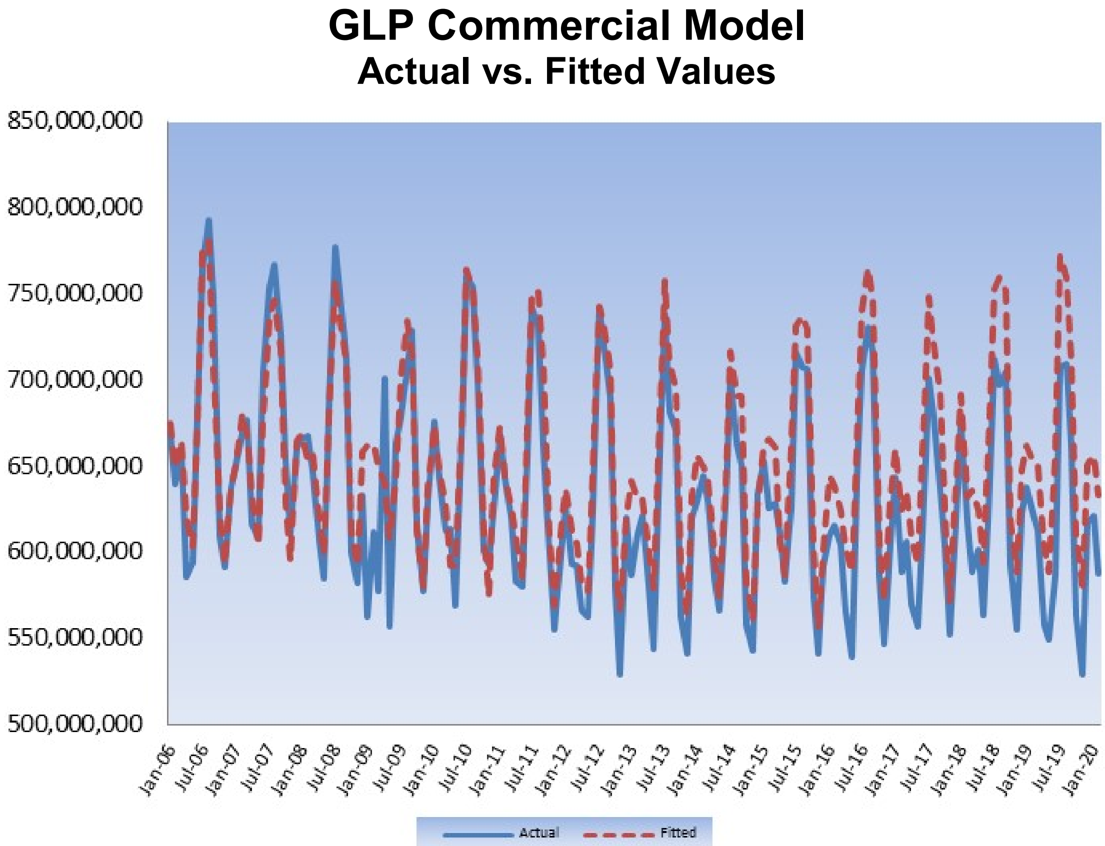
KWH	= Electricity sales,
PRICEELEC	= Real price of electricty,
ECON	= Real Wage and Salary Disbursements (except for Rate HS where it is number of households),
HDD	= Heating degree days,
THI	= Temperature-humidity index,
MONTH	= Vector of binary variables for each heating month,
EFFICIENCY	= Appliance efficiency index,
COVID	= Variables capturing pandemic period
t	= Billing-month,
a	= Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 3-6, show that the commercial models also fit the historical data well.

The estimated coefficients of the commercial models indicate that while the small commercial space heating are sensitive to price, with estimated elasticites of -0.01 for GLP and -0.25 for HS, the large customers are not. In addition, while the coefficients on wages, the economic indicator in the GLP and LPL models (households is the driver for rate HS), are highly statistically significant, this does not imply large sales increases given the relatively low elasticities, 0.16 for LPL-S, that are estimated.

[1] In the cases where it was not necessary to incorporate economic variables interactive with the weather specifications the variables were included separately..

Figure 3


GLP Commercial Model
Actual vs. Fitted Values
850,000,000
800,000,000
750,000,000
700,000,000
650,000,000
600,000,000
550,000,000
500,000,000
Jan-06
Jul-06
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Jul-18
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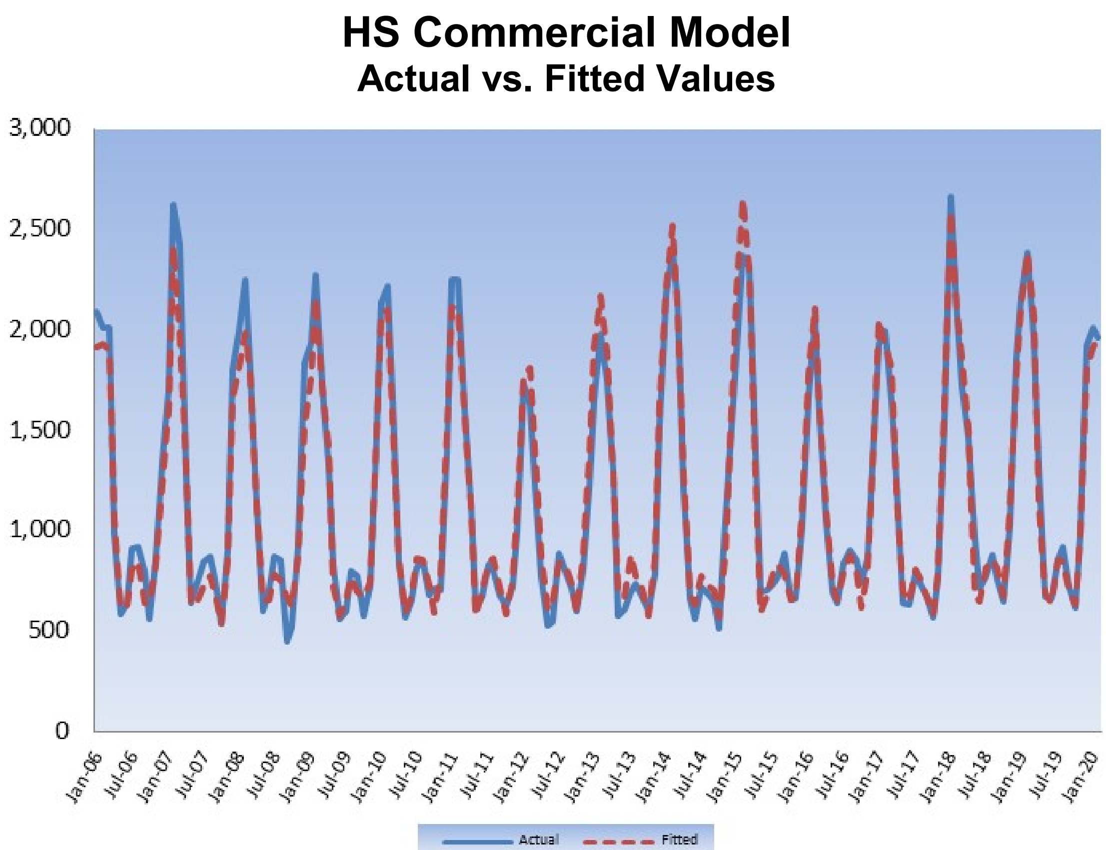
Jul-19
Jan-20
Actual
Fitted


HS Commercial Model
Actual vs. Fitted Values
3,000
2,500
2,000
1,500
1,000
500
0
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08
Jan-09
Jul-09
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Jul-10
Jan-11
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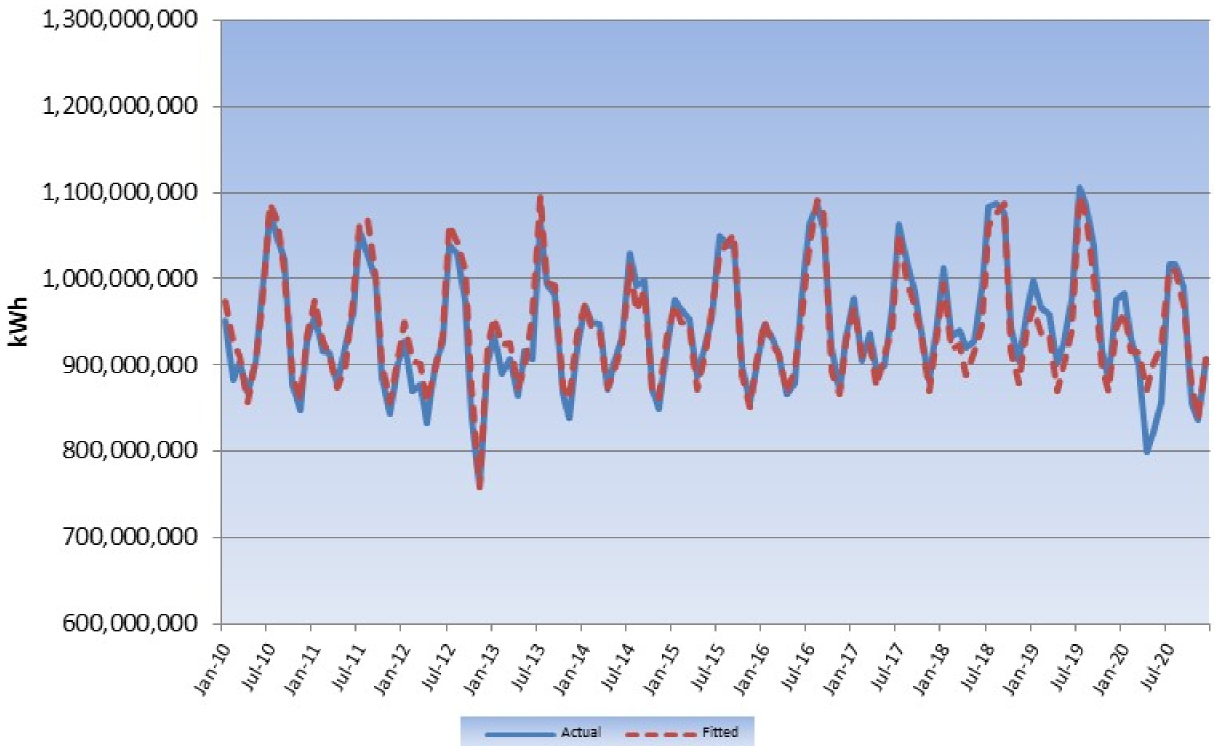
Jan-20
Actual
Fitted

LPL-S Commercial Model
Actual vs. Fitted Values



LPL-P Commercial Model
Actual vs. Fitted Values

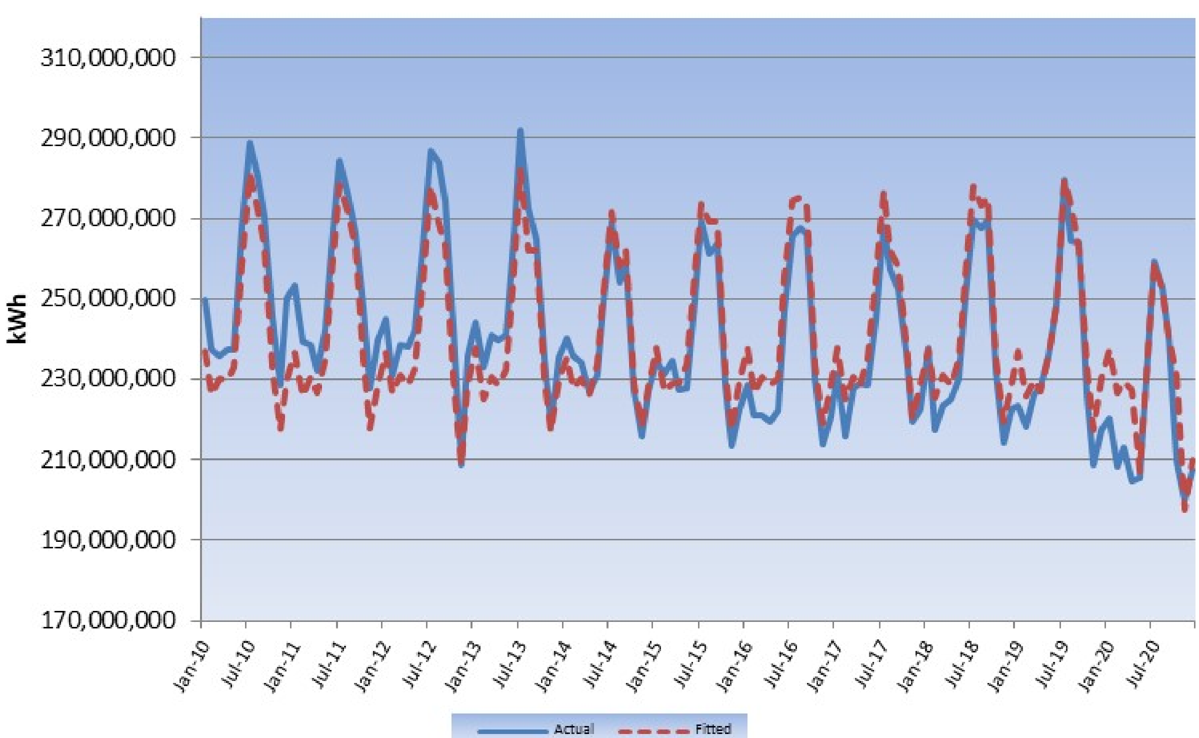


Table 3

Estimated Coefficients of the Commercial Electricity Sales Models

(standard errors in parentheses)

Rate	THIxPRICE	HDDxPRICE	HDDxECON	THIxECON	EFFICIENCY	COVID-THI	COVID-Summer	COVID-Winter	R2	n
GLP	-26.5		123.5	26.2	4,807,329				0.9509	158
	(22.9)		(14.2)	(4.1)	(557,427)					
HS		-4.6617	0.00080	0.00002		16.56200		22,851	0.9668	158
		(0.9931)	(0.00006)	(0.000003)		(2.722)		(17246)		
LPL-S			110.9	45.7		45.7			0.9027	132
			(20.3)	(0,004)		(0,004)				
LPL-P				6.4			25,462.1	20,252	0.85	132
				(0,002)			(4,277)	(6,597)		

The projections from each of these models were compared to 2021 actual values – a period of estimated bills at a more normal level and most recent COVID impacts. Based on this analysis, the commercial forecasts were adjusted to increase sales to rates HS and LPL-P and reduce sales to GLP and LPL-S, the most populous rates, reflecting the decreased level of commercial economic activity. The estimated current impact, assumed to be in effect until June 2022, was then assumed to be cut in half through the end of 2022. After 2022, pandemic impacts on sales was assumed to be eliminated. The impacts are summarized in the table below.

Table 4

COVID Sales Impacts in the Commercial Forecasts

	January 2021-June 2022				July 2022-December 2022			
Season	**GLP**	**HS**	**LPL-S**	**LPL-P**	**GLP**	**HS**	**LPL-S**	**LPL-P**
JAN-APR	-5.5%	14.4%	-3.2%	4.2%	-2.3%	7.2%	-1.6%	2.1%
NOV-DEC	-4.7%	14.4%	-3.2%	4.2%	-2.3%	7.2%	-1.6%	2.1%
MAY-OCT	-6.0%	10.3%	-2.7%	0.9%	-3.0%	5.2%	-1.3%	0.5%

Industrial

While electricity sales to the commercial sector are correlated with commercial output because output tends to be correlated with commercial floor space, sales to the PSE&G customers in the industrial sector are correlated with rwwmanufacturing employment which, in recent years has been correlated with industrial output. Therefore the following specification is used:

$$KWH = f(PRICEELEC, EMP, HDD) \qquad [7]$$

where:

EMP = Manufacturing employment.

As with the commercial models, since electricity is used for HVAC purposes, it was necessary for the economic variables to be used as interactive variables with weather to account for the seasonality of some of the data.

Direct estimation of the impacts of COVID on small and medium commercial sales is not possible because of the large percentage of COVID-induced estimated bills in 2020. As a result, these models were estimated through February 2020, the pre-COVID era. The large commercial customers, rates LPL and HTS did not have an issue with estimated bills and binary variables for the pandemic period were incorporated into the LPL-S equation.

As a result, the functional form that was estimated is:

$$KWH_t = f(HDD_t \times PRICEELEC_{a-1}, THI_t \times PRICEELEC_{a-1}, HDD_t \times MFG_a, THI_t \times MFG_a, HDD_t, THI_t, \overline{MONTH}, \overline{COVID}) \qquad [8]$$

where:

KWH	= Electricity sales,
PRICEELEC	= Real price of electricty,
MFG	= Manufacturing employment,
HDD	= Heating degree days,
THI	= Temperature-humidity index,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
COVID	= Variables capturing pandemic period
t	= Billing-month,
a	= Year associated with billing-month, t.

Like the commercial customers, the secondary customers in this class whose billed demand does not exceed 150 kW in any month are served under rate GLP.

This model was estimated for customers in this rate using monthly billing data from the January 2005-July 2019 period (excluding 2009). The larger industrial customers are served under rate LPL. These are also modeled separately for those customers that take service under primary and secondary voltages and these models were estimated using individual customer data from the January 2010-Jly 2019 period aggregated to billing-month to eliminate the effects of out of period billings.

The results of the OLS estimation procedure, summarized in Figures 6-8, show that the industrial models for customers in the two space heating segments fit the historical data fairly well. The data for industrial GSG non-heating customers, however, seems to indicate the presence of out of period adjustments in the billing data which the model doesn't, and can't be expected to, account for. These were addressed with binary variables.

Figure 7

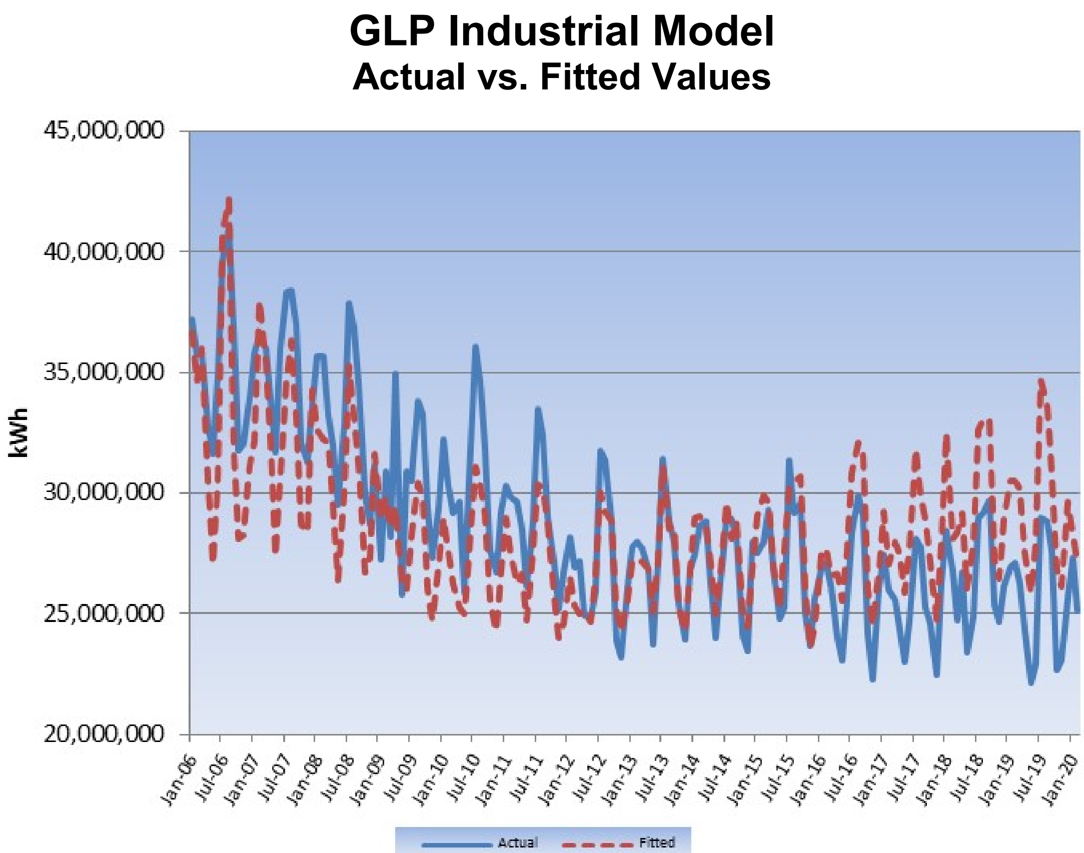


Figure 8

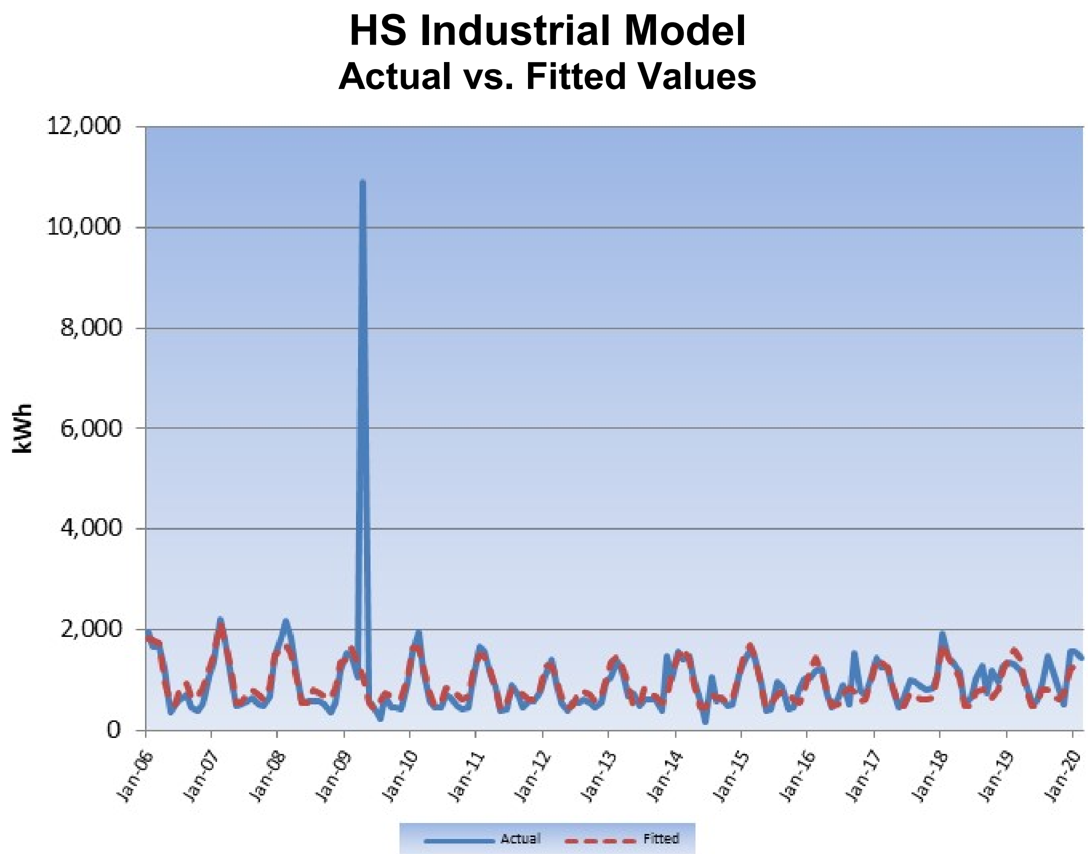


Figure 9

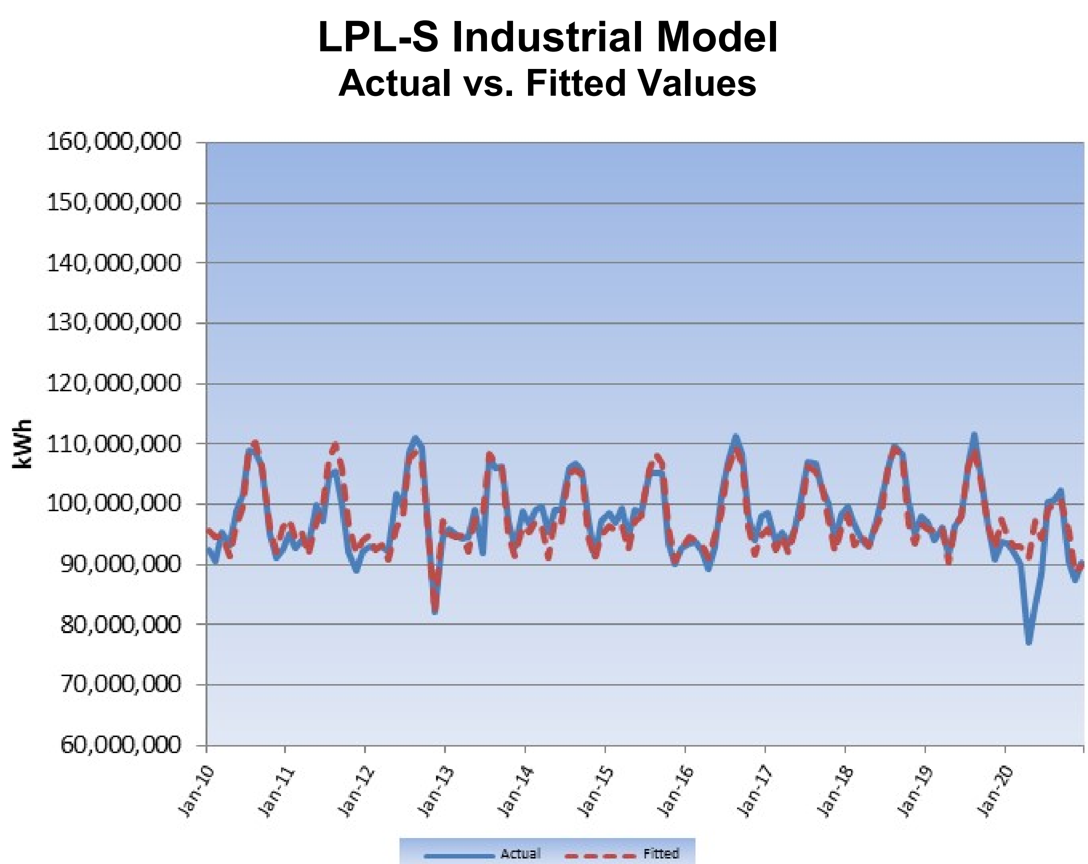


Figure 10

LPL-P Industrial Model
Actual vs. Fitted Values

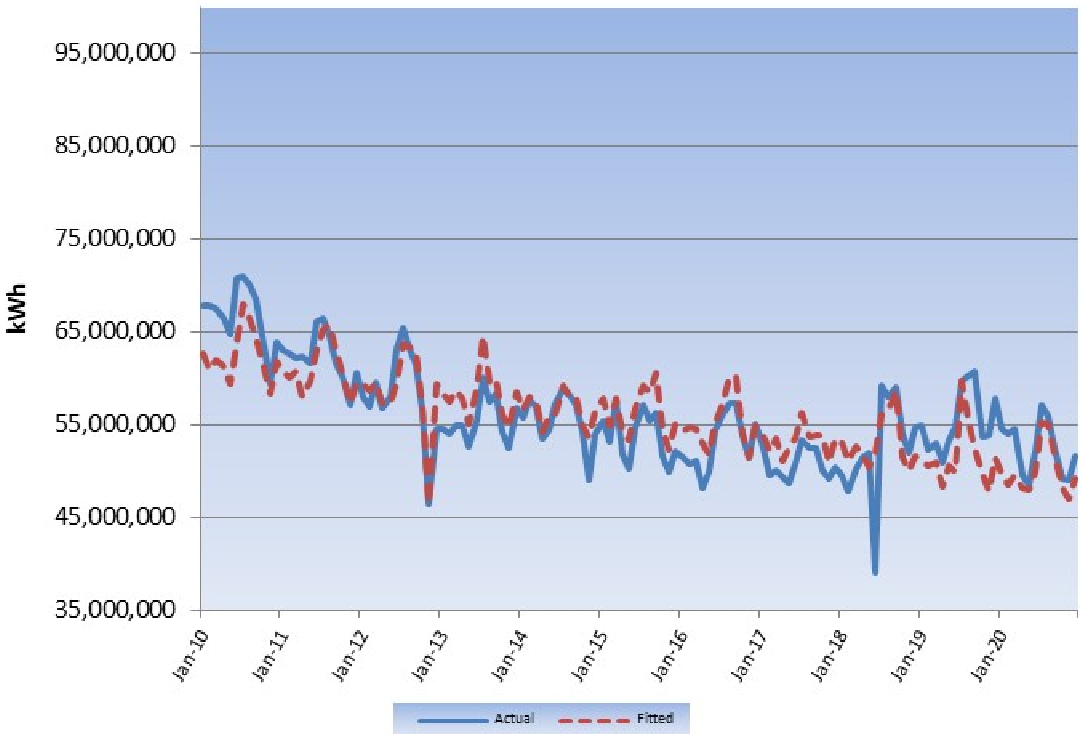


Table 5

Estimated Coefficients of the Industrial Electricity Sales Models
(standard errors in parentheses)

Rate	THIxPRICE	HDDxPRICE	HDDxMFG	THIxMFG	HDD	THI	COVID-THI	COVID-HDD	R2	n
GLP	-18.1	-81.902	0.097	0.018					0.63	158
	(3.2)	(16.203)	(0.0105)	(0.0025)						
HS		-2.808	0.0061	0.00027					0.77	158
		(1.485)	(0.0009)	(0.00007)						
LPL-S		-39.210	0.0610	0.00796			-1.49068	-7.98762	0.8084	132
		(27.955)	(0.0217)	(0.00264)			(0.34319)	(4.31826)		
			HDD	**THI**						
LPL-P			0.0000	0.00000	3.17303	2.37470			0.6786	132
			(0.)	(0.)	(3.9716)	(0.7468)				

Like the commercial models, the estimated coefficients of the three industrial models indicate that sensitivity to price is small. Rate GLP has the highest price elasticity with -0.78. The industrial customers also have a significant response to the level of manufacturing employment which is consistent with the decline in electricity sales that has accompanied the decline in manufacturing employment in New Jersey.

The projections from each of these models were compared to 2021 actual values – a period of estimated bills at a more normal level and most recent COVID impacts. Based on this analysis, the industrial forecasts were adjusted to decrease sales to rates GLP and LPL-S and increase sales to LPL-P, The estimated current impact, assumed to be in effect until June 2022, was then assumed to be cut in half through the end of 2022. After 2022, pandemic impacts on sales was assumed to be eliminated. The impacts are summarized in the table below.

Table 6

COVID Sales Impacts in the Commercial Forecasts

	January 2021-June 2022			July 2022-December 2022		
Season	**GLP**	**LPL-S**	**LPL-P**	**GLP**	**LPL-S**	**LPL-P**
JAN-APR	-5.5%	-0.2%	3.1%	-2.8%	-0.1%	1.6%
NOV-DEC	-5.5%	-0.2%	3.1%	-2.8%	-0.1%	1.6%
MAY-OCT	-9.4%	-1.5%	3.3%	-4.7%	-0.8%	1.7%

III Energy Model Customer Forecast

With the BPU approval of the Clean Energy Future (CEF) proposal, the customer forecast has become more important in PSE&G financial planning as revenues have been, for the most part, decoupled from sales as a result of the lost revenue recovery mechanism , the Conservation Incentive Porgram (CIP). Under CIP, the future electric revenues will largely be determined by a "normal" average use per customer and the number of customers. The nature of this calculation has resulted a greater emphasis and in several modifications in the customer forecast.

The number of residential customers on the PSE&G system for forecasting purposes have always followed the FERC definition of customers which corresponds to the number of meter billed.

> Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.[2]

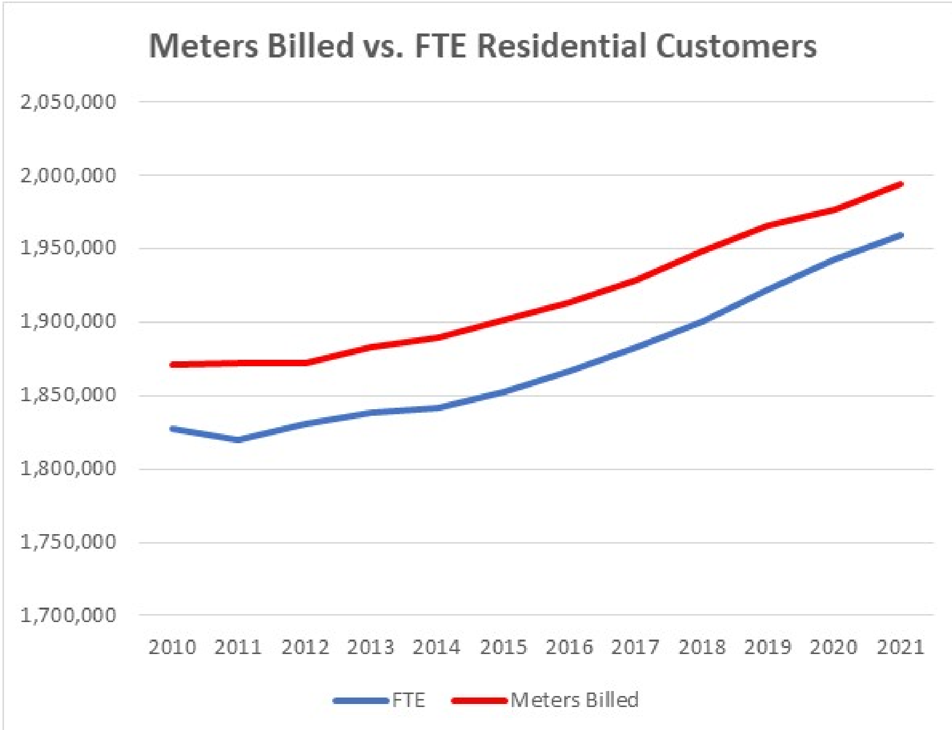
For the purposes of CIP, customers are defined as the total service charge revenue divided by the service charge rate. This calculation results in a number of customers based on the number of full month service charges. This corrects for the fact that customers that are present at a service address for only a partial billing period get a bill that has a service charge prorated for the period that service was rendered to that customer. Meters billed, therefore, can represent, for example, an apartment that had two tenants during a billing period because of a tenant change mid-billing period as two meters billed rather than the one full-time customer that would be an accurate measure. Using the service charge revenue divided by the service charge rate is a more accurate calculation of these full-time customers and this measurement will be referred to as "FTE customers" in this document.

Residential Customers

The meters billed number of Residential customers has exceeded the FTE Residential customer count by differences ranging from 2.3-2.6 percent during the 2012-2019 period. This fairly consistent gap has narrowed to 1.8 percent in both 2020 and the first six months of 2021 most likely due to pandemic induced eviction moratoriums. The consistent variance is reflected in the similar trends in the change in customers as shown in Figure xx.

[2] Federal Energy Regulatory Commission, U.S. Department of Energy , "FERC FINANCIAL REPORT FERC FORM No1: Annual Repport of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report:", OMB No. 1902-0021 (Expires 11/30/2022), https://cms.ferc.gov/sites/default/files/2021-03/form-1_1.pdf, Page 300.

Figure xx



Total Residential FTE customer growth is assumed to be correlated with the change in households in New Jersey. The ten year average annual Increase in FTE customers and households have been 0.6 percent and 0.4 percent, respectively. It is assumed that this relationship will continue to hold true in the future. As a result, total Residential customers are assumed to increase at a 0.5 percent annual rate during the forecast period (2022-2032) as households are expected to increase at a 0.3 percent annual rate.

Customers in rates RHS and RLM are projected to decline at the average annual rate seen during the 2010-2020 period of 4 percent and 1 percent respectively. As a result, rate RS customers are projected to increase at a 0.6 percent rate during the forecast period.

Commercial and Industrial Customers

The number of customers in the small and medium commercial and industrial rate, rate GLP, also utilizes the FTE definition of customers. These customers increased at an average rate of 1.0 percent during the 2017-2020 period and this is expected to continue during the forecast period. Industrial GLP customers are expected to decline at the 1 percent rate experienced since 2017. Commercial customers are predicted to increase at a 1 percent annual average rate during the forecast period.

It should be noted that the number of customers in this rate is not, due to the heterogeneity of the customers in this rate, highly correlated with kWh sales.

IV Energy Model Forecast Assumptions

The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts are described in more detail below.

Economic Assumptions

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy.com March 2019 forecast. This forecast assumes that, nationally, the economy continues to recover at a slow but steady rate. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. The forecast is summarized in Table 7.

Weather during the forecast period is assumed to be "normal" as defined by the average daily weather during the twenty-year period ending December 31, 2017.

Efficiency/NEM Assumptions

Historical installed net metered solar capacity is based on BPU Office of Clean Energy data through February 2019. Projected capacity is based on largely attaining the recent RPS standards through net metered solar installations.. The translation into energy values is based on the National Renewable Energy Laboratory's PVWatts® program. This data is summarized in Table 8.

Historical and projected impact of efficient lighting is from the PSE&G Residential End-Use Model. This data is summarized in Table 9. Projected electric vehicle and PSE&G efficiency program impacts are based on PSE&G Department of Renewables and Energy Solutions information. The New Jersey Energy Master Plan impacts are based on New Jersey Clean Energy Program data. This data is summarized in Table 10.

Historical and projected commercial energy use per square foot is from the U.S. Department of Energy's Annual Energy Outlook 2020. This data is summarized in Table 8.

Table 7

National and New Jersey Economic Forecast Assumptions

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
United States														
Gross Domestic Product, (Bil. USD, SAAR)	19,543	20,612	21,433	20,938	22,577	24,517	25,753	26,983	28,136	29,242	30,383	31,580	32,819	34,106
Industrial Production: Total, (Index 2012=100, SA)	104	109	109	102	110	113	114	116	117	118	119	121	122	124
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	15,992	16,493	16,889	17,714	18,212	17,923	18,391	18,842	19,207	19,610	20,067	20,561	21,070	21,584
Employment: Total Nonagricultural, (Mil. #, SA)	147	149	151	142	145	151	153	155	156	156	157	158	159	159
Household Survey: Unemployment Rate, (%, SA)	4.3	3.9	3.7	8.1	5.7	4.3	4.0	3.9	4.1	4.2	4.2	4.3	4.2	4.3
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	245	251	256	259	265	272	279	286	293	300	306	313	320	327
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.9	2.0	2.1	0.4	0.1	0.2	0.6	1.5	2.4	2.5	2.5	2.5	2.4	2.4
Terms Conventional Mortgages: All Loans														
Fixed Effective Rate, (%, NSA)	4.1	4.7	4.4	3.8	3.9	4.3	4.8	5.2	5.5	5.8	5.8	5.8	5.8	5.7
New Jersey														
Real Personal Income, (Mil. 09$, SAAR)	544,786	556,962	569,814	604,789	625,424	612,017	624,969	638,812	649,981	662,249	676,134	691,296	706,813	721,889
Employment: Total Nonagricultural, (Ths., SA)	4,121	4,159	4,197	3,851	3,931	4,054	4,114	4,145	4,159	4,172	4,186	4,200	4,215	4,229
Employment: Total Manufacturing, (Ths., SA)	247	250	251	238	242	246	245	241	237	233	229	225	221	218
Employment: Total Non-Manufacturing, (Ths., SA)	3,874	3,909	3,946	3,613	3,689	3,808	3,869	3,904	3,922	3,939	3,957	3,975	3,994	4,011
Labor: Unemployment Rate, (%, SA)	4.5	4.0	3.4	9.8	7.0	5.0	4.3	4.1	4.2	4.3	4.3	4.3	4.3	4.3
Population: Total, (Ths.)	8,886	8,885	8,881	8,888	8,903	8,917	8,934	8,953	8,971	8,986	8,997	9,003	9,006	9,008
Households: Total, (Ths.)	3,343	3,353	3,363	3,346	3,345	3,415	3,437	3,454	3,471	3,484	3,495	3,504	3,514	3,524
Housing Starts: Single-family, (#, SAAR)	11,568	12,255	12,243	12,637	17,278	19,241	19,840	19,957	19,987	18,785	17,265	15,472	14,307	13,646

Table 8

PSE&G Net Metered Solar Forecast Assumptions

	Capacity - Added DC (kW)						Capacity - DC (kW)					
Month/Year	RS	GLP	LPL-S	LPL-P	HTS	Total	RS	GLP	LPL-S	LPL-P	HTS	Total
2002	20.3	155.3	35.6	-	-	211.2	20.3	155.3	35.6	-	-	211.2
2003	81.6	13.6	479.8	-	-	575.0	101.9	168.9	515.4	-	-	786.2
2004	352.5	145.6	488.1	100.3	-	1,086.5	454.4	314.4	1,003.5	100.3	-	1,872.7
2005	911.1	888.0	2,792.3	245.8	-	4,837.2	1,365.5	1,202.4	3,795.8	346.1	-	6,709.8
2006	1,383.8	1,819.4	5,471.2	662.9	-	9,337.3	2,749.3	3,021.8	9,267.0	1,009.0	-	16,047.1
2007	869.7	1,585.8	3,726.2	470.1	-	6,651.9	3,619.0	4,607.6	12,993.2	1,479.2	-	22,699.0
2008	1,270.1	1,822.1	2,616.9	1,637.0	-	7,346.1	4,889.1	6,429.7	15,610.1	3,116.2	-	30,045.0
2009	2,543.6	5,734.6	8,146.1	4,423.2	3,282.3	24,129.7	7,432.7	12,164.3	23,756.2	7,539.4	3,282.3	54,174.8
2010	5,231.3	8,100.7	20,878.6	12,985.5	4,874.2	52,070.3	12,664.0	20,264.9	44,634.7	20,524.9	8,156.5	106,245.0
2011	14,203.8	21,351.8	56,775.6	40,637.5	21,866.5	154,835.3	26,867.8	41,616.8	101,410.4	61,162.3	30,023.1	261,080.3
2012	13,418.0	24,252.0	57,714.3	42,426.0	20,981.0	158,791.2	40,285.8	65,868.7	159,124.6	103,588.3	51,004.1	419,871.5
2013	15,094.5	12,555.3	35,210.9	27,744.8	10,857.2	101,462.7	55,380.3	78,424.0	194,335.5	131,333.1	61,861.2	521,334.2
2014	17,897.3	4,854.8	16,528.0	6,174.9	1,259.3	46,714.2	73,277.6	83,278.9	210,863.5	137,508.0	63,120.5	568,048.5
2015	34,571.8	4,548.0	9,557.3	4,394.3	3,050.1	56,121.4	107,849.4	87,826.9	220,420.8	141,902.3	66,170.6	624,169.9
2016	59,573.6	4,994.4	17,441.1	15,579.8	9,975.1	107,564.0	167,422.9	92,821.3	237,861.9	157,482.1	76,145.7	731,733.9
2017	54,359.3	8,640.6	28,511.2	31,501.8	19,570.9	142,583.9	221,782.2	101,462.0	266,373.1	188,983.9	95,716.5	874,317.8
2018	58,237.0	10,152.2	31,324.9	23,147.5	10,237.9	133,099.5	280,019.2	111,614.2	297,698.0	212,131.4	105,954.4	1,007,417.2
2019	57,398.4	9,872.7	34,421.7	31,136.1	22,415.6	155,244.4	337,417.6	121,486.9	332,119.8	243,267.5	128,370.0	1,162,661.7
2020	52,448.1	6,610.5	26,436.3	37,573.3	19,764.4	142,832.7	389,865.7	128,097.4	358,556.0	280,840.8	148,134.4	1,305,494.4
2021	59,519.3	14,556.7	49,603.3	56,954.6	32,289.4	212,923.3	449,385.0	142,654.1	408,159.4	337,795.4	180,423.8	1,518,417.7
2022	71,071.6	22,934.5	75,676.3	83,614.0	51,946.2	305,242.6	520,456.5	165,588.6	483,835.6	421,409.5	232,370.0	1,823,660.2
2023	65,543.1	17,257.9	56,945.3	62,918.4	39,088.8	241,753.5	585,999.7	182,846.4	540,781.0	484,327.8	271,458.8	2,065,413.8
2024	61,652.8	12,355.3	40,768.6	45,044.9	27,984.7	187,806.3	647,652.4	195,201.8	581,549.6	529,372.7	299,443.5	2,253,220.0
2025	59,605.2	9,775.1	32,254.5	35,637.8	22,140.4	159,413.0	707,257.6	204,976.9	613,804.1	565,010.5	321,583.9	2,412,633.0

Table 9

PSE&G Energy Reduction Due to Efficient Lighting Assumptions (MWh)

	Singlie-Family Dwelling Units				Multi-Family Dwelling Units				Total Dwelling Units			
Year	60W	75W	100W	Total	60W	75W	100W	Total	60W	75W	100W	Total
2005	35,635	3,824	4,145	43,604	10,631	1,141	1,237	13,009	46,266	4,965	5,382	56,613
2006	55,451	6,828	8,251	70,530	16,390	2,017	2,436	20,843	71,842	8,845	10,687	91,373
2007	101,607	13,872	17,929	133,408	32,271	4,421	5,727	42,419	133,878	18,293	23,656	175,827
2008	158,766	22,570	29,868	211,204	49,321	7,016	9,287	65,624	208,087	29,586	39,155	276,828
2009	212,524	30,757	41,112	284,393	65,545	9,485	12,677	87,706	278,069	40,242	53,788	372,100
2010	266,804	39,001	52,413	358,217	81,187	11,869	15,952	109,008	347,991	50,870	68,364	467,226
2011	319,000	46,984	63,359	429,343	96,579	14,217	19,193	129,989	415,579	61,201	82,553	559,332
2012	375,204	55,570	75,138	505,912	116,266	17,208	23,287	156,761	491,471	72,778	98,425	662,674
2013	436,530	64,948	87,932	589,411	133,261	19,813	26,843	179,917	569,791	84,761	114,775	769,328
2014	510,709	76,394	103,430	690,534	160,815	24,045	32,559	217,419	671,525	100,439	135,989	907,953
2015	589,191	88,518	119,777	797,486	183,786	27,599	37,355	248,739	772,977	116,117	157,131	1,046,225
2016	654,337	98,558	133,374	886,269	205,812	30,989	41,943	278,744	860,149	129,548	175,316	1,165,013
2017	721,053	108,656	147,356	977,065	225,081	33,904	45,991	304,977	946,134	142,560	193,347	1,282,042
2018	772,294	116,303	158,128	1,046,725	243,355	36,635	49,825	329,815	1,015,649	152,938	207,953	1,376,540
2019	808,644	121,686	165,782	1,096,112	256,468	38,580	52,578	347,626	1,064,828	160,224	218,300	1,443,353
2020	840,264	126,355	172,444	1,139,062	267,901	40,271	54,980	363,152	1,107,599	166,543	227,303	1,501,445
2021	929,561	139,409	191,326	1,260,297	297,763	44,640	61,289	403,691	1,227,070	184,012	252,561	1,663,643
2022	976,355	146,250	201,210	1,323,815	313,873	46,998	64,687	425,558	1,290,159	193,238	265,882	1,749,279
2023	987,568	147,900	203,558	1,339,026	318,387	47,664	65,630	431,681	1,305,886	195,554	269,173	1,770,614
2024	998,539	149,514	205,857	1,353,910	322,954	48,338	66,584	437,876	1,321,424	197,842	272,426	1,791,692
2025	1,009,119	151,071	208,073	1,368,263	327,446	49,001	67,522	443,969	1,336,497	200,062	275,580	1,812,138

Table 10

PSE&G Additional Energy Impact Assumptions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Electric Vehicles																
Vehicles	40	83	330	891	1,556	2,257	3,375	5,561	10,661	16,795	23,165	34,331	53,119	82,157	125,215	186,319
MWH	158	320	1,273	3,429	5,995	8,707	13,038	21,481	41,215	64,986	89,725	133,457	206,603	318,979	484,626	718,364
Clean Enegy Future (MWh)																
RS	-	-	-	-	-	-	-	-	-	-	36,921	201,426	349,634	457,733	529,554	602,465
GLP	-	-	-	-	-	-	-	-	-	-	-	43,904	199,380	407,671	659,912	951,343
LPL-S	-	-	-	-	-	-	-	-	-	-	-	21,008	93,570	191,949	315,862	458,786
LPL-P	-	-	-	-	-	-	-	-	-	-	-	7,583	32,482	67,460	116,095	172,086
HTS-ST	-	-	-	-	-	-	-	-	-	-	-	7,003	30,479	62,938	106,208	156,052
Energy Master Plan (MWh)																
RS	71,874	81,764	59,966	79,144	102,378	110,901	120,476	129,044	135,623	142,678	150,923	150,923	150,923	150,923	150,923	150,923
GLP	2,954	27,522	34,452	54,716	87,516	111,649	132,587	153,401	184,922	224,286	243,601	243,601	243,601	243,601	243,601	243,601
LPL-S	509,310	580,270	429,054	568,688	751,171	842,532	935,457	1,027,340	1,117,837	1,202,850	1,304,367	1,304,367	1,304,367	1,304,367	1,304,367	1,304,367

Table 11

Commercial Energy per Square Foot (MMBtu per sq. ft.)

Commercial End-Use	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooking	0.0002	0.0002	0.0002	0.0002	0.0003	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008
Lighting	0.0118	0.0115	0.0112	0.0110	0.0107	0.0059	0.0056	0.0054	0.0052	0.0051	0.0057	0.0055	0.0053	0.0051	0.0050	0.0048
Refrigeration	0.0048	0.0047	0.0046	0.0045	0.0044	0.0071	0.0071	0.0071	0.0071	0.0071	0.0070	0.0069	0.0068	0.0067	0.0066	0.0065
Computing	0.0026	0.0024	0.0015	0.0013	0.0011	0.0041	0.0039	0.0038	0.0037	0.0036	0.0035	0.0034	0.0034	0.0033	0.0033	0.0032
Other Equipment (non-Computing)	0.0028	0.0027	0.0027	0.0027	0.0026	0.0025	0.0037	0.0040	0.0042	0.0044	0.0046	0.0048	0.0050	0.0051	0.0053	0.0054
Total Non-Heating Non-Cooling	0.0223	0.0215	0.0202	0.0197	0.0190	0.0206	0.0213	0.0212	0.0211	0.0211	0.0218	0.0215	0.0213	0.0211	0.0210	0.0208

A. Calendar-Month Sales Calculation

Introduction

Utilities have traditionally had a disconnection in the timing of their revenues and their costs. Revenues from retail sales are a revenue stream from meter readings and the resulting bills to their customers that occur on a daily basis throughout the month. The bills issued from meter reads in the current month's meter reading schedule are all recorded as billing-month revenue. Billing-month revenue will include revenue from electricity or gas delivered during the previous month while excluding deliveries of electricity or gas delivered during the current month that occurred after the meters were read. Expenses, on the other hand, such as wages, fuel, depreciation, etc., have been recorded on a calendar-month basis. This inconsistency in the revenue and expense streams can be tolerated if there are no major changes in the revenue and/or expense streams. If major changes are occurring, such as a rapid increase in fossil fuel prices or a high seasonality in sales, a comparison of the billing-month revenue and the calendar-month expenses can give a false view of a utility's financials. To remedy this situation, the sales and revenue accrual calculation, the estimation of calendar-month sales and revenue from billed sales and revenue and the estimation of unbilled sales and revenue was developed.

Section II will discuss how, in theory, the billed sales and the unbilled estimates are used to calculate calendar-month sales using a simple example and introduce the notation that will serve as the basis of the analysis. A description of the theory's specific application to PSE&G's meter reading schedule, that can have a single billing month encompass up to four calendar-months, follows.

Section III will describe the implementation of the estimation of the calendar-month sales and revenue process at PSE&G.

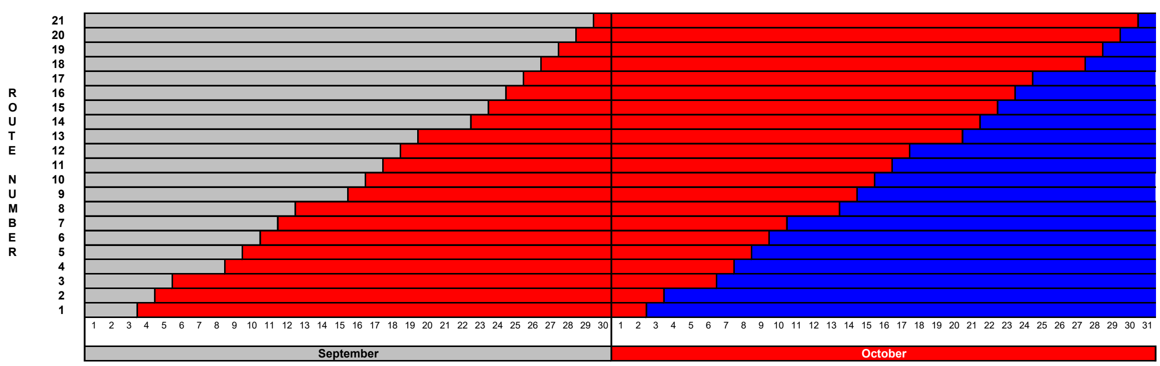
The Unbilled and Calendar-Month Estimation

A Simple Example

Utilities generally read all of their meters every month on 21 workdays. Figure 1, below shows a hypothetical October billing-month (in red) as determined by the September and October meter reading schedules. In the chart, each row represents a Route Number or a group of meters that are always read on the same day (although the day when they are all read may vary from month to month). The bottom row is red on all the days after the September read date, September 3rd until the October read date, October 2nd. If it is assumed that the customers' meters are read at noon, the October bill to these customers will reflect 28.5 days of service in September and only 1.5 days in October[3]. The second row from the bottom represents Route 2 whose customers' meters were read on September 4th and October 3rd. The October bill to these customers will reflect 27.5 days of service in September and only 2.5 days in October. This continues until the top row, Route 21, that had meter reading days of September 29th and October 30th. The October bills to these customers represent only 1.5 days of September service and 29.5 days of October service.

Figure 1

Hypothetical October 2008 Billing-Month



From the red portion of the diagram, it can be seen that the October billing-month consists of September sales that are billed in October that, to facilitate discussion, will be referred to as SEP B> OCT and October sales that are billed in October i.e., OCT B> OCT . The calendar-month sales are defined as the red and blue rectangle defined by the month of October and the 21 read-cycles. This consists of OCT B> OCT sales and the October unbilled sales, OCT B> NOV , the October sales that will be billed in November.

[3] Or, more realistically, if the meter reads for all the Route 1 customers are evenly distributed throughout an 8:00 AM to 4:00 PM workday, the reads, on average, would represent a half day's sales on the read day.

The relationship between billed, unbilled, and calendar-month sales can be derived from these identities from the steps below.

$$\text{October Calendar} = \boxed{\text{OCT B> OCT}} + \boxed{\text{OCT B> NOV}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} \qquad [1]$$

Adding and subtracting $\boxed{\text{SEP B> OCT}}$ to the r.h.s. of [1] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} + \boxed{\text{SEP B> OCT}} - \boxed{\text{SEP B> OCT}} \qquad [2]$$

Rearranging the r.h.s. of [2] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [3]$$

Substituting [1] into the l.h.s. of [3] yields:

$$\boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [4]$$

This is the familiar:

October Calendar = October Billed + October Unbilled – September Unbilled[4] [5]

This formula for the accrual of calendar-month sales and revenues is preferred to any direct estimation of calendar-month sales because any error in the unbilled estimate is
“reversed out” in the following month. The advantage of this is that, as the calendar time period extends, the potential error resulting from unbilled estimates is reduced. This can be seen by summing up [5] over the 2008 calendar-year as:

$$\text{Calendar-Year 2008} = \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Billed}_i + \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Unbilled}_i - \sum_{i=\text{DEC07}}^{\text{NOV08}} \text{Unbilled}_i \qquad [6]$$

[4] The difference between the current month’s unbilled and the previous month’s is often referred to as
the “net unbilled”.

Where:

$Billed_i$ = Billing-month sales in month i,
$Unbilled_i$ = Unbilled sales in month i.

That simplifies to:

$$\text{Calendar-Year 2008} = \sum_{i=JAN08}^{DEC08} Billed_i + Unbilled_{DEC08} - Unbilled_{DEC07} \qquad [7]$$

The key result from [7] is that the annual calendar-year sales are the annual billed sales, a very large real number, and the difference between two monthly unbilled estimates. Since the error that can be expected in the difference between the two monthly unbilled estimates can be assumed to be quite small compared to the annual billed total, the calendar-year estimate, as a result, can be expected to be very accurate.

The same general results described in this simple example apply to PSE&G's more complicated meter reading schedule that is described below.

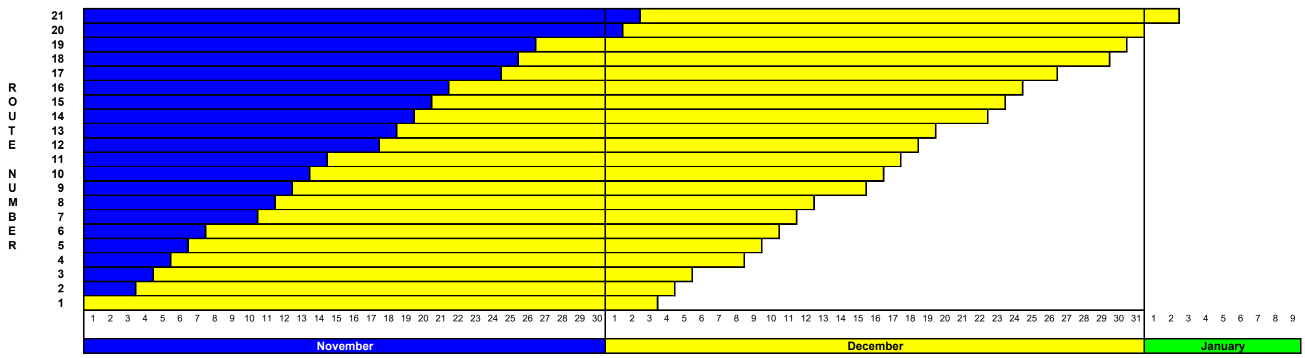
A More General Example

Unlike the hypothetical October billing-month, discussed above, that spanned two months, September and October, the PSE&G billing-month can encompass as many as four months. For example, the December 2008 PSE&G billing month, illustrated in Figure 2. has meter reading dates ranging from October 31st to January 2nd. As a result, it spans four months, October, November, December, and January[5].

[5] This is the original PSE&G December 2008 meter reading schedule. It has since been "compressed" to accommodate the implementation of iPower, the new billing and customer information system.

Figure 2

PSE&G December 2008 Billing-Month



Therefore, to develop a general algorithm applicable to PSE&G, the definition of billed, unbilled, and calendar sales must be expanded to include the potential of having sales from two additional calendar months reflected in a billing-month. December 2008 billing month, for example, is defined as:

December Billed = OCT B> DEC / NOV B> DEC / DEC B> DEC / JAN B> DEC [8]

Given the additional components of the billed, OCT B> DEC , i.e. the "under billed" sales, and JAN B> DEC , the "excess billed" sales, the addition of the current unbilled and subtraction of the previous month's unbilled to the December billed, as defined in the simple example above, will overstate December calendar-month sales by the sum of under billed and excess billed sales. As a result, the December unbilled needs to be redefined as:

December Unbilled = DEC B> JAN / DEC B> FEB + NOV B> JAN - JAN B> DEC [9]

December Unbilled = December Unbilled
+ January Underbilled – December Excess Billed[10]

December calendar can then be defined as December billed plus the new

December unbilled less the equivalent November unbilled or:

$$\boxed{\begin{array}{l}\text{DEC B> OCT}\\ \text{DEC B> NOV}\\ \text{DEC B> DEC}\\ \text{DEC B> JAN}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}}$$

$$+ \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}}$$

$$- \boxed{\begin{array}{l}\text{NOV B> DEC}\\ \text{NOV B> JAN}\end{array}} - \boxed{\text{OCT B> DEC}} + \boxed{\text{DEC B> NOV}} \qquad [11]$$

or, in words:

December Calendar = December Billed
+ December Unbilled
- November Unbilled [12]

This is the general formula that is used to calculate unbilled sales at PSE&G.

The PSE&G Gas Calendar-Month Estimation

The estimation of calendar-month gas sales at PSE&G is based on the notion that gas sales can be divided into two components: a weather sensitive component and a non-weather sensitive component. The weather sensitive component is affected by the winter weather as measured by heating degree days (HDD). The non-weather component is simply a function of the number of days in the sales period. As a result, sales during the unbilled periods can be estimated based on the HDD and number of days during the unbilled periods and the estimates of the weather-sensitive sales per HDD and non-weather sensitive sales per day.

The estimate of the weather-sensitive sales per HDD for each rate, the HDD coefficient, is the sum of the coefficients associated with its model's independent variables that have a HDD component divided by the number of days in the billing period. In the case of RSG that, unlike the other rates, is modeled on a use per customer basis, this result is multiplied by the number of customers.

The estimate of the non-weather sensitive sales per day for each rate, the base coefficient, is the value of the model equation with all of the coefficients associated with HDD set to zero and divided by the number of days in the billing period. As in the case of the HDD coefficient, the RSG result is multiplied by the number of customers.

Given the structure of the models, these coefficients will vary by month and by year. The current estimates for 2008 and 2009 are shown in Table 1 below.[6]

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

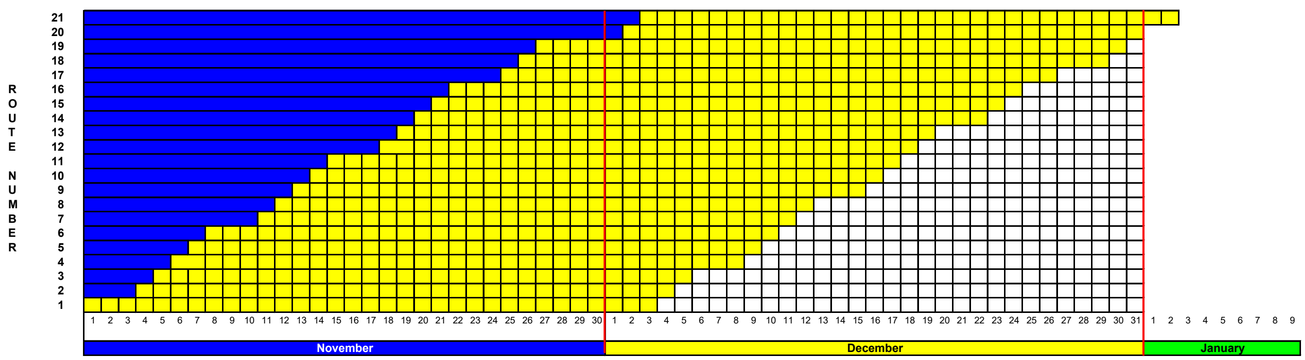
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	3,942	(15,873)	3,333	2,978	501	1,047,971	79,608	145,023	8,767
Feb-08	1,554,914	253,674	234,372	4,811	69,746	45,607	175,674	3,942	(15,256)	3,333	3,786	501	1,172,070	79,608	167,056	8,767
Mar-08	1,343,904	249,936	236,373	4,737	25,553	45,607	158,654	3,942	(16,832)	3,333	2,893	501	1,053,237	79,608	138,433	8,767
Apr-08	1,337,980	248,305	190,526	4,692	13,895	45,607	150,129	3,942	(15,769)	3,333	5,681	501	1,076,058	79,608	159,387	8,767
May-08	1,267,108	251,443	164,912	4,741	146,976	45,607	117,463	3,942	332	3,333	4,166	501	838,647	79,608	137,277	8,767
Jun-08	1,086,639	250,233	135,407	4,714	126,187	45,607	95,849	3,942	2,561	3,333	3,704	501	708,324	79,608	129,981	8,767
Jul-08	984,641	248,954	116,905	4,704	135,270	45,607	94,660	3,942	3,907	3,333	2,680	501	610,707	79,608	119,171	8,767
Aug-08	912,999	249,456	104,709	4,666	103,926	45,607	80,601	3,942	2,045	3,333	2,578	501	613,535	79,608	119,770	8,767
Sep-08	940,487	252,748	111,693	4,746	108,515	45,607	84,252	3,942	2,953	3,333	2,730	501	581,470	79,608	129,852	8,767
Oct-08	809,244	249,439	113,383	4,671	115,541	45,607	90,002	3,942	3,184	3,333	1,932	501	728,815	79,608	116,580	8,767
Nov-08	1,076,293	250,792	138,927	4,687	(9,962)	45,607	107,114	3,942	(7,929)	3,333	5,262	501	769,823	79,608	112,495	8,767
Dec-08	1,191,333	252,604	187,367	4,690	(9,608)	45,607	130,211	3,942	(18,805)	3,333	2,214	501	902,036	79,608	120,543	8,767
Jan-09	1,481,212	248,163	214,955	4,643	56,601	45,745	153,926	3,711	(15,827)	3,259	2,952	490	1,041,705	79,850	144,156	8,190
Feb-09	1,548,542	252,236	228,920	4,692	69,856	45,745	171,980	3,711	(15,254)	3,259	3,796	490	1,173,921	79,850	167,320	8,190
Mar-09	1,393,454	253,517	239,084	4,687	26,121	45,745	168,175	3,711	(17,054)	3,259	2,980	490	1,076,642	79,850	141,509	8,190
Apr-09	1,331,091	250,149	185,138	4,617	13,721	45,745	148,255	3,711	(15,497)	3,259	5,622	490	1,062,628	79,850	157,398	8,190
May-09	1,266,433	253,309	160,992	4,665	145,815	45,745	116,535	3,711	352	3,259	4,136	490	832,022	79,850	136,193	8,190
Jun-09	1,094,707	252,091	133,240	4,638	126,187	45,745	95,849	3,711	2,565	3,259	3,704	490	708,324	79,850	129,981	8,190
Jul-09	987,359	250,802	114,502	4,629	134,644	45,745	94,222	3,711	3,889	3,259	2,668	490	607,880	79,850	118,620	8,190
Aug-09	925,740	251,308	103,701	4,591	104,600	45,745	81,124	3,711	2,058	3,259	2,595	490	617,512	79,850	120,546	8,190
Sep-09	953,382	254,625	110,592	4,670	109,193	45,745	84,778	3,711	2,971	3,259	2,747	490	585,098	79,850	130,662	8,190
Oct-09	808,699	251,291	110,672	4,596	114,612	45,745	89,279	3,711	3,169	3,259	1,918	490	722,957	79,850	115,643	8,190
Nov-09	1,077,388	252,654	135,835	4,612	(9,899)	45,745	106,433	3,711	(7,834)	3,259	5,235	490	764,927	79,850	111,779	8,190
Dec-09	1,203,734	254,479	184,915	4,615	(9,637)	45,745	130,597	3,711	(18,750)	3,259	2,238	490	904,708	79,850	120,900	8,190

[6] While the coefficient is called the "base" coefficient, it really does not measure base use per day. Rather it is the intercept term in a simple regression. As a result, it can be negative reflecting the intercept of a regression that is outside of the relevant range.

The billed, unbilled, excess billed, and underbilled days and heating degree days are derived from the meter reading schedule and daily weather data. The measure used is the Average Route Days (ARD). The ARD are defined as the number of days across all routes for a given period divided by 21, the total number of routes. This concept is illustrated in Figure 3, a slightly different version of the December 2008 billing-month, shown below.

Figure 3

PSE&G December 2008 Billing-Month



Each square represents an ARD.[7] The total yellow blocks in each row represent the number of days in that particular route during the December billing-month. The sum of all the yellow blocks, 677, divided by 21 represent the average number of days in the December billing-month, i.e., the average number of days across the 21 routes or 32.24.

The number of excess billed days, $\boxed{\text{JAN B> DEC}}$, is:

1.5 (January 1st and half of January 2nd) / 21 = 0.07 [13]

HDD for each period are a weighted sum of the daily HDD where the weight is the ARD associated with that day. For example, from the diagram it can be seen that on December 21st, the sales to 8 routes, routes 14-21, will be in the

[7] Well, not exactly. Remember that it is assumed that the meters are read at noon. As a result the last yellow block to the right of each row counts as a half day. On the other hand, the last blue block on the right of each row also counts as a half day in the December billing-month so, the math works for the billing-month but, the half needs to be taken into account when discussing portions of the unbilled and billed periods. For a clearer discussion, however, the half days will be, for the most part, ignored.

December billing-month while sales to the first thirteen routes will be in the January billing-month. As a result , 8/21 or 38 percent of the HDD on December 20th will be assigned to the December billing month and 62 percent will be assigned to the January billing month.

HDD for underbilled and excess billed periods are assigned in a similar manner.

From Table 2 below that shows the normal monthly billed an unbilled HDD and days by type, it can be seen that underbilled days and HDD occur rarely while excess billed days are quite common.

Table 2

Billed and Unbilled Days and Weather
2008-2009

Billing Month	Heating Degree Days				Days			
	Billed	Unbilled	Excess Billed	Under Billed	Billed	Unbilled	Excess Billed	Under Billed
Jan-08	795.06	322.08	0.59	-	31.67	12.76	0.02	0.00
Feb-08	786.44	283.76	5.90	-	30.19	11.83	0.29	0.00
Mar-08	643.82	187.74	2.62	-	30.67	12.10	0.21	0.00
Apr-08	360.41	73.05	0.20	-	30.14	11.83	0.10	0.00
May-08	108.21	13.78	0.05	-	29.90	13.05	0.21	0.00
Jun-08	15.47	0.14	-	-	30.33	12.60	0.10	0.00
Jul-08	0.14	-	-	-	30.71	12.81	0.02	0.00
Aug-08	0.01	0.03	-	-	29.57	14.29	0.07	0.00
Sep-08	1.87	7.02	0.04	-	30.71	13.52	0.02	0.00
Oct-08	60.34	87.80	-	-	29.38	15.12	0.00	0.00
Nov-08	255.88	213.78	1.65	-	29.76	15.43	0.10	0.00
Dec-08	578.34	338.40	1.75	0.17	32.24	14.19	0.07	0.02
Jan-09	797.36	361.02	1.75	-	31.86	13.33	0.07	0.00
Feb-09	786.19	277.80	7.41	-	30.14	11.48	0.36	0.00
Mar-09	634.56	188.08	1.17	-	30.00	12.21	0.10	0.00
Apr-09	361.92	73.58	0.46	-	30.52	11.79	0.19	0.00
May-09	108.91	13.36	0.05	-	30.14	12.67	0.21	0.00
Jun-09	15.07	0.12	-	-	30.33	12.21	0.10	0.00
Jul-09	0.12	-	-	-	30.86	12.38	0.12	0.00
Aug-09	0.01	0.03	-	-	29.38	13.90	0.02	0.00
Sep-09	1.97	6.92	0.04	-	30.52	13.38	0.02	0.00
Oct-09	61.71	86.34	-	-	29.62	14.74	0.00	0.00
Nov-09	261.34	207.03	1.65	-	29.95	14.88	0.10	0.00
Dec-09	582.57	329.38	3.90	-	32.14	13.81	0.17	0.00

On a monthly basis, the necessary coefficient, weather, and day data are transmitted to PSE&G accounting services each month. They are used to calculate the actual current month unbilled sales, UnbilledTherms, using:

UnbilledTherms = UnbilledDays x BASECoef + UnbilledHDD x HDDCoef [14]

Where:

UnbilledDays = the number of route days in the unbilled period as defined by [9],

Unbilled HDD = the number of HDD in the unbilled period as defined by [9],

BASECoef = the Base coefficient,

HDDCoef = the HDD coefficient.

The results of this calculation, with the previous month's unbilled results, are used to calculate calendar-month sales.

Unbilled, and as a consequence, calendar-month revenue is calculated by pricing the unbilled therms at the projected tariff rates. Adding the net unbilled revenue to the billing-month revenues results in the estimate of calendar-month revenue.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of Changes in its Electric Conservation Incentive Program
(2022 PSE&G Electric Conservation Incentive Program)

BPU Docket No. _______________

DIRECT TESTIMONY

OF

KAREN REIF
VICE PRESIDENT, RENEWABLES AND ENERGY SOLUTIONS

February 1, 2022

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
KAREN REIF
VICE PRESIDENT, RENEWABLES AND ENERGY SOLUTIONS

Q. Please state your name, affiliation and business address.

A. My name is Karen B. Reif and I am the Vice President of Renewables and Energy Solutions for Public Service Electric and Gas Company ("PSE&G" or the "Company"). My principal place of business is 80 Park Plaza, Newark, New Jersey, 07102

Q. Please describe your education and business experience.

A. I have a Bachelor of Arts degree in International Studies from Emory University, and a Master of Business Administration in Finance and Strategy from Carnegie Melon University. I have worked for PSE&G and its affiliate PSEG Services Corporation in various positions. I have also worked for ScottMadden Management Consultants as a consultant. I joined PSEG in 1995. I have held multiple positions across the organization including various roles in trading, deregulated subsidiaries, information technology and most recently, continuous improvement. I spent 14 years in the Information Technology Department, holding several leadership roles including system implementation, business relationship management and project management/quality support. Prior to becoming Vice President of Renewables and Energy Solutions, I served as the Senior Director of Continuous Improvement for PSEG Services Corporation. I established this function for PSEG, which is responsible for developing sustainable and quantifiable business improvements based on industry best practices. In July of 2018, I was named Vice President of Renewables and Energy Solutions. My professional experience includes finance, strategy, business relationships, application implementation, quality assurance, process management and program management. I have primary management and oversight responsibility for the design, planning and operations of renewable energy, electric vehicles, energy storage and energy efficiency programs.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of this testimony is to provide a summary of the spending activity related to the CIP Shareholder Contribution ("SC") over the past several months, an update on the SC expenditures to date, and an explanation of how the Company plans to show the SC spending for both its natural gas and electric CIP.

Q. How is the balance of your testimony organized?

A. The balance of my testimony is organized as follows:

I. Shareholder Contribution background

II. Shareholder Contribution Program Activity Summary

III. Shareholder Contribution Expenditure Update

IV. Shareholder Contribution Spending Plan

I. <u>Shareholder Contribution (SC) background</u>

Q. Please describe the Shareholder Contribution funding construct.

A. The Shareholder Contribution construct was established in the Company's Clean Energy Future – Energy Efficiency ("CEF-EE") filing, which was approved on September 23, 2020 in Dockets Nos. GO18101112 and EO18101113. Pursuant to the Company's CEF-EE stipulation, paragraph 38, SC pending activities may include the following:

> The shareholder contribution will support initiatives designed to aid customers in reducing their costs of natural gas and electricity and to reduce each utility's peak demand. The initiatives may include efforts such as education and outreach, as well as enhancements to standard incentives to further encourage customer engagement in the CEF-EE Program (e.g., the distribution of free EE kits within

low- and moderate-income census tracts), grants to schools and community organizations, and a business EE portal.

- Community Education and Outreach: This category covers community outreach activities, such as presentations, lunch and learns, outreach tables, trade shows, business conferences, and green fairs. It may also include grants or initiatives with community organizations. Particular emphasis will be placed on low- and moderate-income communities.

- Municipal and NGO (non-governmental organization) Outreach: This category includes activities to work with municipalities and other organizations and may include funding for special studies or projects and partnerships to promote EE.

- Customer Engagement: This category includes activities to increase customer awareness and engagement in programs, including enhanced incentives for promotional purposes, such as the offering of a flash sale. Particular emphasis will be placed on low- and moderate-income customers. A business engagement portal may be explored to evaluate the potential to provide customized information to this diverse customer segment.

- Energy Efficient Economy: This category supports efforts to engage and develop a diverse supplier and workforce base to support the delivery of EE services.

II. Shareholder Contribution Program Activity Summary

Q. Please describe the programs and initiatives that the SC funds support.

A. Consistent with the provisions of the CEF-EE stipulation and order, SC spending activity includes the following initiatives and programs:

- PSE&G's Job's Program Training Site: Funding was used for modifications to a training site that was developed with the Urban League of Essex County to support the PSE&G Clean Energy Jobs program. The site was built to host the BPI Air Leakage Control Installer (ALCI) training, which is an entry-level training course for an installer position. The common area includes two separate rooms, one that includes four working stations where the majority of the hands-on training will occur, and the other with training tables and a projector to provide general classroom training. A separate room was specifically built out and designed to perform the blow-in insulation portion of the ALCI training.
- Outreach and community events: Through SC funding PSE&G engaged a diverse vendor to expand our community presence and help drive awareness of our energy efficiency programs. The Company created a dynamic, interactive vending machine for use at high traffic locations throughout New Jersey such as malls during the 2021 holiday season and into 2022. This interactive vending machine will educate customers through a fun trivia game about how to save money and be more energy efficient. With a portion of this funding we were able to purchase small event tool-kits and giveaways to promote the CEF-EE programs at community events such as local green fairs and municipal events such as the NJ League of Municipalities Annual Conference.
- Organizational memberships and sponsorships: PSE&G sponsored the Clean Energy and Sustainability Analytics Center (CESAC) at Montclair State University's Third Annual

Clean and Sustainable Energy Summit. The summit provided us the opportunity to discuss energy efficiency and the benefits of New Jersey's plan for a clean and sustainable energy future. This summit also provided a venue for informed participant-driven discussion on clean energy and climate change policies in New Jersey and beyond. A portion of this funding also went toward a sponsorship with the Association of New Jersey Environmental Commissions ("ANJEC"). The Company utilized this engagement to promote the benefits of energy efficiency to the attendees of the ANJEC environmental congress. The sponsorship also included a full-page ad in ANJEC's four quarterly newsletters which reach more than 5000 municipal officials and environmental commission members. PSE&G plans to continue to promote and raise awareness of our energy efficiency programs to this audience.

- Marketplace Free shipping: The funding is being used to offer customers free shipping for orders placed in the on-line Marketplace that do not meet the $49 minimum order amount to receive free shipping. The intent is to increase customer participation and encourage customers to make multiple purchases on small orders of energy efficient products where the shipping costs may be a deterrent. This promotion will continue into 2022.

Upcoming activity:

- Sustainable Jersey Grant: The purpose of this partnership is to collaborate with Sustainable Jersey to assist municipalities and schools in raising awareness of PSE&G incentives for energy-related projects within their communities. A portion of the funding will be used for grants awarded to municipalities to engage in energy efficiency projects. Sustainable Jersey will also provide technical assistance to municipalities in support of this effort. The funding will also go toward developing a local government energy training program and the Empowered Schools program administered by the Alliance to Save Energy.

C&I Trade Ally Incentive: This bonus will support increased awareness and participation in the CEF EE C&I programs amongst our business customers and our contractor network. Funding for this initiative will provide a bonus paid directly to approved Trade Allies who bring in energy efficient projects totaling at least 250K kWh.

- C&I Small Business Kits: This initiative will enhance market awareness of PSE&G's Business Energy Efficiency program offerings. We will partner with AM Conservation to create small business kits that include a BR30 LED lamp, an A19 LED lamp, an advanced Tier 1 Power strip, a PSE&G EE program brochure, and a product guide. The initiative targets small businesses in market segments such as accommodation, food services, retail trade, art, entertainment, recreation and other services. These free kits will be mailed to small business customers to raise program awareness and encourage program participation starting in 2021.

Q. Is the Company considering additional programs and initiative to support with SC funds?

A. Yes, the Company continues to explore additional initiatives and ideas for SC spending that is consistent with the SC goals delineated in the approved CEF-EE stipulation.

III. <u>Shareholder Contribution Spending</u>

Q. Please summarize the SC spending the Company to date

A. As of November 30, 2021, the Company has recorded expenses of approximately $325,906 for the initial several months of SC activity. A summary of actual expenses is included in Schedule KR-CIP-1.

IV. Shareholder Contribution Spending Plan

Q. Can you describe how the Company plans to comply with the required annual spending, given that the electric CIP and gas CIP deferral periods are different?

A. Pursuant to the CEF-EE stipulation, the Shareholder Contribution funding is to be $3.3 million per year, with 55% allocated to electric distribution and 45% allocated to natural gas distribution. However, the deferral periods for the electric and natural gas CIPs are not aligned; the first electric deferral period is June 2021 – May 2022, and the first natural gas deferral period is October 2021 – September 2022. Given this misalignment within the first year, the Company determined it would be consistent with the intent of the CEF-EE stipulation and order and more straightforward from a reporting standpoint to adjust the $3.3 million within the first 18 months to account for this misalignment, and then begin to report against the $3.3 on an annual 12 month basis. Therefore, the Company is targeting to spend $3,905,000 by September 2022; $3.3 million to account for the October 2021-September 2022 period, when both electric and gas deferral periods are in effect, plus an additional $605,000, representing the June 2021-September 2021 period, when only the electric deferral period is in effect. Please see Schedule KR-CIP-2 for the full calculations related to this spending plan. After September 2022, the Company will spend $3.3 million every 12 months in accordance with the CEF-EE Program approval.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT C

Schedule KR-CIP-1

CIP recorded expenses through Nov 30, 2021					
Activities	**Jun**	**Sep**	**Oct**	**Nov**	**Grand Total**
Jobs Program Training Sites	52,000				52,000
Organizational memberships and sponsorships		21,800			21,800
Outreach and community events		1,729	2,853	247,524	252,106
Marketplace free shipping			149,155		149,155
Total	52,000	23,529	152,008	98,369	**325,906**

ATTACHMENT C

Schedule KR-CIP-2

Shareholder Contribution Spending

Total		Percent	Annual	Monthly
$ 3,300,000	E	55%	$1,815,000	$151,250
	G	45%	$1,485,000	$123,750

Electric Deferral June 2021 - May 2022

Gas Deferral Oct 2021 - Sep 2022

	Reporting Time Period Spending		
Totals	6/21-9/22	10/22-9/23	10/23-9/24
Electric	$2,420,000	$1,815,000	$1,815,000
Gas	$1,485,000	$1,485,000	$1,485,000
Total	$3,905,000	$3,300,000	$3,300,000

	Electric	Gas
6/1/2021	$151,250	
7/1/2021	$151,250	
8/1/2021	$151,250	
9/1/2021	$151,250	
10/1/2021	$ 151,250	$ 123,750
11/1/2021	$ 151,250	$ 123,750
12/1/2021	$ 151,250	$ 123,750
1/1/2022	$ 151,250	$ 123,750
2/1/2022	$ 151,250	$ 123,750
3/1/2022	$ 151,250	$ 123,750
4/1/2022	$ 151,250	$ 123,750
5/1/2022	$ 151,250	$ 123,750
6/1/2022	$ 151,250	$ 123,750
7/1/2022	$ 151,250	$ 123,750
8/1/2022	$ 151,250	$ 123,750
9/1/2022	$ 151,250	$ 123,750
10/1/2022	$ 151,250	$ 123,750
11/1/2022	$ 151,250	$ 123,750
12/1/2022	$ 151,250	$ 123,750
1/1/2023	$ 151,250	$ 123,750
2/1/2023	$ 151,250	$ 123,750
3/1/2023	$ 151,250	$ 123,750
4/1/2023	$ 151,250	$ 123,750
5/1/2023	$ 151,250	$ 123,750
6/1/2023	$ 151,250	$ 123,750
7/1/2023	$ 151,250	$ 123,750
8/1/2023	$ 151,250	$ 123,750
9/1/2023	$ 151,250	$ 123,750
10/1/2023	$ 151,250	$ 123,750
11/1/2023	$ 151,250	$ 123,750
12/1/2023	$ 151,250	$ 123,750
1/1/2024	$ 151,250	$ 123,750
2/1/2024	$ 151,250	$ 123,750
3/1/2024	$ 151,250	$ 123,750
4/1/2024	$ 151,250	$ 123,750
5/1/2024	$ 151,250	$ 123,750
6/1/2024	$ 151,250	$ 123,750
7/1/2024	$ 151,250	$ 123,750
8/1/2024	$ 151,250	$ 123,750
9/1/2024	$ 151,250	$ 123,750
10/1/2024	$ 151,250	$ 123,750
11/1/2024	$ 151,250	$ 123,750
12/1/2024	$ 151,250	$ 123,750

ATTACHMENT D

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of Changes in its Electric Conservation Incentive Program
(2022 PSE&G Electric Conservation Incentive Program)

BPU Docket No. _______________

DIRECT TESTIMONY

OF

STEPHEN SWETZ
SENIOR DIRECTOR - CORPORATE RATES AND REVENUES REQUIREMENTS

February 1, 2022

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR - CORPORATE RATES AND REVENUES REQUIREMENTS

Q. Please state your name and business address.

A. My name is Stephen Swetz. My business address is 80 Park Plaza, T-8, Newark, New Jersey 07102.

Q. By whom are you employed and in what capacity?

A. I am the Senior Director - Corporate Rates and Revenues Requirements, PSEG Services Corporation. My credentials are set forth in the attached Schedule SS-ECIP-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Public Service Electric and Gas Company's ("PSE&G", "the Company") derivation of the Electric Distribution Conservation Incentive Program ("ECIP") rates for the Company's Residential Service ("RS"), Residential Heating Service ("RHS"), Residential Load Management ("RLM"), General Lighting & Power Service ("GLP") and Large Power & Lighting Service - Secondary ("LPL-S") rate schedules as well as the results of the Earnings and the BGS Savings Tests as approved by the Board on September 23, 2020, in the Clean Energy Future – Energy Efficiency ("CEF-

EE") Board Order in Docket Nos. GO18101112 and EO18101113 ("CEF-EE Order").

Q. Please describe the ECIP mechanism.

A. As set forth in the Testimony of PSE&G Witness Michael P. McFadden, the ECIP mechanism provides a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer, removing the disincentive for the Company to encourage customers to conserve energy. The ECIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline revenue per customer from the actual revenue per customer and multiplying the resulting revenue per customer by the actual number of customers for the month.

Q. What rate schedules are included in the ECIP?

A. The ECIP is applicable to each of the following customer groups:

- Group I – RS and RHS
- Group Ia – RLM
- Group II – GLP
- Group III – LPLS

Q. What is the current total ECIP deferral balance?

A. As shown in PSE&G's petition in this matter, Attachment A, Schedule 7, the Company's total deferral for the ECIP is $51,551,188, representing $72,568,455 of non-weather related electric distribution margin deficiencies partially offset by a refund due to customers of $21,017,267 related to weather related electric distrubition margin.

Q. Are there any limitations on the amount of margin deficieny that can be collected from customers throught the ECIP?

A. Yes. There are three specific tests that are part of the ECIP:

1. Earnings Test;
2. BGS Savings Test; and
3. Variable Margin Test.

The three tests are described below.

Q. Please briefly describe PSE&G's ECIP Earnings Test.

A. The earnings test is applicable to the total ECIP deferral, including both weather and non-weather components. If the calculated Electric ROE ("EROE") exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of revenues through the ECIP shall not be allowed for the applicable filing period and shall not be carried over to subsequent filing periods.

Q. How is the EROE calculated?

A. The earnings test determines actual EROE based on the actual net income of the utility for the most recent 12-month period divided by the average of the beginning and ending common equity balances for the corresponding period.

Q. What time period is utilized for the earnings tests?

A. The earnings test for this filing is based on the latest available twelve month financial statements filed with FERC and/or the BPU, which is April 2021 through March 2022 for this filing. Since March 2022 actual results are not available, the earnings test in this initial filing contains actual results through September 2021 and forecasted results through March 2022. The Company will provide an updated earnings test with all actual results when they are available.

Q. What are the results of the Earnings Test?

A. Please see PSE&G's petition in this matter, Attachment A Schedule 6 for the results of the Earnings Test.

Q. Please describe the BGS Savings Test.

A. The BGS Savings Test recognizes opportunities to reduce peak demand and lower commodity costs through reductions in customer usage. As a result, non-weather related margins are limited to the level of BGS savings achieved when these savings are less than 75 percent of the non-weather related electric distribution margin deficiency, i.e. BGS Savings Test. Any amount that exceeds the above limitation may be deferred for future recovery and is subject to a recovery test in a future year consistent with the amount by which the non-weather related electric distributon margin deficiency exceeded the recovery test.

Q. How is the BGS Savings Test calculated?

A. The BGS Savings Test recognizes three categories of savings:

i. Category One includes the Company's permanent savings realized from the reduction in PJM Final Zonal Unforced Capacity ("UCAP") Obligation from the 2011/2012 energy year compared to the 2020/2021 energy year multiplied by the 2020/2021 PS Zonal Net Load Price. The permanent BGS savings are $64.506 million. These amounts will remain after the re-setting of the ECIP benchmarks in future base rate cases.

ii. Category Two includes BGS cost savings from ongoing reductions of the Company's PJM Final Zonal UCAP Obligation. This category of savings is calculated as any annual incremental UCAP Obligation savings after the 2020/2021 energy year. Any annual incremental UCAP Obligation savings will be multiplied by the most recent PS Zonal Net Load Price. Due to the potential for UCAP increases due to electric vehicles and electrification, savings are set as a minimum of the incremental obligation savings or zero.

iii. Category Three is the Company's savings associated with avoided capacity costs to meet customer growth on a prospective basis beginning with the first annual ECIP filing following implementation of these terms. Avoided capacity costs are calculated on a monthly basis and are equal to the net change in customers for ECIP multiplied by the corresponding obligation per customer and the current PS Zonal Net Load Price per month.

Q. What are the results of the BGS Savings Test?

A. Please see the petition, Attachment A, Schedule 5 for the results of the BGS Savings Test. Since the BGS Savings Test amount was higher than the non-weather deferral, the BGS Savings Test did not result in a limitation on the Company's ECIP recovery of non-weather related revenues.

Q. Are there any other limitations on setting the ECIP?

A. Yes. As stated in the CEF-EE Order, recovery of non-weather related margin deficiencies is limited by a Variable Margin Test. Please see the testimony of Michael P. McFadden for a description and the results of the Variable Margin Revenue Test at Attachment A, Schedule 5. The application of the Variable Margin Revenue Test resulted in the Company's ECIP recovery of non-weather related distribution margin deficiencies totaling $72,568,455 being limited to $38,767,864.

Q. What is the net ECIP balance to be collected from customers over the upcoming ECIP Period?

A. As shown in Attachment A, Schedule 7 the net ECIP amounts to $17,750,598 which represents $38,767,864 of allowed margin recovery partially offset by weather related refunds to residential customers totaling $21,017,267. As a result of the limitation on allowed margin revenue recovery a remaing

$33,800,591 of distribution margin deficiency will be deferred for recovery in a future ECIP period.

Q. Please show proposed ECIP rates.

A. The ECIP rates calculated in Schedule SS-ECIP-2 are summarized below:

		ECIP Rates Without SUT	ECIP Rates with SUT	
Group I	RS & RHS	($0.001108)	($0.001181)	Per kilowatt-hour
Group Ia	RLM	($0.000598)	($0.000638)	Per kilowatt-hour
Group II	GLP	$0.6371	$0.6793	Per kilowatt of monthly peak demand
Group III	LPL-S	$0.6108	$0.6513	Per kilowatt of monthly peak demand

Q. What are the annual rate impacts to the typical residential customer?

A. Based upon rates effective February 1, 2022, the annual average bill impacts of the rates requested are set forth in Schedule SS-ECIP-3.

The annual impact of the proposed rates to the typical residential electric customer using 740 kWh in a summer month and 6,920 kWh annually would be a decrease in the annual bill from $1,279.64 to $1,271.52 or $8.12, or approximately 0.63% (based upon Delivery Rates and BGS-RSCP charges in effect February 1, 2022 and assuming that the customer receives BGS-RSCP service from PSE&G).

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE INDEX

Schedule SS-ECIP-1	Qualifications
Schedule SS-ECIP-2	Rate Calculations
Schedule SS-ECIP-3	Residential Bill Impacts
Schedule SS-ECIP-4	Tariff Sheets

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII)
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	The Second Energy Strong Program (Energy Strong II)
Public Service Electric & Gas Company	E/G	ER21101201 and GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	The Second Energy Strong Program (Energy Strong II)
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 - GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 - GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 - GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER18070688 - GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 - GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 - GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 and GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 - GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER17030324 - GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 - GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 - GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757-GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389-GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II
Public Service Electric & Gas Company	G	ER14070656	written	Jul-14	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER14070651-GR14070652	written	Jul-14	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER14070650	written	Jul-14	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR14050511	written	May-14	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR14040375	written	Apr-14	Remediation Adjustment Charge-RAC 21
Public Service Electric & Gas Company	E/G	ER13070603-GR13070604	written	Jun-13	Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	ER13070605	written	Jul-13	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR13070615	written	Jun-13	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR13060445	written	May-13	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO13020155-GO13020156	written/oral	Mar-13	Energy Strong / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GO12030188	written/oral	Mar-13	Appliance Service / Tariff Support
Public Service Electric & Gas Company	E	ER12070599	written	Jul-12	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12070606-GR12070605	written	Jul-12	RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR12060489	written	Jun-12	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR12060583	written	Jun-12	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12030207	written	Mar-12	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER12030207	written	Mar-12	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR11060338	written	Jun-11	Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR11060395	written	Jun-11	Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO11010030	written	Jan-11	Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Oct-10	RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E/G	ER10080550	written	Aug-10	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER10080550	written	Aug-10	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR09050422	written/oral	Mar-10	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER10030220	written	Mar-10	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E	EO09030249	written	Mar-09	Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	EO09010056	written	Feb-09	Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO09020125	written	Feb-09	Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO08080544	written	Aug-08	Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Jun-08	Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval

PUBLIC SERVICE ELECTRIC AND GAS
CONSERVATION INCENTIVE PROGRAM
CALCULATION OF ECIP RATES

	Initial ECIP Deferral	RS & RHS	RLM	GLP	LPLS	Total	Reference
(1)	CIP Carry-Forward	$0	$0	$0	$0	$0	Attachment A Schedules 1 through 3
(2)	CIP Weather	($20,711,587)	($305,679)	$0	$0	($21,017,267)	Attachment A Schedule 4
(3)	CIP Non-Weather	$11,923,271	$369,329	$31,592,710	$28,683,145	$72,568,455	Attachment A Schedule 5
(4)	**Total CIP Deferral**	**($8,788,316)**	**$63,650**	**$31,592,710**	**$28,683,145**	**$51,551,188**	(4) = (1) + (2) + (3)
(5)	CIP Collection	$0	$63,650	$31,592,710	$28,683,145	$60,339,505	(5) = IF (4) < 0, 0, (4)
(6)	CIP Collection %	0.0%	0.1%	52.4%	47.5%	100.0%	
(7)	CIP Savings Test Recoverable Amount					**$38,767,864**	Attachment A Schedule 5, Page 2
(8)	CIP Refunds					($8,788,316)	Row (4) RS & RHS
(9)	CIP Maximum Recoverable Amount					$47,556,181	(9) = (7) - (8)
(10)	**CIP (Refund) / Charge**	**($8,788,316)**	**$50,165**	**$24,899,585**	**$22,606,430**	**$38,767,864**	(10) = (IF (4) < 0, (4)), ((4) * (6))
(11)	CIP Carry-Forward	$0	$13,485	$6,693,125	$6,076,714	$12,783,324	(11) = (10) - (4)

	Final ECIP Rate	RS&RHS	RLM	GLP	LPLS	Total	
(12)	CIP Carry-Forward	$0	$0	$0	$0	$0	(1)
(13)	CIP Weather	($20,711,587)	($305,679)	$0	$0	($21,017,267)	(2)
(14)	CIP Non-Weather	$11,923,271	$369,329	$31,592,710	$28,683,145	$72,568,455	(3)
(15)	**Total CIP Deferral**	**($8,788,316)**	**$63,650**	**$31,592,710**	**$28,683,145**	**$51,551,188**	(15) = (12) + (13) + (14)
(16)	CIP Non-Weather Savings Cap					**$38,767,864**	(7)
(17)	CIP Allocation of Non-Weather Savings Cap	16%	1%	44%	40%	**100%**	(17) = (3) / Total (3)
(18)	CIP Non-Weather Allocation	$6,369,707	$197,305	$16,877,608	$15,323,246	**$38,767,864**	(18) = (16) * (17)
(19)	CIP Weather	($20,711,587)	($305,679)	$0	$0	**($21,017,267)**	(2)
(20)	**CIP (Refund) / Charge**	**($14,341,881)**	**($108,374)**	**$16,877,608**	**$15,323,246**	**$17,750,598**	(20) = (18) + (19)
(21)	CIP Carry-Forward	$5,553,565	$172,024	$14,715,103	$13,359,899	$33,800,591	(21) = (15) - (20)
(22)	Projected Use (000) *	12,980,585	N/A	181,822	26,561	25,154	Attachment A Schedules 1 through 3

		RS	RHS	RLM	GLP	LPLS	
(23)	CIP Rate	-0.001105	-0.001105	-0.000596	0.6354	0.6092	(23) = (20) / ((22) * 1000)
(24)	CIP Rate w/ Assessment	-0.001108	-0.001108	-0.000598	0.6371	0.6108	(24) = (23) * (1 / (1 - (0.22% + 0.05%))
(25)	CIP Rate w/SUT	-0.001181	-0.001181	-0.000638	0.6793	0.6513	(25) = (24) * 1.06625

* kWh (RS, RHS & RLM) and kW (GLP & LPLS)

TYPICAL RESIDENTIAL ELECTRIC BILL IMPACTS

The effect of the proposed Electric Conservation Incentive Program (ECIP) charge on typical residential electric bills, if approved by the Board, is illustrated below:

Residential Electric Service					
If Your Monthly Summer kWhr Use Is:	And Your Annual kWhr Use Is:	Then Your Present Annual Bill (1) Would Be:	And Your Proposed Annual Bill (2) Would Be:	Your Annual Bill Change Would Be:	And Your Percent Change Would Be:
185	1,732	$362.84	$360.76	($2.08)	(0.57)%
370	3,464	666.44	662.36	(4.08)	(0.61)
740	6,920	1,279.64	1,271.52	(8.12)	(0.63)
803	7,800	1,436.70	1,427.49	(9.21)	(0.64)
1,337	12,500	2,290.12	2,275.32	(14.80)	(0.65)

(1) Based upon current Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect February 1, 2022 and assumes that the customer receives BGS-RSCP service from Public Service.
(2) Same as (1) except includes the proposed ECIP.

Residential Electric Service					
If Your Annual kWhr Use Is:	And Your Monthly Summer kWhr Use Is:	Then Your Present Monthly Summer Bill (3) Would Be:	And Your Proposed Monthly Summer Bill (4) Would Be:	Your Monthly Summer Bill Change Would Be:	And Your Percent Change Would Be:
1,732	185	$37.83	$37.61	($0.22)	(0.58)%
3,464	370	70.73	70.29	(0.44)	(0.62)
6,920	740	138.43	137.56	(0.87)	(0.63)
7,800	803	150.49	149.54	(0.95)	(0.63)
12,500	1,337	252.77	251.19	(1.58)	(0.63)

(3) Based upon current Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect February 1, 2022 and assumes that the customer receives BGS-RSCP service from Public Service.
(4) Same as (3) except includes the proposed ECIP.

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Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 2**

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CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO
RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	Conservation Incentive Program including SUT	
RS & RHS	$(0.001108)	$(0.001181)	Per kilowatt-hour
RLM	$(0.000598)	$(0.000638)	Per kilowatt-hour
GLP	$0.6371	$0.6793	Per kilowatt of monthly peak demand
LPL-S	$0.6108	$0.6513	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers (“ANC”) shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program (“CIP”) Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company’s books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer (“ARC”) shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company’s books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer ("BRC") shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RS & RHS
Group IA:	RLM
Group II:	GLP
Group III:	LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65°F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2021-2022 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2022	992	
February 2022	833	
March 2022	693	
April 2022	357	189
May 2022	128	926
June 2021		2,993
July 2021		5,507
August 2021		4,847
September 2021		2,174
October 2021	236	391
November 2021	516	
December 2021	818	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2021-2022 Winter Period for HDD and 2021 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	**HDD**	**THI**	**HDD**	**THI**	**HDD**	**THI**
January 2022	475,206	154,756	12,919	514	6,275	2,041
February 2022	474,987	154,685	12,843	511	6,377	2,074
March 2022	474,902	154,657	12,787	508	6,409	2,085
April 2022	475,583	154,879	12,712	505	6,312	2,053
May 2022	475,790	154,946	12,681	504	6,184	2,012
June 2021	455,913	154,354	12,929	514	6,365	2,070
July 2021	458,664	155,285	12,881	512	6,185	2,012
August 2021	456,939	154,701	12,728	506	6,427	2,090
September 2021	458,141	155,108	12,676	504	6,281	2,043
October 2021	458,714	155,302	12,586	500	6,280	2,043
November 2021	459,202	155,468	12,550	499	6,211	2,020
December 2021	460,274	155,831	12,461	495	6,228	2,026

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	**RS & RHS**	**RLM**	**GLP**	**LPL-S**
Jun	$30.26	$87.92	$129.53	$2,669.62
Jul	37.65	99.56	149.32	3,911.18
Aug	34.81	93.44	144.52	3,948.53
Sep	21.37	42.69	90.25	2,217.92
Oct	13.79	16.88	54.33	1,610.54
Nov	14.98	15.45	48.46	1,000.64
Dec	18.57	19.90	48.39	856.78
Jan	20.60	21.67	51.81	918.58
Feb	17.06	18.87	49.47	921.00
Mar	16.39	18.10	49.53	922.50
Apr	13.98	14.31	49.06	878.89
May	15.43	18.46	87.32	1,707.49
Total Annual	**$254.88**	**$467.25**	**$951.99**	**$21,563.65**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge, the Technology Innovation Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 93**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.039972	$ 0.042620

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.043793	$ 0.046694

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 94**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 94**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 99**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033234	$ 0.035436	$ 0.049594	$ 0.052880

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.015634	$ 0.016670	$ 0.054494	$ 0.058104

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 100**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 100**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 105**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 105**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:
Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:
$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.015007	$ 0.016001	$ 0.071911	$ 0.076675
Off-Peak	$ 0.015007	$ 0.016001	$ 0.015007	$ 0.016001

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:
This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:
This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 106**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 106**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand shall be applied. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.

This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 130**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 130**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit and the Zero Emission Certificate Recovery Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 143**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 143**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6538	$ 1.7634	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.1809	$ 9.7891	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 144**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 144**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit and the Zero Emission Certificate Recovery Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

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Superseding
B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO
RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	**Conservation Incentive Program including SUT**	
RS & RHS	$(0.001108)	$(0.001181)	Per kilowatt-hour
RLM	$(0.000598)	$(0.000638)	Per kilowatt-hour
GLP	$0.6371	$0.6793	Per kilowatt of monthly peak demand
LPL-S	$0.6108	$0.6513	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers (“ANC”) shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program (“CIP”) Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company’s books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer (“ARC”) shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company’s books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer (“BRC”) shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RS & RHS
Group IA:	RLM
Group II:	GLP
Group III:	LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage (“FAU”) shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65°F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2021-2022 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2022	992	
February 2022	833	
March 2022	693	
April 2022	357	189
May 2022	128	926
June 2021		2,993
July 2021		5,507
August 2021		4,847
September 2021		2,174
October 2021	236	391
November 2021	516	
December 2021	818	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2021-2022 Winter Period for HDD and 2021 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	**HDD**	**THI**	**HDD**	**THI**	**HDD**	**THI**
January 2022	475,206	154,756	12,919	514	6,275	2,041
February 2022	474,987	154,685	12,843	511	6,377	2,074
March 2022	474,902	154,657	12,787	508	6,409	2,085
April 2022	475,583	154,879	12,712	505	6,312	2,053
May 2022	475,790	154,946	12,681	504	6,184	2,012
June 2021	455,913	154,354	12,929	514	6,365	2,070
July 2021	458,664	155,285	12,881	512	6,185	2,012
August 2021	456,939	154,701	12,728	506	6,427	2,090
September 2021	458,141	155,108	12,676	504	6,281	2,043
October 2021	458,714	155,302	12,586	500	6,280	2,043
November 2021	459,202	155,468	12,550	499	6,211	2,020
December 2021	460,274	155,831	12,461	495	6,228	2,026

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	**RS & RHS**	**RLM**	**GLP**	**LPL-S**
Jun	$30.26	$87.92	$129.53	$2,669.62
Jul	37.65	99.56	149.32	3,911.18
Aug	34.81	93.44	144.52	3,948.53
Sep	21.37	42.69	90.25	2,217.92
Oct	13.79	16.88	54.33	1,610.54
Nov	14.98	15.45	48.46	1,000.64
Dec	18.57	19.90	48.39	856.78
Jan	20.60	21.67	51.81	918.58
Feb	17.06	18.87	49.47	921.00
Mar	16.39	18.10	49.53	922.50
Apr	13.98	14.31	49.06	878.89
May	15.43	18.46	87.32	1,707.49
Total Annual	**$254.88**	**$467.25**	**$951.99**	**$21,563.65**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 66D**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge, the Technology Innovation Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 93**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.039972	$ 0.042620

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.043793	$ 0.046694

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 99**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033234	$ 0.035436	$ 0.049594	$ 0.052880

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.015634	$ 0.016670	$ 0.054494	$ 0.058104

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.015007	$ 0.016001	$ 0.071911	$ 0.076675
Off-Peak	$ 0.015007	$ 0.016001	$ 0.015007	$ 0.016001

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand shall be applied. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.

This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit and the Zero Emission Certificate Recovery Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6538	$ 1.7634	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.1809	$ 9.7891	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit and the Zero Emission Certificate Recovery Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECTRIC CUSTOMERS

In The Matter of the Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Conservation Incentive Program (2022 Electric CIP Rate Filing)

Notice of Filing and Notice of Public Hearings

BPU Docket No. XXXXXXXXXX

TAKE NOTICE that, on February 1, 2022, Public Service Electric and Gas Company ("PSE&G," or "Company") filed a Petition and supporting documentation with the New Jersey Board of Public Utilities ("Board" or "BPU") seeking Board approval for cost recovery associated with the Electric Conservation Incentive Program ("ECIP" or "Program").

On September 23, 2020, the Board issued an Order approving the Clean Energy Future – Energy Efficiency Program in Docket Nos. GO18101112 and EO18101113 ("Order"). In this Order, the Board approved a Conservation Incentive Program ("CIP") that allows the Company to account for lost sales revenue from the decrease in customer usage.

Under the Company's proposal, PSE&G seeks Board approval to recover approximately $52 million as a result of lower revenue per customer compared to an approved baseline. The deferral consists of $73 million of non-weather related lost revenue, offset by favorable residential weather of $21 million. The approved CIP limits recovery of the $73 million non-weather deferral to $39 million, for the upcoming recovery period, which when offset by the $21 million of residential weather, results in an overall increase to customers of $18 million for the upcoming recovery period, and a deferral for recovery in a subsequent CIP recovery period of $34 million. The CIP deferral is calculated by applicable rate schedule and thus some rate schedules can receive a credit while others a charge based on the difference between actual revenue and the baseline by rate schedule.

The proposed Electric CIP charges, if approved by the Board, are shown in Table #1.

The approximate effect of the proposed impact on typical electric residential monthly bills, if approved by the Board, is illustrated in Table #2.

Based on the filing, a typical residential electric customer using 740 kilowatt-hours per summer month and 6,920 kilowatt-hours on an annual basis would see a decrease in the annual bill from $1,279.64 to $1,271.52, or $8.12 or approximately 0.63%.

The Board has the statutory authority pursuant to N.J.S.A. 48:2-21, to establish the ECIP at levels it finds just and reasonable. Therefore, the Board may establish the ECIP at a level other than that proposed by PSE&G. As a result, the described charges may increase or decrease based upon the Board's decision.

A copy of the Company's filing is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings.

PLEASE TAKE FURTHER NOTICE that due to the COVID-19 pandemic, telephonic public hearings have been scheduled for the following date and times so that members of the public may present their views on the Company's ECIP filing.

Date:
Time:
Dial In:
Meeting ID:
Passcode:

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the telephonic public hearings. Members of the public are invited to participate by utilizing the Dial-In number and Passcode set forth above and may express their views on the ECIP filing. All comments will be made part of the final record of the proceeding and will be considered by the Board. In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

The Board will also accept written and/or electronic comments. While all comments will be given equal consideration and will be made part of the final record of this proceeding, the preferred method of transmittal is via the Board's Public Document Search Tool by searching for the specific docket listed above, and then posting the comment by utilizing the "Post Comments" button.

Emailed comments may be filed with the Secretary of the Board, in PDF or Word format, to board.secretary@bpu.nj.gov. Detailed instructions for e-Filing can be found on the Board's home page at https://www.nj.gov/bpu/agenda/efiling.

Written comments may be submitted to the Board Secretary, Aida Camacho-Welch, at the Board of Public Utilities, 44 South Clinton Avenue, 1st Floor, P.O. Box 350, Trenton, New Jersey 08625-0350. All mailed or emailed comments should include the name of the petition and the docket number.

All comments are considered "public documents" for purposes of the State's Open Public Records Act. Commenters may identify information that they seek to keep confidential by submitting them in accordance with the confidentiality procedures set forth in N.J.A.C. 14:1-12.3.

Table # 1
Electric CIP Charges

	ECIP Charges		
Rate Schedule	**Present Charge (Incl SUT)**	**Proposed Charge (Incl SUT)**	
RS & RHS	$0.000000	($0.001181)	Per kilowatt-hour
RLM	0.000000	(0.000638)	Per kilowatt-hour
GLP	0.0000	0.6793	Per kilowatt of monthly peak demand
LPL-S	0.0000	0.6513	Per kilowatt of monthly peak demand

Table # 2
Residential Electric Service

If Your Annual kWhr Use Is:	And Your Monthly Summer kWhr Use Is:	Then Your Present Monthly Summer Bill (1) Would Be:	And Your Proposed Monthly Summer Bill (2) Would Be:	Your Monthly Summer Bill Change Would Be:	And Your Monthly Percent Change Would Be:
1,732	185	$37.83	$37.61	($0.22)	(0.58)%
3,464	370	70.73	70.29	(0.44)	(0.62)
6,920	740	138.43	137.56	(0.87)	(0.63)
7,800	803	150.49	149.54	(0.95)	(0.63)
12,500	1,337	252.77	251.19	(1.58)	(0.63)

(1) Based upon current Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect February 1, 2022, and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.
(2) Same as (1) except includes the proposed ECIP.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY