Danielle Lopez
Associate Counsel - Regulatory

Public Service Electric Gas Company
80 Park Plaza – T20, Newark, New Jersey 07102-4194
email: danielle.lopez@pseg.com

February 3, 2025

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of Changes it its Electric Conservation
Incentive Program
(2025 PSE&G Electric CIP Rate Filing)

BPU Docket No. __________________

VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL

Sherri L. Lewis, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Lewis:

Enclosed for filing on behalf of petitioner Public Service Electric and Gas Company is the Petition, Testimony of Michael McFadden, Lauren Thomas and 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)

Public Service Electric and Gas Company for Approval of Changes it its Electric Conservation Incentive Program (2025 PSE&G Electric CIP Rate Filing)
BPU Docket No.

Sherri L. Lewis, Board Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, NJ 08625-0350

Brian O. Lipman, Director
Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

Maura Caroselli, Esq.
Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

Mamie W. Purnell, Esq.
Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

Terrence Coleman, Paralegal
Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

Carol Artale
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Rachel Boylan
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Mahogany A. Hall
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Michael Kammer
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Benjamin S. Hunter
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Jacqueline O'Grady
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Stacy Peterson
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Stacy Richardson
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Andrew Tuzzo
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Hanaa Rohman
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Benjamin Witherell
NJ Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625

Matko Ilic, DAG
NJ Dept. of Law and Public Safety
Richard J. Hughes Justice Complex
Public Utilities Section
25 Market Street, P.O. Box 112
Trenton, NJ 08625

Danielle Lopez, Esq.
PSE&G
80 Park Plaza, T20
P.O. Box 570
Newark, NJ 07102

Joseph F. Accardo, Jr.
PSE&G
80 Park Plaza, T20
P.O. Box 570
Newark, NJ 07102

Maria Barling
PSE&G
80 Park Plaza, T20
P.O. Box 570
Newark, NJ 07102

Bernard Smalls
PSE&G
80 Park Plaza, T20
P.O. Box 570
Newark, NJ 07102

Caitlyn White
PSE&G
80 Park Plaza, T20
P.O. Box 570
Newark, NJ 07102

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 (2025 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 2.3 million electric and 1.9 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, 2025, for new rates effective June 1, 2025. 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.

[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"). 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.

9. 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.

10. 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").

11. 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.

12. 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.

13. 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.

14. 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.

15. 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.

16. 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.

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

18. 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.

19. 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.

20. 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.

THE CIP

21. 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

22. 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

23. 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

24. 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.

25. 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.

26. 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.

27. 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).

28. 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

29. 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 D, Schedule SS-ECIP-4. 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.

<u>REQUEST FOR COST RECOVERY</u>

30. 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.

31. Per the CEF-EE Order, the electric baseline revenue per customer is based on the billing determinants approved in the most recent base rate case and the latest variable margin rates per rate schedule, including any Infrastructure Investment Program ("IIP") rate adjustments. The June 1, 2024 through September 30, 2024 variable margin revenue for this filing is based on the Infrastructure Advancement Program ("IAP") rate adjustment approved for new rates effective June 1, 2024 in Docket No. ER23110783 and the approved billing determinants from the Company's 2018 base rate case. The Company's 2023 base rate case in Docket Nos. ER23120924 and GR23120925 was approved effective October 15, 2024 and included revised CIP baseline revenue per customer factors as shown in Revised Original Sheet Number 66C of the Company's Electric tariff. Because the 2023 rate case was approved in the middle of the month, the baseline revenue factor for October 2024 is prorated at 14 days at the pre-rate case baseline revenue per customer and 17 days at the approved rate case baseline revenue per customer. 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, 2024 – May 31, 2025, and the calculation of the Variable Margin Test. Attachment C is the testimony of Lauren

Thomas, PSE&G's Vice President of Clean 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.

32. 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.

33. The Company's total deferral for the electric CIP ("ECIP") is forecasted to be $87,060,160. The deferral balance is forecasted to include $27,457,059 of non-weather related margin deficiencies, partially offset by $9,123,390 of weather related refunds to residential customers, $68,726,492 deferred margin recovery from the prior ECIP period (comprised of a non-weather carry-forward balance of $66,018,162 and an over-recovery of $1,367,443 as a result of not updating provisionally approved rates), as well as an under-collection of the approved prior ECIP balance of $4,075,773.

34. 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.

35. The application of the Variable Margin Test resulted in the Company's ECIP recovery of non-weather related distribution margin deficiencies totaling $92,107,778 ($24,457,059 non-weather related deficiencies plus $64,650,719 prior year carry-forward balance) being limited to $71,402,087.

36. The net ECIP amounts to $64,987,026 - representing $71,402,087 of allowed non-weather margin recovery partially offset by weather related refunds to residential customers totaling $9,123,390 as well as under recovered margin recovery from the Company's prior ECIP period of $2,708,330 ($4,075,773 - 1,367,443). As a result of the limitation on allowed margin revenue recovery, a remaining $22,073,134 of distribution margin deficiency will be deferred for recovery in a future ECIP period.

37. The ECIP rates are summarized below:

		ECIP Rates Without SUT	**ECIP Rates with SUT**	
Group I	RS & RHS	($0.000215)	($0.000229)	Per kilowatt-hour
Group Ia	RLM	$0.006859	$0.007313	Per kilowatt-hour
Group II	GLP	$0.8237	$0.8783	Per kilowatt of monthly peak demand
Group III	LPL-S	$1.7944	$1.9133	Per kilowatt of monthly peak demand

38. Based upon rates effective February 1, 2025, the annual average bill impacts of the rates requested are set forth in Schedule SS-ECIP-3.

39. The average monthly impact of the proposed rates to the typical residential electric customer using 683 kWh in a summer month and 558 kWh in an average month (6,700 kWh annually) would be a decrease in the average monthly bill from $134.25 to $133.25 or $1.00, or approximately 0.74% (based upon Delivery Rates and BGS-RSCP charges in effect February 1, 2025 and assuming that the customer receives BGS-RSCP service from PSE&G).

40. 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.

41. 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.

42. 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, 2025 per the CEF-EE Stipulation, upon issuance of a written BPU order.

43. 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

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

Joseph F. Accardo, Esq. Senior Vice President, State Regulatory Affairs & Centralized Services Public Service Electric and Gas Company 80 Park Plaza, T20 P.O. Box 570 Newark, NJ 07102 joseph.accardojr@pseg.com	Danielle Lopez, Esq. Associate Counsel - Regulatory Public Service Electric and Gas Company 80 Park Plaza, T20 P.O. Box 570 Newark, NJ 07102 danielle.lopez@pseg.com
Caitlyn White Regulatory Filings & Systems Supervisor Public Service Electric and Gas Company 80 Park Plaza, T20 P.O. Box 570 Newark, NJ 07102 caitlyn.white@pseg.com	Bernard Smalls Paralegal Public Service Electric and Gas Company 80 Park Plaza, T20 P.O. Box 570 Newark, NJ 07102 bernard.smalls@pseg.com
Maria Barling Regulatory Case Coordinator Public Service Electric and Gas Company 80 Park Plaza, T20 P.O. Box 570 Newark, NJ 07102 maria.barling@pseg.com	

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, 2024 – May 31, 2025, 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, 2025 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
Associate Counsel - Regulatory
Public Service Electric and Gas Company
80 Park Plaza, T20
P. O. Box 570
Newark, New Jersey 07102

DATED: February 3, 2025

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 (2025 PSE&G ELECTRIC CIP RATE FILING)	**) BPU DOCKET NO. __________**

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

Public Service Electric and Gas
Conservation Incentive Program
Group I: Residential Service RS and RHS
June 2024 - May 2025

Customer Class	Actual/ Estimate	Actual per Books[1] Total Class Variable Revenues	Actual per Books[1] Number of Customers	Actual Avg. Revenue / Cust.	Baseline Revenue / Cust.[2]	Difference	Margin Variance
(a)		(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	(g) = (c) * (f)
Residential							
Jun-24	Act	78,025,316	2,001,695	39.0	37.2	1.7	$3,479,073
Jul-24	Act	96,912,704	1,987,944	48.8	44.9	3.8	$7,615,717
Aug-24	Act	75,346,842	2,011,333	37.5	41.6	(4.1)	($8,252,449)
Sep-24	Act	47,043,419	2,001,152	23.5	23.9	(0.4)	($731,292)
Oct-24	Act	33,340,463	2,001,039	16.7	16.9	(0.2)	($389,064)
Nov-24	Act	36,880,459	2,020,825	18.3	19.2	(1.0)	($1,988,785)
Dec-24	Frcst	49,939,621	2,011,587	24.8	25.8	(0.9)	($1,882,265)
Jan-25	Frcst	57,107,931	2,006,063	28.5	28.2	0.3	$621,917
Feb-25	Frcst	46,020,957	2,007,316	22.9	23.7	(0.8)	($1,523,326)
Mar-25	Frcst	45,023,913	2,008,570	22.4	22.4	0.1	$125,046
Apr-25	Frcst	37,618,617	2,009,822	18.7	18.6	0.1	$196,673
May-25	Frcst	52,089,419	2,011,075	25.9	20.7	5.2	$10,530,166
Total		655,349,661		326.9	322.9	3.9	$7,801,411

Margin Deficiency/ (Credit)	$	(7,801,411)
Prior Period (Over) / Under Recovery[3]	$	20,035,980
Total Deficiency/(Credit)	$	12,234,569
Projected Residential kWh Use		13,856,219,509
Pre-tax CIP Charge/(Credit) per kWh	$	0.0009
BPU/RC Assessment Factor		1.002600
CIP Charge/(Credit) including assessments	$	0.000900
6.625% Sales Tax	$	0.000060
Proposed After-tax CIP Charge/(Credit) per kWh	**$**	**0.000960**
Current After-tax CIP Charge/(Credit) per kWh	$	0.0015460
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kWh	$	(0.000586)

[1] Per Attachment A, 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 Eattachment A, Schedule 1, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group I: Residential Service RS and RHS

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	
Customers													
Service Charge Revenues	9,287,866	9,224,060	9,332,585	9,285,344	9,645,008	11,094,330	11,325,234	11,294,135	11,301,189	11,308,249	11,315,298	11,322,352	
Service Charge Rate (pre-tax)	4.64	4.64	4.64	4.64	4.82	5.49	5.63	5.63	5.63	5.63	5.63	5.63	
Total Customers	2,001,695	1,987,944	2,011,333	2,001,152	2,001,039	2,020,825	2,011,587	2,006,063	2,007,316	2,008,570	2,009,822	2,011,075	2,006,535
Volumes													
RS kWh	1,574,729,930	1,945,221,129	1,594,218,172	1,017,774,674	817,599,198	832,524,660	1,112,532,636	1,265,384,458	1,019,909,621	998,545,873	835,964,325	910,819,474	
RHS kWh	4,564,785	5,887,168	4,863,897	3,182,593	4,035,230	6,554,650	10,503,066	12,466,967	9,466,190	7,807,793	4,153,776	2,944,827	
Total Volumes	1,579,294,715	1,951,108,297	1,599,082,069	1,020,957,267	821,634,427	839,079,311	1,123,035,702	1,277,851,425	1,029,375,811	1,006,353,666	840,118,101	913,764,302	7,354,897,073
Revenues													
Volume Charge Revenues	$78,025,316	$96,912,704	$75,346,842	$47,043,419	$33,340,463	$36,880,459	$49,939,621	$57,107,931	$46,020,957	$45,023,913	$37,618,617	$52,089,419	$577,324,345
Total Revenue	78,025,316	96,912,704	75,346,842	47,043,419	33,340,463	36,880,459	49,939,621	57,107,931	46,020,957	45,023,913	37,618,617	52,089,419	655,349,661

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group I: Residential Service RS and RHS
June 2023 - May 2024

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	TOTAL
Beginning Under/(Over) Recovery $	35,931,628	35,704,210	35,177,410	32,865,138	31,388,834	30,200,750	28,987,441	27,363,532	25,515,759	24,027,281	22,572,094	21,357,283	35,931,628
kWh Sales	1,579,294,715	1,951,108,297	1,599,082,069	1,020,957,267	821,634,427	839,079,311	1,123,035,702	1,277,851,425	1,029,375,811	1,006,353,666	840,118,101	913,764,302	14,001,655,092
Pre-tax Recovery Rate per kWh[1]	0.000270	0.000270	0.001446	0.001446	0.001446	0.001446	0.001446	0.001446	0.001446	0.001446	0.001446	0.001446	
Recovery $*	227,418	526,799	2,312,273	1,476,304	1,188,083	1,213,309	1,623,910	1,847,773	1,488,477	1,455,187	1,214,811	1,321,303	15,895,648
Ending Under/(Over) Recovery $	35,704,210	35,177,410	32,865,138	31,388,834	30,200,750	28,987,441	27,363,532	25,515,759	24,027,281	22,572,094	21,357,283	20,035,980	20,035,980

[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 2024 - May 2025

		Actual per Books[1]					
	Actual/	Total Class	Number of	Actual Avg. Revenue /	Baseline Revenue /		Margin
Customer Class	Estimate	Revenues	Customers	Cust.	Cust.[2]	Difference	Variance
(a)		(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	
Residential Load Management							
Jun-24	Act	1,016,859	9,614	105.8	97.0	8.7	$83,870
Jul-24	Act	1,302,188	13,229	98.4	109.9	(11.5)	($151,667)
Aug-24	Act	921,718	11,929	77.3	103.1	(25.9)	($308,723)
Sep-24	Act	533,603	11,244	47.5	47.1	0.3	$3,606
Oct-24	Act	198,845	11,758	16.9	18.0	(1.1)	($13,184)
Nov-24	Act	187,267	10,836	17.3	21.4	(4.1)	($44,237)
Dec-24	Frcst	276,868	11,634	23.8	21.5	2.3	$26,297
Jan-25	Frcst	273,237	11,300	24.2	27.1	(2.9)	($33,245)
Feb-25	Frcst	224,730	11,294	19.9	21.1	(1.2)	($13,399)
Mar-25	Frcst	217,872	11,287	19.3	22.0	(2.7)	($30,756)
Apr-25	Frcst	190,096	11,280	16.9	18.3	(1.5)	($16,602)
May-25	Frcst	397,366	11,274	35.3	21.0	14.3	$161,035
Total		5,740,648		502.4	527.7	(25.3)	($337,004)

Margin Deficiency/ (Credit)	$	337,004
Prior Period (Over) / Under Recovery[3]	$	413,858
Total Deficiency/(Credit)	$	750,862
Projected Residential kWh Use		168,486,954
Pre-tax CIP Charge/(Credit) per kWh	$	0.0045
BPU/RC Assessment Factor		1.002600
CIP Charge/(Credit) including assessments	$	0.004469
6.625% Sales Tax	$	0.000296
Proposed After-tax CIP Charge/(Credit) per kWh	**$**	**0.0048**
Current After-tax CIP Charge/(Credit) per kWh	$	0.002419
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kWh	$	0.0023

[1] Per Attachment A, 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 Attachment A, Schedule 1, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group Ia: RLM

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	
Customers													
Service Charge Revenues	125,656	172,900	155,912	146,965	153,677	141,628	152,062	147,691	147,613	147,521	147,430	147,351	
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	9,614	13,229	11,929	11,244	11,758	10,836	11,634	11,300	11,294	11,287	11,280	11,274	
Volumes													
RLM kWh	21,900,443	28,471,602	20,753,465	14,165,701	10,660,499	10,172,311	12,872,371	14,766,358	12,144,916	11,774,311	10,273,234	12,130,261	
Total Volumes	21,900,443	28,471,602	20,753,465	14,165,701	10,660,499	10,172,311	12,872,371	14,766,358	12,144,916	11,774,311	10,273,234	12,130,261	180,085,472
Revenue													
Volume Charge Revenues	1,016,859	1,302,188	921,718	533,603	198,845	187,267	276,868	273,237	224,730	217,872	190,096	397,366	5,740,648
Total Revenue	1,016,859	1,302,188	921,718	533,603	198,845	187,267	276,868	273,237	224,730	217,872	190,096	397,366	5,740,648

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group Ia: Residential Load Management (RLM)
June 2023 - May 2024

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Frcst Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Act May-25	TOTAL
Beginning Under/(Over) Recovery $	744,568	729,960	709,995	677,938	653,814	630,794	601,663	568,247	540,763	514,118	490,870	463,419	744,568
kWh Sales	28,471,602	20,753,465	14,165,701	10,660,499	10,172,311	12,872,371	14,766,358	12,144,916	11,774,311	10,273,234	12,130,261	21,900,443	180,085,472
Pre-tax Recovery Rate per kWh[1]	0.000962	0.000962	0.002263	0.002263	0.002263	0.002263	0.002263	0.002263	0.002263	0.002263	0.002263	0.002263	
Recovery $	14,608	19,965	32,057	24,125	23,020	29,130	33,416	27,484	26,645	23,248	27,451	49,561	330,710
Ending Under/(Over) Recovery $	729,960	709,995	677,938	653,814	630,794	601,663	568,247	540,763	514,118	490,870	463,419	413,858	413,858

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

* June 2022 Recovery $ reflects 16/30 of the revenue calculation because the rate was implemented on June 15, 2022

Public Service Electric and Gas
Conservation Incentive Program
Group II: General Power & Light (GLP)
June 2024 - May 2025

		Actual per Books[1]					
Customer Class	Actual/ Estimate	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-24	Act	32,909,026	283,855	115.9	132.3	(16.3)	($4,636,786)
Jul-24	Act	37,379,651	286,076	130.7	152.5	(21.8)	($6,241,554)
Aug-24	Act	36,865,733	287,035	128.4	147.6	(19.1)	($5,495,397)
Sep-24	Act	24,131,151	281,081	85.9	92.2	(6.3)	($1,772,817)
Oct-24	Act	13,039,673	284,798	45.8	53.3	(7.5)	($2,145,928)
Nov-24	Act	10,882,639	287,506	37.9	39.8	(2.0)	($563,361)
Dec-24	Frcst	11,247,616	285,400	39.4	42.6	(3.2)	($909,586)
Jan-25	Frcst	10,412,215	284,144	36.6	41.9	(5.3)	($1,493,861)
Feb-25	Frcst	10,997,959	284,366	38.7	37.7	1.0	$275,536
Mar-25	Frcst	11,381,287	284,588	40.0	41.5	(1.5)	($431,778)
Apr-25	Frcst	11,222,292	284,811	39.4	40.8	(1.4)	($399,126)
May-25	Frcst	27,883,972	285,034	97.8	42.1	55.7	$15,873,426
Total		238,353,213		836.5	864.3	(27.8)	($7,941,232)

Margin Deficiency/ (Credit)	$	7,941,232
Prior Period (Over) / Under Recovery[3]	$	23,750,924
Total Deficiency/(Credit)	$	31,692,156
Projected GLP Annual kW Use		26,171,780
Pre-tax CIP Charge/(Credit) per kW	$	1.2109
BPU/RC Assessment Factor		1.002600
CIP Charge/(Credit) including assessments	$	1.2140
6.625% Sales Tax	$	0.0804
Proposed After-tax CIP Charge/(Credit) per kW	**$**	**1.2944**
Current After-tax CIP Charge/(Credit) per kW	$	0.9976
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kW	$	0.2968

[1] Per Attachment A, 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 Attachment A, Schedule 2, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group II: General Power & Light (GLP)

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	
Customers													
Service Charge Revenues	1,335,635	1,345,540	1,350,640	1,333,393	1,462,945	1,953,733	2,037,551	2,079,410	2,081,052	2,082,695	2,084,345	2,085,996	
Service Charge Rate (pre-tax)	4.71	4.70	4.71	4.74	5.14	6.80	7.14	7.32	7.32	7.32	7.32	7.32	
Total Customers	283,855	286,076	287,035	281,081	284,798	287,506	285,400	284,144	284,366	284,588	284,811	285,034	
Demand													
GLP Annual kW	2,375,381	2,639,924	2,608,643	2,303,335	2,214,277	2,030,867	1,908,326	1,872,811	2,047,540	2,102,775	2,127,768	2,187,153	
Total Demand	2,375,381	2,639,924	2,608,643	2,303,335	2,214,277	2,030,867	1,908,326	1,872,811	2,047,540	2,102,775	2,127,768	2,187,153	26,418,801
Revenues													
Vol/Demand Charge Revenues	32,909,026	37,379,651	36,865,733	24,131,151	13,039,673	10,882,639	11,247,616	10,412,215	10,997,959	11,381,287	11,222,292	27,883,972	238,353,213
Total Revenue	32,909,026	37,379,651	36,865,733	24,131,151	13,039,673	10,882,639	11,247,616	10,412,215	10,997,959	11,381,287	11,222,292	27,883,972	238,353,213

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group II: General Power & Light (GLP)
June 2023 - May 2024

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	TOTAL
Beginning Under/(Over) Recovery $	48,391,577	46,679,358	43,506,986	41,357,514	39,291,151	37,395,945	35,615,095	33,867,388	31,956,624	29,994,314	28,008,681	25,967,629	48,391,577
kW Demand	2,639,924	2,608,643	2,303,335	2,214,277	2,030,867	1,908,326	1,872,811	2,047,540	2,102,775	2,127,768	2,187,153	2,375,381	26,418,801
Pre-tax Recovery Rate per kW[1]	1.2161	1.2161	0.9332	0.9332	0.9332	0.9332	0.9332	0.9332	0.9332	0.9332	0.9332	0.9332	
Recovery $*	1,712,219	3,172,371	2,149,472	2,066,364	1,895,206	1,780,850	1,747,707	1,910,764	1,962,310	1,985,633	2,041,051	2,216,706	24,640,653
Ending Under/(Over) Recovery $	46,679,358	43,506,986	41,357,514	39,291,151	37,395,945	35,615,095	33,867,388	31,956,624	29,994,314	28,008,681	25,967,629	23,750,924	23,750,924

[1] Pre-tax Recovery Rate per therm excluding BPU and RC assessments.
* June 2022 Recovery $ reflects 16/30 of the revenue calculation because the rate was implemented on June 15, 2022

Public Service Electric and Gas
Conservation Incentive Program
Group III: Large Power & Light - Seconday (LPLS)
June 2024 - May 2025

Customer Class	Actual/ Estimate	Actual per Books[1] Total Class Revenues	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-24	Act	25,997,914	9,654	2,693.0	2,746.3	(53)	($514,825)
Jul-24	Act	30,853,988	9,523	3,239.9	4,023.5	(784)	($7,462,264)
Aug-24	Act	32,411,499	9,600	3,376.1	4,062.0	(686)	($6,584,132)
Sep-24	Act	21,436,221	9,878	2,170.2	2,281.6	(111)	($1,100,901)
Oct-24	Act	7,429,354	9,406	789.9	1,776.2	(986)	($9,277,340)
Nov-24	Act	7,555,186	9,618	785.5	856.9	(71)	($686,708)
Dec-24	Frcst	7,804,446	9,898	788.5	782.4	6	$59,749
Jan-25	Frcst	7,477,026	9,493	787.6	863.4	(76)	($719,573)
Feb-25	Frcst	7,367,554	9,501	775.5	797.4	(22)	($208,964)
Mar-25	Frcst	7,530,752	9,510	791.9	845.2	(53)	($506,923)
Apr-25	Frcst	7,674,352	9,519	806.2	811.2	(5)	($47,617)
May-25	Frcst	17,148,124	9,528	1,799.8	835.0	965	$9,192,655
Total		180,686,416		18,804.0	20,681.2	(1,877)	($17,856,843)

Margin Deficiency/ (Credit)	$	17,856,843
Prior Period (Over) / Under Recovery[3]	$	25,893,173
Total Deficiency/(Credit)	$	43,750,016
Projected LPLS Annual kW Use		25,307,813
Pre-tax CIP Charge/(Credit) per kW	$	1.7287
BPU/RC Assessment Factor		1.002600
CIP Charge/(Credit) including assessments	$	1.7332
6.625% Sales Tax	$	0.1148
Proposed After-tax CIP Charge/(Credit) per kW	**$**	**1.8480**
Current After-tax CIP Charge/(Credit) per kW	$	1.1925
Increase/ (Decrease) in After-tax CIP Charge/(Credit) per kW	$	0.6555

[1] Per Attachment A, 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 Attachment A, Schedule 3, Page 3

Public Service Electric and Gas
Customers and Volumes / Demands

Group III: LPLS

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	
Customers													
Service Charge Revenues	3,357,358	3,311,833	3,338,668	3,435,136	3,271,095	3,344,954	3,442,367	3,301,381	3,304,163	3,307,293	3,310,423	3,313,553	
Service Charge Rate (pre-tax)	348	348	348	348	348	348	348	348	348	348	348	348	
Total Customers	9,654	9,523	9,600	9,878	9,406	9,618	9,898	9,493	9,501	9,510	9,519	9,528	
Demand													
LPLS kW	2,322,303	2,498,429	3,108,239	2,315,710	1,445,937	1,991,986	1,850,281	2,003,705	1,974,369	2,018,103	2,056,585	2,138,380	
Total Demand	2,322,303	2,498,429	3,108,239	2,315,710	1,445,937	1,991,986	1,850,281	2,003,705	1,974,369	2,018,103	2,056,585	2,138,380	25,724,026
Revenues													
Demand Charge Revenues	25,997,914	30,853,988	32,411,499	21,436,221	7,429,354	7,555,186	7,804,446	7,477,026	7,367,554	7,530,752	7,674,352	17,148,124	180,686,416
Total Revenue	25,997,914	30,853,988	32,411,499	21,436,221	7,429,354	7,555,186	7,804,446	7,477,026	7,367,554	7,530,752	7,674,352	17,148,124	180,686,416

PUBLIC SERVICE ELECTRIC AND GAS
STATEMENT OF ESTIMATED UNDER/(OVER) RECOVERED CIP BALANCE
Group III: Large Power & Light - Seconday (LPLS)
June 2023 - May 2024

	Act Jun-24	Act Jul-24	Act Aug-24	Act Sep-24	Act Oct-24	Act Nov-24	Frcst Dec-24	Frcst Jan-25	Frcst Feb-25	Frcst Mar-25	Frcst Apr-25	Frcst May-25	TOTAL
Beginning Under/(Over) Recovery $	52,891,612	51,524,072	48,334,086	45,750,911	44,137,969	41,915,908	39,851,920	37,616,787	35,414,379	33,163,186	30,869,066	28,483,702	52,891,612
kW Demand	2,498,429	3,108,239	2,315,710	1,445,937	1,991,986	1,850,281	2,003,705	1,974,369	2,018,103	2,056,585	2,138,380	2,322,303	25,724,026
Pre-tax Recovery Rate per kW[1]	1.0263	1.0263	1.1155	1.1155	1.1155	1.1155	1.1155	1.1155	1.1155	1.1155	1.1155	1.1155	
Recovery $*	1,367,540	3,189,985	2,583,175	1,612,942	2,222,060	2,063,988	2,235,133	2,202,408	2,251,194	2,294,120	2,385,363	2,590,530	26,998,439
Ending Under/(Over) Recovery $	51,524,072	48,334,086	45,750,911	44,137,969	41,915,908	39,851,920	37,616,787	35,414,379	33,163,186	30,869,066	28,483,702	25,893,173	25,893,173

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

* June 2022 Recovery $ reflects 16/30 of the revenue calculation because the rate was implemented on June 15, 2022

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-24	Act	0	0	0	484,122	0	3,026	4,452	1,426	141,326	201,504,380	201,504,380	$0.0494	$9,950,286
Jul-24	Act	0	0	0	480,789	0	5,779	6,944	1,165	140,353	163,472,055	163,472,055	$0.0494	$8,072,250
Aug-24	Act	0	0	0	486,473	0	4,846	4,865	19	142,012	2,715,278	2,715,278	$0.0494	$134,080
Sep-24	Act	0	0	0	484,013	0	2,285	1,629	-656	141,294	(92,628,375)	(92,628,375)	$0.0494	($4,573,989)
Oct-24	Act	218	136	(81)	483,992	(39,369,507)	421	354	-67	141,288	(9,500,216)	(48,869,723)	$0.0396	($1,936,658)
Nov-24	Act	520	399	(120)	488,776	(58,693,882)	0	0	0	142,685	0	(58,693,882)	$0.0448	($2,629,779)
Dec-24	Frcst	798	798	0	485,222	0	0	0	0	141,647	0	0	$0.0448	$0
Jan-25	Frcst	980	980	0	495,154	0	0	0	0	144,547	0	0	$0.0448	$0
Feb-25	Frcst	826	826	0	495,472	0	0	0	0	144,639	0	0	$0.0448	$0
Mar-25	Frcst	679	679	0	495,790	0	0	0	0	144,732	0	0	$0.0448	$0
Apr-25	Frcst	344	344	0	496,107	0	160	160	0	144,825	0	0	$0.0448	$0
May-25	Frcst	117	117	0	496,425	0	985	985	0	144,918	0	0	$0.0448	$0
TOTAL		4,482	4,280	-201		-98,063,389	17,501	19,388	1,887		265,563,121	167,499,732		$9,016,190

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-24	Act	0	0	0	10,527	0	3,026	4,452	1,426	396	564,070	564,070	$0.0559	$31,505
Jul-24	Act	0	0	0	10,509	0	5,779	6,944	1,165	395	459,996	459,996	$0.0559	$25,692
Aug-24	Act	0	0	0	10,440	0	4,846	4,865	19	392	7,502	7,502	$0.0559	$419
Sep-24	Act	0	0	0	10,368	0	2,285	1,629	-656	390	(255,430)	(255,430)	$0.0559	($14,267)
Oct-24	Act	218	136	(81)	10,326	(839,980)	421	354	-67	388	(26,094)	(866,074)	$0.0310	($26,812)
Nov-24	Act	520	399	(120)	10,437	(1,253,290)	0	0	0	392	0	(1,253,290)	$0.0355	($44,551)
Dec-24	Frcst	798	798	0	10,141	0	0	0	0	381	0	0	$0.0355	$0
Jan-25	Frcst	980	980	0	10,109	0	0	0	0	380	0	0	$0.0355	$0
Feb-25	Frcst	826	826	0	10,058	0	0	0	0	378	0	0	$0.0355	$0
Mar-25	Frcst	679	679	0	10,007	0	0	0	0	376	0	0	$0.0355	$0
Apr-25	Frcst	344	344	0	9,955	0	160	160	0	374	0	0	$0.0355	$0
May-25	Frcst	117	117	0	9,904	0	985	985	0	372	0	0	$0.0355	$0
TOTAL		4,482	4,280	-201		-2,093,271	17,501	19,388	1,887		750,043	(1,343,227)		($28,013)

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-24	Act	0	0	0	4,631	0	3,026	4,452	1,426	1,476	2,104,218	2,104,218	$0.0466	$97,993
Jul-24	Act	0	0	0	6,372	0	5,779	6,944	1,165	2,031	2,365,181	2,365,181	$0.0466	$110,146
Aug-24	Act	0	0	0	5,746	0	4,846	4,865	19	1,831	35,012	35,012	$0.0466	$1,631
Sep-24	Act	0	0	0	5,416	0	2,285	1,629	-656	1,726	(1,131,565)	(1,131,565)	$0.0466	($52,697)
Oct-24	Act	218	136	(81)	5,663	(460,672)	421	354	-67	1,805	(121,362)	(582,034)	$0.0176	($10,262)
Nov-24	Act	520	399	(120)	5,219	(626,751)	0	0	0	1,663	0	(626,751)	$0.0185	($11,597)
Dec-24	Frcst	798	798	0	5,446	0	0	0	0	1,736	0	0	$0.0185	$0
Jan-25	Frcst	980	980	0	5,443	0	0	0	0	1,735	0	0	$0.0185	$0
Feb-25	Frcst	826	826	0	5,440	0	0	0	0	1,734	0	0	$0.0185	$0
Mar-25	Frcst	679	679	0	5,436	0	0	0	0	1,733	0	0	$0.0185	$0
Apr-25	Frcst	344	344	0	5,433	0	160	160	0	1,732	0	0	$0.0185	$0
May-25	Frcst	117	117	0	5,430	0	985	985	0	1,731	0	0	$0.0185	$0
TOTAL		4,482	4,280	-201		-1,087,423	17,501	19,388	1,887		3,251,483	2,164,061		$135,214

Total
All Groups

		TOTAL kWh	MARGIN IMPACT
Jun-24	Act	204,172,667	10,079,785
Jul-24	Act	166,297,231	8,208,089
Aug-24	Act	2,757,792	136,130
Sep-24	Act	(94,015,370)	(4,640,953)
Oct-24	Act	(50,317,831)	(1,973,733)
Nov-24	Act	(60,573,923)	(2,685,927)
Dec-24	Frcst	0	0
Jan-25	Frcst	0	0
Feb-25	Frcst	0	0
Mar-25	Frcst	0	0
Apr-25	Frcst	0	0
May-25	Frcst	0	0
TOTAL		168,320,565	$9,123,390

Public Service Electric and Gas
Conservation Incentive Program Filing
June 2023 - May 2024
CIP Recovery Tests
Summary

Determine Weather and Non-Weather CIP Impacts

	Weather	Non-Weather	Total
CIP Group I RS RHS	$ (8,988,177)	$ 1,186,766	$ (7,801,411)
CIP Group II RLM	$ (135,214)	$ 472,218	$ 337,004
CIP Group III GLP	$ -	$ 7,941,232	$ 7,941,232
CIP Group IV LPLS	$ -	$ 17,856,843	$ 17,856,843
Total Deficiency/(Credit)	$ (9,123,390)	$ 27,457,059	$ 18,333,668

Step 2: Apply Modified BGS Savings Test

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

Non-Weather Impact	$ 27,457,059
75% Factor	75%
Subtotal	$ 20,592,794
Prior Year Carry-Forward (Modified BGS Savings Test)	$ -
Non-weather Impact Subject to Test	**$ 20,592,794**

B. BGS Savings

Permanent Capacity Savings (Attach A, Schedule 6, Page 3)	$ 64,505,906
Additional Capacity BGS Savings (Attach A, Schedule 6, Page 3)	$ -
Avoided Cost BGS Savings (Attach A, Schedule 6, Page 4)	$ 16,257,351
Total BGS Savings	**$ 80,763,258**

C. Results

Non-Weather Impacts Passing Test (current accrual)	**$ 27,457,059**
Non-Weather Impacts Passing Test (prior year carry-forward)	**$ -**
Non-Weather Impacts Exceeding Test	**$ -**

Public Service Electric and Gas
Conservation Incentive Program Filing
June 2023 - May 2024
CIP Recovery Tests
Summary

Step 3: Apply Variable Margin Revenue Test

A. Non-weather Impact Subject to Variable Margin Revenue Test		
Non-Weather Impact	$ 27,457,059	
Prior Year Carry-Forward (Variable Margin Revenue Test)	$ 66,018,162	
Non-weather Impact Subject to Test	**$ 93,475,221**	
B. Variable Margin Revenues		
Variable Margin Revenues (Attachment A, Schedule 5)	$ 1,098,493,642	
Factor	6.5%	
Total Fixed Recovery Cap	**$ 71,402,087**	
C. Results		
Non-Weather Impacts Passing Test (current accrual)	**$ 5,383,925**	
Non-Weather Impacts Passing Test (prior year carry-forward)	**$ 66,018,162**	
Non-Weather Impacts Exceeding Test	**$ 22,073,134**	

Step 4: Determine Recoverable Non-Weather CIP Impacts

A. Current Year Accrual Recoverable Non-Weather Impacts		
Amount Passing Modified BGS Savings Test	$ 27,457,059	
Amount Passing Variable Margin Revenue Test	$ 5,383,925	
Recoverable Amount		**$ 5,383,925**
B. Previous Carry-Forward Recoverable Amounts		
Amount Passing Modified BGSS Savings Test		**$ -**
Amount Passing Variable Margin Revenue Test	$ 66,018,162	
Deduction for any amount also included in above	$ -	
		$ 66,018,162
Total Non-Weather Recoverable CIP Amount		**$ 71,402,087**

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
2023/2024	9,420	11,229	$18.61
2024/2025*	9,700	11,778	$21.27

Incremental Capacity Savings*	0
PS Zonal Net Load Capacity Cost per kW-year	$21.27
Total Additional Capacity Reductions	**$ -**

* 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 $
2024/2025*	**$ 16,257,351**

VI. Total of all Savings

CIP Recovery Year	Permanent Capacity Savings	Additional Capacity BGSS Savings	Avoided Cost BGSS Savings	Annual $
2024/2025*	$ 64,505,906	$ -	$ 16,257,351	**$ 80,763,258**

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	2,001,695	125,634	2.4	$1.75	521,182
July	1,876,061	1,987,944	122,442	2.4	$1.81	526,655
August	1,865,502	2,011,333	138,830	2.4	$1.81	600,527
September	1,872,503	2,001,152	127,984	2.4	$1.75	533,747
October	1,873,168	2,001,039	128,174	2.4	$1.81	552,162
November	1,872,865	2,020,825	134,277	2.4	$1.75	559,885
December	1,886,548	2,011,587	120,992	2.4	$1.81	517,528
January	1,890,595	2,006,063	125,975	2.4	$1.81	537,686
February	1,880,088	2,007,316	154,944	2.4	$1.63	600,670
March	1,852,372	2,008,570	90,206	2.4	$1.81	392,964
April	1,918,364	2,009,822	145,746	2.3	$1.75	593,296
May	1,864,076	2,011,075	133,193	2.4	$1.81	576,585
Subtotal	1,877,882	2,006,535	129,033			$6,512,887
Group 2: RLM						
June	12,114	9,614	(2,783)	7.1	$1.75	(34,306)
July	12,213	13,229	1,115	7.0	$1.81	14,082
August	11,549	11,929	(284)	7.4	$1.81	(3,794)
September	12,247	11,244	(304)	7.0	$1.75	(3,712)
October	12,179	11,758	(489)	7.0	$1.81	(6,193)
November	12,329	10,836	(1,343)	6.9	$1.75	(16,266)
December	12,188	11,634	(695)	7.0	$1.81	(8,799)
January	12,017	11,300	(888)	7.1	$1.81	(11,408)
February	12,039	11,294	(723)	7.1	$1.63	(8,371)
March	12,316	11,287	(752)	6.9	$1.81	(9,419)
April	12,310	11,280	(1,036)	6.9	$1.75	(12,562)
May	12,397	11,274	(1,036)	6.9	$1.81	(12,895)
Subtotal	12,158	11,390	(768)			($113,642)
Group 3: GLP						
June	269,005	283,855	19,096	8.9	$1.75	297,756
July	264,759	286,076	26,725	9.4	$1.81	453,500
August	259,351	287,035	22,496	8.6	$1.81	347,219
September	264,539	281,081	33,433	8.8	$1.75	511,869
October	247,648	284,798	26,119	9.0	$1.81	425,088
November	258,679	287,506	20,831	8.9	$1.75	322,934
December	266,675	285,400	24,295	8.9	$1.81	392,478
January	261,105	284,144	21,169	8.9	$1.81	340,344
February	262,975	284,366	27,811	9.3	$1.63	420,956
March	256,555	284,588	17,164	8.6	$1.81	267,821
April	267,424	284,811	20,170	8.9	$1.75	312,969
May	264,641	285,034	16,029	8.8	$1.81	255,311
Subtotal	261,946	284,891	22,945			$4,348,243
Group 4: LPLS						
June	8,883	9,654	798	267.1	$1.75	372,276
July	8,727	9,523	640	270.0	$1.81	311,971
August	8,370	9,600	873	270.9	$1.81	426,811
September	8,140	9,878	1,508	277.3	$1.75	730,319
October	9,014	9,406	1,266	273.8	$1.81	625,420
November	7,780	9,618	604	267.6	$1.75	282,245
December	8,886	9,898	2,119	276.8	$1.81	1,058,556
January	8,481	9,493	607	266.5	$1.81	291,892
February	8,891	9,501	1,020	287.4	$1.63	478,084
March	8,867	9,510	619	251.7	$1.81	281,177
April	8,846	9,519	652	275.2	$1.75	313,587
May	8,856	9,528	682	274.0	$1.81	337,526
Subtotal	8,645	9,594	949			$5,509,864
				Total Avoided Capacity Cost BGS Savings		$16,257,351

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)	$647,576,838
Group II (RLM)	$6,077,704
Group III (GLP)	$246,295,781
Group IV	$198,543,319
Total Variable Margin	$1,098,493,642

Customer Class		Actual/ Estimate	Number of Customers	Baseline Revenue / Cust.	Variable Revenue
Group I: Residential Service RS and RHS					
	Jun-24	Act	2,001,695	37.2	$74,547,007
	Jul-24	Act	1,987,944	44.9	$89,296,553
	Aug-24	Act	2,011,333	41.6	$83,596,983
	Sep-24	Act	2,001,152	23.9	$47,778,367
	Oct-24	Act	2,001,039	16.9	$33,726,375
	Nov-24	Act	2,020,825	19.2	$38,868,842
	Dec-24	Frcst	2,011,587	25.8	$51,829,966
	Jan-25	Frcst	2,006,063	28.2	$56,490,697
	Feb-25	Frcst	2,007,316	23.7	$47,551,082
	Mar-25	Frcst	2,008,570	22.4	$44,907,093
	Apr-25	Frcst	2,009,822	18.6	$37,427,195
	May-25	Frcst	2,011,075	20.7	$41,556,676
Total				322.9	$647,576,838
Group Ia: Residential Load Management (RLM)					
	Jun-24	Act	9,614	97.0	$933,009
	Jul-24	Act	13,229	109.9	$1,453,910
	Aug-24	Act	11,929	103.1	$1,230,477
	Sep-24	Act	11,244	47.1	$529,942
	Oct-24	Act	11,758	18.0	$212,011
	Nov-24	Act	10,836	21.4	$231,486
	Dec-24	Frcst	11,634	21.5	$250,602
	Jan-25	Frcst	11,300	27.1	$306,479
	Feb-25	Frcst	11,294	21.1	$238,149
	Mar-25	Frcst	11,287	22.0	$248,596
	Apr-25	Frcst	11,280	18.3	$206,670
	May-25	Frcst	11,274	21.0	$236,374
Total				527.7	$6,077,704
Group II: General Power & Light (GLP)					
	Jun-24	Act	283,855	132.3	$37,546,992
	Jul-24	Act	286,076	152.5	$43,620,272
	Aug-24	Act	287,035	147.6	$42,362,173
	Sep-24	Act	281,081	92.2	$25,903,626
	Oct-24	Act	284,798	53.3	$15,186,851
	Nov-24	Act	287,506	39.8	$11,445,455
	Dec-24	Frcst	285,400	42.6	$12,157,192
	Jan-25	Frcst	284,144	41.9	$11,904,897
	Feb-25	Frcst	284,366	37.7	$10,723,741
	Mar-25	Frcst	284,588	41.5	$11,812,453
	Apr-25	Frcst	284,811	40.8	$11,620,680
	May-25	Frcst	285,034	42.1	$12,011,450
Total				864.3	$246,295,781
Group III: Large Power & Light - Seconday (LPLS)					
	Jun-24	Act	9,654	2,746.3	$26,512,747
	Jul-24	Act	9,523	4,023.5	$38,316,298
	Aug-24	Act	9,600	4,062.0	$38,995,618
	Sep-24	Act	9,878	2,281.6	$22,537,093
	Oct-24	Act	9,406	1,776.2	$16,706,695
	Nov-24	Act	9,618	856.9	$8,241,878
	Dec-24	Frcst	9,898	782.4	$7,744,744
	Jan-25	Frcst	9,493	863.4	$8,196,640
	Feb-25	Frcst	9,501	797.4	$7,576,514
	Mar-25	Frcst	9,510	845.2	$8,037,702
	Apr-25	Frcst	9,519	811.2	$7,721,930
	May-25	Frcst	9,528	835.0	$7,955,458
Total				20,681.2	$198,543,319

ATTACHMENT A
Schedule 6

CONFIDENTIAL

TO BE PROVIDED UPON EXECUTION OF THE NON-DISCLOSURE AGREEMENT

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
(2025 PSE&G Electric Conservation Incentive Program)

BPU Docket No. ______________

DIRECT TESTIMONY

OF

MICHAEL P. McFADDEN
DIRECTOR – SALES AND REVENUE FORECASTING

February 3, 2025

ATTACHMENT B

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 work address is 80 Park Plaza, Newark, New Jersey 07102.

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Finance from the Rutgers School of Business and a Master 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, 2024 – May 31, 2025 ("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, 2024 through November 30, 2024. Schedule MPM-ECIP-1 also includes a forecast of the consumption factors for the remaining forecast period of December 1, 2024 through the May 31, 2025; 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 approved in the most recent base rate case and the latest variable margin rates per rate schedule, including any Infrastructure Investment Program ("IIP") rate adjustments. The

ATTACHMENT B

June 1, 2024 through September 30, 2024 variable margin revenue for this filing is based on the Infrastructure Advancement Program ("IAP") rate adjustment approved for new rates effective June 1, 2024 in Docket No. ER23110783 and the approved billing determinants from the Company's 2018 base rate case. The Company's 2023 base rate case in Docket Nos. ER23120924 and GR23120925 was approved effective October 15, 2024 and included revised CIP baseline revenue per customer factors as shown in Revised Original Sheet Number 66C of the Company's Electric tariff. Because the 2023 rate case was approved in the middle of the month, the baseline revenue factor for October 2024 is prorated at 14 days at the pre-rate case baseline revenue per customer and 17 days at the approved rate case baseline revenue per customer. Please see the table below for the baseline revenue per customer for each rate schedule during this CIP period.

Month	RS & RHS	RLM	GLP	LPLS
Jun	37.2	97.0	132.3	2,746.3
Jul	44.9	109.9	152.5	4,023.5
Aug	41.6	103.1	147.6	4,062.0
Sep	23.9	47.1	92.2	2,281.6
Oct	16.9	18.0	53.3	1,776.2
Nov	19.2	21.4	39.8	856.9
Dec	25.8	21.5	42.6	782.4
Jan	28.2	27.1	41.9	863.4
Feb	23.7	21.1	37.7	797.4
Mar	22.4	22.0	41.5	845.2
Apr	18.6	18.3	40.8	811.2
May	20.7	21.0	42.1	835.0
TOTAL ANNUAL	**322.9**	**527.7**	**864.3**	**20,681.2**

ATTACHMENT B

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 charges. Finally, for rate schedule LPLS, the variable margin is from the annual and summer demand charges. Per the CEF-EE Order, the number of customers is calculated as the actual monthly service charge revenue divided by the service charge rate. Please note the service charge rate is prorated for rate changes to coincide with the billing cycle so that the service charge rate matches the service charge rate reflected in the billed revenue.

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, 2024 through May 31, 2025 results based on actual data from June 1, 2024 through November 30, 2024 and a forecast for the remaining months from December 1, 2024 through May 31, 2025. 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.

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. 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 calculation used for the 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 2024 – November 2024 and a forecast December 2024 – May 2025. 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 2024 – May 2025 have been calculated based on the 20-year period weather history ending December 2023 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 2024 – November 2024 is an over-collection of ($9,123,390) from the warmer than normal summer 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 $18,333,668. As a result, the non-weather ECIP deferral subject to the ECIP savings test is $27,457,059 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 $71,402,087. As shown in Attachment A, Schedule 5, the limit to the non-weather recovery is comprised of the CIP carry-Forward from the last ECIP proceeding of $64,650,719 and the remainder of $6,751,368 from the current period non-weather deferral. The difference between the actual deferral and the non-weather recovery cap estimated at $22,073,134 will be carried-forward to the next ECIP recovery period.

ATTACHMENT B

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%. Based on actual results from June 2024 through November 2024 and a forecast from December 2024 – May 2025, total variable margin is $1,098,493,642, resulting, after applying the 6.5% rate, in a variable margin cap of $71,402,087.

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	Wage	Customers	HDD Consumption Factor	THIxWage Coefficient	Wage	Customers	THI Consumption Factor
Jun-24	0.7561	0.3209	1,995,482	484,122	0.22071	0.3209	1,995,482	141,326
Jul-24	0.7561	0.3209	1,981,741	480,789	0.22071	0.3209	1,981,741	140,353
Aug-24	0.7561	0.3209	2,005,171	486,473	0.22071	0.3209	2,005,171	142,012
Sep-24	0.7561	0.3209	1,995,032	484,013	0.22071	0.3209	1,995,032	141,294
Oct-24	0.7561	0.3209	1,994,944	483,992	0.22071	0.3209	1,994,944	141,288
Nov-24	0.7561	0.3209	2,014,665	488,776	0.22071	0.3209	2,014,665	142,685
Dec-24	0.7561	0.3209	2,000,014	485,222	0.22071	0.3209	2,000,014	141,647
Jan-25	0.7561	0.3274	2,000,096	495,154	0.22071	0.3274	2,000,096	144,547
Feb-25	0.7561	0.3274	2,001,379	495,472	0.22071	0.3274	2,001,379	144,639
Mar-25	0.7561	0.3274	2,002,663	495,790	0.22071	0.3274	2,002,663	144,732
Apr-25	0.7561	0.3274	2,003,946	496,107	0.22071	0.3274	2,003,946	144,825
May-25	0.7561	0.3274	2,005,229	496,425	0.22071	0.3274	2,005,229	144,918

Reflects actual customers through November 2024 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-24	1.6942	6,214	10,527	0.06367	6,214	396
Jul-24	1.6942	6,203	10,509	0.06367	6,203	395
Aug-24	1.6942	6,162	10,440	0.06367	6,162	392
Sep-24	1.6942	6,120	10,368	0.06367	6,120	390
Oct-24	1.6942	6,095	10,326	0.06367	6,095	388
Nov-24	1.6942	6,160	10,437	0.06367	6,160	392
Dec-24	1.6942	5,986	10,141	0.06367	5,986	381
Jan-25	1.6942	5,967	10,109	0.06367	5,967	380
Feb-25	1.6942	5,937	10,058	0.06367	5,937	378
Mar-25	1.6942	5,907	10,007	0.06367	5,907	376
Apr-25	1.6942	5,876	9,955	0.06367	5,876	374
May-25	1.6942	5,846	9,904	0.06367	5,846	372

Reflects actual customers through November 2024 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-24	0.4817	9,614	4,631	0.15350	9,614	1,476
Jul-24	0.4817	13,229	6,372	0.15350	13,229	2,031
Aug-24	0.4817	11,929	5,746	0.15350	11,929	1,831
Sep-24	0.4817	11,244	5,416	0.15350	11,244	1,726
Oct-24	0.4817	11,758	5,663	0.15350	11,758	1,805
Nov-24	0.4817	10,836	5,219	0.15350	10,836	1,663
Dec-24	0.4817	11,307	5,446	0.15350	11,307	1,736
Jan-25	0.4817	11,300	5,443	0.15350	11,300	1,735
Feb-25	0.4817	11,294	5,440	0.15350	11,294	1,734
Mar-25	0.4817	11,287	5,436	0.15350	11,287	1,733
Apr-25	0.4817	11,280	5,433	0.15350	11,280	1,732
May-25	0.4817	11,274	5,430	0.15350	11,274	1,731

Reflects actual customers through November 2024 and a forecast thereafter.

Schedule MPM-ECIP-2

DRAFT

Electricity Sales and Billed Demand Forecast - 2025

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

November 2024

Contents

I Introduction

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

The sales and demand forecasts serve 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 2025 electricity sales and billed demand forecasts. The second section describes the econometric sales models. Section III describes the customer forecast. A discussion of the forecast assumptions used to develop the sales forecast follows. Section V describes the billed demand models.

Appendix A contains tables containing the major assumptions. Appendix B contains detailed information on the billing period to calendar-month conversion.

II 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.

$$KWH/CUST = f(PRICEELEC, INCOME, WEATHER) \quad [1]$$

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 (THI).

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:

$$\begin{aligned} \mathrm{KWH/CUST}_t = \; & f(\mathrm{HDD}_t \times \mathrm{PRICEFUEL}_{a-1}, \mathrm{THI}_t \times \mathrm{PRICEELEC}_{a-1}, \\ & \mathrm{HDD}_t \times \mathrm{INCOME}_{a-1}, \mathrm{THI}_t \times \mathrm{INCOME}_{a-1}, \\ & \mathrm{CFL}_t, \overline{\mathrm{MONTH}}_{a-1},) \end{aligned} \qquad [2]$$

where:

KWH/CUST	= Average electricity sales per customer less the impact of net metered solar,
PRICEELEC	= Real price of electricity,
PRICEFUEL	= 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),
$\overline{\mathrm{MONTH}}$	= Vector of binary variables for each month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The residential rates were estimated using data from January 2010-December 2023. All rates exclude data from the February 2020-December 2020 COVID period. The results of the OLS estimation procedure are summarized in Table 1 and Figures 1-3.

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

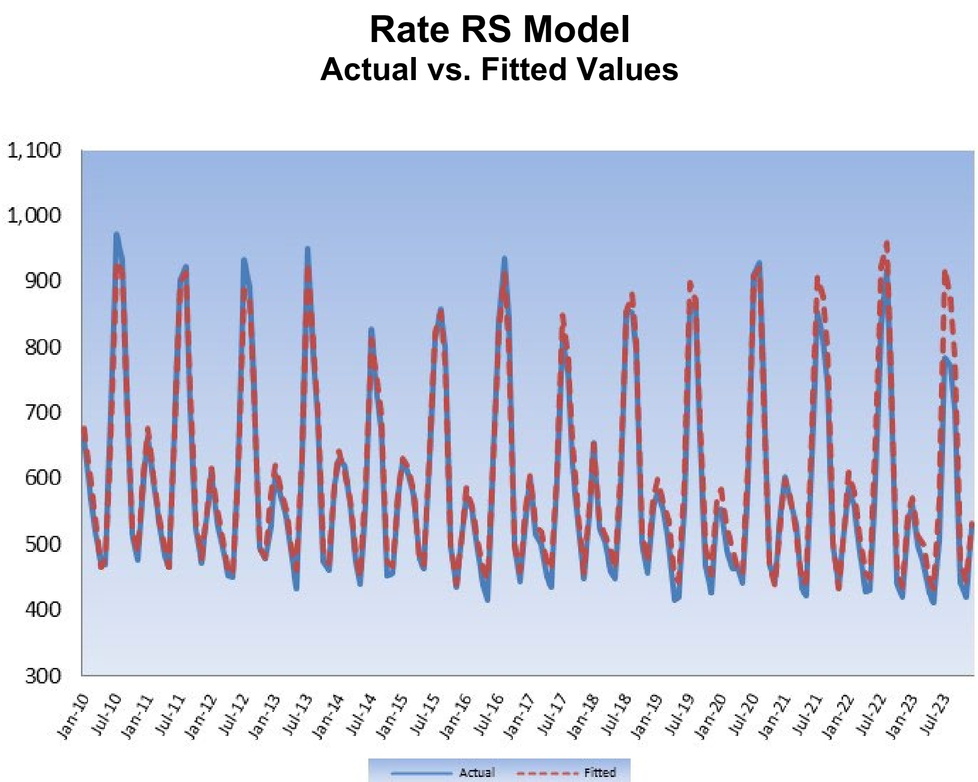
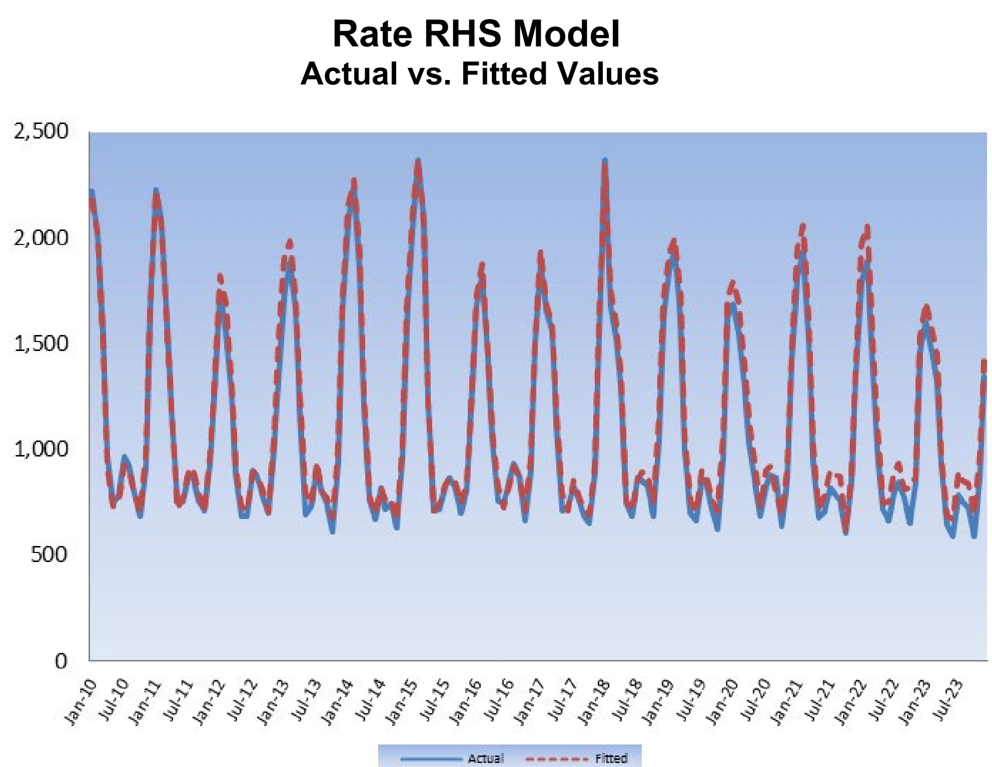


Figure 2



.Figure 3

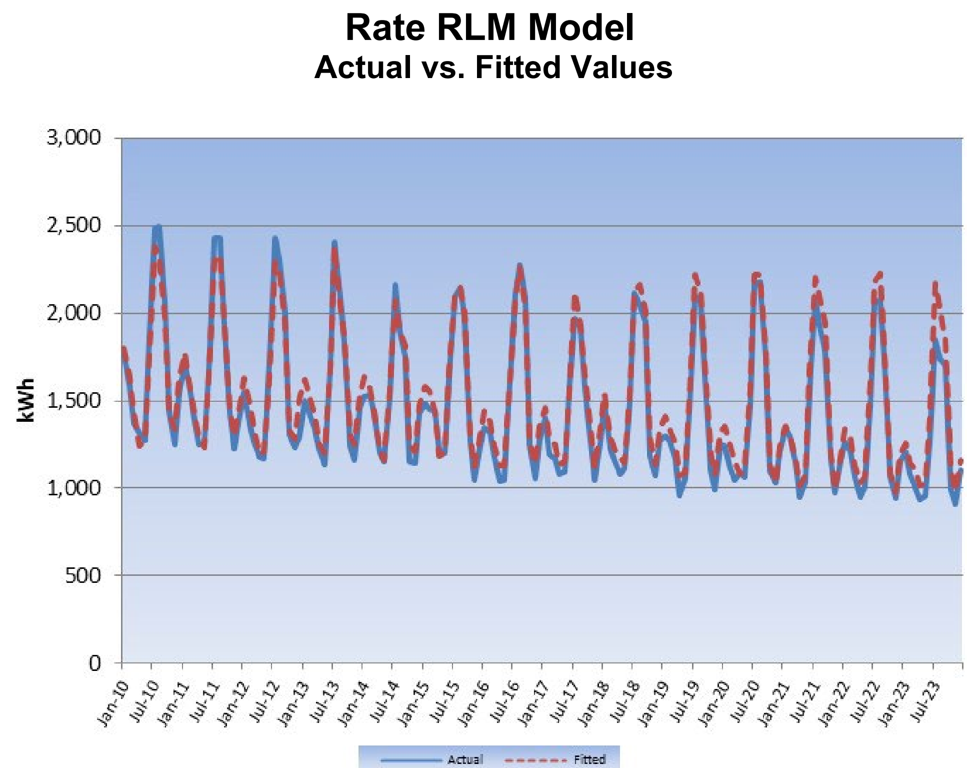


Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

Rate	HDDxWAGE	THIxWAGE	HDD	THI	CFL	R2	n
RS	0.7561	0.2207			-0.8092	0.98	158
	(0.0811)	(0.0127)			(0.0872)		
RHS			1.6942	0.0637		0.99	158
			(0.0464)	(0.0085)			
RLM			0.1635	0.4817	-6.1306	0.97	158
			(0.0133)	(0.0729)	(0.2905)		
WH				0.0018		0.51	158
				(0.0024)			

A key element of the residential forecast is the projection of the number of residential electric 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 2023 is also included in the models.

$$KWH = f(PRICEELEC, OUTPUT, WEATHER, EFFICIENCY) \quad [3]$$

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:

$$OUTPUT = f(INCOME, HSH) \quad [4]$$

Substituting [4] into [3] yields:

$$KWH = f(PRICEELEC, INCOME, HSH, WEATHER, EFFICIENCY) \quad [5]$$

Historical annual household estimates for New Jersey are 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.

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 using monthly billing data from December 2012 to December 2023 (excluding data from March 2020-December 2020)

The larger commercial 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-December 2023 period aggregated to billing-month to eliminate the effects of out of period billings. As a result, these large commercial customers did not have an issue with estimated bills and binary variables for the pandemic period were incorporated into the LPL equations. As a result, the functional form that was estimated for each of the three groups of commercial customers is[1]:

$$\begin{aligned} KWH_t = f(&HDD_t \times PRICEELEC_{a-1}, THI_t \times PRICEELEC_{a-1}, \\ &HDD_t \times ECON_{a-1}, THI_t \times ECON_{a-1}, \\ &HDD_t \times HSH_{a-1}, THI_t \times HSH_{a-1}, \\ &MONTH, EFFICIENCY, COVID) \end{aligned} \qquad [6]$$

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 4-7, show that the commercial models also fit the historical data well.

The estimated coefficients of the commercial models indicate the Commercial customers no longer have a measurable sensitivity to price. In addition, while the

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

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, 0.15 for LPL-S, that are estimated.

Figure 4

GLP Commercial Model
Actual vs. Fitted Values

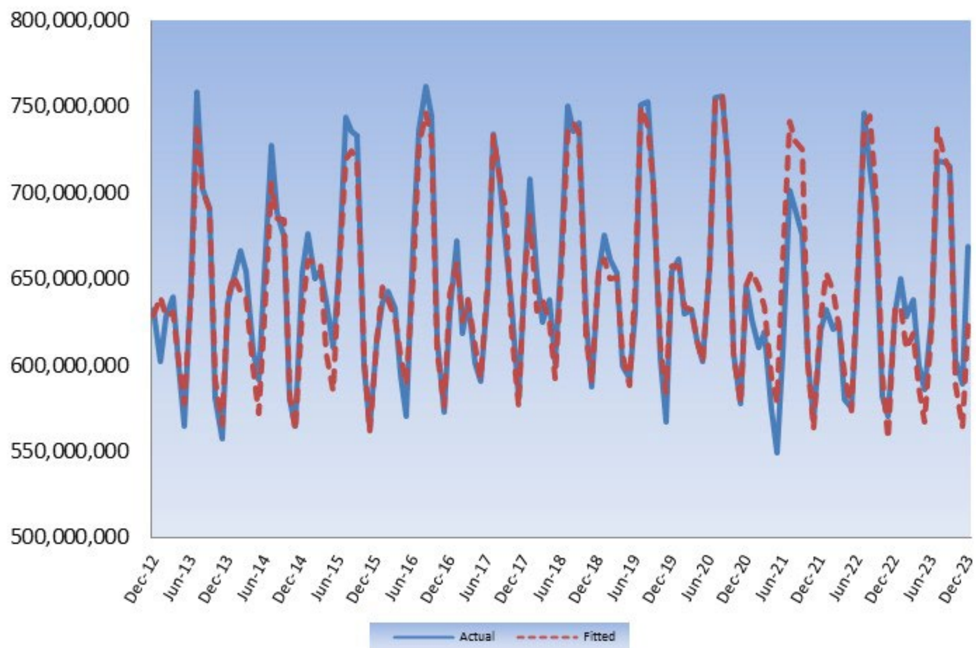


Figure 5

HS Commercial Model
Actual vs. Fitted Values

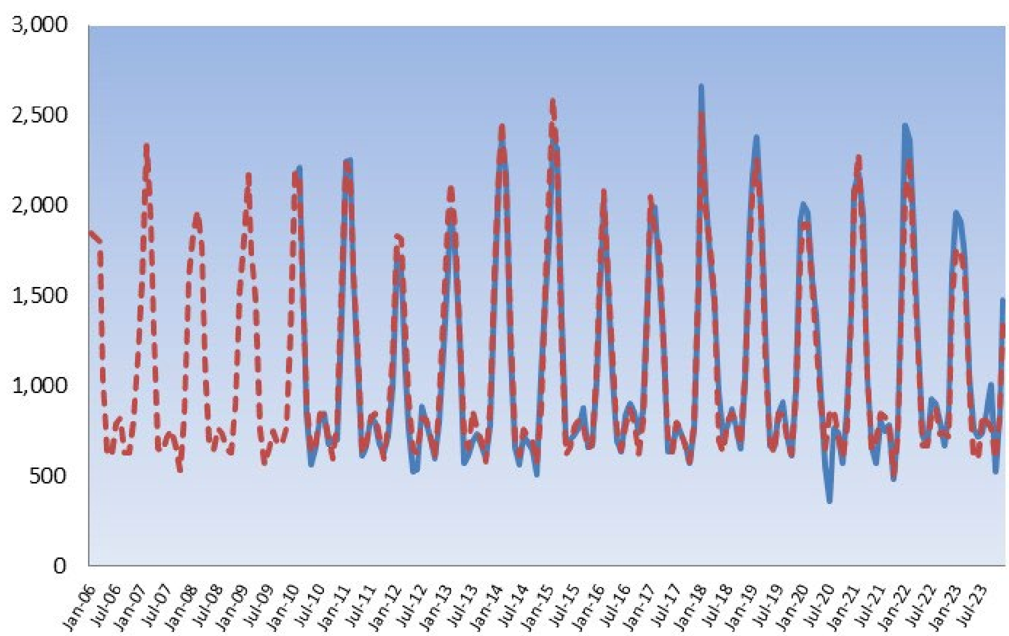


Figure 6

LPL-S Commercial Model
Actual vs. Fitted Values

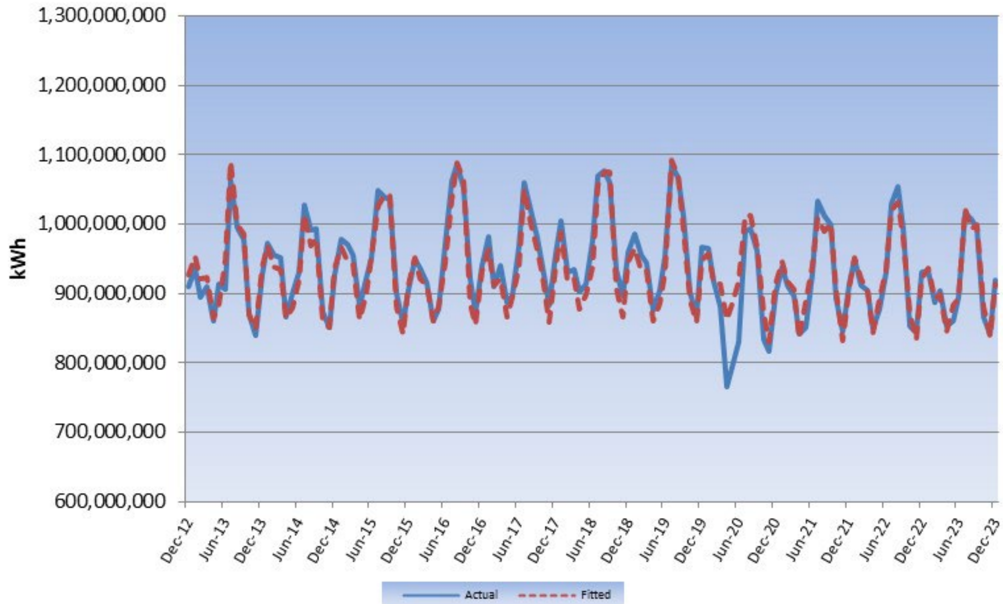


Figure 7

LPL-P Commercial Model
Actual vs. Fitted Values

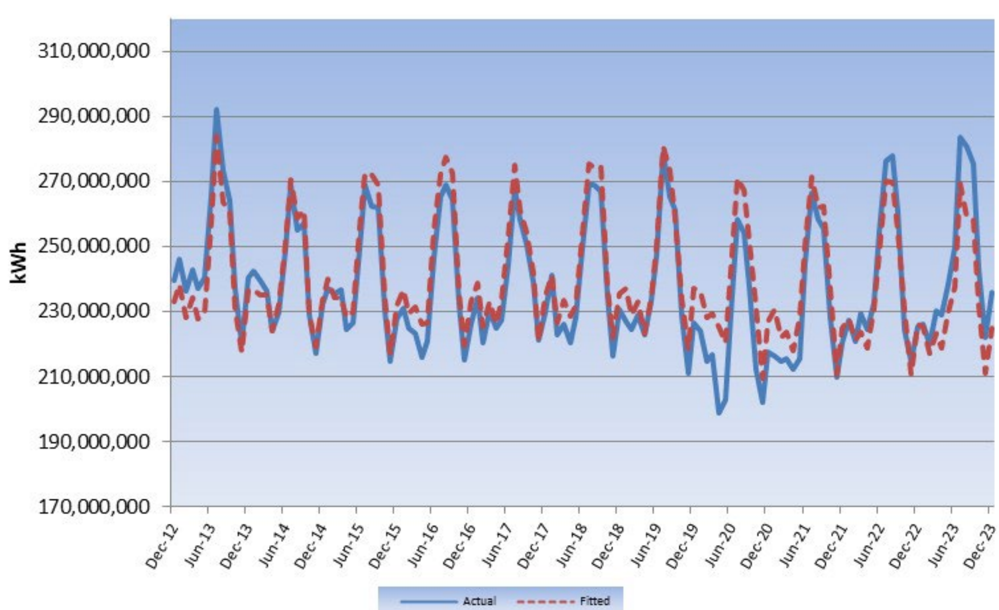


Table 3

Estimated Coefficients of the Commercial Electricity Sales Models

(standard errors in parentheses)

Rate	HDDxECON	THIxECON	EFFICIENCY	COVID-THI	COVID-Summer	COVID-Winter	R2	n
GLP	107.2	16.9	6,186,209				0.92	168
	(18.2)	(2.4)	(1,103,123)					
HS	0.51420	0.01693					0.97	168
	(0.03429)	(0.00311)						
LPL-S	96.6	42.8		45.7	-16.2	-20,565.4	0.9	168
	(18.9)	(3.4)		(3.6)	(1.7)	(5958.0)		
	HDD	**THI**						
LPL-P	14.7	8.1			-10,574.7	-8,044	0.84	168
	(9.5)	(1.7)			(2626.8)	(2296.8)		

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 manufacturing employment which, in recent years has been correlated with industrial output. Therefore, the following specification is used:

KWH = *f*(PRICEELEC, EMP, HDD) [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 industrial sales, rate GLP< is not possible because of the large percentage of COVID-induced estimated bills in 2020. As a result, the March 2020-December 2020 period was omitted from the estimation period of December 2012-December 2023. As with the commercial customers, the large industrial customers, rates LPL-S and LPL-P did not have an issue with estimated bills and binary variables for the pandemic period were incorporated into these equations.

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

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

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.

The results of the OLS estimation procedure, summarized in Figures 8-11, show that the industrial models for customers in the two space heating segments fit the historical data fairly well.

Figure 8

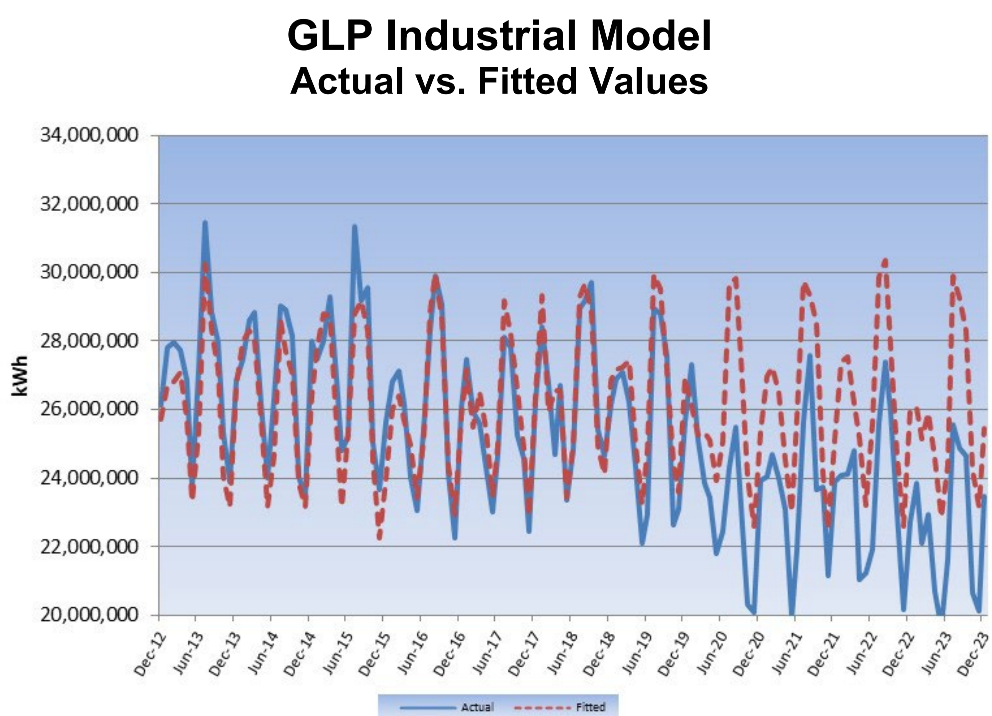


Figure 9

HS Industrial Model
Actual vs. Fitted Values

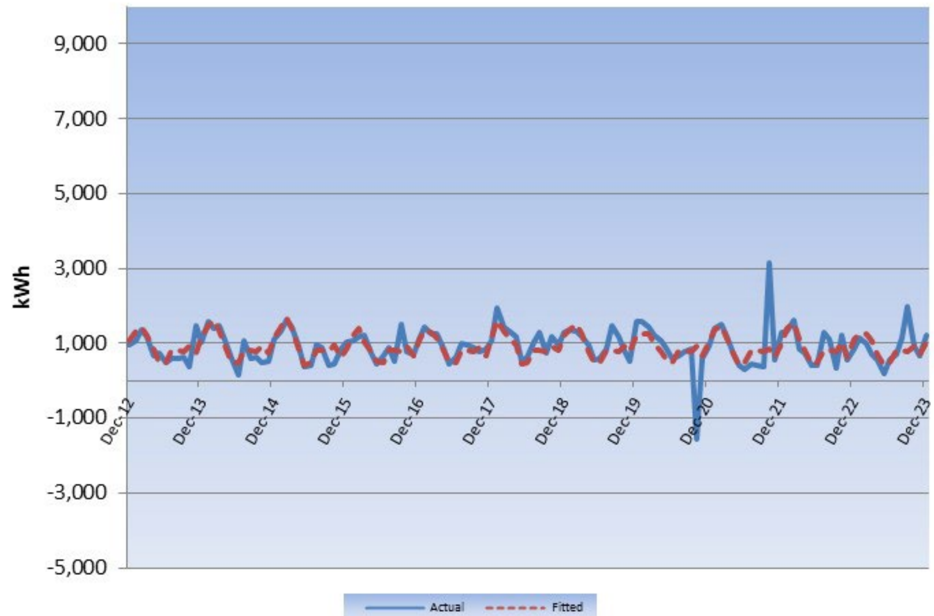


Figure 10

LPL-S Industrial Model
Actual vs. Fitted Values

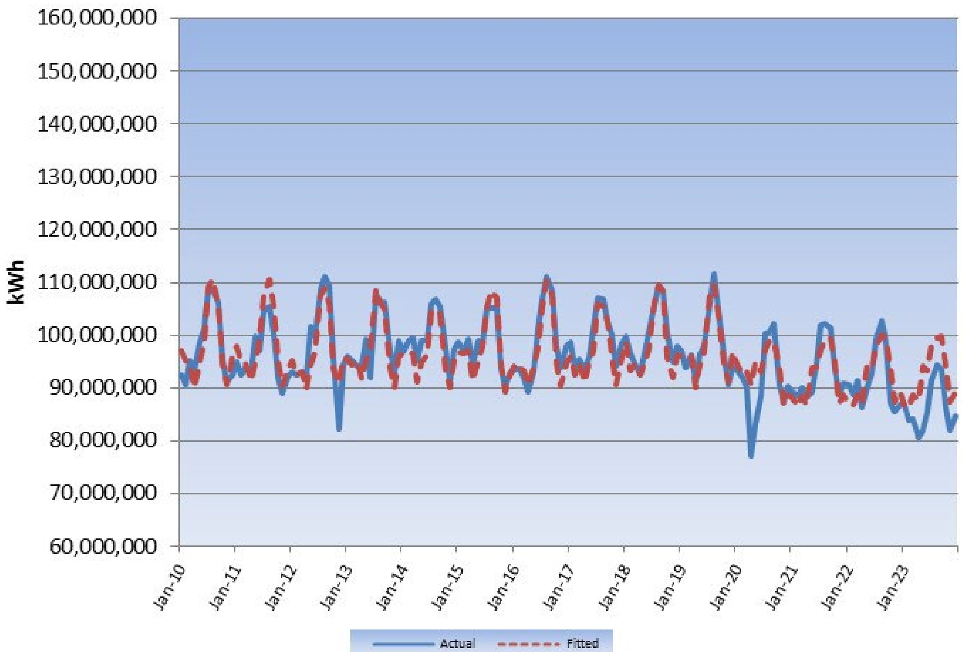


Figure 11

LPL-P Industrial Model
Actual vs. Fitted Values

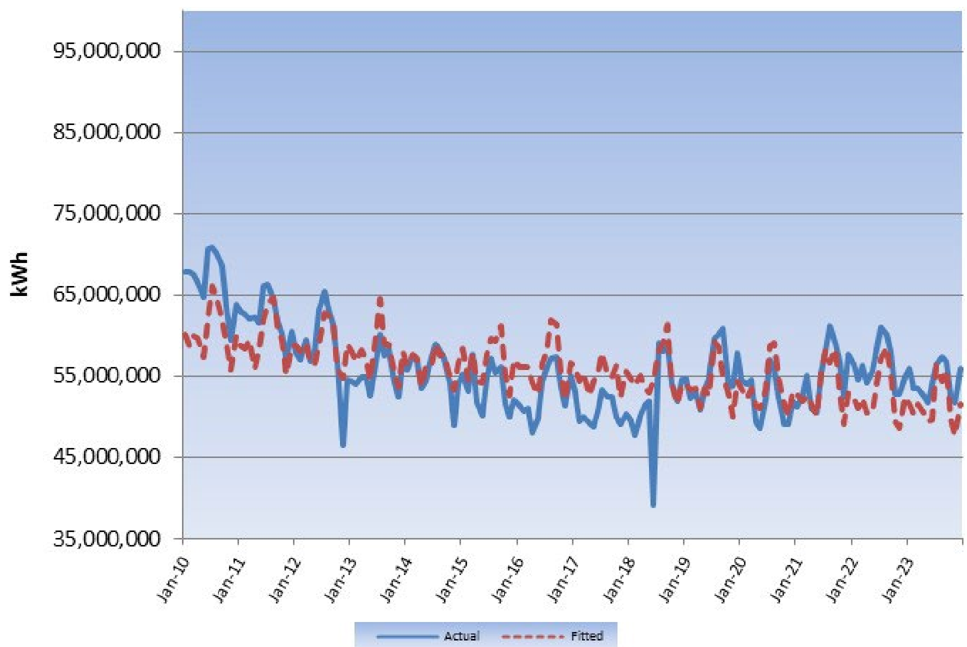


Table 5

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

Rate	THIxPRICE	HDDxPRICE	HDDxMFG	THIxMFG	COVID-THI	COVID-HDD	R2	n
GLP			0.036 (0.0098)	0.004 (0.0017)			0.61	158
HS			0.000 (0.0001)				0.51	158
LPL-S		-16.697 (31.163)	0.064 (0.0238)	0.010 (0.00287)	-1.79793 (0.23486)	-8.74 (1.597)	0.76	158
				THI				
LPL-P				2.80608 (0.7455)			0.50	158

Like the commercial models, the estimated coefficients of the three industrial models indicate that sensitivity to price is small. Rate LPL-S has the only measured price elasticity with -0.03. 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.

It should be noted that the largest commercial and industrial customers who take service under the High Tension Service rate (HTS) are not modeled econometrically since these customers are few in number, not measured as weather-sensitive, and subject to wide swings in sales. Recent history serves as the basis for the forecasts of these customers.

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 Program (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.

Residential Customers

Total Residential FTE customer growth has been found to be correlated with the change in residential building permits in New Jersey. The ten-year average annual Increase in FTE customers has been 142% of the building permits. 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 0.6 percent annual rate during the forecast period (2025-2034) as permits are expected to decrease at a 4.3 percent average annual rate.

Customers in rates RHS and RLM are projected to decline at the annual rate of 6 percent and 0.7 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. The numbers of these customers are expected to continue the trend seen in the 2021-2023 period. Industrial GLP customers are expected to decline at a 1 percent rate while commercial customers are predicted to increase at a 1 percent annual average rate during the forecast period.

While an increase in the number of large customers is, in general, not anticipated, the number of commercial customers in rate LPL-S is expected to increase at 1.3 percent annual rate. It is also anticipated that a data center customer will be added to the commercial HTS-ST rolls in 2025.

It should be noted that the number of non-residential customers is not, due to the heterogeneity of the customers in this sector, 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

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy.com June 2024 forecast. This forecast assumes that, nationally, the economy continues to grow 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 A-1.

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, 2023.

Efficient Lighting

EISA 2007 mandated the elimination of the manufacturing of most incandescent bulbs triggering the migration to more efficient halogen and compact fluorescent (CFL) bulbs. Lighting technology, due to EISA 2007, increased rapidly resulting in the large-scale migration to light emitting diode (LED technology. While the conversion from incandescent to high efficiency bulbs in the existing stock is, for the most part, complete, the legislation results in savings during the forecast period as new housing utilizes the more efficient bulbs rather than incandescent bulbs.

Historical and projected impact of efficient lighting is from the PSE&G Residential End-Use Model utilizing the timing of the phasing in of the mandates and the shipments of the relevant bulb types from the National Electrical Manufacturers Association. This data is summarized in Table A-3.

Net Metered Solar

Historical installed net metered solar capacity is based on BPU Office of Clean Energy data through May 2024. Overall, it is assumed that NJ will reach its final and interim EMP solar targets (i.e. 12 GWs by 2030). The translation into energy values is based on the National Renewable Energy Laboratory's PVWatts® program as utilized by the BPU. The BPU assumed a fixed roof mount with a 20 degree tilt and 180 degree azimuth. System losses were assumed to be 26.25%

and inverter efficiency was assumed to be 96%.[2] The efficiency of the panels were assumed to degrade at a rate of 0.8% a year. This data is summarized in Table A-2.

Non-Program Commercial Sector Efficiency

The 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 2023, referenced above is shown in Table A-6.

Energy Efficiency Programs

The forecast includes the impacts of five energy efficiency programs. These include:

- Pre-CEF 2017 PSE&G Programs
- New Jersey Administered Programs
- Clean Energy Futures I
- Clean Energy Futures Extension
- Clean Energy Futures II

The Pre-CEF PSE&G Programs initiated consist of energy efficiency programs directed at hospitals, multi-family dwellings, and municipal (direct install) buildings t(he Comfort Partners program is jointly administered by PSE&G and New Jersey and is accounted for with the New Jersey administered efficiency programs). The historical and projected efficiency impacts of these programs are based on PSE&G Department of Renewables and Energy Solutions (RES) information and summarized in Table A-5.

Estimates of the historical impacts of the efficiency programs administered by the New Jersey Board of Public Utilities (BPU), including Comfort Partners, were obtained from the New Jersey's Clean Energy Program Report[3] submitted annually by the BPU Office of Clean Energy. These were available through the 2020 program year. Since the savings attributed to the PSE&G service area were in excess of the utility-specific annual energy use reduction targets directed in the BPU order 2020-0610 8D, no additional incremental savings were projected. This information is also summarized in Table A-5.

Explicit estimates of annualized savings for CEF1, CEF-extension, and CEF2 were obtained from RES and converted to monthly actual savings based on the assumption of new measures being installed at a constant rate for the twelve months of the year. The seasonality of the savings and the distribution of non-

[2] State of New Jersey, Board of Public Utilities, "NOTICE Monthly Report on Status toward Attainment of the 5.1% Milestone for Closure of the SREC Program", February 7, 2020, p. 2.
[3] New Jersey BPU Office of Clean Energy, "New Jersey's Clean Energy Program Report Submitted to the New Jersey Board of Public Utilities, (various years).

residential measures to rate classes is based on the pro forma results submitted with the CEF filing.

All the energy efficiency measures were assumed to have a useful lifetime of either 12.8 years for electric measures or 9.6 years for natural gas efficiency measures. These estimated lifetimes are based on the 2023 mix of conservation measures to which individual useful lifetime estimates of each measure is applied based on BPU protocols to measure resource savings[4]. This information is summarized in Table A-4.

Plug-In Electric Vehicles

Plug-in electric vehicles (PEV) consist of those vehicles classified as battery electric vehicles (BEV) and plug-in electric hybrid vehicles (PHEV). While BEVs run solely on battery power and need to be charged at an external charging station, a PHEV can charge from an external source but may also make use of its internal combustion engine. Both types of PEVs are accounted for in the forecasting process. In addition, the stock of PEVs is disaggregated into light duty (Class 1-2a, < 8,500 pounds), medium duty (Class 2a & 3, < 14,000 pounds), heavy duty vehicles (Class 4 - 8, >14,000 pounds), school busses and transit busses. The light duty vehicle (LDV) segment is fairly monolithic and consists primarily of passenger cars and light trucks (SUVs, cross-overs, vans, and pick-ups). By contrast, the medium- and heavy-duty (MHDV) segments are extremely diverse, and includes buses of all sizes, long-haul tractor-trailers, fire trucks, refuse vehicles, local delivery and freight, etc).

Historical data on the stock of PEVs in New Jersey is available from motor vehicle registration data published by Atlas Public Policy in six month “snapshots” beginning in 6/30/2017 with the latest available data being from 12/31/2023.[5] The stock of PEVs in the electric service territory of PSEG was derived by extracting all of the vehicle registrations from the zip codes in the PSEG electric service territory. Prior to 6/30/2017, the stock of PEVs in the PSEG service territory was estimated based on the model year of the stock of PEVs from the 2018 model year and before.

The forecast of PEV vehicle stock and energy use was developed by Gabel Associates in April 2022 based on the latest data available.

The Gabel forecast projects both vehicle sales and the number of registered vehicles in operation (VIO) from 2022 to 2035, building on historical data back to 2011 (for sales) and 2016 (for registered VIO).[6] The forecast projects LDV and MHDV segments separately, then combines them to create a consolidated

[4] New Jersey Board of Public Utilities, “New Jersey’s Clean Energy Program Protocols to Measure Resource Savings FY2020, July 10, 2019.
[5] Atlas Public Policy, https://www.atlasevhub.com/materials/state-ev-registration-data/ (web site).
[6] Note: the Gabel forecast methodology description is from;
Warner Mark, “Re: Updated LDV Forecast July 18, 2022 (email), August, 15, 2022.

forecast for vehicles, annual energy consumption due to vehicle charging, and power impacts at peak time (6PM).

The vehicle adoption projection for the LDV segment is based on the new Advanced Clean Cars II rule (ACC II) adopted by NJ in 2023. The ACC II rule establishes a mandate that 100% of LDV sales be “zero emission” by 2035, which for this analysis are all assumed to be PEVs. It is anticipated that the ACC II mandate is the most appropriate planning baseline from a compliance perspective, which over time will supersede the EV Law scenario. This assumption is then combined with assumptions about the natural vehicle replacement rate per segment. There is very little data on electrified MHDV sales in NJ, so the MHDV vehicle projection is based primarily on the ACT requirements. The state-wide forecast is translated to the PSE&G territory based on historical percentage of statewide PEV registrations as estimated to evolve over time.

Building on the vehicle projections, the estimates of daily PEV charging load is based on statistics synthesized by Gabel from multiple studies, especially regarding the average number of kWh per vehicle per day, broken out into five segments: LDV-residential, LDV-workplace, and LDV-public-charging, MHDV-depot, and MHDV-on-the-road (e.g. truck stops). Based on this segmentation, 42% of charging energy is expected to be in the commercial sector (workplace and MHDVs) 2025, with the balance primarily residential (mostly for privately owned vehicles for personal use). This bottoms-up analysis is rolled up to provide a territory-wide view of aggregate energy consumption (MWHRs).

This forecast is summarized in Table A-7.

V Demand Model Specification and Estimation

Introduction

Demand measures are an important billing determinant for non-residential customer bills. The demand that is used as a billing determinant is based on the highest measured demand during the billing period. In the case of annual billed demand, a charge that is levied each month of the year, the highest demand that occurred on any day and at any time during the billing period is used. In the case of summer billed demand, a charge that is levied in the months of June through September, the highest demand during the billing period that occurred during the PJM on-peak period is used. The PJM on-peak period is defined as non-weekend, non-holiday days between the hours of 7 AM and 10 PM.

Model Specification and Estimation

The demand measures are a function of the load shape of the customers and, as a result, are dependent upon how much electricity is used and when it's used. The demand model, as a result, has demand being determined by the monthly energy sales, an indicator of overall demand, and the most extreme seasonal weather, a determinant of the magnitude of the greatest hourly energy use during the billing period. Since there are economic incentives to curtail demand during the PJM peak hours, the annual demand is used as the dependent variable in the model equations.

Consistent with the energy models, the estimated impact of the net metered solar on both energy and billed demand has been removed 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.

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

$$KW\_ANN_t = f(KWH_t, THI\_MAX_t, HDD\_MAX_t) \qquad [3]$$

where:

KW_ANN_t = Annual billed kW demand in billing month t,
KWH_t = kWh electricity sales in billing month t,
THI_MAX_t = Maximum THI in billing month t,
HDD_MAX_t = Maximum HDD in billing month t,.

This model was estimated separately for rates GLP, LPL-S and LPL-P for both the Commercial and Industrial customer classes. The models were estimated using monthly data from the January 2010- December 2023 period. The results of the OLS estimation procedure are summarized in Table 6 and Figures 12-17.

Table 6

Estimated Coefficients of the Billed Demand Models
(standard errors in parentheses)

Class	Rate	kWh	Maximum THI	R^2	n
Commercial	GLP	0.0013	16,348	0.89	168
		(0.0001)	(755.6)		
	LPL-S	0.0010	15,077	0.88	168
		(0.0001)	(739.2)		
	LPL-P	0.0008	3,323	0.79	168
		(0.0001)	(315.0)		
Industrial	GLP	0.0029	642	0.81	168
		(0.0001)	(58.6)		
	LPL-S	0.0013	1,122	0.94	168
		(0.0001)	(66.3)		
	LPL-P	0.0017	416	86.00	168
		(0.0001)	(57.2)		

As Figures 12-17 illustrate, the high values of the coefficients of determination of all of the models 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 billed demand. The winter weather variable was not significant in any of the demand models. This is most likely due to the the winter peak is much lower than the summer peak, closer to the monthly average peak and, as a result, highly correlated with the monthly sales. The summer weather, however, is a key predictor of summer electricity billed demand by these non-residential rates..

Figure 12

GLP Commercial Demand Model
Actual vs. Fitted Values

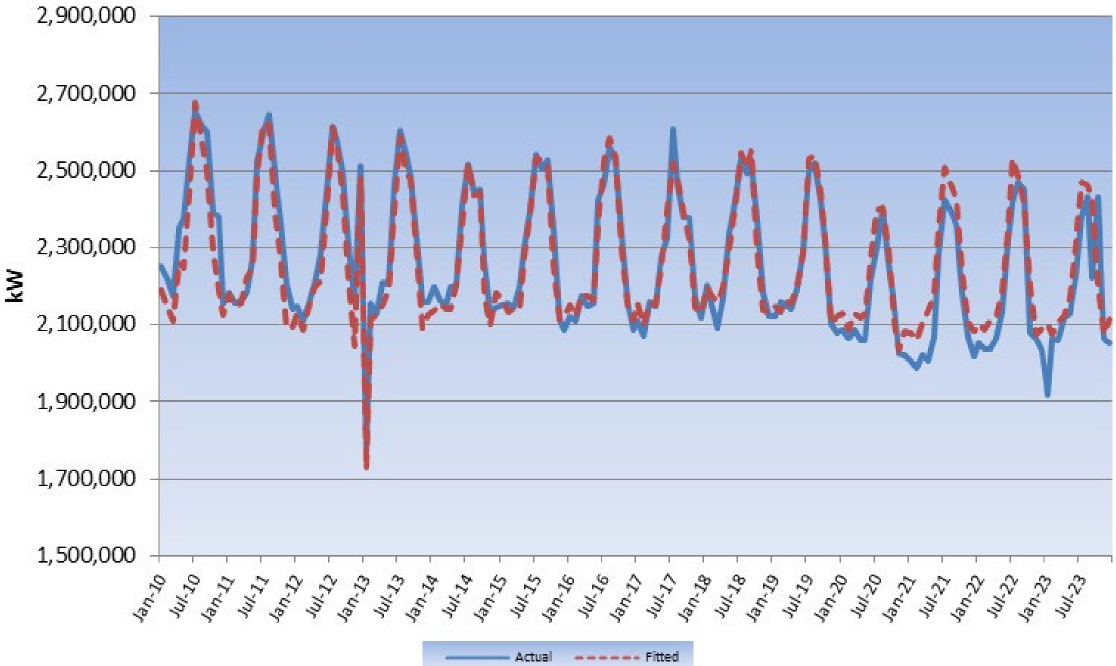


Figure 13

LPL-S Commercial Demand Model
Actual vs. Fitted Values

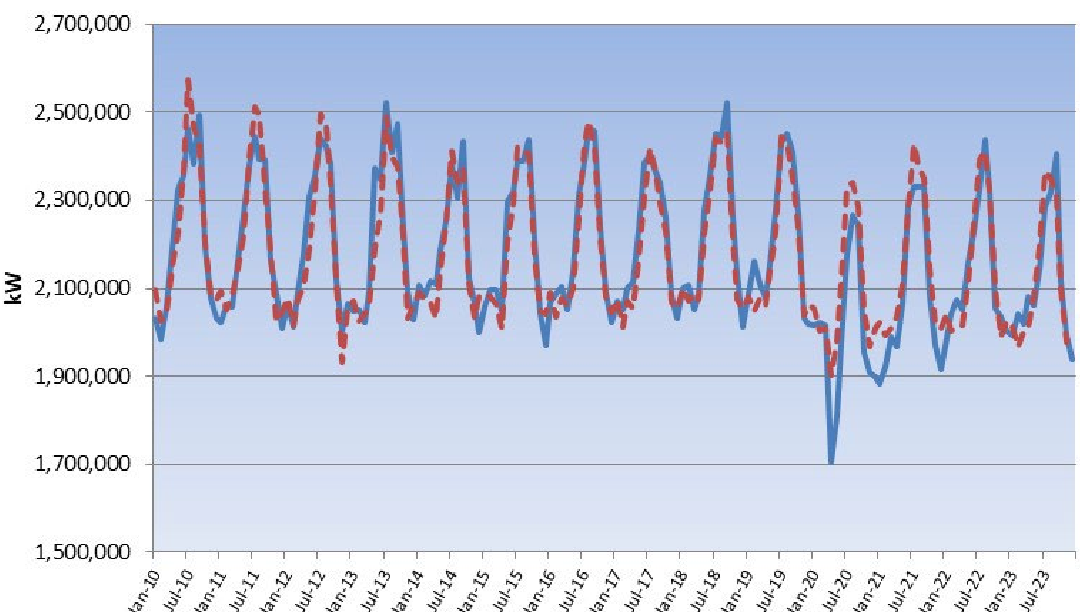


Figure 14

LPL-P Commercial Demand Model
Actual vs. Fitted Values

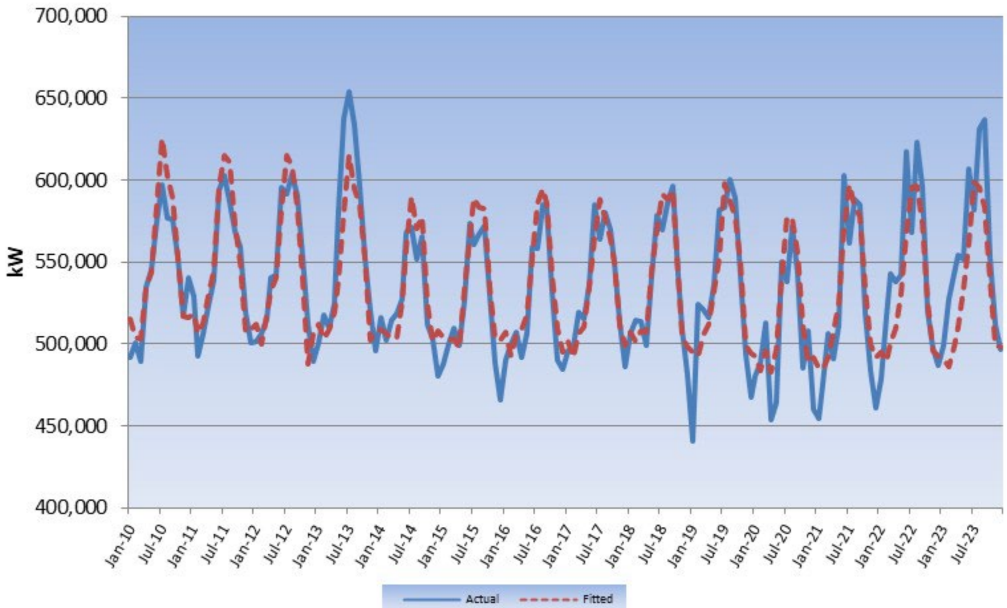


Figure 15

GLP Industrial Demand Model
Actual vs. Fitted Values

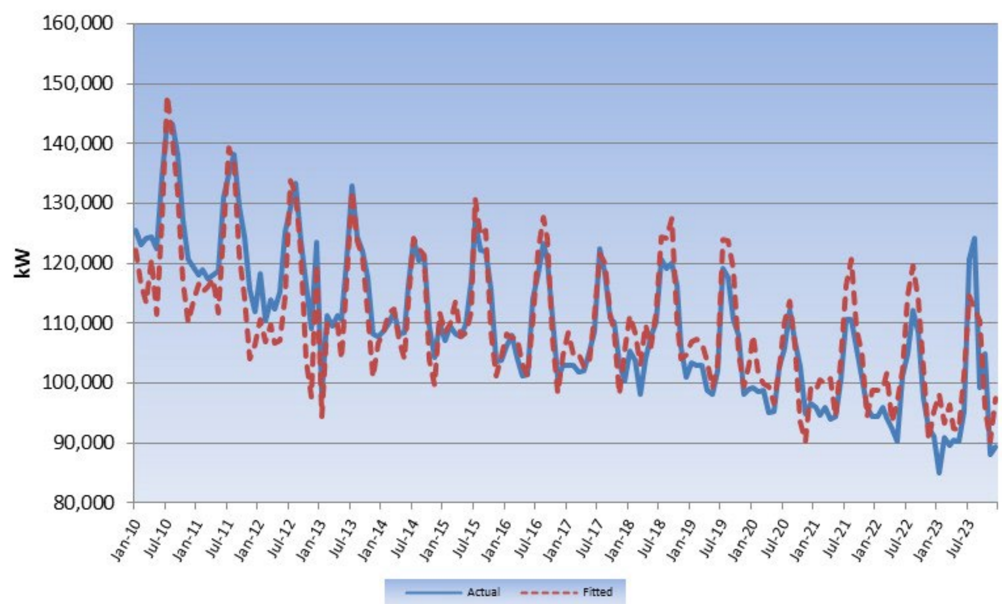


Figure 16

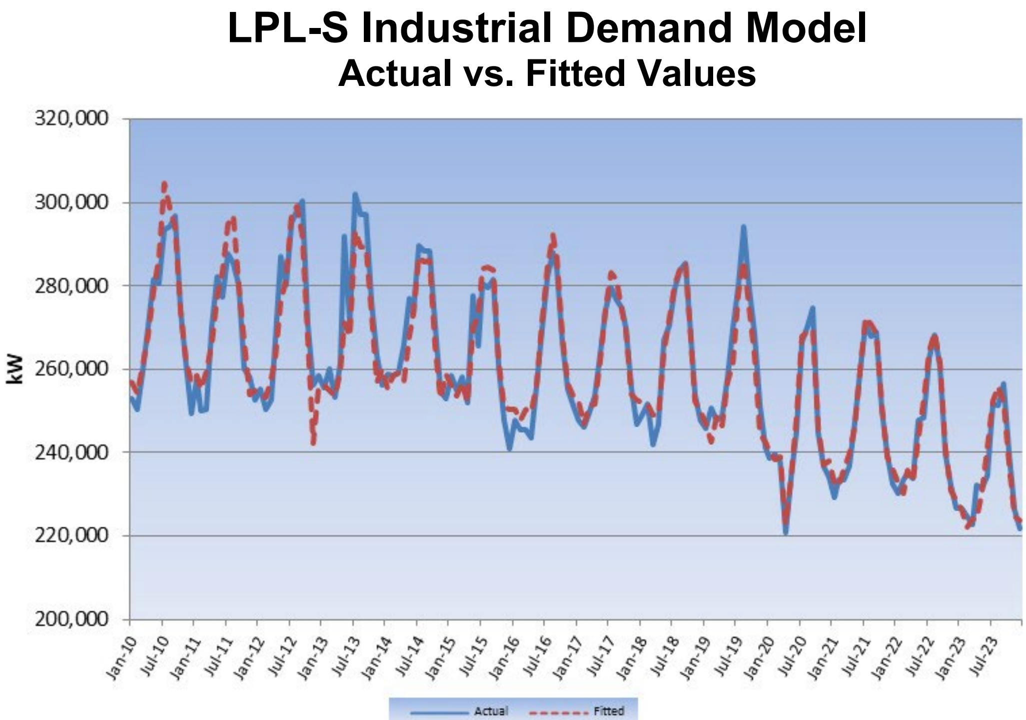
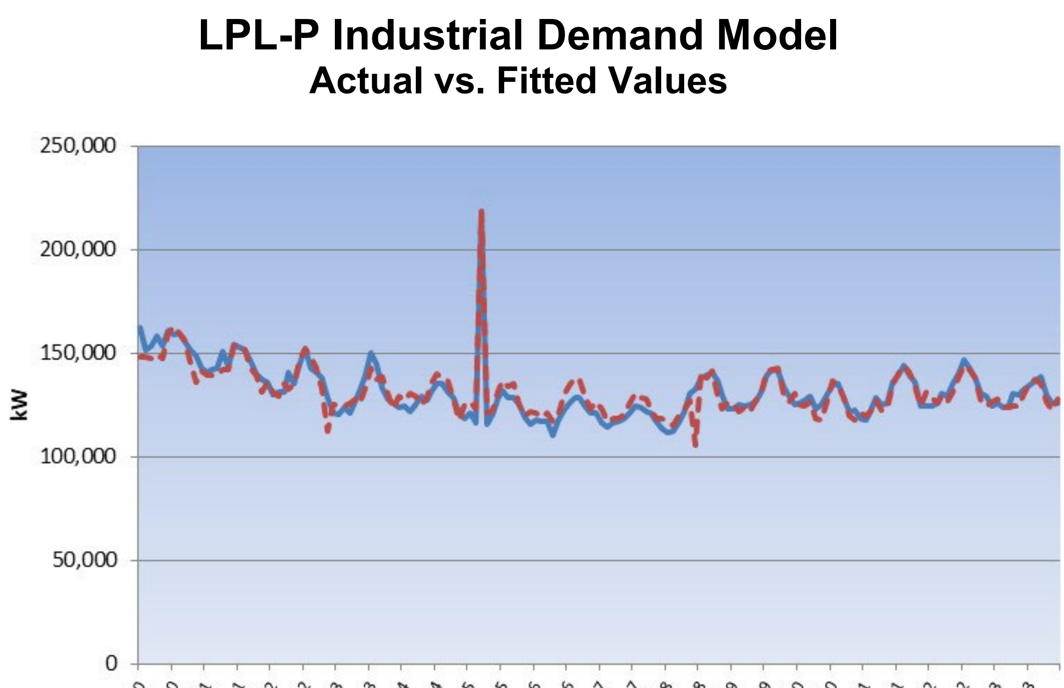


Figure 17



A. Energy Forecast Assumption Tables

Table A-1

National and New Jersey Economic Forecast Assumptions

	ECONOMY.COM JUN 2024 UPDATE																	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
EMPLOYMENT (thousands)																		
Total Non - Farm	4,152	4,189	3,850	4,029	4,235	4,323	4,391	4,413	4,415	4,411	4,407	4,403	4,400	4,396	4,393	4,391	4,389	4,388
Goods Producing	409	414	392	400	416	422	426	429	427	423	419	413	408	403	398	393	389	385
Service Proving	3,742	3,775	3,458	3,629	3,819	3,901	3,965	3,984	3,988	3,988	3,988	3,990	3,992	3,994	3,995	3,998	4,000	4,003
HOUSING STARTS (numbers)																		
Total	24,540	28,680	27,990	32,104	34,173	28,606	26,733	26,717	27,987	27,906	27,137	25,777	24,242	22,787	21,389	20,040	18,788	17,635
Single - Family	12,331	12,317	13,085	14,441	13,619	15,045	15,149	15,133	16,456	16,528	16,002	15,244	14,335	13,368	12,453	11,619	10,863	10,175
Multi - Family	12,209	16,363	14,905	17,664	20,554	13,561	11,584	11,584	11,532	11,377	11,135	10,533	9,907	9,418	8,936	8,421	7,926	7,460
PERSONAL INCOME																		
Total (millions)																		
Nominal	591,913	624,832	657,848	705,180	714,995	750,004	787,125	817,154	848,379	881,119	916,344	952,367	988,443	1,025,187	1,063,182	1,102,671	1,143,360	1,185,789
Real (2017)	580,016	603,621	628,702	647,244	616,171	623,002	637,684	647,266	657,612	668,701	680,889	692,940	704,492	715,789	727,504	739,461	751,240	763,020
Per - Capita (thousands)																		
Nominal	64,091	67,474	70,948	76,091	77,187	80,702	84,507	87,691	91,058	94,635	98,526	102,535	106,565	110,670	114,923	119,358	123,946	128,738
Real (2017)	62,803	65,184	67,805	69,839	66,518	67,037	68,463	69,460	70,583	71,820	73,210	74,604	75,952	77,270	78,638	80,042	81,438	82,839
CPI - US (1982 = 100)	251	256	259	271	293	305	314	322	330	337	345	352	360	368	376	384	392	401
30yr MORTGAGE RATE - US (%)	4.6	4.2	3.5	3.3	5.7	7.1	7.1	6.7	6.5	6.4	6.3	6.3	6.2	6.2	6.1	6.1	6.1	6.0
UNEMPLOYMENT RATE - NJ (%)	4.0	3.5	9.4	6.7	3.9	4.4	4.7	4.4	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4

Table A-2

PSE&G Net Metered Solar Forecast Assumptions

	Capacity - Added DC (kW)						Capacity - DC (kW)					
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	86.8	13.6	479.8	-	-	580.2	107.1	168.9	515.4	-	-	791.4
2004	357.9	145.6	488.1	100.3	-	1,091.9	465.0	314.4	1,003.5	100.3	-	1,883.3
2005	911.1	888.0	2,792.3	245.8	-	4,837.2	1,376.1	1,202.4	3,795.8	346.1	-	6,720.4
2006	1,389.9	1,819.4	5,471.2	662.9	-	9,343.3	2,765.9	3,021.8	9,267.0	1,009.0	-	16,063.7
2007	875.9	1,585.8	3,726.2	470.1	-	6,658.1	3,641.9	4,607.6	12,993.2	1,479.2	-	22,721.8
2008	1,270.1	1,822.1	2,616.9	1,637.0	-	7,346.1	4,911.9	6,429.7	15,610.1	3,116.2	-	30,067.9
2009	2,553.4	5,734.6	8,558.4	5,223.5	3,282.3	25,352.2	7,465.3	12,164.3	24,168.5	8,339.7	3,282.3	55,420.1
2010	5,256.2	8,142.5	20,878.6	12,985.5	4,874.2	52,137.0	12,721.5	20,306.8	45,047.0	21,325.2	8,156.5	107,557.1
2011	14,231.5	21,397.3	56,793.4	40,637.5	21,866.5	154,926.1	26,953.0	41,704.1	101,840.4	61,962.7	30,023.1	262,483.2
2012	13,419.0	24,252.0	57,714.3	42,426.0	20,981.0	158,792.2	40,372.0	65,956.0	159,554.7	104,388.7	51,004.1	421,275.4
2013	15,104.5	12,675.7	35,278.4	27,768.0	10,857.2	101,683.9	55,476.5	78,631.7	194,833.1	132,156.7	61,861.2	522,959.3
2014	17,906.8	4,854.8	16,528.0	6,174.9	1,259.3	46,723.7	73,383.3	83,486.5	211,361.1	138,331.6	63,120.5	569,683.0
2015	34,578.2	4,548.0	9,557.3	4,394.3	3,050.1	56,127.9	107,961.6	88,034.5	220,918.3	142,725.9	66,170.6	625,811.0
2016	59,579.1	5,003.4	17,441.1	15,579.8	9,975.1	107,578.5	167,540.7	93,037.9	238,359.5	158,305.7	76,145.7	733,389.5
2017	54,359.3	8,640.6	28,511.2	31,501.8	19,570.9	142,583.9	221,900.0	101,678.6	266,870.7	189,807.5	95,716.5	875,973.4
2018	58,237.0	10,152.2	31,324.9	23,147.5	10,237.9	133,099.5	280,137.0	111,830.8	298,195.6	212,955.0	105,954.4	1,009,072.8
2019	57,430.8	9,872.7	34,421.7	31,136.1	22,415.6	155,276.9	337,567.8	121,703.5	332,617.3	244,091.1	128,370.0	1,164,349.7
2020	52,831.8	6,761.0	26,882.0	37,573.3	19,764.4	143,812.7	390,399.6	128,464.5	359,499.3	281,664.4	148,134.4	1,308,162.3
2021	61,296.4	9,776.7	36,042.8	47,956.5	32,521.6	187,594.0	451,696.0	138,241.2	395,542.2	329,620.9	180,656.0	1,495,756.4
2022	76,500.8	18,605.1	66,558.6	59,950.8	28,648.8	250,264.1	528,196.8	156,846.4	462,100.8	389,571.7	209,304.8	1,746,020.5
2023	103,982.4	13,938.8	49,865.2	44,914.7	21,463.5	234,164.7	632,179.2	170,785.2	511,966.1	434,486.4	230,768.3	1,980,185.2
2024	87,147.7	10,958.4	39,202.9	35,310.9	16,874.1	189,493.9	719,326.9	181,743.6	551,168.9	469,797.2	247,642.4	2,169,679.0
2025	73,304.6	11,053.4	39,542.9	35,617.1	17,020.4	176,538.3	792,631.5	192,797.0	590,711.8	505,414.3	264,662.8	2,346,217.4
2026	84,881.1	10,958.5	39,203.4	35,311.3	16,874.3	187,228.7	877,512.6	203,755.6	629,915.2	540,725.6	281,537.1	2,533,446.0
2027	103,460.1	11,600.7	41,500.7	37,380.6	17,863.1	211,805.2	980,972.7	215,356.2	671,415.9	578,106.2	299,400.2	2,745,251.2
2028	112,768.3	12,492.8	44,692.3	40,255.3	19,236.9	229,445.6	1,093,741.0	227,849.1	716,108.2	618,361.5	318,637.1	2,974,696.8
2029	111,866.1	12,715.8	45,490.0	40,973.8	19,580.2	230,626.0	1,205,607.1	240,564.9	761,598.2	659,335.3	338,217.3	3,205,322.8
2030	110,971.2	12,614.1	45,126.1	40,646.0	19,423.6	228,781.0	1,316,578.3	253,179.0	806,724.3	699,981.3	357,640.9	3,434,103.9
2031	102,988.3	11,722.0	41,934.7	37,771.4	18,049.9	212,466.4	1,419,566.6	264,901.0	848,659.0	737,752.8	375,690.8	3,646,570.2
2032	97,096.5	11,063.1	39,577.5	35,648.2	17,035.3	200,420.6	1,516,663.2	275,964.1	888,236.5	773,401.0	392,726.1	3,846,990.9

Table A-3

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 A-4

PSE&G EE Program Energy Impact Assumptions

PSE&G		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	RS	30,040	30,040	30,040	38,566	41,779	60,469	60,469											
	GLP	98,804	110,046	118,977	129,616	143,350	148,305	166,611											
	LPL-S	85,158	87,022	99,822	113,651	123,506	133,919	136,029											
	Total	214,003	227,108	248,839	281,833	308,634	342,692	363,109											
NJ-BPU	**RS**	102,045	111,057	113,403	113,170	113,287	112,157	110,167	107,723	104,759	101,086	95,968	122,537	108,130	89,667	90,343	81,111	77,314	75,506
	GLP	111,649	132,587	153,401	184,922	224,286	254,969	271,916	281,619	291,323	298,072	283,208	285,981	275,421	252,324	237,894	226,660	215,550	193,732
	LPL-S	842,532	935,457	1,027,340	997,392	994,936	1,038,411	1,096,024	1,131,839	1,169,856	1,189,717	1,213,290	1,459,040	1,413,939	1,325,989	1,329,162	1,330,770	1,333,421	1,337,457
	Total	1,056,226	1,179,101	1,294,143	1,295,484	1,332,510	1,405,537	1,478,106	1,521,181	1,565,938	1,588,876	1,592,466	1,867,558	1,797,490	1,667,981	1,657,399	1,638,541	1,626,285	1,606,695
CEF	**RS**						1,857	160,730	552,966	934,142	1,096,867	1,181,329	1,293,325	1,389,839	1,468,293	1,546,747	1,625,201	1,703,655	1,782,109
	GLP							7,100	144,109	378,311	573,975	735,236	948,978	1,165,938	1,364,059	1,562,179	1,760,300	1,958,421	2,156,541
	LPL-S							3,550	72,055	189,155	286,987	367,618	474,489	582,969	682,029	781,090	880,150	979,210	1,078,271
	LPL-P							1,315	26,687	70,058	106,292	136,155	175,737	215,915	252,603	289,292	325,981	362,670	399,359
	HTS-ST							1,183	24,018	63,052	95,662	122,539	158,163	194,323	227,343	260,363	293,383	326,403	359,424
	Total						1,857	173,878	819,835	1,634,717	2,159,784	2,542,878	3,050,692	3,548,984	3,994,328	4,439,672	4,885,016	5,330,360	5,775,704

Table A-5

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	2026	2027
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	0.0008	0.0008	0.0008	0.0008	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	0.0052	0.0051	0.0050	0.0049	0.0049	0.0049
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	0.0063	0.0062	0.0062	0.0062	0.0061	0.0061
Computing	0.0026	0.0024	0.0015	0.0013	0.0011	0.0041	0.0039	0.0038	0.0037	0.0036	0.0035	0.0045	0.0045	0.0045	0.0045	0.0045	0.0046	0.0046
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	0.0019	0.0018	0.0018	0.0018	0.0018	0.0017	0.0017
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	0.0197	0.0187	0.0185	0.0183	0.0182	0.0182	0.0181

Table A-6

PSE&G Electric Vehicle Forecast Assumptions

Number of Electric Vehicles by Type

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Light Duty	**Private**	21,632	31,979	49,166	76,752	118,129	173,803	248,863	346,065	459,990	587,204	728,454	880,965	1,041,243
	Fleet	2,136	2,581	4,136	6,779	10,685	15,684	22,463	31,232	41,519	52,996	65,749	79,509	93,979
	Total	23,768	34,560	53,302	83,531	128,814	189,487	271,326	377,297	501,509	640,200	794,203	960,474	1,135,222
Medium Duty	**Total**	-	-	52	872	1,677	2,218	2,916	3,906	5,228	6,856	8,765	10,935	13,346
Heavy Duty	**Total**	4	4	4	43	276	767	1,468	2,398	3,708	5,403	7,430	9,674	12,054
School Bus	**Total**	-	-	1	14	33	74	147	253	395	576	789	1,030	1,297
Transit Bus	**Total**	-	-	12	50	80	149	269	416	577	751	935	1,131	1,335
Total		23,772	34,564	53,371	84,510	130,880	192,695	276,126	384,270	511,417	653,786	812,122	983,244	1,163,254

Charging Load of Electric Vehicles by Type
(MWh)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Light Duty	**Home**	47,529	70,112	107,768	168,296	259,568	380,999	545,499	758,524	1,010,602	1,286,829	1,596,278	1,930,381	2,287,357
	Public	14,835	21,883	33,636	52,528	81,015	118,915	170,258	236,746	315,424	401,638	498,222	602,500	713,918
	Work	7,417	10,942	16,818	26,264	40,507	59,458	85,129	118,373	157,712	200,819	249,111	301,250	356,959
	Fleet	7,248	8,738	14,009	22,965	36,266	53,110	76,062	105,745	140,907	179,402	222,563	269,125	318,912
	Total	77,029	111,675	172,231	270,052	417,357	612,482	876,948	1,219,389	1,624,644	2,068,688	2,566,173	3,103,256	3,677,145
Medium Duty	**Total**	-	-	448	7,567	14,556	19,206	25,253	33,824	45,385	59,366	75,894	94,674	115,836
Heavy Duty	**Total**	94	87	84	997	6,455	17,922	34,282	56,004	86,793	126,156	173,456	225,827	282,063
School Bus	**Total**	-	-	8	166	404	925	1,832	3,153	4,941	7,204	9,878	12,909	16,256
Transit Bus	**Total**	-	-	919	3,955	6,266	11,722	21,143	32,700	45,468	58,989	73,511	88,851	105,208
Total		77,123	111,762	173,690	282,737	445,038	662,256	959,457	1,345,070	1,807,231	2,320,404	2,898,912	3,525,517	4,196,508

B. 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.

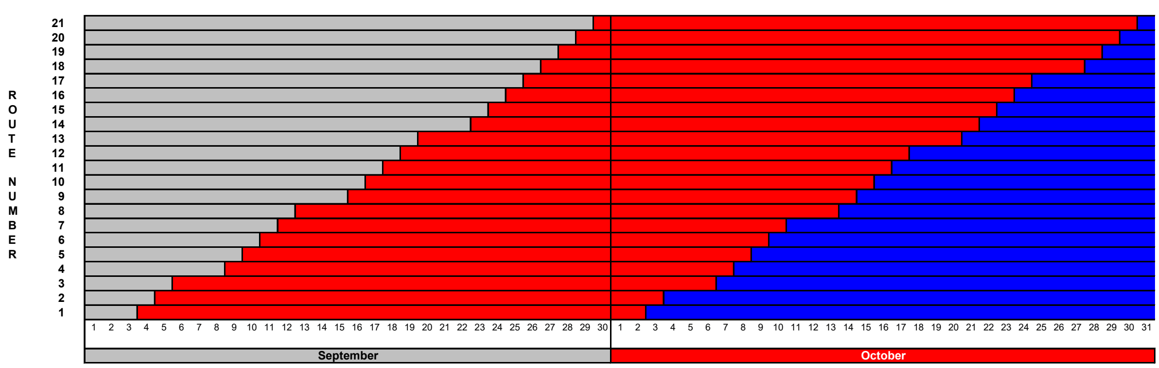
The Unbilled and Calendar-Month Estimation

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[7]. 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.

[7] 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.

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

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

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

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

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

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[8] [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:

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

[8] 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.

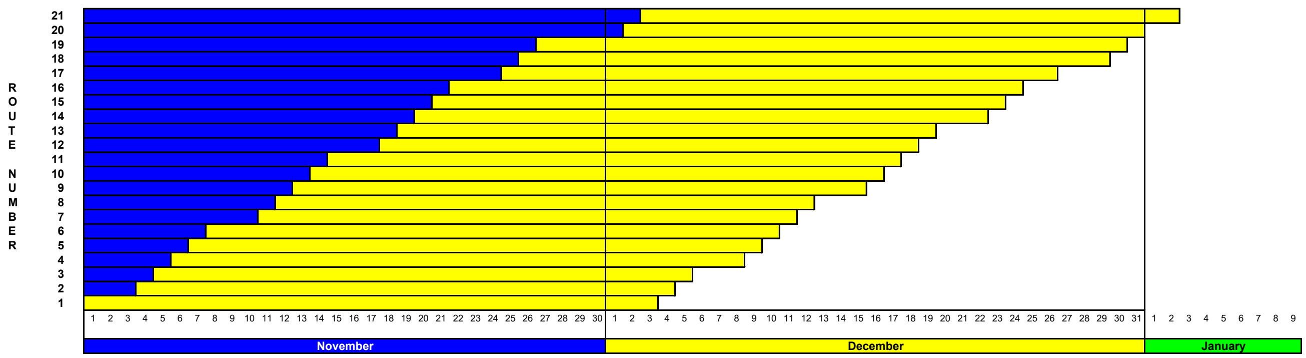
A More General Example

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[9].

[9] 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:

$$\text{December Billed} \quad = \quad \boxed{\begin{array}{r}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}} \qquad [8]$$

Given the additional components of the billed, $\boxed{\text{OCT B> DEC}}$, i.e. the “under billed” sales, and $\boxed{\text{JAN B> DEC}}$, 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:

$$\text{December Unbilled} \; = \; \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} \; + \; \boxed{\text{NOV B> JAN}} \; - \; \boxed{\text{JAN B> DEC}} \qquad [9]$$

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:

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

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.[10]

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

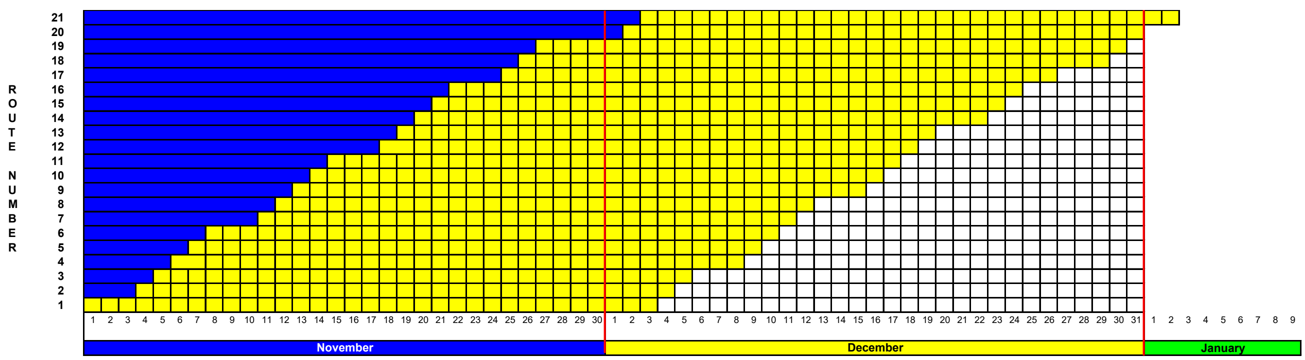
Billing	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	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

[10] 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.[11] 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, 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

[11] 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

	Heating Degree Days				Days			
Billing Month	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:

$$UnbilledTherms = UnbilledDays \times BASECoef + UnbilledHDD \times HDDCoef \quad [14]$$

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
(2025 PSE&G Electric Conservation Incentive Program)

BPU Docket No. ______________

DIRECT TESTIMONY

OF

LAUREN THOMAS
VICE PRESIDENT
CLEAN ENERGY SOLUTIONS

February 3, 2025

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
LAUREN THOMAS
VICE PRESIDENT CLEAN ENERGY SOLUTIONS

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

A. My name is Lauren Thomas and I am the Vice President of Clean 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 became vice president, Clean Energy Solutions - Customer Solutions, effective January 2025. In this role I am responsible for overseeing the customer experience as it relates to PSE&G's energy efficiency, electric vehicle and solar energy programs.Prior to my current role, I was managing director, Transmission and Substation Construction and Maintenance, responsible for executing over $1B a year in electric transmission and distribution projects, as well as maintaining our transmission system and substations.

I joined PSEG in 2008 and have held various positions in finance before joining Projects and Construction in 2011. There I was a project director for a portfolio of substation projects and managed the Project Development, Estimating and Transmission Growth teams. Most recently, I led the Transformation and Centralized Services department, where I was responsible for Technical Training, Transportation, Materials and Logistics, and Utility Culture. Prior to joining PSEG, I spent seven years working at BASF in operations, process engineering, project management, and process optimization.

I hold a Bachelor of Science from Rensselaer Polytechnic Institute in chemical engineering and a Master of Business Administration from the University of Michigan in operations and strategy. I also hold a Project Management Professional (PMP) certification.

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 Conservation Incentive Program ("CIP") Shareholder Contribution ("SC") over the past several months, and an update on the SC expenditures to date,

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

I. <u>Shareholder Contribution 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, the SC CIP spending for PY3 (October 2023 through September 2024) includes a $359,904 spending shortfall from PY2 which brought our PY3 budget to $3,659,904. Activities from October 2023- December 2024 include the following initiatives and programs:

- Outreach and community events: In 2024, PSE&G continued to engage with a vendor to help drive awareness of our energy efficiency programs through community events such as participation in the NJ Home & Garden Shows in Edison, Secaucus, Lincroft, and South Jersey. We also used the funding to promote our energy efficiency programs at community fairs such as the Cherry Blossom Festival in Newark and other street and county fairs in Burlington, Highland Park, Bordentown, Woodbridge, Verona, Fair Lawn, Garfield and West Orange. Other events we participated in are the North Brunswick Heritage Day, Cherry Hill Harvest Festival, Newark Downtown District Harvest Festival, Fanwood Vendor Popup as well as at various malls like Quaker Bridge, Newport Centre and The Mills at Jersey Gardens. Having a presence at these events creates the opportunity to promote our energy efficiency program offerings while engaging with the public to answer any questions they may have. The funding was also used to purchase promotional giveaways to support these events.
- The Great Energy Escape Mobile Unit: PSE&G developed and launched a new event component to serve as a hands-on educational experience, engage with key audiences, promote

program participation and raise awareness of the residential energy efficiency program offerings. With *The Great Energy Escape*, PSE&G is making energy efficiency tangible and relatable by gamifying the experience. Participants are challenged with solving 12 puzzles that enable them to emerge from an "escape room" – designed to mirror a residence – before time expires. This experience connects participants to PSE&G's residential energy efficiency programs, energy technologies rebates, and discounts, in addition to generating awareness about PSE&G program offerings.

- Organizational sponsorships: PSE&G funded the following sponsorships in 2024 using CIP:
  - Clean Energy and Sustainability Analytics Center (CESAC) at Montclair State University's 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.
  - Rutgers Day: Participated in the 16th Annual Rutgers Day event - this event draws 25-30k attendees across various Rutgers' campuses where we promoted our program offerings to students, alumni and other attendees.
  - Edison Electric Institute: EEI's semi-annual National Key Account Workshop is the venue where national, chain, and multi-site energy users can tackle all of their energy-related needs which includes energy efficiency.
  - New Jersey Manufacturing Extension Program: "Made in New Jersey" Manufacturing Day provided opportunity to engage with and educate decision-makers on the benefits of the many energy efficiency programs available through CEF-EE.

- NJSBDC Awards Event: PSE&G was a sponsor of the New Jersey Small Business Development Center Awards event. The awards celebrated outstanding achievements, innovation and resilience honoring the accomplishments of New Jersey small businesses. We were able to engage with these small businesses, raise awareness and encourage participation in our programs.
- NJCCC Sustainability in Motion: The funds were used for a sponsorship of the Sustainability in Motion Conference which was co-hosted by the New Jersey Clean Communities Council and the Association of New Jersey Recyclers. The sponsorship included a full-page ad in the conference booklet, booth space for the promotion of our energy efficiency programs, and 2 email blasts.
- NJ Chamber of Commerce: PSE&G sponsored the ReNew Jersey Business Summit & Expo hosted by the NJ Chamber of Commerce. The Chamber consistently works to improve New Jersey's business climate and provide its members with opportunities to promote and grow their businesses and we had the opportunity to engage with those businesses to promote our programs.
- The Chemical Industry: PSE&G participated as an exhibitor in the 39th Annual Chemistry Council of NJ (CCNJ) Conference. This gathering was a unique occasion to connect, engage, and promote the EE programs to key industry decision-makers. Exhibiting at the CCNJ Conference gave us the chance to highlight our programs, strengthen client relationships, and engage with potential new clients.
- The African American Chamber of Commerce of New Jersey: PSE&G sponsored the AACCNJ Juneteenth Black Business Expo in 2024. The AACCNJ Expo proved to be a dynamic, educational and interactive event focused on entrepreneurship and the

economic and cultural empowerment of underperforming communities. PSE&G had the opportunity to promote energy efficiency programs to attendees and exhibitors.

- Association of New Jersey Environmental Commissions (ANJEC): A sponsorship of the ANJEC Congress expanded PSE&G's visibility with sustainability councils for a number of municipalities in our service territory in addition to offering outreach opportunities to promote energy efficiency programs to attendees and exhibitors.
- Energy Efficiency Alliance of New Jersey Sponsorship of the EEA-NJ conference which attracts hundreds of energy efficiency businesses, utilities, regulators and advocates from New Jersey and beyond provided high visibility of EE across two days of energy efficiency policy, education and networking.
- New Jersey School Boards Association: Attendance at the annual NJSBA conference provided PSE&G an opportunity to engage with hundreds of school business administrators and members of school boards who are responsible for making decisions on upgrading school facilities to become more energy efficient. Sponsorship at these events and conferences provided us the opportunity to promote our Energy Efficiency Programs and raise awareness through ad/marketing placement, panel participations, representation at the events or exhibits.

- Marketplace Free Shipping and Offer Center: PSE&G continues to use the funding 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 continuation of this promotion has increased customer participation and encourages customers to make multiple purchases on small orders of energy efficient products. The Marketplace Offer Center funding is being used to cover the gap between the cost of a smart thermostat or other energy efficiency products and the associated rebates in order to provide them to low-moderate income customers at no cost.

- Sustainable Jersey: PSE&G partnered with Sustainable Jersey to empower schools, municipalities, residents and businesses to better manage energy use and leverage PSE&G's energy-efficiency programs and incentives. There are three program tracks including residential outreach, business outreach and technical assistance for school and municipal facilities. To date, 35 municipalities have joined at least one program track (8 have joined 2 tracks and 2 municipalities have participated in all 3 tracks). A total of $147,500 in Grants has been distributed through the Sustainable Jersey/PSE&G Energy Efficiency Partnership Program. Sustainable Jersey has also recruited and engaged nearly 100 schools in PSE&G service territory for participation in the EmPowered Schools program administered by the Alliance to Save Energy.
- ROI- NJ: The funds were used toward a 6-month engagement with ROI- NJ to promote the energy efficiency Program offerings. ROI- NJ is an influential media organization that delivers local news and information to business and consumer audiences. They continued to gain the respect and trust of those who live and work in New Jersey. A 6-month sponsorship with ROI-NJ exposed our programs to thousands of potential participants.
- Commercial & Industrial (C&I) Trade Ally Incentive: Funding was used to provide a Trade Ally Bonus incentive (calculated from total incentive per project) and a $1,000 bonus for each project that is approved for On-Bill Repayment (OBR) paid directly to participating Trade Allies. This bonus supported increased awareness and participation in the C&I energy efficiency programs amongst our business customers and our contractor network.

- Somerset Patriots Engagement: PSE&G sponsored the Somerset Patriots 2024 baseball season as an opportunity to expose tens of thousands of customers to our energy efficiency programs. Included in this sponsorship was an on-field promotion and banner with the PSE&G energy efficiency website; nine concourse table activations, a full-page ad in the game program, social media postings, and a scoreboard promotion showing a 30 second energy efficiency video at 69 home games.
- Home Weatherization Kits: CIP funding was used to target PSE&G's low-moderate income (LMI) customers by sending Home Weatherization kits and using those kits as an outlet to promote the program. These free kits introduced the Home Weatherization program, encouraged participation, and increased awareness. Each kit included one (1) door and window weatherstripping kit, one (1) self-adhesive door sweep, ten (10) switch and outlet sealing gaskets, three (3) window insulation kits, and two (2) creative executions of 8.5" X 11" insert.

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 SC spending obligations.

A. Pursuant to the CEF-EE stipulation, the Shareholder Contribution funding is $3.3 million per year. However, the deferral periods for the electric and natural gas CIPs are not aligned; the first electric deferral period was June 2021 – May 2022, and the first natural gas deferral period was October 2021 – September 2022. Given this misalignment, the Company proposed an approach to be consistent with the intent of the CEF-EE stipulation and order and proposed to spend $3,905,000 for the first 16 months to account for this misalignment and then begin to report against the $3.3 on an annual 12-month basis.[1] Pursuant to the Order dated April 12, 2023, the Company's Shareholder Contribution funding was set at $3,905,000 for the period June 2021 to September 2022; $3.3 million to account for the October 2021-September 2022 period, when both electric and gas deferral periods were in effect, plus an additional $605,000, for the June 2021-September 2021 period, when only the electric deferral period was in effect.

Q. Please summarize SC spending over the prior spending periods and any carryover budget.

A. Total PY1 spending was $3,844,986 versus a budget of $3,905,000, resulting in a shortfall of $60,014 which carried over to PY2. Total PY2 spending was $3,000,110, against a budget of $3,360,014 (inclusive of the PY1 shortfall), leaving a shortfall of $359,904. This shortfall has been added to the $3.3 million PY3 budget for a total of $3,659,904. The PY3 spend was $3,361,012 leaving a shortfall of $298,892 which was added to PY4.

Program Year	PY2	PY3	PY4
	10/22-9/23	**10/23-9/24**	**10/24-9/25**
Total CIP Spend	$3,000,110	$3,361,012	$1,061,650*
Budget	$3,360,014	$3,659,904	$3,598,892
Difference (Shortfall)	$359,904	$298,892	N/A

*Reflects actual spend from 10/24-12/24

[1] In the Matter of Public Service Electric and Gas Company for Approval of Changes in its Gas Conservation Incentive Program (2022 PSE&G Gas Conservation Incentive Program Rate Filing), BPU Docket No. GR22060362, Petition filed June 1, 2022.

Q. Please summarize the Company SC spend over the PY3 and PY4 funding period.

A. Between October 1, 2023 and December 31, 2024, the Company recorded SC expenses of approximately $4.423 million. A summary of actual expenses is included in Schedule LT-ECIP-1.

Q. Does this conclude your testimony?

A. Yes, it does. Thank you.

CIP recorded expenses through December 2024

Activities	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	PY 3 Total	Oct-24	Nov-24	Dec-24	Total
Outreach and community events	$ 57,570.94	$ 35,171.27	$ 69,173.12	$ 79,640.84	$ 111,724.08	$ 29,731.25	$ 43,259.49	$ 67,008.25	$ 48,267.13	$ 109,049.90	$ 131,583.95	$ 33,623.59	**$ 815,803.81**	$ 217,290.93	$ 182,907.26	$ 72,070.75	**$ 1,288,072.75**
Organizational sponsorships	$ 8,800.00				$ 15,500.00	$ 17,228.97	$ 28,090.00	$ 50,152.46	$ 21,875.00		$ 5,000.00		**$ 146,646.43**	$ 2,256.27	$ 8,066.25		**$ 156,968.95**
Marketplace Free Shipping	$ 28,481.17	$ 44,653.49	$ 14,992.33	$ 18,843.24	$ 8,810.18	$ 29,685.45	$ 13,881.30	$ 4,679.17	$ 7,399.54	$ 13,774.49	$ 10,193.72	$ 6,174.03	**$ 201,568.11**	$ 11,680.33	$ 11,371.39	$ 31,135.41	**$ 255,755.24**
Offer Center	$ 537.75	$ 83.65	$ 322.65	$ 262.90	$ 717.00	$ 991.85	$ 1,031.92	$ 1,084.99	$ 122.10		$ 495.87		**$ 5,650.68**	$ 378.05		$ 316.37	**$ 6,345.10**
Sustainable Jersey	$ 105,866.00	$ 226,517.00	$ 500,000.00	$ 31,343.53							$ 529,808.00		**$ 1,393,534.53**				**$ 1,393,534.53**
Trade Allies Incentives	$ 222,631.46												**$ 222,631.46**				**$ 222,631.46**
Somerset Patriots						$ 51,000.00							**$ 51,000.00**				**$ 51,000.00**
Home Weatherization Kits												$ 524,177.03	**$ 524,177.03**			$ 524,177.02	**$ 1,048,354.05**
Total	$ 423,887.32	$ 306,425.41	$ 584,488.10	$ 130,090.51	$ 136,751.26	$ 128,637.52	$ 86,262.71	$ 122,924.87	$ 77,663.77	$ 122,824.39	$ 677,081.54	$ 563,974.65	**$ 3,361,012.05**	$ 231,605.58	$ 202,344.90	$ 627,699.55	**$ 4,422,662.08**

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
(2025 PSE&G Electric Conservation Incentive Program)

BPU Docket No. _______________

DIRECT TESTIMONY

OF

STEPHEN SWETZ
SENIOR DIRECTOR - CORPORATE RATES AND REVENUES REQUIREMENTS

February 3, 2025

ATTACHMENT D

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 are the components of the ECIP deferral balance?

A. As shown in, Attachment D Schedule SS-ECIP-2 of this Testimony the Company's currect deferral is forecasted to be $87,060,160. The deferral balance is forecasted to include $27,457,059 of non-weather related margin deficiencies, partially offset by $9,123,390 of weather related refunds to residential customers, $68,726,492 deferred margin recovery from the prior ECIP period (comprised of a non-weather carry-forward balance of $66,018,162 and an over-recovery of $1,367,443 as a result of not updating provisionally approved rates), as well as an under-collection of the approved prior ECIP balance of $4,075,773.

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 2024 through March 2025 for this filing. Since March 2025 actual results are not available, the earnings test in this initial filing contains actual results through September 2024 and forecasted results through March 2025. 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 confidential 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 $64,505,906. 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 $92,107,778 being limited to $71,402,087.

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

A. As shown in Attachment D, Schedule SS-ECIP-2 the net ECIP balance to be recovered from customers is $64,987,026. This represents $71,402,087 of allowed margin recovery partially offset by weather related refunds to residential customers totaling $9,123,390 as well as under recovered margin recovery from the Company's prior ECIP period of $2,708,330 ($4,075,773 - 1,367,443). As a result of the limitation on allowed margin revenue recovery a remaing $22,073,134 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	($0.000215)	($0.000229)	Per kilowatt-hour
Group Ia	RLM	$0.006859	$0.007313	Per kilowatt-hour
Group II	GLP	$0.8273	$0.8783	Per kilowatt of monthly peak demand
Group III	LPL-S	$1.7944	$1.9133	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, 2025, the annual average bill impacts of the rates requested are set forth in Schedule SS-ECIP-3.

The average monthly impact of the proposed rates to the typical residential electric customer using 683 kWh in a summer month and 558 kWh in an average month (6,700 kWh annually) would be an decrease in the average monthly bill from $134.25 to $133.25 or $1.00, or approximately 0.74% (based upon Delivery Rates and BGS-RSCP charges in effect February 1, 2025 and assuming that the customer receives BGS-RSCP service from PSE&G).

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE INDEX

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).

<u>WORK EXPERIENCE</u>

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	E	-	written	Feb-25	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	-	written	Feb-25	GSMP II Extension / Cost Recovery
Public Service Electric & Gas Company	E/G	ER24120878	written	Dec-24	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER24120878	written	Dec-24	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER24110838 and GR24110839	written	Nov-24	Infrastructure Advancement Program (IAP) - First Gas Roll-In and Second Electric Roll-in
Public Service Electric & Gas Company	E/G	ER24070484 and GR24070490	written	Jun-24	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, CEF-EE, CSEP, SuSI and TREC
Public Service Electric & Gas Company	E	ER24060375	written	Jun-24	SPRC 2024
Public Service Electric & Gas Company	G	GR24060369	written	Jun-24	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	G	GR24060375	written	Jun-24	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER24020073	written	Feb-24	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	ER23120924 & GR23120925	written	Dec-23	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E/G	QO23120874	written	Dec-23	Clean Energy Future - Energy Efficiency II Program
Public Service Electric & Gas Company	E/G	G018101112 and EO18101113	written	Nov-23	Clean Energy Future - Energy Efficiency Extension 2 Program
Public Service Electric & Gas Company	E	ER23110783	written	Nov-23	Infrastructure Advancement Program (IAP) - First Roll-In
Public Service Electric & Gas Company	E/G	ER23050273	written	Nov-23	Energy Strong II Program (Energy Strong II) - Fifth Roll-In
Public Service Electric & Gas Company	E/G	ER - 23090634 & GR - 23090635	written	Sep-23	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	GR23070448	written	Jul-23	COVID-19 Filing
Public Service Electric & Gas Company	E/G	ER23070423 & GR23070424	written	Jul-23	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, and CEF-EE
Public Service Electric & Gas Company	E	ER - ER23060412	written	Jul-23	SPRC 2023
Public Service Electric & Gas Company	G	GR23060330	written	Jun-23	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR23060332	written	Jun-23	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E	ER23050273	written	May-23	Energy Strong II Program (Energy Strong II) - Fourth Roll-In
Public Service Electric & Gas Company	G	GR23030102	written	Mar-23	Gas System Modernization Program III (GSMPIII)
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	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	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
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	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & 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	Energy Strong II Program (Energy Strong II) - First Roll-In
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

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
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 & 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
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
a	Actual CIP Carryforward Balance	16,565,555	347,481	24,148,903	24,956,223	$66,018,162	Final Stipulation, Exhibit B
b	Actual vs Approved (Over) / Under recovery	($530,517)	($6,617)	$1,248,922	($2,079,232)	($1,367,443)	b = c - a
c	Approved CIP Carry-Forward	$16,035,038	$340,864	$25,397,825	$22,876,991	$64,650,719	Final Stipulation, Exhibit C
d	Final CIP Carry-Forward	$19,505,463	$407,241	$24,999,846	$23,813,941	$68,726,492	Attachment A Schedules 1 through 3
e	**(Over) / Under Collection**	**$3,470,425**	**$66,377**	**($397,979)**	**$936,950**	**$4,075,773**	
(1)	CIP Carry-Forward	$19,505,463	$407,241	$24,999,846	$23,813,941	$68,726,492	Attachment A Schedules 1 through 3
(2)	CIP Weather	($8,988,177)	($135,214)	$0	$0	($9,123,390)	Attachment A Schedule 4
(3)	CIP Non-Weather	$1,186,766	$472,218	$7,941,232	$17,856,843	$27,457,059	Attachment A Schedule 5
(4)	**Total CIP Deferral**	**$11,704,053**	**$744,245**	**$32,941,078**	**$41,670,784**	**$87,060,160**	(4) = (1) + (2) + (3)
(5)	CIP Non-Weather Collection	$1,186,766	$472,218	$7,941,232	$17,856,843	$27,457,059	(5) = IF (4) < 0, 0, (3)
(6)	CIP Collection %	4.3%	1.7%	28.9%	65.0%	100.0%	
(7)	CIP Savings Test Recoverable Amount					**$71,402,087**	Attachment A Schedule 5, Page 2
(8)	CIP Refunds					$0	Row (4) RS & RHS
(9)	CIP Maximum Recoverable Amount					$71,402,087	(9) = (7) - (8)
(10)	**Recoverable CIP Non-Weather**	**$3,086,186**	**$1,228,002**	**$20,651,175**	**$46,436,724**	**$71,402,087**	(10) = (IF (4) < 0, (4)), ((6) * (9))

	Final ECIP Rate	RS&RHS	RLM	GLP	LPLS	Total	
(11)	Prior Period (Over) / Under Recovery	$2,939,908	$59,760	$850,943	($1,142,282)	$2,708,330	(b) + (e)
(12)	CIP Weather	($8,988,177)	($135,214)	$0	$0	($9,123,390)	(2)
(13)	Recoverable CIP Non-Weather	$3,086,186	$1,228,002	$20,651,175	$46,436,724	$71,402,087	(10)
(14)	**CIP (Refund) / Charge**	**($2,962,083)**	**$1,152,548**	**$21,502,118**	**$45,294,442**	**$64,987,026**	(14) = (11) + (12)+ (13)
(15)	CIP Carry-Forward	$14,666,135	($408,303)	$11,438,960	($3,623,658)	$22,073,134	(15) = (4) - (14)
(16)	Projected Use (000) *	13,856,220	168,487	26,172	25,308		Attachment A Schedules 1 through 3

		RS	RHS	RLM	GLP	LPLS	
(17)	CIP Rate	-0.000214	-0.000214	0.006841	0.8216	1.7897	(17) = (14) / ((16) * 1000)
(18)	CIP Rate w/ Assessment	-0.000215	-0.000215	0.006859	0.8237	1.7944	(18) = (17) * (1 / (1 - (0.22% + 0.05%))
(19)	CIP Rate w/SUT	-0.000229	-0.000229	0.007313	0.8783	1.9133	(19) = (18) * 1.06625

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

TYPICAL RESIDENTIAL ELECTRIC BILL IMPACTS

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

Residential Electric Service - Average Monthly Bill					
If Your Average Monthly kWh Use Is:	And Your Jun. to Sep. Avg. Monthly kWh Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
140	171	$37.98	$37.74	($0.24)	-0.63 %
279	342	69.98	69.49	(0.49)	-0.70
558	683	134.25	133.25	(1.00)	-0.74
650	803	155.85	154.69	(1.16)	-0.74
977	1,279	233.75	232.01	(1.74)	-0.74

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect February 1, 2025, and assumes that the customer receives BGS-RSCP service from Public
(2) Same as (1) except includes decrease in the CIP.

Residential Electric Service - Monthly Summer Bill				
If Your Monthly Summer kWh 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:
171	$48.31	$48.01	($0.30)	-0.62 %
342	90.65	90.04	(0.61)	-0.67
683	176.18	174.96	(1.22)	-0.69
803	207.51	206.09	(1.42)	-0.68
1,279	331.89	329.62	(2.27)	-0.68

(3) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect February 1, 2025, and assumes that the customer receives BGS-RSCP service from Public Service.

(4) Same as (3) except includes decrease in the CIP.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY | **XXX Revised Sheet No. 66 Superseding**

B.P.U.N.J. No. 17 ELECTRIC | **XXX Revised 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	($0.000215)~~$0.001450~~	($0.000229)~~$0.001546~~	Per kilowatt-hour
RLM	$0.006859~~0.002269~~	$0.007313~~0.002419~~	Per kilowatt-hour
GLP	$0.8237~~0.9356~~	$0.8783~~0.9976~~	Per kilowatt of monthly peak demand
LPL-S	$1.7944~~1.1184~~	$1.9133~~1.1925~~	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 | **XXX Revised Sheet No. 66B**
Superseding
B.P.U.N.J. No. 17 ELECTRIC | **XXX Revised 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 2024~~3~~-2025~~4~~ Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2025~~4~~	980~~1,006~~	
February 2025~~4~~	826~~868~~	
March 2025~~4~~	679~~683~~	
April 2025~~4~~	344~~355~~	160~~150~~
May 2025~~4~~	117~~123~~	985~~969~~
June 2024~~3~~		3,026~~3,034~~
July 2024~~3~~		5,779~~5,678~~
August 2024~~3~~		4,846~~4,895~~
September 2024~~3~~		2,285~~2,229~~
October 2024~~3~~	218~~225~~	421~~392~~
November 2024~~3~~	520~~516~~	
December 2024~~3~~	798~~810~~	

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 **XXX Revised Sheet No. 66C**
Superseding
B.P.U.N.J. No. 17 ELECTRIC **XXX Revised 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 2024~~3~~-2025~~4~~ Winter Period for HDD and 2024~~3~~ 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 2025~~4~~	495,154~~499,559~~	144,547~~157,424~~	10,109~~10,585~~	380~~392~~	5,443~~5,785~~	1,735~~1,705~~
February 2025~~4~~	495,472~~499,834~~	144,639~~157,510~~	10,058~~10,519~~	378~~390~~	5,440~~5,781~~	1,734~~1,704~~
March 2025~~4~~	495,790~~500,110~~	144,732~~157,597~~	10,007~~10,453~~	376~~387~~	5,436~~5,776~~	1,733~~1,702~~
April 2025~~4~~	496,107~~500,385~~	144,825~~157,684~~	9,955~~10,388~~	374~~385~~	5,433~~5,772~~	1,732~~1,701~~
May 2025~~4~~	496,425~~500,661~~	144,918~~157,771~~	9,904~~10,322~~	372~~382~~	5,430~~5,768~~	1,731~~1,700~~
June 2024~~3~~	484,122~~491,345~~	141,326~~154,835~~	10,527~~11,077~~	396~~410~~	4,631~~5,547~~	1,476~~1,635~~
July 2024~~3~~	480,789~~492,413~~	140,353~~155,172~~	10,509~~11,127~~	395~~412~~	6,372~~5,189~~	2,031~~1,529~~
August 2024~~3~~	486,473~~493,412~~	142,012~~155,487~~	10,440~~11,057~~	392~~410~~	5,746~~6,912~~	1,831~~2,037~~
September 2024~~3~~	484,013~~491,384~~	141,294~~154,848~~	10,368~~11,048~~	390~~409~~	5,416~~5,844~~	1,726~~1,723~~
October 2024~~3~~	483,992~~491,727~~	141,288~~154,956~~	10,326~~10,995~~	388~~407~~	5,663~~5,147~~	1,805~~1,517~~
November 2024~~3~~	488,776~~493,005~~	142,685~~155,358~~	10,437~~11,026~~	392~~408~~	5,219~~6,487~~	1,663~~1,912~~
December 2024~~3~~	485,222~~495,295~~	141,647~~156,080~~	10,141~~10,961~~	381~~406~~	5,446~~5,636~~	1,736~~1,661~~

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	$49.93	$89.43	$190.42	$2,980.84
Jul	63.16	105.67	206.67	3,843.31
Aug	60.29	128.31	214.92	4,126.83
Sep	40.90	84.03	204.58	4,099.11
Oct	19.37	17.53	51.55	1,874.50
Nov	19.23	21.36	39.81	856.90
Dec	25.77	21.54	42.60	782.42
Jan	28.16	27.12	41.90	863.44
Feb	23.69	21.09	37.71	797.44
Mar	22.36	22.02	41.51	845.18
Apr	18.62	18.32	40.80	811.21
May	20.66	20.97	42.14	834.96
Total Annual	**$392.14**	**$577.40**	**$1,154.59**	**$22,716.15**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 66**
Superseding
B.P.U.N.J. No. 17 ELECTRIC **XXX Revised 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	($0.000215)	($0.000229)	Per kilowatt-hour
RLM	$0.006859	$0.007313	Per kilowatt-hour
GLP	$0.8237	$0.8783	Per kilowatt of monthly peak demand
LPL-S	$1.7944	$1.9133	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.

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 2024-2025 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2025	980	
February 2025	826	
March 2025	679	
April 2025	344	160
May 2025	117	985
June 2024		3,026
July 2024		5,779
August 2024		4,846
September 2024		2,285
October 2024	218	421
November 2024	520	
December 2024	798	

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.

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 2024-2025 Winter Period for HDD and 2024 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 2025	495,154	144,547	10,109	380	5,443	1,735
February 2025	495,472	144,639	10,058	378	5,440	1,734
March 2025	495,790	144,732	10,007	376	5,436	1,733
April 2025	496,107	144,825	9,955	374	5,433	1,732
May 2025	496,425	144,918	9,904	372	5,430	1,731
June 2024	484,122	141,326	10,527	396	4,631	1,476
July 2024	480,789	140,353	10,509	395	6,372	2,031
August 2024	486,473	142,012	10,440	392	5,746	1,831
September 2024	484,013	141,294	10,368	390	5,416	1,726
October 2024	483,992	141,288	10,326	388	5,663	1,805
November 2024	488,776	142,685	10,437	392	5,219	1,663
December 2024	485,222	141,647	10,141	381	5,446	1,736

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	$49.93	$89.43	$190.42	$2,980.84
Jul	63.16	105.67	206.67	3,843.31
Aug	60.29	128.31	214.92	4,126.83
Sep	40.90	84.03	204.58	4,099.11
Oct	19.37	17.53	51.55	1,874.50
Nov	19.23	21.36	39.81	856.90
Dec	25.77	21.54	42.60	782.42
Jan	28.16	27.12	41.90	863.44
Feb	23.69	21.09	37.71	797.44
Mar	22.36	22.02	41.51	845.18
Apr	18.62	18.32	40.80	811.21
May	20.66	20.97	42.14	834.96
Total Annual	**$392.14**	**$577.40**	**$1,154.59**	**$22,716.15**

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 (2025 Electric CIP Rate Filing)

Notice of Filing and Notice of Public Hearings

BPU Docket No.

PLEASE TAKE NOTICE that, on February 3, 2025, 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 adjustments in the cost recovery associated with its Electric Conservation Incentive Program ("ECIP" or "Program").

By Order dated September 23, 2020, the Board approved the Clean Energy Future – Energy Efficiency Program in Docket Nos. GO18101112 and EO18101113 ("Order"). By the Order, the Board approved a Conservation Incentive Program ("CIP") that allows the Company to recover for lost sales revenue from the potential decrease in customer usage resulting from the Company's energy efficiency programs. Recoveries under the ECIP are subject to limitations based on the Company's earnings and based on offsetting savings achieved by the Company in the costs of Basic Generation Service.

Under the Company's proposal, PSE&G seeks Board approval to recover approximately $87 million as a result of lower revenue per customer compared to an approved baseline. The deferral consists of $27 million of non-weather-related lost revenue, offset by a refund of $9 million that is due to customers because of increased revenues resulting from warmer-than-normal weather, and adding in $69 million of under-recovered margin recovery from the Company's prior ECIP period. The approved CIP limits recovery of the $27 million non-weather deferral to $71 million, for the upcoming recovery period, which, when offset by the $9 million refund and adding in the $3 million under-collection, results in an overall increase to customers of $65 million for the upcoming recovery period, and a deferral for recovery in a subsequent CIP recovery period of $22 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 average monthly bills, if approved by the Board, is illustrated in Table #2.

Based on the filing, a typical residential electric customer using 683 kWh in a summer month and 558 kWh in an average month (6,700 kWh annually) would see a decrease in the average monthly bill from $134.25 to $133.25, or $1.00 or approximately 0.74%.

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

PSE&G's costs addressed in the Petition will remain subject to audit by the Board, and Board approval shall not preclude or prohibit the Board from taking any such actions deemed appropriate as a result of any such audit.

Any assistance required by customers in ascertaining the impact of the proposed rate increase will be provided by the Company upon request.

A copy of this Notice is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings and was provided to the New Jersey Division of Rate Counsel ("Rate Counsel"), who will represent the interests of all PSE&G customers in this proceeding. The Petition may also be viewed on the Board's website, https://publicaccess.bpu.state.nj.us, where you can search by the above-captioned docket number. The Petition and Board file may also be reviewed at the Board located at 44 South Clinton Avenue, 1st Floor, Trenton, NJ, with an appointment. To make an appointment, please call (609) 913-6298.

PLEASE TAKE FURTHER NOTICE that virtual public hearings are scheduled on the following date and times so that members of the public may present their views on the Petition.

DATE:
TIMES: 4:30 p.m. and 5:30 p.m.

Join Virtually:

There are two options for joining.
Either go to this website:
https://www.microsoft.com/en-us/microsoft-teams/join-a-meeting
and enter the following information:

Meeting ID: 992 979 119 781
Passcode: 3X59PZ

-or-

Join by Phone
Dial In: (973) 536-2286
Phone conference ID: 537 811 425#

When prompted, enter the Meeting ID number to access the meeting.

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

Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's Public Document Search tool: (https://publicaccess.bpu.state.nj.us). Comments are considered public documents for purposes of the State's Open Public Records Act. Only public documents should be submitted using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submissions, confidential information may also be filed electronically via the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage at https://www.nj.gov/bpu/agenda/efiling/.

Emailed and/or written comments may also be submitted to:
Sherri L. Golden, Secretary of the Board
44 South Clinton Ave.
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-913-6241
Email: board.secretary@bpu.nj.gov

Table # 1
Electric CIP Charges

	ECIP Charges		
Rate Schedule	**Present Charge (Incl SUT)**	**Proposed Charge (Incl SUT)**	
RS & RHS	$0.001546	($0.000229)	Per kilowatt-hour
RLM	0.002419	0.007313	Per kilowatt-hour
GLP	0.9976	0.8783	Per kilowatt of monthly peak demand
LPL-S	1.1925	1.9133	Per kilowatt of monthly peak demand

Table # 2
Residential Electric Service

If Your Average Monthly kWhr Use Is:	And Your Jun. to Sep. Average Monthly kWhr Use is:	Then Your Present Average Monthly Bill (1) Would Be:	And Your Proposed Average Monthly Bill (2) Would Be:	Your Average Monthly Bill Change Would Be:	And Your Percent Change Would Be:
140	171	$37.98	$37.74	($0.24)	(0.63)%
279	342	69.98	69.49	(0.49)	(0.70)
558	683	134.25	133.25	(1.00)	(0.74)
650	803	155.85	154.69	(1.16)	(0.74)
977	1,279	233.75	232.01	(1.74)	(0.74)

(1) Based upon current Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect February 1, 2025, 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.

Danielle Lopez
Associate Counsel-Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY