STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _______________

DIRECT TESTIMONY
OF
MICHAEL P. MCFADDEN

DIRECTOR OF SALES AND REVENUE FORECASTING

December 29, 2023
P-2

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL MCFADDEN
DIRECTOR OF SALES AND REVENUE FORECASTING
PSEG SERVICES COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael P. McFadden. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by PSEG Services Corporation ("PSEG Services"), a subsidiary of Public Service Enterprise Group Incorporated ("PSEG" or "Enterprise"), as the Director of Sales and Revenue Forecasting. I have been employed by Enterprise for 15 years in a number of financial positions, primarily supporting the financial analyses and determination of revenue requirements associated with regulatory filings by Public Service Electric and Gas Company ("PSE&G, or the "Company"). Since June 2021, I have been the Director of Sales and Revenue Forecasting. My credentials are set forth in Schedule MPM-1.

Q. What are the key points in your testimony?

A. In support of PSE&G's December 2023 electric and gas base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), my testimony addresses the following key topics:

1) ***Context for Request and Value to Customers*** **–** I first provide some context to customer bills, explaining: a) the value the Company provides to its customers compared to peers both in cost, customer satisfaction, and reliability; b) how the

Company's bills compare to the income of median- and low-income families; c) how PSE&G's distribution costs, the subject of this proceeding, compare with those of regional peers; d) how PSE&G's total customer bill compares to that of regional peers; and e) ways customers can control their bills through proposed time of use rates and other programs the Company offers.

2) ***Factors Driving Rate Increase*** **–** I discuss the key drivers of the Company's rate request, which include recovery of Board-approved capital investments and deferrals, and resets of Board-approved cost recovery clauses. Major drivers include stipulated base programs and deferred investments such as those for Energy Strong II ("ES II"), the extension of the Gas System Modernization Program ("GSMP II"), the Infrastructure Advancement Program ("IAP"), the Clean Energy Future – Energy Cloud Program ("CEF-EC", or "AMI"), the Clean Energy Future – Electric Vehicle Program ("CEF-EV"), and the NJ Transit Mason Substation Project ("Mason Substation") along with other significant capital expenditures.

3) ***Mitigation of Rate Increases*** – I discuss the actions PSE&G has taken to mitigate rate increases. This includes steps taken to control costs charged to customers, a proposal to increase the flow-back of certain tax benefits to customers, and the benefits customers receive through PSE&G's Appliance Service Business.

4) ***Capital Structure and Cost of Capital*** – I discuss the Company's requested return on equity ("ROE") and capital structure that are critical both to the preservation of the Company's credit ratings and access to capital, and also to ensure just and reasonable rates. The allowed ROE and capital structure should appropriately recognize the conditions in the financial markets supporting our request.

5) ***Appliance Service Business ("ASB")*** **–** I address the significant benefits of the Company's ASB and the Company's request to retain 50 percent of the Gas ASB margins (revenues less expenses), the same percentage allowed on the electric side of ASB, to continue to provide this benefit to customers.

6) ***Pension & OPEB Expense Recovery*** **–** I discuss the Company's proposal to defer changes in pension and other post-employment benefit ("OPEB") expenses above or below the amount reflected in rates, ensuring recovery from customers, or return to customers, of cost changes outside the Company's control to ensure there are no winners or losers.

7) ***Gas Bad Debt Expense Recovery in Societal Benefits Charge ("SBC")*** **–** I address the Company's request, first raised in the COVID-19 proceeding,[1] to recover Gas bad debt expenses through a new social component of the SBC in the same manner as is currently done for Electric bad debt expenses.

8) ***Storm Cost Recovery Mechanism*** **–** I provide details on how costs for significant storm events are currently accounted for and recovered from customers, as well as PSE&G's proposal to recover those costs through a new tariff clause, the "Storm Recovery Charge." The proposal will ensure only prudently incurred costs are recovered from customers in a timely manner through a mechanism that allows for Board-approved increases or decreases outside a base rate case.

9) ***Conservation Incentive Program ("CIP") Baseline Reset*** **–** I explain the approved CIP mechanism for both electric and gas service and propose the new

[1] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

baseline use (for gas) or revenue (for electric) per customer as a result of this proceeding.

10) ***Embedded Cost of Debt Rate Recovery*** **–** I discuss the Company's proposal to defer changes in the embedded cost of debt from the rate established at the end of the test year, recognizing the current debt market conditions. The deferral mechanism would apply only to the debt component of rate base approved by the Board.

11) ***Incentive Compensation*** **-** I explain why recovery of incentive compensation is appropriate, integral to strong operating performance, and benefits customers.

12) ***Deferral Authority on Credit Card and Debit Card Fees and the IT Expenditures Required to Implement TOU Rates*** **–** I address the Company's request for deferral authority on incremental expenses the Company will incur if permitted to assume the cost of credit card payments from customers. In addition, the Company proposes to implement changes to its billing system to allow for time of use rates and requests deferral authority for the expenditures that will occur after the test year.

13) ***Test Year and Revenue Requirements*** **-** Finally, I support the test year and associated calculation of the Company's revenue request in this proceeding and test year and post-test year adjustments.

Q. Why is PSE&G making this base rate filing at this time?

A. This filing is being made, in part, to comply with the BPU's May 22, 2018 Order approving PSE&G's next phase of the Gas System Modernization Program ("GSMP II").[2] The

[2] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"),* B.P.U. Docket No. GR17070776, "Decision and Order Approving Stipulation" (May 22, 2018) ("GSMP II Order").

GSMP II Order required the filing of a base rate case by no later than January 1, 2024.[3] In addition, the 'BPU's approval of the Company's ES II filing required the Company to submit a base rate case no later than December 31, 2023.[4] This filing is in compliance with those Orders and seeks approval to increase PSE&G's annual revenue requirements for both its electric and gas operations as discussed later in my testimony.

Q. What is the rate increase being sought?

A. Please see the table below for the breakdown of the net rate increase sought in this proceeding. Beyond the proposed base rate increase, the Company is also seeks: 1) recovery of storm costs through a new clause component rather than through base rates, 2) recovery of gas bad debt expense through a new component of the SBC rather than through base rates, and 3) an adjustment to flow-back certain tax benefits to customers through the Tax Adjustment Credit ("TAC").

Table 1

Rate Case Net Impact to Customers

Overall Total Revenue Impact ($M)	**Electric**	**Gas**	**Total**
Base Rates	$522	$423	$945
Tax Adjustment Credit ("TAC")	-$98	-$102	-$200
Storm Recovery Mechanism	$38	$1	$39
Gas Bad Debt in SBC	$0	$42	$42
Net Total Revenue Impact $	$462	$364	$826
Net Total Bill Impact %	8%	11%	9%

[3] Parallel requirements exist in *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, B.P.U. Docket No. EO18101115, Decision and Order Approving Stipulation (January 7, 2021) ("CEF-EC Order"), and *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, B.P.U. Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

[4] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Second Energy Strong program ("Energy Strong II")*, B.P.U. Docket Nos. EO18060629 and GO18060630, Final Decision and Order Approving Stipulation (September 11, 2019) ("Energy Strong II Order").

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision:

- Schedule MPM-1: Credentials
- Schedule MPM-2: Determination of Revenue Requirements
- Schedule MPM-3: Determination of Rate Base
- Schedule MPM-4: Weighted Average Cost of Capital
- Schedule MPM-5: Long Term Debt
- Schedule MPM-6: Revenue Factor
- Schedules MPM-7 through 18: Support for components of rate base
- Schedule MPM-19: Income Statement
- Schedules MPM-20 through 28: Support for components of the income statement
- Schedule MPM-29: *Pro-forma* Distribution Operating Income
- Schedules MPM-30 through 53: Support for *pro forma* adjustments to test year operating income
- Schedule MPM-54E and 54G: revised Electric Baseline Revenue per Customer and Gas Baseline Use per Customer amounts for the Conservation Incentive Program as a result of the revised billing determinants approved in this proceeding.
- Schedule MPM-55: Interest Rate Adjustment Mechanism

II. CONTEXT FOR REQUEST AND VALUE TO CUSTOMERS

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, all but one of the six other NJ electric and gas utilities have filed two base rate cases.

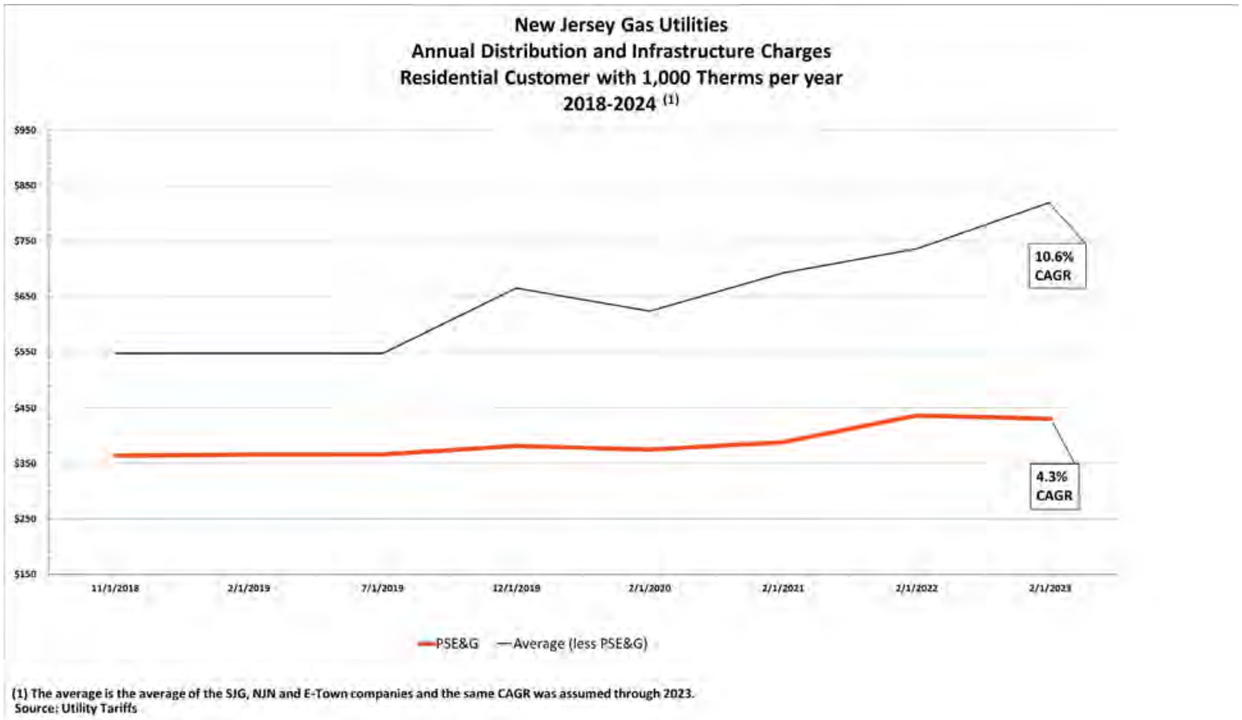
Q. How has PSE&G been able to avoid filing for a rate case until now?

A. This is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently while being good stewards of the electric and gas distribution systems and providing the funds needed to operate and maintain the systems effectively. This is achieved by regularly benchmarking Company costs, exceptional employee performance, and creating appropriate employee incentives to continue to improve upon historic success.

Q. How have PSE&G's Gas distribution rates, the subject of this proceeding, changed since the 2018 base rate case?

A. The Gas distribution rates have increased since 2018 primarily as the result of GSMP II and ES II rate adjustments for work to modernize the gas system and replace cast iron and unprotected steel mains, which provide both reliability and carbon-emissions benefits to customers. The distribution component of a Residential Gas customer bill using 1,000 therms per year has increased at a compound annual growth rate ("CAGR") of 4.3% since 2018. Despite the considerable investment to modernize the gas system, this increase is less than half of the statewide average of 10.6%. PSE&G's distribution rates are considerably less than those of the New Jersey average as PSE&G has been able to control costs and maximize the value of its prior investments.

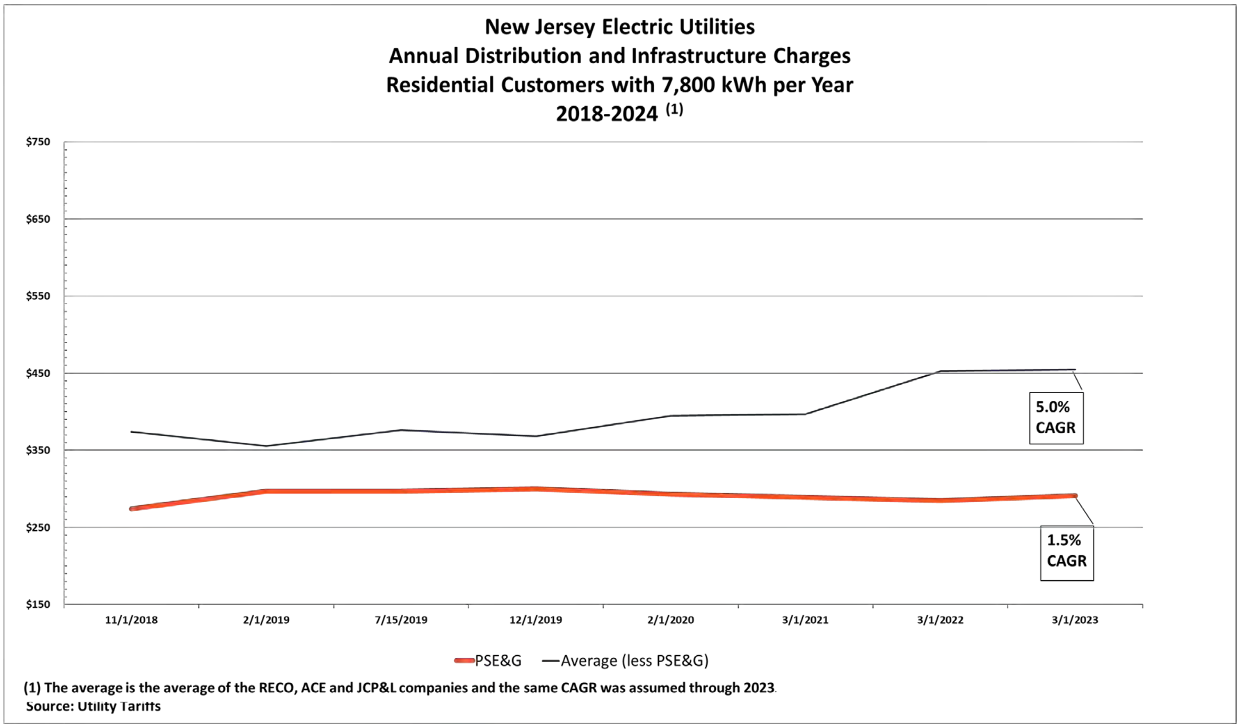
Chart 1



Q. How have PSE&G's Electric distribution rates changed since the 2018 base rate case?

A. The distribution component of a Residential Electric customer bill for a customer using 7,800 kWh per year has increased at a CAGR of 1.5%, well below the statewide comparable average of 5.0%. and below inflation levels. This modest increase is driven primarily by rate increases from the ES II Program to modernize the Company's electric system and to make it more reliable and resilient. As with Gas, the Company has been able to control costs and avoid the need for an earlier base rate case.

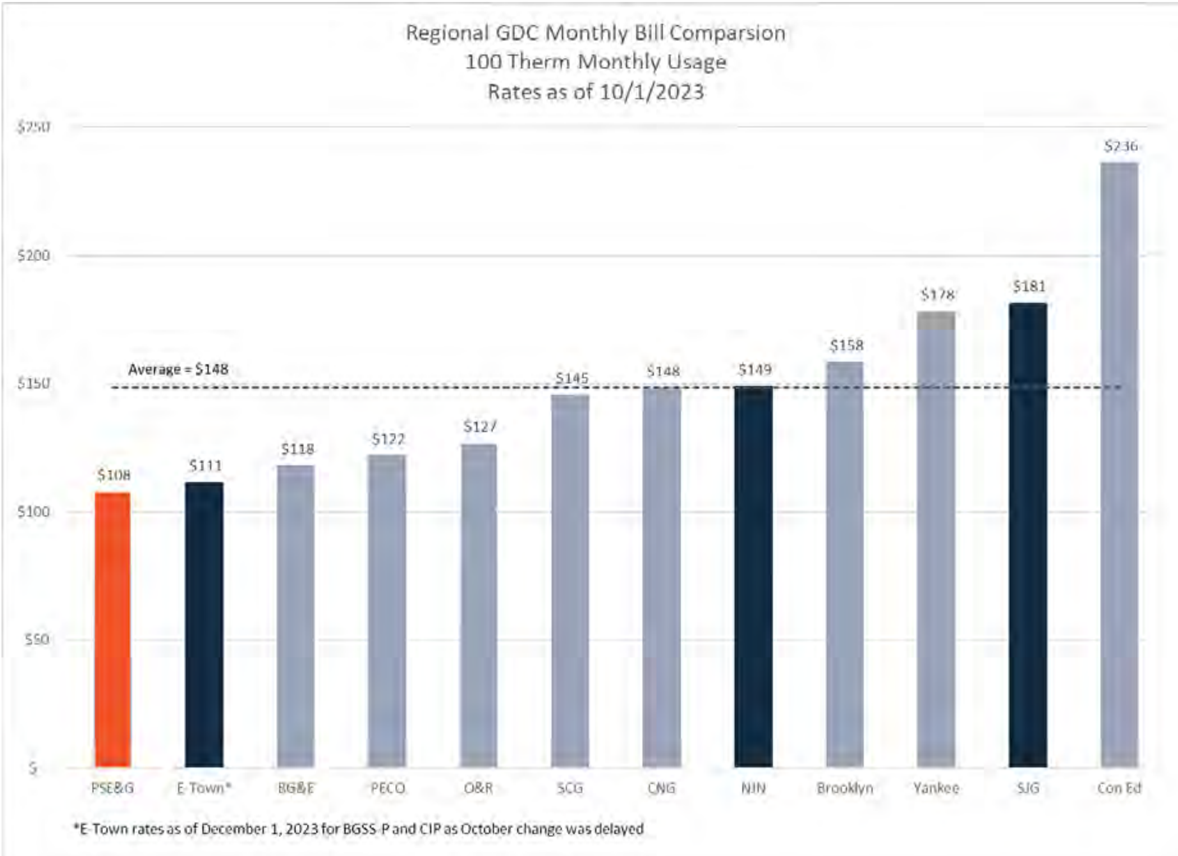
Chart 2



Q. That shows that PSE&G electric and gas distribution charges increased at a relatively lower rate, but how do you compare on a total bill basis?

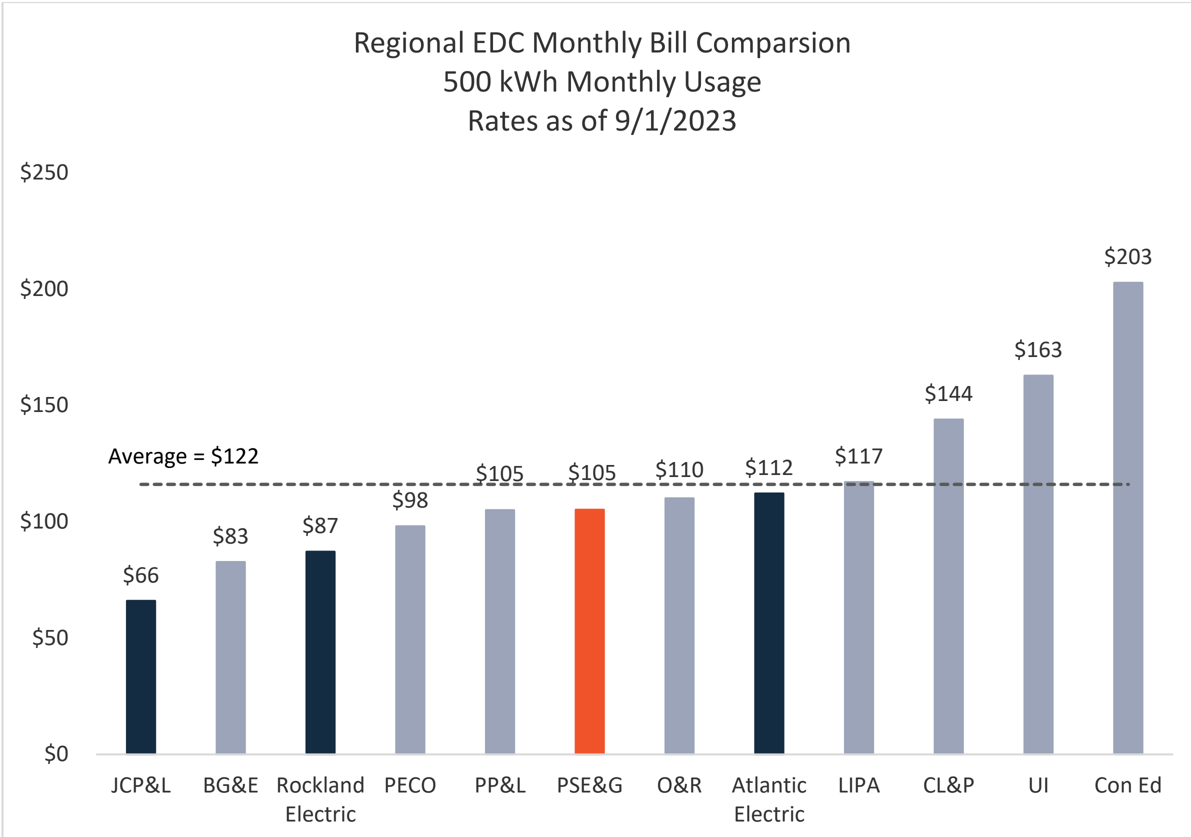
A. PSE&G's bills continue to be lower than the average of its peers.

Chart 3



Regional GDC Monthly Bill Comparsion
100 Therm Monthly Usage
Rates as of 10/1/2023
$250
$200
$150
$100
$50
$
Average = $148
$108
$111
$118
$122
$127
$145
$148
$149
$158
$178
$181
$236
PSE&G
E-Town*
BG&E
PECO
O&R
SCG
CNG
NJN
Brooklyn
Yankee
SJG
Con Ed
*E-Town rates as of December 1, 2023 for BGSS-P and CIP as October change was delayed

Chart 4



Q. Are customers receiving value from the Company's investments and cost control efforts?

A. Absolutely. PSE&G represents a great value to its customers both in terms of cost and reliability. As shown in the tables below, PSE&G ranks the lowest for total distribution O&M per customer compared to both State, Regional and ROE proxy group peers for both Electric and Gas, and PSE&G has the best rating of cost per customer and reliability for Electric.

Chart 5

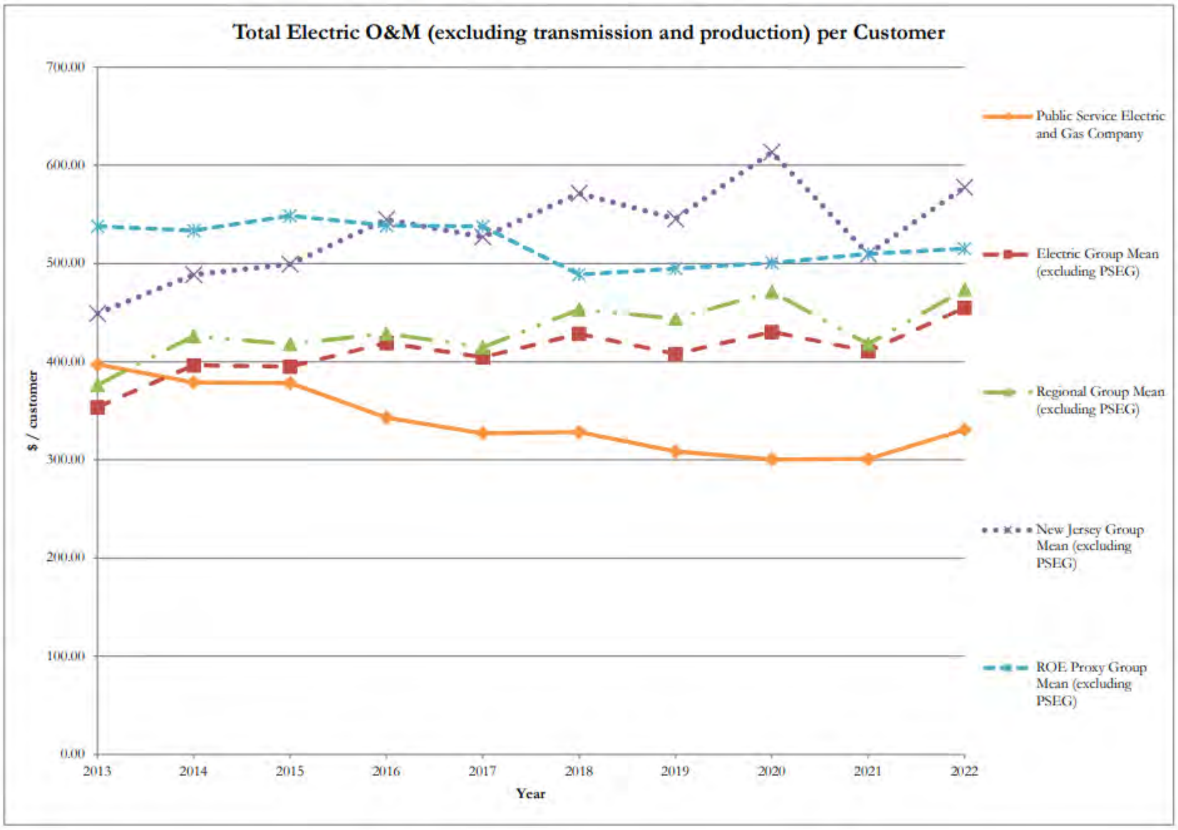
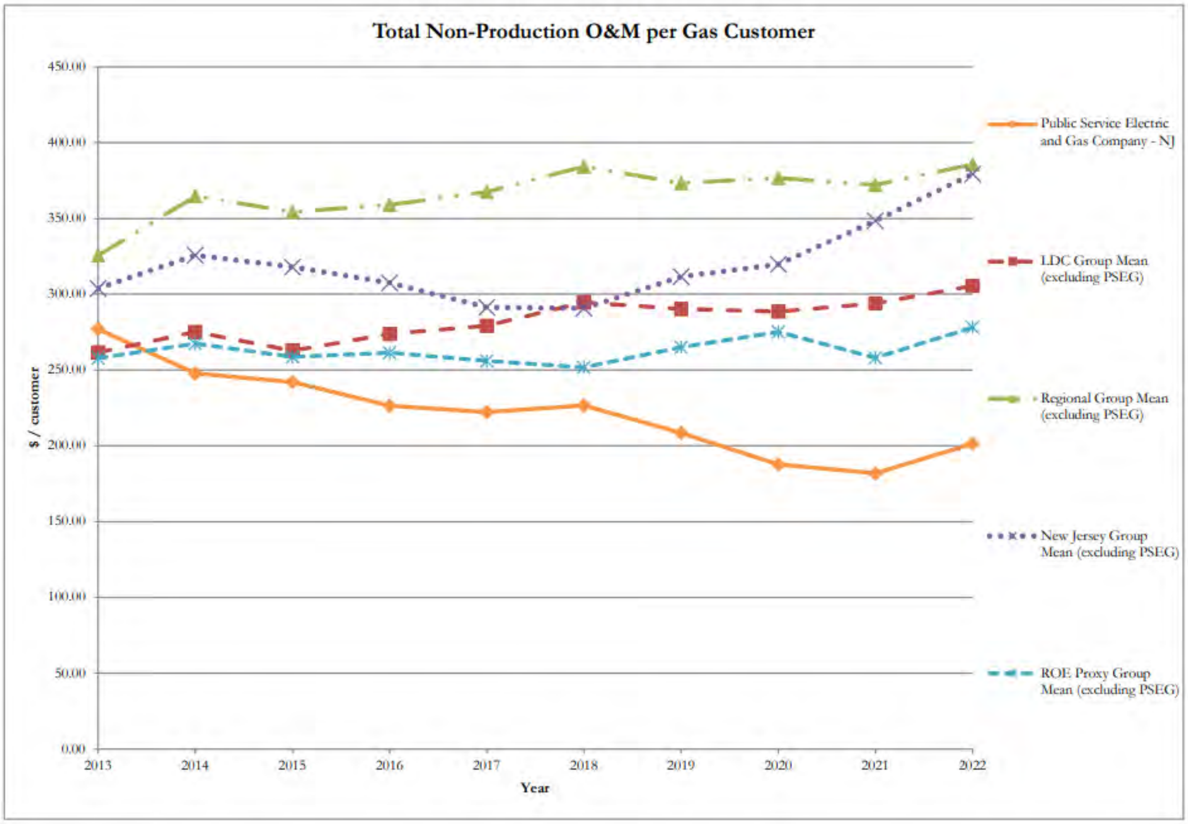
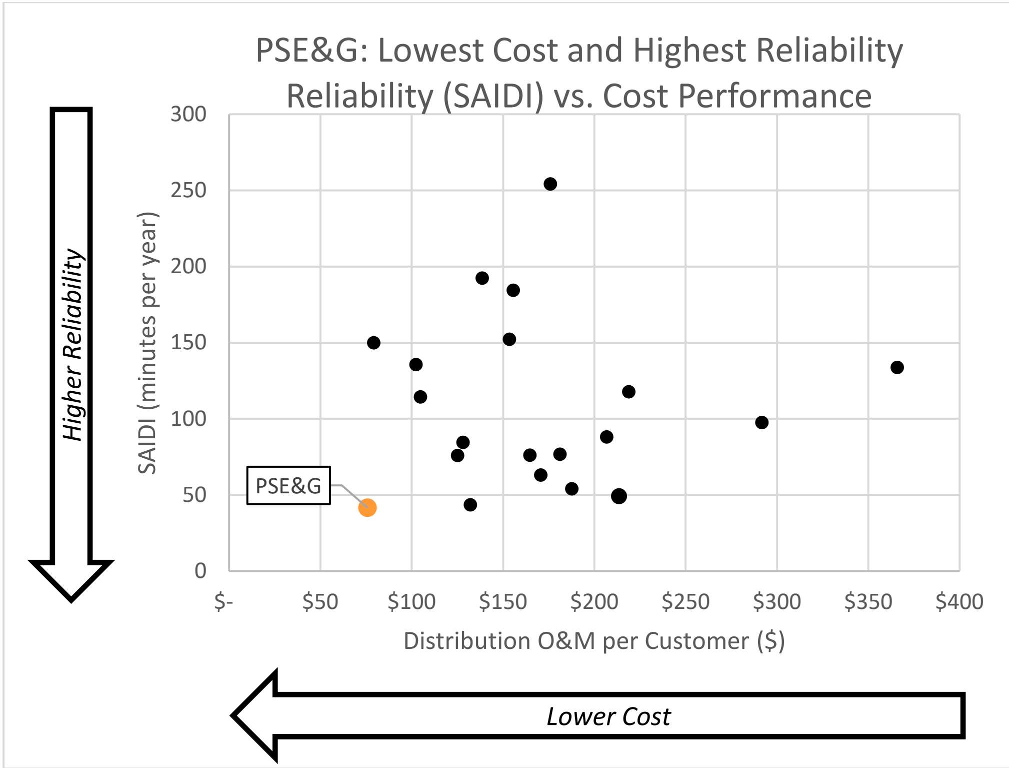

Total Electric O&M (excluding transmission and production) per Customer
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
$ / customer
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company
Electric Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

Chart 6



Total Non-Production O&M per Gas Customer
$ / customer
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company - NJ
LDC Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

Chart 7



For more details on the Company's costs and reliability compared to peers, see the testimony of Michael Adams.

Q. Have customers recognized this value?

A. Yes. The Company's J.D. Power Customer Satisfaction results for Residential and Business customers for both Electric and Gas are illustrated in the following charts. In 2022, the Company achieved better than first quartile results in all four categories.

Chart 8

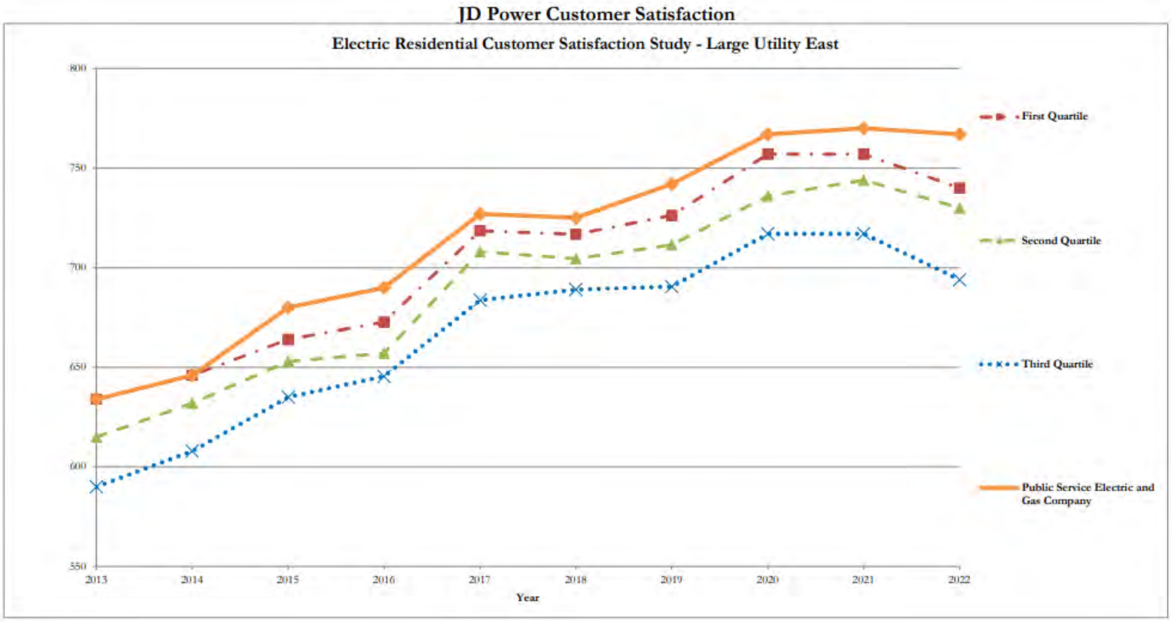


Chart 9

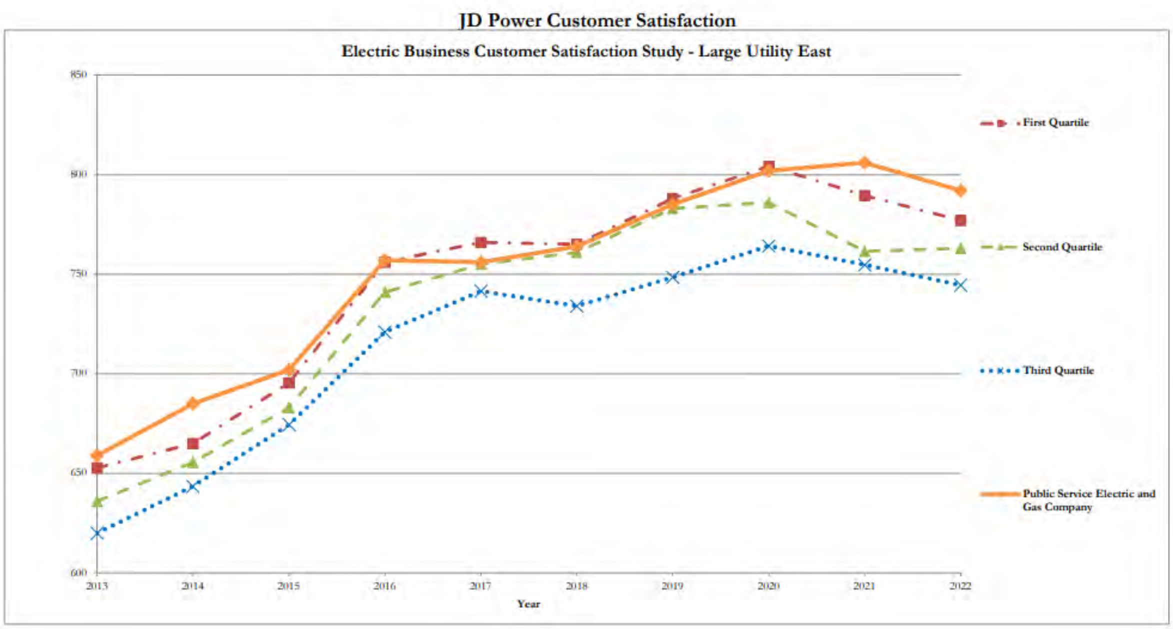


Chart 10

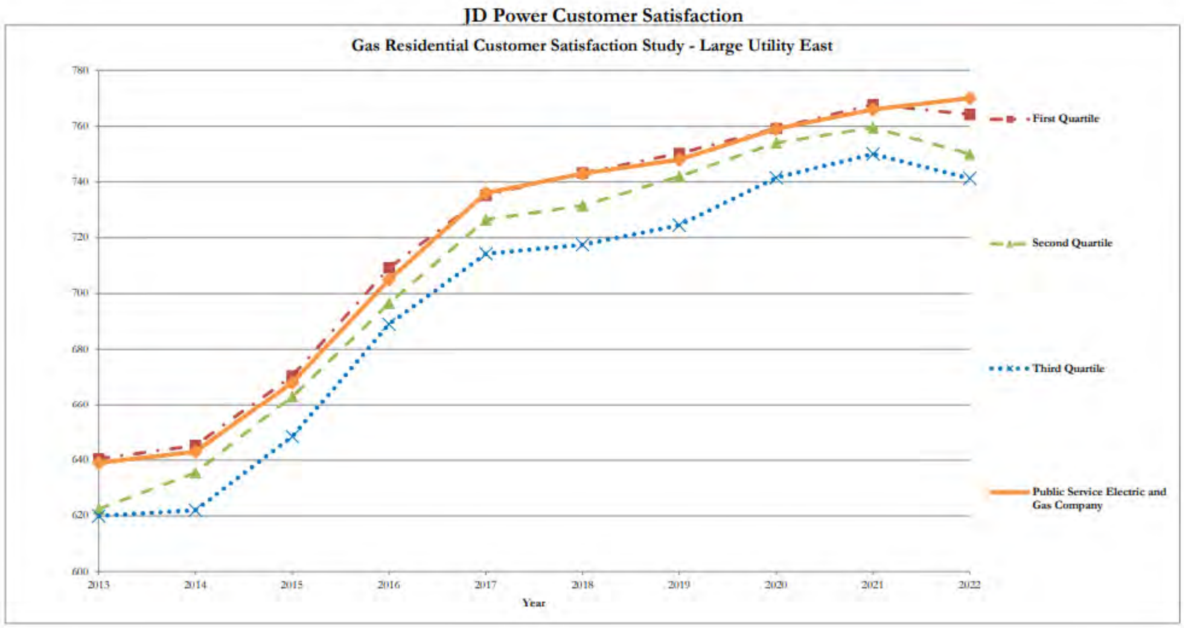
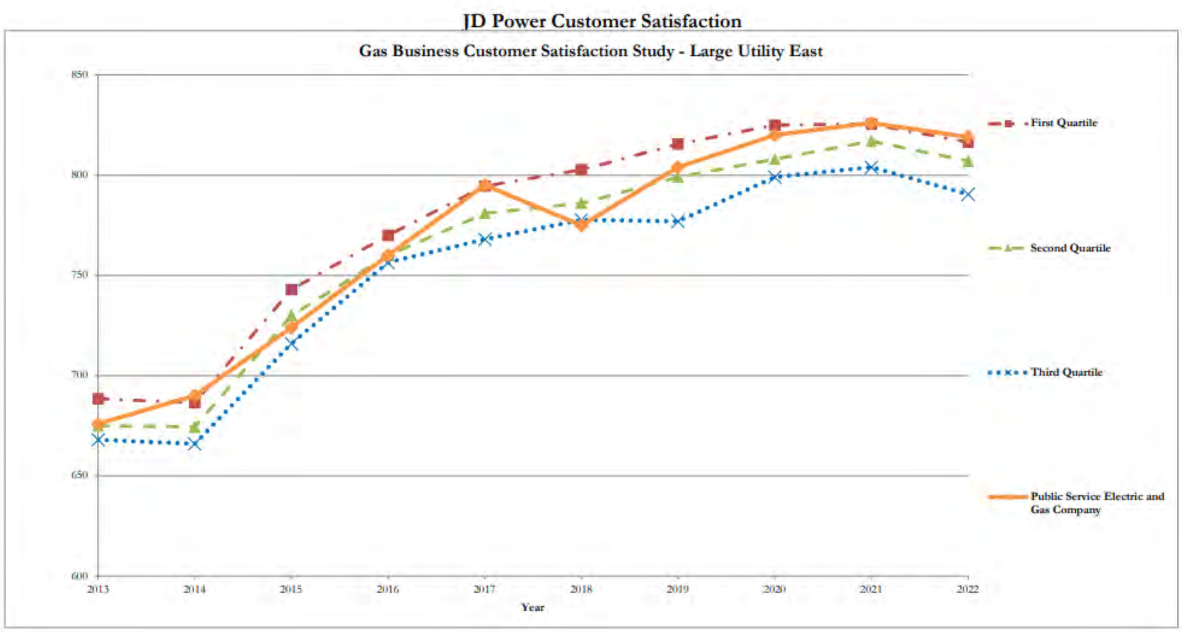


Chart 11



Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of its customer base. PSE&G's Energy Efficiency programs include special incentives targeted to lower income customers. The Company implements the State's Comfort Partners program, which provides free energy savings measures as well as upgrades to address health and safety problems in the home for lower income customers. PSE&G also introduced a new initiative in its Clean Energy Future – Energy Efficiency program targeted to lower income customers between 250% and 400% of the Federal Poverty Level, and customers in overburdened communities. This included financial incentives to both property owners and tenants in apartments and multifamily properties. The Company promotes these programs through multiple channels, including outreach events, digital and traditional media, bill inserts, social media, and marketing by trade allies.

Q. Are there other assistance programs for lower income customers outside of PSE&G's energy efficiency programs?

A. Yes. PSE&G also advocates for various grants provided to lower-income customers, including the Low Income Home Energy Assistance Program ("LIHEAP"), "Lifeline" for senior and disabled adults, the Universal Service Fund ("USF"), Payment Assistance for Electric and Gas ("PAGE"), and "NJ SHARES."

Q. Please describe what these programs are and who is eligible.

A. LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting

Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

Q. How does the Company promote these programs?

A. The Company promotes the use of these services to its customers through bill inserts, community outreach, events, and through its collection correspondence. A dedicated web site with written information and videos is also promoted and all these methods of communication occur in multiple languages where possible and appropriate. PSE&G serves the most diverse demographics in the State and, due to the nature of PSE&G's customer base, has more customers eligible for these low-income programs on a proportionate basis compared to other utilities. Consequently, this customer segment receives special focus.

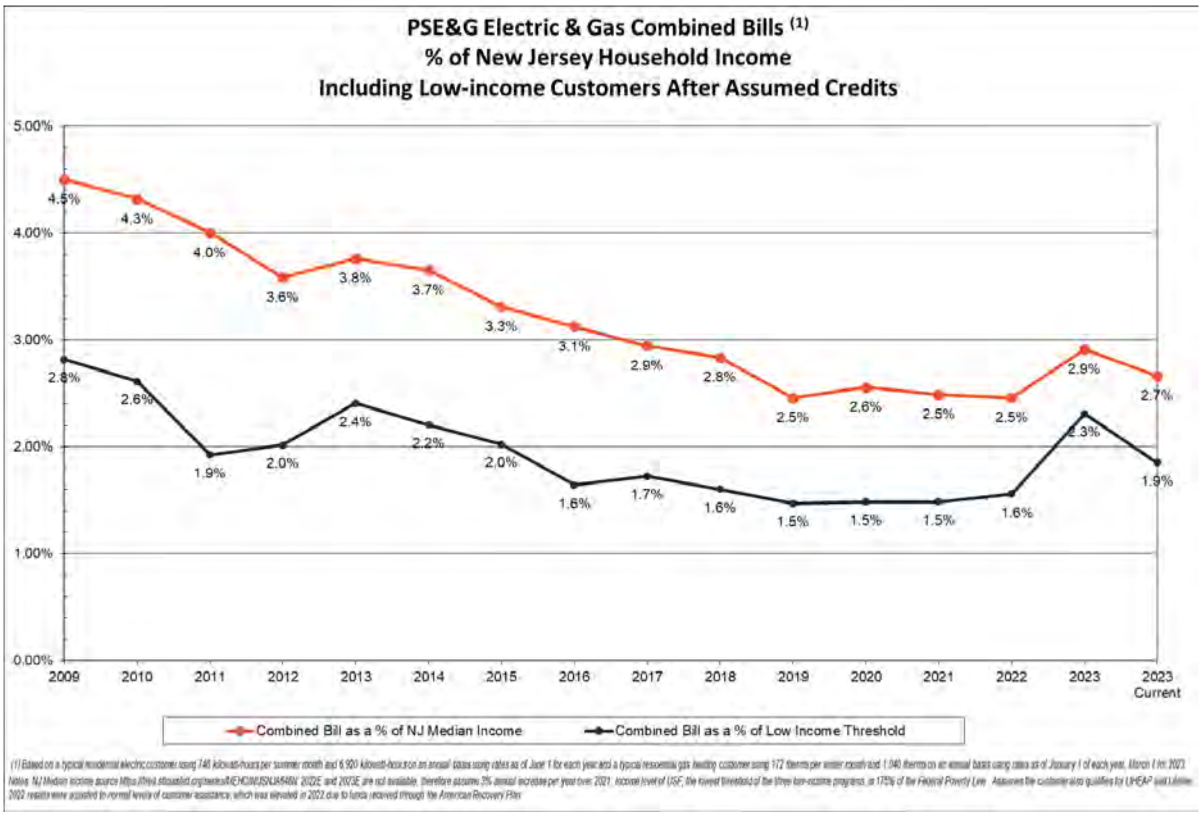
Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances for many customers. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors, as well as an external media campaign designed to provide customers the opportunity to garner financial assistance and enter into deferred payment arrangements.

Q. Have you considered the impact of electric and gas rates on these customers?

A. Yes. As illustrated in the chart below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009.

Chart 12

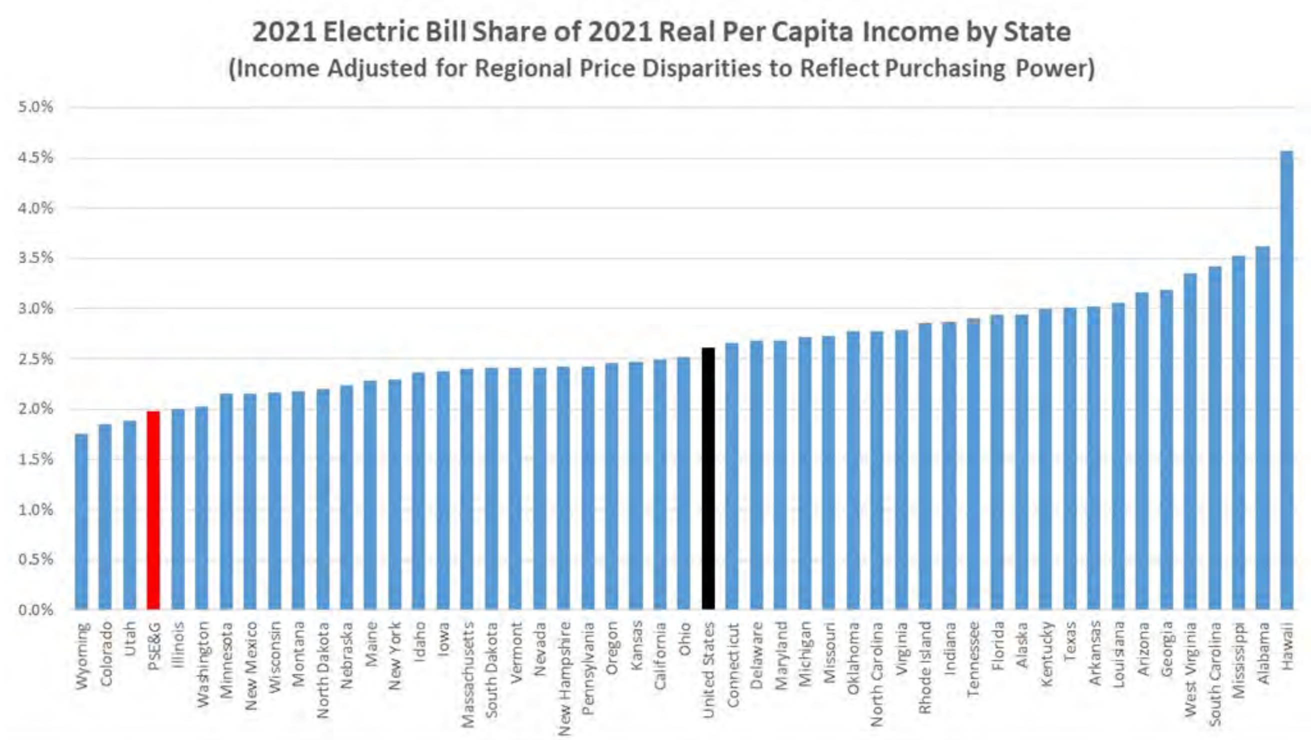


This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does this utility bill portion of overall income compare to other states?

A. Very well. As shown in the chart below, PSE&G's residential electric bill as a percentage of per capita income for NJ is in the top quartile compared to the other states in the US. In other words, PSE&G's total bill represent less share of a customer's wallet than the relative utility bill share in most of the other states.

Chart 13



Source: U.S. Dept. of Commerce, Bureau of Economic Analysis, "Regional Data GDP and Personal Income", June 2023
U.S. Dept. of Energy , Energy Information Agency, "Sales (consumption, revenue, prices & customers", retrieved July 2023.

While PSE&G's bills as a percentage of overall NJ income is very favorable compared to most other states, the Company recognizes the current economic environment and the ongoing need to control costs as much as possible. PSE&G has and will continue to control costs as much as possible to maintain affordable rates for customers without sacrificing reliability.

Q. Beyond cost control efforts, has PSE&G considered any other options for customers to lower their bills?

A. Yes. PSE&G has a robust energy efficiency program open to all customer groups to help customers reduce their usage and overall bill. Further, as discussed in the testimony of Mr. Swetz, PSE&G proposes to implement new voluntary electric time-of-use ("TOU") rate options that will allow customers to reduce their bills (as well as reduce overall system peak demand and the need for additional generation) by shifting usage when they can to off-peak periods. These new proposed TOU rates can be utilized by all residential customers to shift usage away from the system peak demand and will be particularly beneficial to electric vehicle customers that can charge their cars during off-peak hours. Further, PSE&G proposes to offer this TOU program with guaranteed bill protection for customers enrolling in the first 24 months. Customers who opt into the TOU rate options will be eligible for a refund if the total cost of the TOU rate exceeds what they would have been charged on the standard Residential ("RS") rate in the first 12 months of their enrollment. After the first year, the customers may opt-out of the program.

Q. Do you have any final comments on the impact of this filing to customers?

A. Yes. PSE&G recognizes the current economic environment and the need to keep costs to customers as low as possible. However, in addition to the requirement in the GSMP II Order that this case be filed before January 2024, it is important to put this increase in context looking at the utility bill as a percentage of overall income both for low income customers and for customers overall. Further, PSE&G has controlled costs as much as possible, avoiding the need to file a base rate case until now and resulting in a distribution increase over the last five years well below the average for all other NJ electric and gas utilities. The increase is primarily driven by Board approved and traditional utility investments to modernize the electric and gas systems, reduce carbon emissions, and improve reliability and customer satisfaction, and by deferred costs related to major storm events. PSE&G's customers have recognized these benefits as shown in the Company's reliability results and the JD Power results, and thus PSE&G is requesting recovery of these prudent expenditures. Finally, PSE&G will continue to evaluate ways to reduce the impact to customers through additional rate options to send the right price signals to customers to help reduce bills and improve reliability.

III. FACTORS DRIVING THE NEED FOR RATE RELIEF

Q. Why is the Company seeking the requested rate increase?

A. It has been approximately five years since the Company's last base rate case filing, so PSE&G has successfully operated for an extended period of time without having to seek a base rate increase. After five years, and despite the Company's successful execution of its cost mitigation and expense control strategies, there are a number of significant factors that have driven the Company's financial results well below its authorized rate of return and that represent the primary drivers of the rate increase sought in this filing. These factors include recovery of the following:

- Board approved investment programs;
- traditional utility investments;

- insufficient depreciation and cost of removal rates;
- New Business investment with flat sales growth;
- deferred significant storm event costs; and
- working capital requirements

I will address each of these in turn.

A. Board Approved Investment Programs

Q. What are the Board approved infrastructure programs impacting this proceeding?

A. The Board has approved the Company's substantial investments in specific programs with prudency and final recovery to be determined in this proceeding. The Board approved programs that are the subject of this proceeding are:

- NJ Transit Mason Substation;
- GSMP II (as extended);
- Energy Strong II;
- CEF-EC;
- CEF-EV; and
- IAP[5]

Q. How do these programs impact this proceeding?

A. The specifics of each program and its recovery are unique and identified separately below. In general, as discussed in the panel testimony of Company witnesses Mike Schmid and Rick Fonseca, as well as in the testimony of David Johnson, PSE&G seeks a prudency

[5] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of an Infrastructure Advancement Program (IAP)*, B.P.U. Docket Nos. EO21111211 and GO21111212, Decision and Order Approving Stipulation of Settlement (June 29, 2022) ("IAP Order").

determination and final rate recovery on the NJ Transit Mason Substation, GSMP II, Energy Strong II, and CEF-EC programs. While PSE&G seeks a prudency determination and recovery of investments and expenditures associated with the CEF-EV and IAP programs that are in-service, each program will continue to have investment beyond the end of this proceeding and will require a final prudency determination on all expenditures outside this proceeding in a subsequent rate case.

Q. Please briefly summarize each program and its recovery mechanism.

A. A description of each program or area is set forth below:

a. **New Jersey Transit Mason Substation –** By Order dated November 21, 2017, making use of funds remaining from the original Energy Strong program approved in 2014, the Board approved a plan to demolish the facilities known as the Mason Substation, comprising a number of buildings and electric plant that at the time were owned by the New Jersey Transit Corporation ("NJ Transit"), and to rebuild the facilities under PSE&G ownership.[6] The substation, which is a crucial facility for both NJ Transit and for electric customers in northern New Jersey, suffered severe damage during Superstorm Sandy. The cost of the rebuilt facility is shared between NJ Transit and PSE&G. The Board authorized PSE&G to recover its prudently incurred project cost investment of up to $100 million plus an Allowance for Funds Used During Construction, in a subsequent base rate case. Station assets are placed into service as they become used and useful. To date $60 million has been placed into service and the remaining $40 million is expected to be placed in

[6] *See I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Construction of the Mason Substation Damaged During Superstorm Sandy*, BPU Docket No. EO16080788, Decision and Order Approving Stipulation (November 21, 2017), at 3-4.

service by November 2024. Therefore, as discussed in the panel testimony Mr. Schmid and Mr. Fonseca, the Company is seeking recovery of its prudently incurred substation-related costs consistent with the Mason Substation Order.

b. **GSMP II –** In the GSMP II Order, the BPU authorized the Company to invest and seek recovery through periodic rate "roll-ins" of up to $1.575 billion in capital costs over a five-year period.[7] The capital investments under GSMP II have enhanced gas system safety and achieved leak reductions. The roll-ins of GSMP II costs, which already have been approved in previous roll-in proceedings, are subject to prudency review in this base rate case.[8] The GSMP II Order also established requirements for "Stipulated Base" expenditures of approximately $300 million and other baseline capital expenditures that were not eligible for recovery through the GSMP II roll-in mechanism and thus will be recovered in this proceeding, adding to the Company's unrecovered capital balance. The Board approved the final GSMP II investment roll-ins by Order issued May 24, 2023.[9] PSE&G's revenue requirement includes all investment associated with the GSMP II Program. All revenues associated with GSMP II projects already rolled into rates are included in Operating Revenues and thus form no part of PSE&G's incremental revenue request in this proceeding. On October 11, 2023, the Board approved a two-and-a-half-year extension of GSMP II for $902 million ($752M for accelerated recovery

[7] A limited amount of O&M costs relating to the amortization of cost offsets from methane leak reductions were included in the GSMP II Rate Mechanism. GSMP II Order at p. 10.
[8] GSMP II Order at p. 8.
[9] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (December 2022 GSMP Rate Filing)*, B.P.U. Docket No. GR22120749, Decision and Order Approving Stipulation (May 24, 2023).

and $150M for Stipulated Base) starting January 1, 2024 ("GSMP II Extension").[10] GSMP II Extension will not have any rate roll-ins during the test year and thus no revenue adjustment is required. However, as described in more detail below, PSE&G will make a rate base adjustment to exclude GSMP II Extension accelerated recovery investment in the test year from the request in this case; that investment will be recovered in a future rate adjustment to ensure the investment is not double-counted. See Schedule MPM-18 for the rate base adjustment.

c. **Energy Strong II –** The Company was authorized in the Energy Strong II Order to invest up to $691.5 million ($641 million for electric and $50.5 million for gas). The rate adjustments relating to Energy Strong II costs are subject to prudency review in this base rate case.[11] The Energy Strong II Order also authorized recovery of up to $150.5 million ($100 million for electric and $50.5 million for gas) of incremental costs for specified Energy Strong II projects to the extent incurred (also known as Stipulated Base), in the Company's next base rate case. The Company is effectively and reasonably managing the Energy Strong II Program as described in the panel testimony of Mr. Schmid and Mr. Fonseca. PSE&G's proposed revenue requirement includes all investment associated with the Energy Strong II Program. Likewise, all revenues associated with the Infrastructure Improvement Program Charges for Energy Strong II projects already rolled into rates, or that will

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[10] *I/M/O of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"),* BPU Docket No. GR17070776, and *I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP III"),* BPU Docket No. GR23030102, Decision and Order Approving Settlement (October 11, 2023) ("GSMP II Extension Order").

[11] Energy Strong II Order at 8.

be rolled into rates during the test year, are included in Operating Revenues, and thus form no part of the Company's incremental revenue request in this proceeding.

d. **CEF-EC –** By Order dated January 7, 2021, the Board approved PSE&G's CEF-EC proposal authorizing installation of 2.2 million advance metering infrastructure ("AMI") meters and related infrastructure and information technology over an approximately four-year period.[12] The Board approved deferral of actual investment up to $707 million and expenses of $71 million, or a total of $778 million for total CEF-EC expenditures. The CEF-EC Order also allowed for the recovery of prudent legacy meter stranded costs, recognizing that the acceleration of the AMI deployment will result in legacy meters being replaced before they are fully depreciated. Finally, the CEF-EC Order called for a *pro forma* revenue requirement adjustment in this proceeding to account for future savings at the completion of the AMI deployment. The CEF-EC Order allowed for deferral of program-related costs without any recovery until this base rate case. The CEF-EC program description and status are detailed in the testimony of Company Witness David Johnson. The details of the CEF-EC impact to rate base are shown on Schedule MPM-16. The proposed amortization of the CEF-EC deferrals is shown on Schedule MPM-47, and the *pro forma* revenue requirement adjustment is shown on Schedule MPM-48 and described in more detail below. Consistent with the CEF-EC Order, in this rate case PSE&G seeks recovery of prudently incurred actual AMI expenditures as well as stranded costs related to legacy meters.

[12] *See* CEF-EC Order.

e. **CEF-EV –** By Order dated January 27, 2021, the Board approved PSE&G's CEF-EV program, in which the Company was authorized to invest up to $166.2 million to implement its CEF-EV program and to incur up to $38 million of incremental O&M expenses associated with the program.[13] The CEF-EV program description and status are detailed in the testimony of Company Witness Karen Reif. Consistent with the CEF-EV Order, in this rate case PSE&G seeks recovery of prudently incurred actual investments and CEF-EV related O&M expenses. The details of the CEF-EV impact to rate base are shown on Schedule MPM-17. The details of the proposed amortization of the CEF-EV deferrals are shown on Schedule MPM-49 and described in more detail below. In addition, while not a factor impacting the rate request in this proceeding, the CEF-EV Order allowed for annual roll-in filings for investment not expected to be in-service by six months after the end of the test year in this base rate case. The testimony of Company witness Mr. Swetz details the template for those future roll-in filings.

f. **IAP –** The Company was authorized in the IAP Order to invest up to $351.0 million ($281.2 million for electric and $69.8 million for gas) to be recovered through an accelerated rate adjustment mechanism, designated the IAP Rate Mechanism.[14] The IAP program description and status are detailed in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca. The Board also required stipulated base expenditures of $160.0 million on incremental costs outside the IAP Rate Mechanism to be recovered in the Company's next base rate case if found to be reasonable and prudent. While this program is not complete and final prudency on

[13] *See* CEF-EV Order.
[14] *See* IAP Order.

all expenditures outside of this proceeding will not occur until a future base rate case proceeding, PSE&G estimates $53 million of stipulated base expenditures in service through the end of the test year on May 31, 2024 and a total of $73 million in service up to 6 months beyond the end of the test year; PSE&G seeks to recover those costs in this proceeding. In addition, as described in more detail below, PSE&G will make a rate base adjustment to exclude IAP investment in the test year from the request in this case; that investment will be recovered in a future rate roll-in to ensure the investment is not double-counted. See Schedule MPM-15 for the rate base adjustment.

Q. Why was the authorized interim recovery of costs associated with these programs insufficient?

A. The Company was approved for interim rate adjustments for only a portion of its Energy Strong II, GSMP II and IAP investments. PSE&G seeks recovery of the investment in these programs that is not subject to interim recovery, referred to as Stipulated Base. The Company was authorized by the Board to make these investments with recovery to commence in a base rate case proceeding. For the NJ Transit Mason Substation, CEF-EC, and CEF-EV programs, there was no interim recovery approved before this proceeding and recovery for all in-service expenditures will commence from this rate case proceeding.

Q. Are there any adjustments to the GSMP II, Energy Strong II, or IAP interim rate adjustments to ensure recovery of investments is not double-counted?

A. Yes. As described in more detail below, a *pro forma* adjustment is being proposed to annualize any interim rate adjustments during the test year to ensure the Company does not double count the revenues associated with any of these programs. These adjustments will increase the Company's Operating revenue as if the interim rates were in effect for the entire test year, which reduces PSE&G's request. There were no rate adjustments during the test year for the gas business as all rate adjustment occurred by the June 1, 2023 start of the test year. There are ES II and IAP rate adjustments during the test year for electric. Please see Schedule MPM-44 for the adjustment.

B. Traditional Utility Investments

Q. Have the Company's non-program-related investments impacted PSE&G's request in this proceeding?

A. Yes. From the conclusion of PSE&G's prior base rate case through the start of the current test year on June 1, 2023, the Company has invested $5.8 billion ($2.4 billion for electric and $3.4 billion for gas) in service to support safe, proper, and reliable service. To put that amount into context, the Company's approved total rate base balance in the 2018 base rate case was $9.5 billion ($5.5 billion for electric and $4.0 billion for gas). While some of that investment is associated with Board approved programs detailed above, the majority is associated with traditional utility base investments. These investments include accelerating the replacement of the aging cast iron and unprotected steel piping in the Company's system and modernizing the gas system to reduce methane emissions and improve safety and reliability, as well as improving the performance of the electric system by retiring certain older substations and investing in circuits prone to outages. Details concerning PSE&G's base capital investments are discussed by panel witnesses Mr. Schmid and Mr. Fonseca. This capital investment far exceeds the amount the Company is recovering in depreciation expense in current rates, increasing PSE&G's rate base and the depreciation expense needed to recover this investment. PSE&G is seeking recovery of and on all prudent investment in the system in this proceeding.

C. Insufficient Depreciation and Cost of Removal Rates

Q. Please explain the impact of depreciation on PSE&G's need for rate relief.

A. It is widely acknowledged that aging infrastructure is one of our nation's greatest challenges. Since depreciation rates are the mechanism through which a utility recovers the dollars expended for its capital projects, establishing the appropriate depreciation rates for a utility is critical to establishing just and reasonable rates. Properly set depreciation rates allow the Company to recover its investments timely, charge those costs to the customers who benefited from their use, and fund new capital construction. Company witness Mr. John Spanos has conducted a detailed evaluation of PSE&G's assets and developed new depreciation rates based on that evaluation to recover the costs of replacing aging infrastructure over its useful life and account for the cost to remove assets in the future. As described in Mr. Spanos' testimony, the Company's current depreciation rates are insufficient, largely due to the fact that the rates are not permitting the Company to recover its cost to remove and retire plant for which there is no more useful life (i.e., cost of removal). Prior reductions in the accrual for cost of removal have resulted in under-collection of those costs. The Company is proposing new depreciation rates that properly account for cost of removal and will allow the Company to appropriately recover its expected costs as it replaces aging infrastructure See Schedule MPM-41 for the impact of the proposed depreciation rates.

D. Flat Sales Despite Customer Growth

Q. How have PSE&G's sales changed since the last rate case?

A. On a weather-normalized basis, electric sales have slightly declined while gas sales have slightly increased. However, customers have steadily increased, so on a per customer basis, weather-normalized sales for both electric and gas have declined.

Q. Has this decline in sales meaningfully impacted the Company's margin (revenues less expenses)?

A. No. The Company's margin has been maintained due to the Conservation Incentive Program ("CIP").

Q. Please describe the CIP.

A. The CIP 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").[15] The CIP 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. Because of the CIP, flat to declining sales growth is not a factor requiring PSE&G to request rate relief.

Q. What is the impact of a base rate case filing on the CIP?

A. Anytime a base rate case is filed, the CIP baselines will reset. As described in more detail below, PSE&G will reset the CIP baselines in this proceeding to the approved billing

[15] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis*, Order Adopting Stipulation, BPU Docket Nos. GO18101112 and EO18101113 (September 23, 2020).

determinants for this test year of June 2023 through May 2024. This will shift the recovery of the revenue from the CIP accrual to base rates, increasing rates in this proceeding (but significantly lowering the CIP accrual for future years). Generally, this is just a transition of recovery from the CIP to base rates. However, the CIP is recovered or refunded to customers on a one-year lagged basis, so when base rates increase, the CIP accrual will subsequently decline, but the CIP rate in effect will remain, resulting in a net increase in rates to customers. The details of the *pro forma* adjustment to remove the CIP accrual currently included in operating revenues for recovery in base rates is shown in Schedule MPM-50.

E. Major Storm Event Recovery

Q. Please describe the regulatory asset PSE&G seeks to recover in connection with Major Storm Events.

A. The Company seeks to recover $109 million of deferred major storm costs incurred by the Company since the last rate case. As described in detail in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca, that $109 million is the result of five Major Storm Events on the following dates:

- August 4-13, 2020 (Tropical Storm Isaias/State of Emergency) $72M;
- June 3, 2020 (Derecho/thunderstorms) $15M;
- July 17-18, 2019 (Major Storm) $12M;
- September 1-28, 2021 (Hurricane Ida/State of Emergency) $8M; and
- Jan. 31- Feb. 23, 2021 (February 2021 Snow Storms/State of Emergency) $2M;

Q. Is the Company recovering any of these costs through base rates?

A. No, it is not. In the 2018 base rate case, the Company deferred all major storm event costs prior to and during the test year. Those costs, along with other regulatory assets were resolved through a black box settlement, with amortization of the agreed upon total regulatory assets over a five-year period. Because the test year Major Storm Events were deferred, there were no Major Storm Event costs reflected in the test year expenses and thus nothing in base rates to recover any post-test year Major Storm Events.

Q. Can you summarize your request for Major Storm Event costs?

A. The Company is seeking recovery of all prudently incurred Major Storm Event costs that have been deferred since the last rate case. These costs were incurred in preparation for and response to Major Storm Events that are outside the Company's control. As described in more detail below in Section IX, the Company is seeking a Storm Recovery Charge to recover these costs going forward.

F. Working Capital

Q. What is Working Capital?

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments. The amounts included in the test year are described in more detail below.

Q. How has Working Capital changed since the last rate case?

A. The primary driver of the large increase in working capital is related to the Company's cash working capital needs. As described in the testimony of Company witness Mr. Adams, the cash working capital requirement is comprised of a lead-lag study and net asset liability analysis.

Since the last rate case, the cash working capital requirements from the lead-lag study have increased due to a significant increase in the collection lag from customers. Since 2020 the Company's Accounts Receivable balance has increased significantly. While the Company is working with customers to address their arrears, there remains a significant lag in revenue recoveries, increasing working capital needs. This working capital requirement is not for recovery of uncollected bad debt, but recognition of an ongoing lag in revenue recovery. Further, since the last rate case, the Company has successfully managed its pension and OPEB plans, which results in net pension and OPEB income and an offsetting entry to record a pension asset. Each of those are reflected in this rate case (crediting the 2024 pension and OPEB income to customers and recovering the corresponding pension asset which is part of working capital).

Q. Why have Materials and Supplies increased?

A. The increase in inventory is primarily a result of ensuring material availability for planned increases for system maintenance and capital work. Due to extended lead times and supply chain constraints, PSE&G has restructured its approach to purchasing inventory material. The Company has diversified the supplier base in many material categories in an effort to increase material availability and reduce lead times. The Company also implemented more enhanced material forecasting models that have translated into increased inventory levels to support operations. Raw material and labor shortages stemming from the pandemic combined with increased demand industry-wide has also resulted in price increases impacting inventory values. Conductors and transformers are especially vulnerable to fluctuations in the metals markets, and commodities like aluminum and copper have been very volatile the last few years. PSE&G's strategy to diversify suppliers also includes use of international vendors, which adds cost to accommodate overseas shipping and logistics.

IV. MITIGATION OF THE RATE INCREASES

Q. Has PSE&G taken steps to minimize the rate change requested?

A. Yes. I will describe in this section some of the successful cost-containment efforts made to enable the Company to limit its total O&M expense since its last test year in 2018. The Company takes very seriously its responsibility to customers to manage its costs prudently and to be good stewards of the electric and gas distribution systems and the customer funds needed to operate and maintain them effectively. It is important to note, however, that while maintaining a much lower cost structure, PSE&G has preserved operational performance – safety, reliability, and customer satisfaction – that is, generally, top quartile in the industry, as noted above and more comprehensively in the testimony of Michael Adams.

Q. Please discuss the steps that the Company has taken to limit the rate increase.

A. The Company has taken a number of steps to mitigate the magnitude of the rate increases proposed in this proceeding. First, the Company proposes to flow-back to customers significant tax benefits to replace expiration of the unprotected Excess Deferred Income Taxes ("EDIT") refunded to customers through the TAC as a result of the 2018 base rate case. Second, the Company has contained the growth of distribution-related O&M expenses, including electric and gas distribution operating costs, while reducing certain administrative and general ("A&G") costs, including pension and benefits costs. Third, PSE&G has managed its interest costs as prudently as possible and is anticipating approximately the same long-term debt rate as in the 2018 rate case by the end of the test year despite the significant rise in interest rates. Finally, the Company's Appliance Service Business has grown its net margins (revenues less expenses), which reduces the revenue request in this proceeding. All of these factors have enabled the Company to reduce the rate request that it otherwise would have made.

A. Tax Adjustment Credit ("TAC")

Q. Please describe the current TAC.

A. As discussed in the testimonies of Company witnesses Mr. Pardo and Mr. Swetz, the TAC is a mechanism approved in the 2018 base rate case to flow-back certain tax benefits to customers. The TAC allowed for the flow back to customers of the Federal Tax benefit associated with EDIT and the Historic Safe Harbor Adjusted Repair Expense ("SHARE") as outlined in the 2018 rate case order below:[16]

Table 2

Tax Flow-Through Balances $000	Electric	Gas	Total	Amortization
Excess deferred tax (EDIT) flowback - Protected	424,259	326,618	750,877	ARAM
EDIT flowback - Unprotected (Rate Base Related)	175,105	213,929	389,034	5 yr
EDIT flowback - Unprotected (Non-Rate Base Related)	56,308	59,971	116,279	5 yr
Histroic SHARE flowback	130,493	287,201	417,694	10 yr
Total	**786,165**	**887,719**	**1,673,884**	

The TAC also required the flow-back of January – March 2018 income tax recovery, the flow-through of the Current SHARE, a return on the increase in rate base as a result of the flow back at the Company's Weighted Average Cost of Capital ("WACC"), and the payment of interest at WACC on the non-rate base related EDIT.

[16] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order") at Stipulation ¶ 15.

Q. What is meant by "protected" and "unprotected" EDIT?

A. As discussed in the testimony of Mr. Pardo, EDIT can be classified in two categories: (1) those restricted by the normalization provisions of the Tax Cuts and Jobs Act (sometimes referred to as "protected" EDIT); and (2) those that are not (sometimes referred to as "unprotected" EDIT).

Q. What is the status of the Flow-Through Balances approved in the 2018 rate case outlined in the table above?

A. The protected EDIT is amortized to customers using the IRS-mandated Average Rate Assumption Method ("ARAM") and will continue to be refunded to customers through the TAC. As discussed in the testimony of Mr. Pardo, the historic SHARE was designed so one third of the accumulated balance would be refunded over the first approximately five years ending December 31, 2023 and the remaining two thirds would be refunded over the remaining five-year period ending December 31, 2028. The unprotected EDIT balance will primarily be refunded by the end of 2023 and fully refunded by the end of 2024. The unprotected EDIT represents the largest annual amortization, and its completion has resulted in a significant reduction in the amount to be refunded to customers through the TAC.

Q. Is the Company proposing any adjustment to the TAC in this proceeding?

A. As discussed in the testimony of Mr. Pardo, there are tax deductions for what is referred to as Mixed Service costs that are not subject to IRS normalization rules and can be flowed-back to customers. The Company is proposing to flow back both the historic deferred tax balance associated with the Mixed Service deduction as well as the future deductions it will claim. This is consistent with the existing Historic SHARE flow-back to customers through the TAC (although PSE&G is proposing a more accelerated refund of Mixed Service costs to customers than the 10-year period for the SHARE). This represents a significant benefit to customers and lowers the Company's revenue request.

Q. Are there any other changes to the TAC?

A. Yes. As discussed in the testimony of Mr. Pardo, the Company is proposing to refund a pre-set amount for the current period SHARE and Mixed Service deductions, with any difference between the actual and pre-set amount deferred for refund to customers in a future proceeding. This has the benefit of providing consistency in the flow-back to customers to avoid rate swings from changes in the current deduction and will potentially provide an additional balance to flow-back to customers at the end of the amortization of the historic Mixed Service deduction to mitigate future increases to customers when the amortization is complete. To this point, as discussed in the testimony of Mr. Swetz, the Company also proposes to shape the amortization of the historic Mixed Service flowback to decline over an approximately five-year period to avoid a significant impact to customers after the final year of the amortization. Further, as also discussed by Mr. Swetz, the Company is proposing an adjustment to the Gas allocation of the TAC among customer classes so that all of the refund is attributed to firm customers. For more details on the TAC components, please see the testimony of Mr. Pardo. For details on the calculation of the TAC, proposed rates, and bill impacts, see the testimony of Mr. Swetz.

B. Cost Containment Measures – O&M

Q. Does PSE&G describe in this filing the actions that the Company has taken to control electric and gas operating distribution-related O&M expenses?

A. Yes, Mr. Schmid and Mr. Fonseca describe these actions in detail in their panel testimony. In general, the Company seeks to measure and optimize distribution-related O&M

expenses by regularly benchmarking costs and setting targets to improve results year after year. This fosters an environment of continuous improvement and results in a continuous focus on cost control and operational improvement.

These cost control efforts have helped to offset increases in distribution-related O&M costs due to inflation, including cost increases to satisfy regulatory requirements, and other cost increases since the Company's last rate case. Mr. Schmid and Mr. Fonseca's panel testimony on PSE&G's electric and gas operations provides examples of how PSE&G seeks to manage these costs while obtaining strong operating results. One example of cost containment is PSE&G's treatment of wages.

Q. Has the Company taken measures to control wages?

A. Yes. In the area of wages and benefits, the Company has controlled distribution-related O&M growth by regularly assessing its compensation levels to keep them competitive with the market while providing appropriate incentives to employees to focus on key operational metrics and critical business initiatives. The objective has been to ensure employee compensation programs remain market competitive and continue to enable the Company to attract, retain, and develop a talented and diverse workforce. Prior to 2023, PSE&G has generally provided average annual merit/wage increases between 2.5% to 3% to employees. In 2023, annual merit/wage increases averaged 3.5% to 4% in line with current market competitive conditions. The Company is currently evaluating its compensation programs, including but not limited to merit/wage increases, to ensure it remains market competitive. PSE&G also manages union employee costs through a rigorous collective bargaining process. In March 2023, the Company reached a new four-year bargaining agreement with all of its unions that set merit increases between 3% and 4% for the agreements' terms, below recent inflationary levels.

Q. Has the Company taken any other steps to control wages?

A. Yes. In 2022, the Company initiated a Voluntary Exit Incentive Program ("VEIP") for non-represented employees that will result in the voluntary retirement of approximately 240 employees (of which 185 are from the utility and service company) by December 31, 2023, the majority of whom are Final Average Pay (FAP) pension participants. The VEIP offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks, in line with current separation plan provisions. While a portion of these severance benefits will be paid in the test year, PSE&G proposes a *pro forma* adjustment to remove these non-recurring expenses so they are never collected from customers. The Company anticipates savings by 1) not filling all vacated positions, and 2) reducing pension liability, since any external replacements of positions that are vacated will participate in the Cash Balance Pension plan.

C. Cost Containment Measures – A&G (Pension and Benefits)

Q. How has PSE&G's control of pension costs mitigated the impact of the rate increase sought in this filing?

A. PSE&G has a long history of successfully controlling pension costs, and the considerable control the Company has exercised over this expense has translated into an estimated proposed revenue requirement for Pension and Other Post-Employment Benefits ("P&OPEB") *income* of approximately $9 million for calendar year 2024.[17] It should also be noted that the proposed revenue requirement would be relative to PSE&G's pension and OPEB

[17] This estimate will be known and measurable before the end of the test year.

liability of $4.2 billion based on year-end 2022. Even if the estimated income were to decline or even switch to an expense due to market conditions once the 2024 amount is known, it would still be extremely modest compared to the liability.

Q. Please describe the steps that the Company has taken to control P&OPEB costs.

A. PSE&G was among the first utilities in the country to close a Final Average Pay Pension Plan ("FAP") to new entrants and move to a Cash Balance Pension Plan construct for all new hires starting in the mid-1990s. Further, in 2011, the Company froze the FAP benefit structure for existing non-represented employees, which was calculated utilizing the five highest years of compensation through 2011 and created a new FAP benefit structure for existing non-represented employees, which was calculated utilizing the seven highest years of compensation, reducing pension expense and future liability. Since its last base rate case, PSE&G has adopted several cost measures that helped to further lower P&OPEB costs and reduce ongoing volatility. To highlight several:

- Diversifying the investment portfolio to include real assets, such as real estate and infrastructure, to reduce volatility;
- Adjusting the pension plan asset allocation strategy to reduce the funded status sensitivity to interest rate movements;
- Splitting the plan into "active" and "inactive" which allowed for a lengthening of the aggregate amortization period, reducing expense and volatility;
- As noted above, offering a voluntary early retirement plan, eliminating future compensation costs, and reducing associated volatility;
- Negotiating the allowance of a Defined Contribution-only pension offering for the Company's unions that will reduce future pension costs and volatility;

- Reducing medical expenses by transitioning Medicare-eligible retirees to a private exchange for procurement of health insurance and providing an annual credit to retirees by way of deposits into a notional Healthcare Reimbursement Account (HRA); and
- With approval from the BPU, implementing a five-year smoothing of the actuarial gains/(losses) associated with pension asset performance, which reduced 2023 pension expense by $55 million and also reduces the volatility of future pension expense levels.

Based on the investment returns that the Company has achieved in the past, the expected actuarial returns on pension funds in the test year, and the changes noted above that have assisted in improving the funding levels of the plans, PSE&G's pensions and OPEB are currently projected to result in projected income (negative expense) for the test year and calendar year 2024.

Q. Has the management of the returns on the pension funds also lowered expenses?

A. Yes. The management of the Company's pension funds has been exemplary over the long term. For the most recently available 10-year period ending June 30, 2023, PSE&G is in the top quartile ranking in the Trust Universe Comparison Service ("TUCS") rankings for trust returns. TUCS is a report published by Wilshire, an independent investment consulting firm, designed for trusts to evaluate their performance; the ranking reflects all decisions including asset allocation, policy guidelines, and manager selection. The Company's asset allocation decisions and investment manager selections have resulted in annualized long-term returns that exceed the industry median by more than 1% over the ten years through June 30, 2023. This superior management has resulted in higher actual returns and fund balances. As a result, this leads to lower costs in the test year.

Q. As a result of these measures, what is the P&OPEB expense in the test year and are you proposing any *pro forma* adjustments related to P&OPEB expense?

A. As a result of these actions, as well as present market conditions and other factors, the Company projects approximately $54 million of income from P&OPEB in the test year. This is a reduction to the revenue requirement request. However, the test year does not reflect the most recent go forward pension and OPEB revenue requirement. The P&OPEB expense is determined in January for the calendar year. As a result, the 2024 full calendar year expense will be known and measurable before the end of the test year. The Company proposes a *pro forma* adjustment to use the known annual P&OPEB expense at the end of the test year, which will be the 2024 actual P&OPEB expense. A forecast is included in this initial filing, but the final 2024 P&OPEB income will be determined in 2024 and should be used in place of the test year amount to reflect the latest known and measurable amount. If 2024 actual results are P&OPEB income as projected, this would be a reduction to the revenue requirement request. However, the Company cannot offset such a reduction in revenue requirements and make itself whole by taking that cash out of the P&OPEB funds. Additionally, any reductions in revenue requirement reduces operating cash flow and adversely impacts PSE&G's credit metrics. P&OPEB income is an actuarial result of the actions PSE&G took to reduce costs, as described above. Since the projected P&OPEB income is non-cash, the net offset is to record an asset. Each of these items impacts the request in this rate case, with P&OPEB income reducing revenue requirements and the pension asset included in working capital. The Company does not have access to the pension income that would reduce its revenue request in this proceeding and thus should be allowed a working capital adjustment to account for the net pension asset that is driving the pension income.

If a working capital adjustment is not reflected for the P&OPEB asset (net of the impact of smoothing as agreed to in the Pension Accounting Order[18]), any P&OPEB income reflected in the revenue requirement should be $0 as the Company does not have access to the cash associated with the income. Either of these two treatments ensure symmetry between the paper P&OPEB income under the plan and the corresponding P&OPEB asset – with either both included in calculating revenue requirements, or both excluded.

Q. Are you making any other proposal with regard to P&OPEB expense?

A. Yes. As described in more detail later in my testimony, the Company proposes that any difference between the utility P&OPEB income amount credited to customers in this proceeding and actual results be deferred for recovery or refund in a subsequent base rate case proceeding. P&OPEB costs have significant annual volatility driven by factors outside the Company's control, such as market gains and losses and changes in interest rates. The Company has done a very effective job managing P&OPEB costs as noted above. The Pension Accounting Order does help reduce volatility, but significant volatility in annual pension costs remains. Deferring any amount above or below the amount reflected in the revenue requirement in this rate case will allow flexibility in the amount incorporated in rates. A reconciliation mechanism also protects customers and the Company from significant swings in the pension income, so neither is a winner or loser based on short-term market fluctuations.

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[18] *I/M/O Public Service Electric and Gas Company's Request for an Accounting Order Authorizing the Company to Modify Its Pension Accounting for Ratemaking Purposes*, BPU Docket No. ER22090549, Decision and Order Approving Stipulation (February 17, 2023) ("Pension Accounting Order").

D. Cost Containment Measures – Interest Expense

Q. Please describe the steps taken to control the Company's interest costs.

A. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.02%, comparable to the embedded cost of long-term debt as of June 30, 2018 of 3.96%, which was the amount used to establish the cost of capital in the Company's 2018 Distribution Base Rate Case. Despite headwinds due to the inflationary environment, the Company has been able to maintain the embedded cost of debt at virtually the same reduced level set in the 2018 rate case. This result is primarily due to issuing long-dated debt during the historically low interest rate environment experienced over the past decade, strong PSE&G credit ratings, and solid execution of PSE&G's financing plan.

At present and for the foreseeable future, all companies will be faced with a higher interest rate environment. For example, in August 2023, PSE&G issued long-term debt at coupons for a 10-year bond of 5.20% and a 30-year bond at 5.45%, which is well above the Company's current embedded cost of debt. Given the prevailing current interest rate environment, this filing includes the estimated May 31, 2024 embedded cost of 4.02% rather than the October 31, 2023 actual cost of 3.87%. However, the final embedded cost rate will be the actual embedded cost as of May 31, 2024, the last month of the test year. In addition, as explained in more detail later in my testimony, the Company is seeking to defer any change in the embedded cost of debt after the test year given the volatile interest rate market.

E. Appliance Service Business

Q. Has the Company's Appliance Service Business helped to reduce rates?

A. Yes. PSE&G is the only utility in the State that continues to have an Appliance Service Business ("ASB") within the utility structure. As a result of this structure, the majority of the pre-tax earnings of this business are captured in the revenue requirement-setting process of each PSE&G base rate case, including this one. As discussed in more detail below, the Company is proposing to retain 50% of the Gas ASB margins in this proceeding in the same manner as allowed for an Electric utility under the New Jersey Administrative Code. Even with the proposed 50% sharing of all ASB margins, the test year reflects a significant benefit to Electric and Gas customers of approximately $46 million of margin (revenue less expenses) that will offset PSE&G's revenue requirement and is comparable to the margin returned to customers in the last base rate case.

F. Summary Impact of Cost Savings

Q. Please summarize the cost mitigation efforts the Company has accomplished to limit the rate request in this proceeding.

A. The Company has been very successful in controlling costs to limit the impact to customers. While an increase is unavoidable, PSE&G has taken notable steps to limit the impact: 1) PSE&G is the only utility in NJ flowing back significant tax credits to benefit customers, allowed by the Company's strong balance sheet and disciplined cash management; 2) the Company's P&OPEB currently remains a credit to customers, even with the recent downturn in markets; 3) PSE&G is the only NJ utility still providing ASB through the utility, representing a significant benefit to customers in net margin and operational savings; and 4) PSE&G continues to contain utility expenses to reduce the inevitable increase in expense due to inflation and wage increases. PSE&G has been able to accomplish this without sacrificing reliability and customer satisfaction. This is exemplified in the testimony of Mike Adams on how PSE&G compares to its peers in cost, reliability, and customer satisfaction.

V. CAPITAL STRUCTURE AND THE COST OF CAPITAL

Q. Does PSE&G have a need to maintain sufficient financial integrity to raise capital effectively?

A. Yes. The Company's financial integrity depends on, among other things, an approved return on equity ("ROE") that reflects the cost of capital required by investors, and a capital structure that is supportive of the Company's strong credit quality. The current authorized ROE is 9.60% and was set in the Company's last base rate case. As Company witness Ann Bulkley testifies, the Company's overall ROE should be reset at 10.4%, reflecting current market and business conditions. PSE&G proposes to apply its ROE to a capital structure reflecting a common equity component of 55.5%, to support targeted credit statistics, maintain a strong investment grade credit rating, and earn a just and reasonable return for investors.

Q. What is the Company's cost of capital and on what capital structure is PSE&G seeking to have those cost rates applied?

A. PSE&G seeks an overall rate of return of 7.55% that is derived from a capital structure composed of 55.5% equity, 44.29% long-term debt, and 0.21% customer deposits. The embedded cost rate for the Company's long-term debt is estimated to be 4.02% by the end of the test year. Customer deposits are accumulated at a rate of 1.40% as of January 1, 2023. The proposed ROE is 10.4%, as discussed in Ms. Bulkley's testimony.

A. Return on Equity

Q. How did Ms. Bulkley determine an appropriate cost of equity?

A. Ms. Bulkley derived her cost of equity using an analysis of a proxy group of companies that receive a similar percentage of operating income from regulated operations as PSE&G, and possess a set of operating risk characteristics that are substantially comparable to the

Company. She then estimated the Company's Cost of Equity ("COE") by applying several traditional COE estimation methodologies to a proxy group of comparable utilities, including Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. The COE estimation models produce a wide range of results. Based on this analysis, Ms. Bulkley established a range of 10.00% to 11.00% as reasonable and recommended 10.40% based on underlying market conditions and the business, financial, and regulatory risk factors facing PSE&G, including the Company's significant capital expenditures.

Q. Beyond the results of Ms. Bulkley's COE analysis, is there anything else the Board should consider?

A. Yes. While the Company fully supports Ms. Bulkley's analysis and 10.4% ROE recommendation, PSE&G also recognizes that COE estimation models are complex, with each methodology resulting in a wide range of results and different consultants can have different results based on the assumptions employed for each test. In the Company's 2009 base rate case, the parties to the proceeding settled to a 10.30% ROE and in 2018 settled to a 9.60% ROE, both of which were approved by the Board. Without getting into the complexity of each COE methodology, below is a summary of the market conditions for the current and prior PSE&G rate case:

Table 3

Change in Market Conditions Since Company's Last Rate Case					
PSE&G Rate Cases	**Decision Date**	**Federal Funds Rate**	**30-Day Average of 30-Year Treasury Bond Yield**	**Core Inflation Rate**	**Authorized / Proposed ROE**
2018 Rate Case	10/29/2018	2.20%	3.29%	2.13%	9.60%
2023/24 Rate Case	10/31/2023	5.33%	4.84%	4.13%	10.40%

Q. How do these factors impact a utility's ROE?

A. As described in the testimony of Ms. Bulkley, these factors impact the assumptions on risk used to calculate the COE methodologies. At a high-level, a US Treasury bond is considered risk-free and thus a premium above that rate would be needed for any investor to invest in PSE&G over a risk-free treasury bond. As interest rates rise, utility stocks can become less desirable as the premium needed to take on the additional risk declines. As a result, it would be expected that the ROE would increase as interest rates are increasing. Also, in terms of risk, the high Federal Funds Rate and Inflation rate indicate more risk to investors in the future as costs (and interest rates) may continue to rise. As such, market conditions require higher equity returns than at the time the 2018 ROE was approved.

Q. Is there more uncertainty surrounding the electric and gas utility industries in NJ compared to the last rate case?

A. Yes. There have been several BPU Orders, Governor's Executive Orders, legislative acts, and the Energy Master Plan focused on significant expansion of electric vehicle adoption, solar targets, electrification, and the future of the natural gas business as the State promotes the transition to a cleaner environment. PSE&G supports the State's promotion of the transition to a cleaner environment, and it can present opportunities for growth for the Company. However, it also represents significant uncertainty and risk to investors. The BPU is preparing to initiate a proceeding on the future of the natural gas industry. While the electric business has growth opportunities, the significant expansion of electric vehicles and conversion of gas heating to electric will require significant capital investment to ensure the reliability of the distribution system as customers depend on it more than ever. Capital investment will also be required to account for increasing amounts of supply coming from cleaner, more distributed sources as well as potential shifts in the Company's peak. The uncertainty of the impacts of the transition on the utility industry should be taken into consideration when determining the Company's risk and ROE.

Q. Are there any other factors that should be considered by the Board in determining the Company's ROE?

A. Yes. The Company's exemplary operating performance should be considered. As noted above and more extensively in Mr. Adams' testimony, PSE&G has delivered top quartile service (reliability) and customer satisfaction, at the lowest O&M and A&G costs compared to NJ and other peers.

B. Capital Structure and Credit Ratings

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The Company is targeting a capital structure having a 55.5% equity ratio, because this ratio is important to provide support for PSE&G's current credit rating. PSE&G is committed to strong investment-grade credit ratings in order to ensure consistent access to the capital markets at reasonable costs. PSE&G ended 2022 with a 55.1% equity ratio and its current senior secured credit ratings are "A" from S&P and "A1" from Moody's; the credit rating outlooks are stable from both rating agencies. The Company plans to manage its capital structure consistent with its equity ratio approved for ratemaking, so would expect to move toward 55.5% later in 2024. The 55.5% equity percentage was determined by evaluating the equity level needed to maintain certain credit statistics (i.e., Funds from Operation to Debt ("FFO to Debt"), or as Moody's calculates, Cash flow from Operating activities – pre working capital ("CFO pre-WC") to Debt) for a sustained period. Moody's credit opinion indicates that the FFO to Debt range for PSE&G's current rating is between 17% and 20%. While a 54% equity ratio was approved in the 2018 base rate case, the Company has increased its equity ratio to support its credit rating. The Company seeks approval of a 55.5% equity ratio to maintain strong credit ratings in a volatile market environment.

Q. Why is it important to maintain the Company's current credit ratings?

A. PSE&G has approximately $14 billion of long-term debt outstanding as of October 31, 2023. PSE&G also has a significant capital program and several billion dollars of long-term debt maturing in the coming years. Strong credit ratings are essential to executing financing plans and accessing the capital markets on reasonable terms at all times, especially during periods where market volatility can be prevalent. Volatility can limit market access and increase credit spreads.

Markets have experienced significant volatility in recent years that continues to persist. In March 2020, capital markets were not accessible due to uncertainty related to the COVID-19 pandemic. It required substantial government intervention to restore confidence and re-open markets. In early 2022, the Federal Reserve began to battle high levels of inflation, causing significant market uncertainty as rising interest rates impacted the economy. During 2022, volatility translated into periods of reduced market access, where issuers needed to be concerned with "actionable" days. In 2022, a considerable number of the business days were not "actionable", resulting in issuers competing more intensely for capital during periods when markets were open. Later in March 2023, markets were not accessible due to a crisis of confidence in the banking system. Intervention by the Federal Reserve to backstop deposits and assume responsibility for failed banks was required to help stabilize markets. Markets re-opened to issuers but continue to remain susceptible to further developments that could impact the regional banking sector. Impacts to the bank sector have the potential to spill over to the wider economy. Overall, market conditions remain characterized by volatility and are highly susceptible to political, banking, and economic developments, and have proven very dependent on economic data and Federal Reserve response.

The Company has had a strong history of raising low-cost financing, which has directly benefited customers in the form of lower interest expense – both in its infrastructure filings as well as this base rate case proceeding. As noted previously, the Company's cost of debt has remained relatively constant since the 2018 base rate case. This value translates into keeping customer rates low. Overall, preserving the Company's current credit ratings is the most desirable course of action for the reasons cited above, including the importance of executing the Company's debt financing plan during volatile periods.

Q. What key metrics and factors do the rating agencies assess in determining the Company's credit rating?

A. Funds from Operations to Debt (FFO/Debt) represents a key credit measure used by the ratings agencies. Moody's refers to FFO / Debt as CFO pre-WC to Debt. FFO/Debt is a measure of cash flow leverage and indicates a company's ability to support its debt level. For the purpose of demonstrating sound financial management, PSE&G tends to focus on the calculation of FFO to Debt from Moody's more so than S&P's calculation. S&P's analysis follows a "family" approach that develops a corporate credit rating based on a consolidated business and financial profile. S&P uses a top-down approach; Moody's, in contrast, uses a bottom-up approach, which analyzes the business and financial profile of an entity. Given this approach, Moody's credit opinion provides the more useful insights into a subsidiary credit rating.

Q. How has your credit rating changed since the last rate case in 2018?

A. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. PSE&G's senior secured credit ratings from Moody's of A1 and S&P of A are now both in the same 'A' rating category. The below table reflects PSE&G's Senior Secured ratings since 2018:

Table 4

Year – End	S&P	Moody's
2018	A	Aa3
2019	A	Aa3
2020	A	Aa3
2021	A	A1 (one notch downgrade)
2022	A	A1
2023 (Current)	A	A1

Q. What factors led to the downgrade in the Company's credit rating?

A. As indicated during the 2018 base rate case, federal tax reform in 2017 was credit negative for regulated utilities including PSE&G. The loss of bonus depreciation and the decision to flow back excess deferred income taxes to customers placed downward pressure on credit metrics. Moody's credit research referenced weakening financial metrics with limited financial cushion for PSE&G. In 2020, the decline in CFO pre-WC to Debt below the downgrade threshold of 19% was notable driven by impacts related to Tropical Storm Isaias and COVID-19. In May 2021, Moody's changed PSE&G's credit rating outlook from stable to negative, noting the decline in metrics. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. Since 2021, PSE&G's credit ratings have remained unchanged while the Company has executed substantial capital programs, supported by a regulatory equity ratio of 55.1% at year-end 2021 and year-end 2022, with a plan to manage capital structure consistent with an equity ratio approved for ratemaking, so would expect to target 55.5% later in 2024.

Q. Has PSE&G managed its finances to maintain a strong credit rating?

A. Yes. PSE&G has managed to maintain a strong credit profile. This has been achieved through disciplined financial management, including limited dividends to the parent company Public Service Enterprise Group ("PSEG"). From 2019 through 2022, PSE&G demonstrated disciplined financial management while experiencing storms, most notably Tropical Storm Isaias, and the COVID-19 pandemic. As a result of these events, PSE&G incurred significant unexpected costs. These incremental costs were financed consistently with PSE&G's capital structure, which required more retained equity. In addition, PSE&G increased its equity ratio to 55% from 54%, which required more retained equity.

Q. Has Moody's threshold for a credit upgrade or downgrade changed since the last rate case?

A. Yes. Moody's updated its upgrade threshold for CFO pre-WC to debt. In summary, Moody's "raised the bar" for the "Aa3" rating from 19% to 20%. See the table below.

Table 5

Moody's CFO pre-WC to debt			
	Senior Secured Credit Rating	Factors that could lead to an upgrade	Factors that could lead to a downgrade
June 2018	Aa3	excess of 26%	falls below 19%
October 2023	A1	above 20%	below 17%

Moody's credit opinion on PSE&G from October 2023 includes the following:

> **Factors that could lead to an upgrade**
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful improvement in the utility's business risk and that there is greater certainty and visibility for the utility's cash flow generation, the rating could be upgraded.
>
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt, including the adjustment related to energy efficiency investment, is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful decrease in the utility's business risk and greater certainty and visibility with regard to the utility's cash flow generation, the rating could be upgraded.
>
> **Factors that could lead to a downgrade**
> A downgrade could be considered if the regulatory environment deteriorates such that the regulatory lag increases significantly. In addition, if its CFO pre-WC to debt ratio, including energy efficiency investment, remains below 17%, its rating could be downgraded.

Q. Has Moody's conveyed its expectation of the CFO-pre-WC to debt ratio it intends PSE&G to retain to maintain its current rating?

A. Yes. In the PSE&G Credit Opinion from October 2023, Moody's included the following:

> PSE&G is pursuing a substantial capital investment program over the next five years that will grow its rate base. We expect its cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, including the adjustment related to its energy efficiency spending, to be around 18% over the next two to three years.

At year-end 2022, "CFO pre-WC" to Debt was approximately 18%, while the regulatory equity ratio was approximately 55%. A 55% regulatory ratio was important to help deliver Moody's expectations of CFO pre-WC to debt, as referenced in its credit opinion from October 2023.

Q. Do you believe the current approved equity percentage of 54% is sufficient for PSE&G to maintain its current credit rating?

A. PSE&G's current credit rating would be challenged at the 54% equity ratio, which prompted the Company to increase to 55.1%. PSE&G has been gradually increasing its equity ratio above 54%, which was approved in the 2018 distribution base rate case, as we have sought to support PSE&G's credit profile. As shown in the table below, our FFO to debt ratio dropped below the 17% floor in 2020 and increasing PSE&G's regulatory equity ratio to over 55% has been an important measure to help support the current credit profile.

Table 6

Year	Year-End Regulatory Equity Ratio	Moody's CFO pre-WC to Debt
2019 Actual	54.6%	18.2%
2020 Actual	54.5%	16.7%
2021 Actual	55.1%	17.5%
2022 Actual	55.1%	18.1%

Q. Has the Company informed Board Staff or the New Jersey Division of Rate Counsel ("Rate Counsel") that it was increasing its common equity percentage above the approved amount in the last rate case?

A. Yes. In July 2021, PSE&G reached an agreement to lower transmission rates with the Board and Rate Counsel. During the settlement process, PSE&G advised the parties that the Company would increase its equity ratio from 54% to approximately 55% due in part to the lower cash flows due to the reduction in the Transmission ROE agreed to in the settlement. At the end of 2021 and 2022, PSE&G's equity ratio was 55.1%. The actual regulatory equity ratio will vary monthly based on monthly earnings and financing activities.

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The 55.5% equity target was determined by evaluating the capital structure needed to maintain key credit statistics for a sustained period. More specifically, Moody's credit opinion indicates that the CFO pre-WC to Debt range for PSE&G's current rating is between 17% and 20%. The 55.5% equity ratio is expected to support an FFO/Debt level that targets the upper end of the guidance for our credit metrics, which includes sufficient cushion above the low end of the range (17%) for downside risks.

Q. Why is it important to target above the 17% floor for the credit rating range?

A. As made evident by the last four years, unexpected events will impact the Company's cash flow, most recently major storm events and the COVID-19 pandemic. To illustrate the need for some financial flexibility, in 2020 Tropical Storm Isaias and the COVID-19 pandemic adversely impacted the Company's CFO pre-WC to Debt by approximately 2.5%. While those events will not occur every year, unexpected events that impact cash flow can and will occur, so it is important to maintain sufficient cushion above the 17% threshold to help protect the Company's credit profile against unexpected events and cash flow uncertainty.

Q. Are there other factors besides unexpected events that support increasing common equity to 55.5%?

A. Yes. First, PSE&G is unique in the State in flowing back significant tax benefits. This is a significant benefit to customers (and revenue reduction to the Company) of over $200 million per year on average since 2019. The Company is able to flow this amount back to customers because of its disciplined financial management but it does impact the Company's cash flow, and given the size of the credit to customers, any lag in adjusting rates can cause a notable impact on the Company's cash flow. PSE&G also has the highest proportion of low-income customers compared to the other electric and gas utilities in the State and experienced a significant impact on collections during the COVID-19 pandemic, with its Accounts Receivable balance greater than 90 days increasing from $116 million in March 2020 to $442 million in March 2022, an increase of more than 350%, far more than any other New Jersey utility experienced. Finally, PSE&G forecasts a substantial capital program to modernize its system to meet the State's clean energy goals and maintain safe and reliable service.

Q. Can you summarize the basis for the requested 55.5% common equity ratio?

A. Yes. PSE&G has demonstrated strong financial management to support strong credit ratings in a very challenging environment. However, recent years have shown that the 54% common equity amount approved in the last rate case is not sufficient, as PSE&G has proactively increased its common equity ratio to above 55% to support a FFO/Debt ratio to support the Company's credit profile. A 55.5% equity ratio allows PSE&G to better manage a substantial capital investment program, flowing back excess deferred taxes, and to account for unexpected events, such as major storm events, that are becoming more frequent and can have a significant impact on cash flow. The Company forecasts a substantial capital program necessary to meet State goals and maintain safe and reliable service and must have access to financial markets to fund those investments at the lowest rates possible. Maintaining the current credit rating will ensure the best possible execution of PSE&G's financing plans under a range of possible market conditions, and therefore it is critical that the Board approves a 55.5% common equity ratio to support PSE&G's credit profile.

VI. APPLIANCE SERVICE BUSINESS ("ASB")

Q. Can you briefly describe the Appliance Service Business?

A. PSE&G has been servicing appliances in its territory for over a century. The current services offered are for:

1) Appliance Repair Service and Maintenances Services, referred to as "APSO";
2) Replacement Parts Service Contracts, referred to as "Contracts";
3) Water Heater Replacement; and
4) Central Heating and Central Air Conditioning Replacement ("HVAC").

The majority of the work is performed by PSE&G's workforce with the exception of water heating replacement, which is conducted by contractors retained by the Company.

Q. How is the margin from ASB treated for ratemaking?

A. The revenues and expenses associated with the appliance service business are included in the income statement for the utility. The margin (revenues less expenses) in the test year is included for ratemaking purposes in accordance with *N.J.A.C.* 14:4-3.6(r), which has separate regulations for electric and gas utilities. For gas public utilities, the total ASB margins are currently treated above-the-line for ratemaking purposes and credited to customers. For electric public utilities and related competitive business segments of electric public utilities, 50 percent of the total margins are recorded in respective competitive service revenue accounts and treated above-the-line for ratemaking purposes.

Q. Since PSE&G is both an electric and gas utility, how are margins split between the two businesses?

A. In the 2018 rate case, the revenues and expenses were split between electric and gas based on the fuel type for the appliances under contract and being repaired or replaced. Starting in 2023, PSE&G has modified that approach to allocate ASB margins based on a pre-set 55% electric and 45% gas allocation.

Q. Why change the allocation methodology?

A. There are a few reasons why a pre-set allocation is more appropriate at this time.

First, for ratemaking purposes, it adjusts the calculation as if PSE&G consisted of standalone electric and gas utilities for allocating the net benefit of the business. A customer in PSE&G's electric-only service territory can have services for gas appliances, and vice versa. In this instance where an electric-only customer has work completed on gas appliances, that customer is contributing to the net ASB margins, but none of that credit is flowing back to that customer as it will be allocated to PSE&G's gas customers only. The pre-set allocation based on number of customers adjusts the allocation as if we were stand-alone electric and gas utilities and is the same allocation applied to Common Plant for decades. Also, since the approval of the CIP after the 2018 rate case, the primary driver of margin for the utilities is the number of customers, since the CIP is calculated on a per customer basis. Switching to an allocation based on the number of customers aligns the ASB margin with the driver of margin for the electric and gas utility.

Second, the allocation by appliance fuel type does not factor in the nature of the service being provided. While the majority of ASB margins are allocated to the gas utility based on appliance fuel type, the majority of the materials being replaced for the Contract and APSO services are for electrical components. Based on recent history, approximately 60% of the parts repaired and replaced for gas-fueled appliances are for electric components. While using this approach would still directly allocate margins between electric and gas based on the work performed, it would significantly shift ASB margin from gas to electric and create the same cross-subsidization issue as the current allocation by fuel type. For these reasons, PSE&G did not implement this approach, but it supports allocating more margin to electric, which the Company is doing to a lesser extent by allocating based on the number of customers.

Finally, the allocation methodology takes into consideration the State's policy goals targeting increased electrification. The allocation of ASB margins between electric and gas customers in the 2018 rate case was approximately 35% to electric and 65% to gas. That allocation is expected to increase by the end of the test year to approximately 40% electric and 60% gas if margins were allocated by appliance fuel type. As the State moves toward electrification, it is likely the allocation to electric appliances will continue to increase. Since ASB margins are allocated to customers based on the test year amount in a rate case, electric customers will not receive any benefit from the shift in allocation between electric and gas until a subsequent rate case. Implementing the pre-set 55% Electric and 45% Gas allocation at this time will credit electric customers now with the expected shift to more electric appliances in the short-term and will help lower costs to electric customers where costs are expected to increase while the State pursues its electrification and clean energy goals. While PSE&G made this allocation change in 2023, the Company will continue to monitor the driver of the ASB margins and the most appropriate allocation to customers in the future, especially as the electric and gas utilities evolve to meet the State's clean energy goals.

Q. **Does ASB provide a benefit to PSE&G's customers by being part of the utility?**

A. Absolutely. ASB provides significant financial and operational benefits to customers.

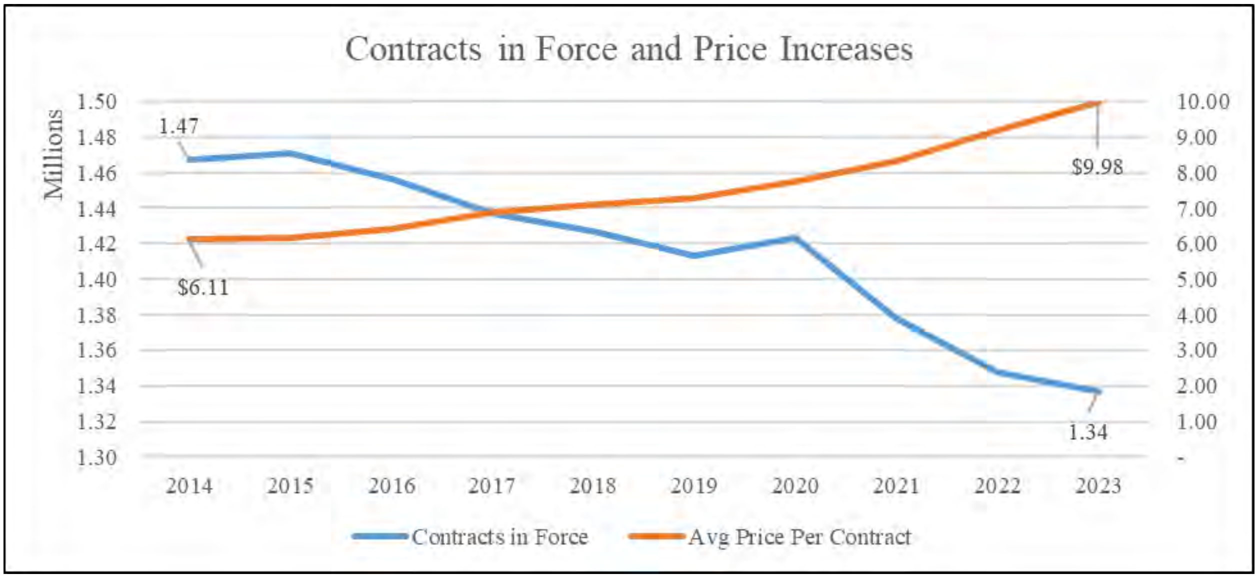
Financial benefits of ASB. The margins from this business help reduce costs to all our customers. For this test year ending May 31, 2024, PSE&G projects annual net margins of $46 million ($25 million to electric and $21 million to gas) to be returned to customers, reducing the annual revenue request in this proceeding. As a reduction to base rates, that amount will be implicitly refunded to customers every year until the conclusion of the Company's next base rate case, when the amount will be reset. This is a significant benefit to customers and includes the proposed retention of 50% of gas margins discussed in more detail below.

Operational benefits of ASB. Having ASB in the utility also has operational benefits. Appliance service technicians are skilled labor that also perform emergency response duties (including responding to emergency calls about gas leaks, carbon monoxide, and fires) as well as meter services, such as meter installations and replacements, and turn on and shutoff services. This work is referred to as regulatory work and the majority is on emergency response in the peak winter season. If not for the ASB Competitive Service business, the Company would have inefficiencies with the workforce due to the inconsistent nature of the work that is weather driven. For example, there are a greater volume of gas leak and appliance diagnostic responses in the winter months as compared to the non-winter months. The need to staff for the peak workload would result in a material increase in costs to our customers.

Q. **Are there challenges in increasing ASB margins going forward?**

A. Yes. PSE&G has been very successful in managing this business, which has benefited customers through a revenue reduction from margins and through more efficient workforce management. However, the number of customers purchasing Contract services has been declining. Other than a temporary increase in 2020, the number of customers purchasing Contracts services has been in decline since 2015. On top of a decline in demand for the business, the Company faces challenges in the supply chain, leading to cost increases and part shortages. While PSE&G can continue to increase Contract prices to offset the costs, the increases only occur once each year and will likely result in a reduction in customer contracts, creating more margin risk. Despite these challenges, PSE&G has been able to increase margins through price increases, and growth in the HVAC business since the last rate case. However, yearly price increases are not a long-term strategy, as continual increases will only hasten the decline in the number of customers.

Chart 14



Q. Are there challenges amplified by the current ratemaking structure?

A. Yes. As mentioned above, the ASB margins included for ratemaking purposes follow *N.J.A.C.* 14:4-3.6(r), which requires 50% of electric margins and 100% of gas margins in the test year returned to customers. Once included in rates, the Company is essentially refunding that amount to customers every year until the margins are reset in a future rate case. As a result, if ASB margins drop below the amount in the test year, the Company would lose money as a result of continuing this business.

Q. How does the Company propose to address this challenge?

A. The Company proposes to retain 50% of the total net margins from the provision of ASB services to its gas customers in the same manner as allowed for its electric customers. While *N.J.A.C.* 14:4-3.6(r) provides rules for ratemaking for electric utilities and gas utilities, it does not specify the treatment for a combined electric and gas utility and the Board can approve this ratemaking treatment to account for the uniqueness of PSE&G's combined electric and gas business. The Company believes that good cause exists for the BPU to approve this ratemaking treatment for the following reasons:

- Given the decline in ASB customers since 2020, the Gas ASB represents more risk than reward going forward;
- The request to retain 50% of the margins is consistent with the ratemaking already allowed for electric margins;
- ASB would still represent a $46 million reduction to our requested annual revenue increase, even at 50% margins for both Electric ASB and Gas ASB;
- Maintaining ASB in the utility provides operational benefits to customers by reducing staffing needs that would only be used for emergency work in the winter period; and
- As the only utility in NJ still providing this service, the N.J.A.C. regulations apply only to PSE&G, but they do not address a combined electric and gas utility.

PSE&G is proud of this business, its skilled workforce, and the value that it generates for customers, both through direct financial benefit in the ratemaking process, and through support of the important services we provide, particularly during emergencies and in challenging weather conditions. However, if there is more risk than reward potential associated with this business, PSE&G will be forced to consider restructuring or exiting this business.

VII. P&OPEB EXPENSE RECOVERY

Q. Is the Company proposing a change in the accounting treatment of P&OPEB expense (or income) in this proceeding?

A. Yes. The Company proposes that any volatility in the P&OPEB income (or expense) above or below the amount set for recovery in this proceeding be deferred for recovery or refund in a subsequent rate case proceeding.

Q. Please briefly describe P&OPEB accounting.

A. Pension expense represents an employer's annual cost for maintaining employees' pension benefits, while OPEB expense reflects the annual expense recognition for retiree healthcare and other post-retirement benefits. Employers that provide a pension plan must calculate and disclose plan assets and liabilities on the balance sheet, and record pension expense on the income statement. Pension expense is comprised of individual components calculated by the plan's actuary. These components include service cost (the P&OPEB earned by employees who are active in the relevant year), interest cost, expected return on plan assets, and amortizations of both prior service cost and actuarial gains / losses.

Q. How are these P&OPEB components reflected on the income statement?

A. The Service Cost component of expense is reflected in the operating section of the income statement. The other components of expense are reflected in non-operating earnings for GAAP. This accounting treatment is due to the concept that the Service Cost component of expense reflects the cost associated with pension benefits earned during the year. The other components of expense are mostly related to the plan's assets, liabilities, historical plan changes, and actuarial assumptions, and are impacted by financial market performance and interest rates. For ratemaking purposes, all components are included as operating and recovered or refunded to customers.

Q. **What is the funding level of the Company' pension obligation?**

A. As of July 31, 2023, the qualified pension plans were funded at approximately 93%.

Q. **Has the Company been successful managing the investment strategy of the pension asset?**

A. Yes. As I have stated previously, the Company has been very successful in managing the investment strategy of the pension assets, as illustrated by the expected P&OPEB income of approximately $9 million for 2024 ($8 million of pension income and $1 million of OPEB), which is positively impacted by the funded status of the pension plans (difference between pension liability and pension assets). This estimated income is after accounting for the Board's February 2023 Pension Accounting Order. If not for the Pension Accounting Order, the projected P&OPEB income would decline by $55 million in 2023 and become an expense.

Q. **Can there be significant annual fluctuations in the pension non-service income?**

A. Yes. The pension non-service income is subject to market performance and given the size of PSE&G's pension assets and liabilities, can reflect significant annual changes.

Q. **How did the Board's Pension Accounting Order address the volatility of pension costs?**

A. In its February 2023 Pension Accounting Order, the Board granted PSE&G the authority to use a calculated value that recognizes changes in fair value in a systematic and rational manner, to "smooth" returns on assets in the Company's pension trust, for purposes of calculating the amortization of net gain or loss component of pension expense. This methodology change results in a timing difference between PSE&G's recognition of the impact of changes in the market-related value of assets in calculating its pension expense for ratemaking purposes versus its current methodology. PSE&G was therefore authorized to (1) record a regulatory asset or liability to account for the difference in the amortization of net gain or loss component of pension expense (or income) between PSE&G's current methodology and this alternative methodology ("smoothing"), and (2) submit for recovery or return in rates the pension expense or income utilizing the proposed methodology for computing the amortization of net gains or losses. Adopting a calculated method for determining the market related value of plan assets in PSE&G's pension trust for purposes of calculating pension expense, like the majority of PSE&G's peer companies and the State of New Jersey itself, will reduce the volatility of PSE&G's income statement and customer rates; improve the usefulness of the information presented to financial statement users; and improve comparability of results for PSE&G and its peers.

Q. **Does the Pension Accounting Order address the volatility in pension non-service income?**

A. While the Pension Accounting Order does reduce the volatility resulting from market fluctuations, there remains significant volatility that can occur based on market changes. The Pension Accounting Order only impacts the gain or loss amortization component of expense. There remains significant cost volatility with respect to the expected return on assets component of pension expense.

Q. **How does the Company's proposal address this volatility?**

A. The proposal would defer any variances between the required actuarial expense/income recorded on the FERC income statements and the amount refunded to customers as a result of this proceeding. This would ensure that neither the customers nor the Company would win or lose based on market fluctuations outside of the amount refunded to customers in this case.

Q. Does this proposal just shift market performance risk to customers?

A. No. While it would allow for recovery of a decline in P&OPEB income, it would also allow an increase in the refund of market gains as well. Fluctuations will occur both up and down and this proposed accounting treatment will ensure variances are equally shared.

Q. Does this proposal incent PSE&G to take excessive risk with its pension investments?

A. No. The management of the investments of the pension plan are subject to fiduciary standards that require the highest level of prudence and care, and all decisions are made in the best interests of plan beneficiaries. In fact, a glide path strategy for the investment allocation of PSE&G's pension asset was adopted and designed to reduce risk by increasing fixed income investments as the funded status of the plan improves. In addition, the pension and OPEB programs cover non-PSE&G employees, whose pension costs are not subject to rate recovery. The Company is therefore incented to manage the entire pension plan to ensure optimal financial results.

Q. Is there precedent in New Jersey for this accounting treatment?

A. Yes. New Jersey American Water utilized deferred accounting for P&OPEB expense in its most recent rate case, deferring any change from the amount proposed in rates in the same manner as PSE&G proposes in this proceeding.

VIII. <u>GAS BAD DEBT RECOVERED IN SBC CLAUSE</u>

Q. How are gas bad debt expenses currently recovered from customers?

A. Gas bad debt expenses are currently recovered in base rates. An average uncollectible rate is included in the revenue factor used to gross-up the revenue increase request in the Company's prior base rate case as well as in post rate case infrastructure program rate adjustments and the gas TAC. There is no true-up between the actual gas bad debt expense incurred and the recovery through base rates (and the TAC).

Q. Does the recovery of gas bad debt expense treatment differ from the recovery of electric bad debt expense?

A. Yes. Electric bad debt expense is recovered through the Social Programs component of the electric Societal Benefits Charge.

Q. Are there any differences between the two businesses that warrant the separate treatment?

A. No. The majority of PSE&G's customers are combined electric and gas customers, so non-payment would impact the Accounts Receivable balance of both businesses, in the same manner. Setting aside the different mechanisms for recovery, there is no difference to PSE&G between non-payment from an electric customer and a gas customer or a combined electric and gas customer, as in all cases it is cash not received by the Company. It would be more logical and less confusing to use the same recovery mechanism without regard to which business the Accounts Receivable balance is attributed.

Q. Which recovery mechanism is better?

A. Recovery of bad debt expenses through the SBC, as is done for the electric business, is the most appropriate method. Through the SBC, all bad debt expenses can be reviewed for prudency and only prudently incurred costs are recovered. Conversely, with base rate recovery, there will always be a mismatch between bad debt expense recovered and the expense incurred so the Company is either recovering too much or too little.

Q. **What is PSE&G's proposal in this proceeding?**

A. As described in the testimony of Mr. Swetz in the COVID-19 proceeding in BPU Docket No. AO20060471, the Company proposes that gas bad debt expenses be recovered through a new Social Programs component of the Gas SBC, consistent with the recovery of electric bad debt expense. For details on the proposed new component of the Gas SBC, please see the testimony of Mr. Stephen Swetz. See Schedule MPM-46 for a *pro forma* adjustment to remove the recovery of gas bad debt from the rate case request so that it can be recovered in the proposed new Social Programs component of the Gas SBC.

As a result of the COVID-19 Order, PSE&G and other New Jersey utilities were permitted to defer the significant increase in gas bad debt expense above the amount included in base rates from March 9, 2020 through March 15, 2023. The Company's proposal in this proceeding does not include deferred COVID-19 bad debt which is being addressed in a separate proceeding.

IX. <u>STORM COST RECOVERY</u>

Q. **Has PSE&G incurred any major storm expenses since the last base rate case in 2018?**

A. Yes. As discussed in more detail in the panel testimony of Mr. Schmid and Mr. Fonseca, the Company has incurred approximately $109 million in incremental O&M expense for preparation and/or restoration efforts associated with five major storm events from July 2018 through November 30, 2023.

Q. What is the definition of a "Major Storm Event"?

A. A Major Storm Event is defined in N.J.A.C. 14:5-1.2 and includes a weather event such as a thunderstorm, tornado, hurricane, heat wave, snow, or ice storm which either affects at least ten percent of the customers in one of the Company's operating areas or results in the declaration of a state of emergency. As discussed in more detail below, the Company is proposing to expand the definition for Major Storm Event costs to include prudent, significant pre-staging costs that are incurred in preparation for a projected Major Storm Event that may not ultimately occur.

Q. How does the Company currently account for the incremental O&M costs associated with Major Storm Events?

A. Consistent with the way in which the Company has accounted for incremental O&M costs associated with Major Storm Events since 2010, the Company defers these costs for future recovery in a manner to be determined by the BPU.

Q. Were base rates set to recover any Major Storm Events that occurred after the conclusion of the 2018 base rate case?

A. No. In the 2018 base rate case, the Company used a *pro forma* adjustment to remove the $25.247 million in Major Storm Event incremental O&M that occurred in the July 2017 through June 2018 test year in that proceeding.[19] As a result, there is no base rate recovery of incremental O&M for post 2018 Major Storm Events in the Company's current base rates.

[19] Schedule SSJ-40 R-2, of Exhibit P-2 12+0 Testimony of Scott Jennings from the 2018 base rate case (*I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030 (filed January 12, 2018)).

Q. Is the Company proposing to use deferral accounting for Major Storm Event costs rather than base rate recovery?

A. Yes. The use of deferral accounting for the costs ensures that customers will pay no more and no less than the Company's actual costs associated with events that are beyond the Company's control and impossible to predict. This protects both the Company and customers. For example, assume the test year Major Storm Event costs were reflected in base rates instead of deferral accounting. Customers would have been paying over $25 million in rates even if no Major Storm Events occurred, such as in 2022. While the Company would have the benefit of collecting above actual costs in all years but 2020, in that year it would have incurred a massive loss due to the over $87 million in deferred costs incurred as a result of Tropical Storm Isaias. The Company should not profit from the absence of Major Storm Events, nor should it be penalized for prudently incurred incremental expenses associated with Major Storm Events.

Q. Is the Company proposing any changes to Major Storm Event recovery in this proceeding?

A. Yes. Deferral accounting, coupled with an annual surcharge mechanism, is the most appropriate means of recovering Major Storm Event costs by protecting the Company from significant financial harm from major weather events outside its control as well as ensuring customers only pay for actual, prudently incurred costs. First, this would allow for a prudence review of the deferrals within a reasonable time after they are incurred instead of reviewing all Major Storm Events that occur between rate cases at the same time. Second, these interim rate proceedings can help the Company maintain its credit ratings (which have benefited customers) as well as prevent any rate shock that could arise if the Company were permitted to recover the costs of all post-test year events at the same time. Finally, the use of a surcharge provides a mechanism to stop the amortization when recovery of the deferral is completed. As a result, the Company is proposing that a new clause, "the Storm Recovery Charge," be created to recover the approximately $109 million in deferred storm costs incurred since the last rate case as well as any future prudently incurred storm costs. For more details on the new clause, please see the testimony of Company witness Mr. Swetz.

Q. Are you proposing any other change to the manner in which costs associated with major storm events are recovered from customers?

A. Yes. Based upon the severity of weather forecasts, the Company may prepare in advance for a storm by procuring and/or mobilizing contractor crews prior to the onset of adverse weather, with the intention of deploying those crews to shorten the duration of customer interruptions. Given the difficulty of moving people and equipment under adverse weather conditions, and the competition among regional utilities to secure adequate emergency support when storms are forecast, the Company simply cannot wait until the impact of an imminent storm is certain; by then it is too late. Therefore, "pre-staging costs" must be recoverable, including any costs to retain contractors to assist with restoration efforts that would otherwise leave for storm duty in another jurisdiction. If the actual weather does not end up meeting the definition of a Major Storm Event, the Company should nonetheless be provided an opportunity to recover prudently incurred "pre-staging costs" incurred to respond to potential storms. The Company proposes that under the Major Storm Events cost recovery clause that it is proposing in this proceeding, it should be permitted to include recovery of pre-staging costs that exceed, in any one instance, $250,000. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prepare more prudently for future storms.

X. CONSERVATION INCENTIVE PROGRAM ("CIP")

Q. How and when was the CIP approved?

A. PSE&G filed for approval of its Clean Energy Future – Energy Efficiency Program ("CEF-EE Program") on October 11, 2018 ("CEF-EE Petition"). Subsequent to the CEF-EE Petition, on June 10, 2020, the Board approved a framework ("Framework Order")[20] for the performance targets; program administration; cost recovery (including lost revenue treatment); evaluation, measurement, and verification ("EM&V"); and filing and reporting standards for implementation of New Jersey's EE and peak demand reduction ("PDR") programs. 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 provided for in the Clean Energy Act ("CEA"). On September 23, 2020, the Board approved a stipulation resolving all matters associated with the CEF-EE Petition, which included approval of the CIP mechanism.

Q. What is the purpose of the CIP and how does it work?

A. The CIP mechanism provides for rate adjustments related to changes in the average use per customer when compared to a baseline, removing the Company's disincentive to encourage customers to conserve energy that exists under traditional ratemaking. The CIP applies to both the Company's electric ("ECIP") and gas ("GCIP") businesses. 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 ("BRC") from the actual revenue per customer and multiplying the resulting revenue per

[20] *I/M/O the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs*, B.P.U. Docket No. QO19010040 et al., Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs (June 10, 2020) ("Framework Order").

customer by the actual number of customers for the month. The GCIP 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 use per customer ("BUC") from the actual use per customer and multiplying the resulting use per customer by the actual number of customers and per therm margin rate for the month.

Q. Are you proposing any adjustments to the CIP in this proceeding?

A. Yes, there are two adjustments that must be made in a base rate case proceeding associated with the CIP. First, a base rate case proceeding will establish new baseline use (gas) or revenue (electric) per customer figures that will go into effect upon approval of this proceeding. Second, a *pro forma* adjustment must be made to the test year income statement to remove the CIP accrual to account for the reset of the CIP baseline.

Q. Please explain the resetting of the BUC and BRC.

A. Aspects of the CIP tariff that interrelate with PSE&G's base rate revenue recoveries must be updated when new base rates are determined in a base rate case. The CIP is designed to adjust for changes in the average use per customer compared to the amount approved to set base rates, and thus the baseline for the CIP must be aligned with the approved billing determinants used to set base rates in this proceeding. In addition to the updated BUC and BRC, the date for determining incremental large customers should be set at June 1, 2024, the first day following the end of the test year. An adjustment to the number of customers is allowed under Rate Schedule Large Volume Gas ("LVG") to account for new customers with significant loads. The calculation of the LVG customer adjustment is the aggregate connected load for all new active customers that exceed 1,200 cubic feet per hour ("CFH") divided by 600 CFH.

Please see Schedule MPM-55E and MPM-55G for the updated BRC and BUC based on the actual results from June 1, 2023 – October 31, 2023 and a forecast from November 1, 2023 – May 31, 2024. The revised baselines will be updated with actual results when available.

Q. Why does the Company need a *pro forma* adjustment for the test year CIP accrual?

A. The CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC. The details associated with the elimination of the test year CIP accrual are reflected in Schedule MPM-50.

XI. EMBEDDED COST OF DEBT RATE RECOVERY

Q. How does the Company recover interest expense in base rates?

A. Interest expense is recovered as the Company's electric and gas rate base multiplied by the long-term debt component of its capital structure and then by the embedded cost of long-term debt. Each of these components will be approved by the Board in this proceeding based on results as of the end of the test year and approved post-test year adjustments.

Q. Can there be significant movements in interest rates?

A. Yes. This is highlighted by recent sharp movements in interest rates attributed to federal reserve policy seeking to lower inflation and other market factors. At the beginning of 2022, the 10-year treasury was approximately 2% and in less than two years, the 10-year treasury has recently been near 5%. Further, the outlook for interest rates is expected to be higher for some time – and certainly during the initial period when rates set in this case will go into effect -- due to a variety of market factors. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.02% based on expected additional financings in the test year. Quite simply, in the current and expected interest environment, any new financing given the level of treasury rates would be expected to significantly exceed the embedded cost of long-term debt.

Q. Has the impact of interest expense increased since the last rate case and do you expect it to continue to grow?

A. Yes. While the path of future interest rates is difficult to predict, the materiality of interest expense will continue to increase as debt grows to finance PSE&G's capital investment program needed to meet the State's clean energy targets and maintain safe and reliable service. PSE&G's long-term debt outstanding has grown significantly since the last rate case (debt outstanding was approximately $9 billion at the end of 2018 and is approximately $14 billion as of October 31, 2023). PSE&G supports the State's transition to a cleaner environment, but that transition will require significant capital investment to the distribution system that will be financed by the Company's approved capital structure, significantly increasing PSE&G's long-term debt balance and overall interest expense. In addition to financing new capital investments, approximately $1.1 billion of the existing long-term debt will come due in 2024 and 2025.

Q. What are the implications of interest rate increases on the rate setting process?

A. Upon setting new rates, PSE&G would not be expected to recover the cost of debt for a period of time that is difficult to predict. The rate setting process should provide the Company an opportunity to earn its allowed return in at least the first-year new base rates go into effect, which is why post-test year pro forma adjustments have been approved by the Board for known and measurable expenses. The current interest rate environment and the need to refinance existing debt after the end of the test year will likely result in the Company's interest expense exceeding its revenue recovery within the first year that new rates go into effect. This treatment could also enable the Company to stay out of rate cases longer than it otherwise would, thereby deferring impacts to customers.

Q. What is the Company's proposal to address changes in interest expense after the test year?

A. The Company proposes a new interest cost reconciliation mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding. Please see Schedule MPM-55 for the proposed calculation of the deferral. The interest cost reconciliation mechanism avoids the need for a *pro forma* adjustment that would increase costs to customers in this proceeding and will provide the Company an opportunity to earn its allowed return. The mechanism also ensures the Company recovers no more or less than its allowed interest expense and can be reevaluated in a future base rate case.

Q. Will the proposed mechanism allow the Company to defer the incremental interest expense on increases in its outstanding long-term debt balance outside of a rate case?

A. No, it will not. Increases in the Company's rate base and associated long-term debt balance will continue to be recovered through the base rate case process and will not be part of the deferral mechanism. The deferral accounts only for changes in the Company's embedded cost of debt. The rate base balance and long-term debt percentage in the mechanism will be the amounts approved by the Board in this proceeding. As a result, the Company will still bear the risk of increases in interest expense associated with investments that have not been approved by the Board.

Q. Would this mechanism be symmetrical and allow for potential refunds to customers?

A. Yes. As the market has shown over the past few years, interest rates can rapidly change downwards (such as during the COVID-19 pandemic) or upwards (such as during periods of inflation and other market crises). If interest rates decline again in the future and reduce the Company's embedded cost of debt, those amounts would similarly be deferred for future refund to customers. Rate movements will be influenced by the prevailing economic environment, which could vary from a re-acceleration of inflation to a hard landing of the U.S. economy. Rate movements could also be driven by a shock to the system such as a pandemic, banking crisis, or global conflict. Fluctuations in interest rates can be higher or lower, and the proposed accounting treatment will ensure variances are shared between the Company and customers.

Q. Does this proposal shelter customers from the execution risk of financing plans to customers?

A. Yes. A long-term bond is priced using a treasury rate and a credit spread. For reference, in August 2023, PSE&G issued 10-year debt with a coupon of 5.20%, reflecting a 10-year treasury as the reference rate plus a credit spread of 103 basis points. Generally, the cost of debt is driven by the treasury component, which is determined by the macroeconomic environment. The credit spread is driven by market volatility, highlighting the need for strong investment grade credit ratings to maintain access to the markets on reasonable terms. Despite the interest rate environment, PSE&G utilizes its credit rating and the strong capabilities of its bank group to run a competitive book building process to obtain the lowest-possible price.

Further, the deferral mechanism will apply only to the approved long-term debt balance in this proceeding and therefore the Company—and not customers—bears the risk on its increased interest expense as its outstanding long-term debt balance increases between rate cases.

Q. Are you proposing any other adjustments associated with the embedded cost of long-term debt?

A. Yes. For the Company's future infrastructure investment program ("IIP") rate adjustment filings, such as GSMP II Extension, IAP and the proposed future CEF-EV rate adjustments, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding. Every IIP rate adjustment filing includes an initial forecast that is trued-up with actual results before new rates are implemented, and the actual embedded cost of long-term debt can be updated at that time. In addition, the WACC in the Company's Green Program Recovery Charge ("GPRC") and TAC should be updated monthly, consistent with the monthly return calculation for each program with a return component. For the GPRC, the size of the programs (such as for the Clean Energy Future – Energy Efficiency II filing) have significantly increased, causing a more significant impact on the debt costs to finance that investment. With regard to the TAC, the Company has voluntarily proposed to flow-back tax benefits to customers on an accelerated basis, reducing customer bills in this proceeding, but lowering the Company's cash flow, which impacts the need and timing for additional financing. As a result, it is appropriate to use the actual long-term debt rate in the calculation of the Company's return in those proceedings.

XII. INCENTIVE COMPENSATION

Q. Please briefly describe the Company's compensation philosophy.

A. PSE&G maintains a compensation structure designed to attract and retain a talented and diverse workforce to operate safely, reliably, and cost-effectively. The Company's compensation structure (salary ranges, incentive compensation targets, and related factors) is regularly benchmarked to enable the Company to attract and retain its management team and overall workforce.

Q. Does the Company base part of employee compensation on the achievement of various incentives?

A. Yes. Similar to industry peers and the vast majority of companies, PSE&G has a compensation program that is a mix of fixed base pay and incentive pay. The incentive pay is dependent upon achieving established goals. For PSE&G these goals are primarily operational and customer focused. The incentive pay program is designed to encourage employees to focus on the goals that have enabled PSE&G to achieve the levels of reliability, safety, and operational excellence that I have described previously. Included in test year expenses are approximately $36 million ($19 million for electric and $17 million for gas) associated with incentive compensation for PSE&G as well as the Service Company allocation to PSE&G to support the utility. Of that amount, approximately $11 million ($6 million electric and $5 million gas) is provided to officers and relates to a mix of targets, including operational performance, but mostly weighted towards financial results. Of the remaining $25 million, $16 million ($8 million each for electric and gas) relates to achieving operational metrics and strategic goals, with the remainder related to achieving financial goals, all of which ultimately benefit customers as discussed more fully below.

Q. Please explain why the Board should approve the recovery of PSE&G's incentive compensation at this time.

A. As a preliminary matter, it should be recognized that an incentive compensation program is not a "bonus" program as that term is commonly understood. As discussed more fully below, it is the combination of fixed compensation and variable compensation that permits the Company to provide a level of overall compensation necessary to attract and retain qualified personnel. In addition, while there are certain metrics that might be characterized as "financial," these metrics actually benefit both shareholders and customers. For example, containing O&M costs benefits shareholders in the year(s) costs are contained, but also helps keep down test year costs that are ultimately recovered from customers through rate cases, thereby lowering customer rates from what they otherwise would be. That is an incontestable benefit to customers, and it is the product of properly incented employees and a properly incented management team. Also, meeting earnings targets enables investors to have confidence in the Company, which helps to keep the cost of capital down. Finally, including financial goals in an at-risk compensation program ensures that employees are properly encouraged to attempt to achieve operational goals in a cost-effective manner. So, fundamentally, there is benefit for all parties – including, demonstrably, PSE&G's customers -- when financial targets are achieved. Nevertheless, as the Company demonstrates below, the majority of PSE&G's variable compensation metrics relate to operational metrics that directly benefit customers and the achievement of which produces tangible, positive effects on the service provided by the Company.

Q. How does the Company's incentive compensation structure correlate variable compensation to operational performance?

A. The annual variable compensation structure is designed so that the majority of the targets relate to operational metrics. Those metrics are focused on Reliability (e.g., SAIDI and other metrics), customer satisfaction (J.D. Power scores and other metrics), and other operational metrics. The metrics have two components that are scored – Part A, which is to compare the Company to peers, generally with a target of top quartile performance, and Part B, which measures whether the Company did better than the prior year, driven by PSE&G's focus on Continuous Improvement. As a result, the incentives are clearly aligned with the needs of customers as the metrics are directly focused on providing strong service.

Q. You stated that PSE&G's incentive compensation program employs metrics that directly benefit the Company's customers. Please explain that statement.

A. The "scorecard" that the Company employs to determine incentive compensation contains metrics that directly benefit customers. PSE&G tracks many operational and customer service metrics and approximately 12 of them are directly included in the variable compensation calculation. These include important operational and customer-facing metrics such as SAIDI, gas leaks per mile, damages per locate requests, JD Power Customer Satisfaction surveys of both electric and gas customers, and other measures.

Clearly, therefore, PSE&G's employees are provided incentive compensation if they achieve operational targets that benefit customers. As a result, the Company's incentive compensation program should be fully recoverable because it delivers clear and tangible benefits to our customers.

Q. Is the incentive compensation program an essential component of overall compensation?

A. Yes. Not only are these programs among the most important tools that management uses to attract and retain talent, align interests, incent performance, and ensure the delivery of high-quality service to customers, but the variable compensation structure has also delivered tangible benefits to customers, as described above. The Company's compensation philosophy is to target total compensation at the median of companies it competes with for talent. Without the incentive compensation program, which is a common component of compensation among PSE&G's peers, the Company would need to increase the fixed base salary cost to attract and retain the caliber of talent needed to achieve its goals. Taking that approach would result in a similar overall level of compensation and a similar overall level of prudent labor expense, even if key metric(s) were not achieved in a given year. Using incentive compensation is a more effective means to motivate employees to achieve targeted results.

Q. Does the Company's workforce expect that incentive compensation will be part of the overall package of compensation and benefits?

A. Yes. Today's workforce fully expects that a portion of their compensation will be tied to the attainment of stated performance objectives. To attract and retain top talent, the Company must continue to offer a compensation structure that is, in part, incentive based.

Q. Are there negative consequences associated with the disallowance of some or all of the Company's incentive compensation costs?

A. Yes. Obviously, to the extent a portion of these costs are disallowed, the Company would not be able to recover its cost of service. But there are larger ramifications. PSE&G's overall compensation program, including incentive compensation, seeks to set salaries around the mean of companies with whom it competes for our talented workforce. To the extent these costs were not incurred, the Company would no longer be aligned with industry and regional compensation benchmarks and would therefore expect incremental turnover, inability to attract quality employees, and a deterioration of service over time. The Company's incentive compensation is a prudent cost and PSE&G requests full recovery of its $36 million of incentive compensation expense.

XIII. DEFERRAL REQUESTS – CREDIT AND DEBIT CARD FEES AND IMPLEMENTATION COSTS FOR TIME OF USE RATES

Q. Is the Company proposing an adjustment to reflect a requested change to the treatment of credit card fees?

A. Yes. As demographics change and the percentage of customers using the digital platforms for paying their bills increases, the need to eliminate the charge for credit and debit cards becomes more important. Since 2010, the percent of payments received via check has dropped from over 52% to 17% and continues to decline each year. Currently, while other payment transaction fees are considered normal business expenses and allowed recovery, the credit card and debit card processing fees are not allowed to be recovered through rates, and each is charged as a pass-through fee to customers at the time of payment. This is the number one reason for dissatisfaction as reported by customers when asked about the billing and payments process for PSE&G.

Customers expect seamless electronic payment options. PSE&G provides the ability to pay via its website, mobile app, phone, and text. The Company has expanded customers' ability to communicate and transact business through digital channels and the Board has recognized and encouraged this additional digital access. For payments, these channels lend themselves to payments via credit and debit cards. As the utility industry and technology continues to modernize, payment methods need to as well.

Q. Is there a disparity in the manner the Company treats credit and debit card payments versus other forms of payments?

A. Yes. Within the existing bill and payment options available to customers, there is already a disparity in the unit cost of those transactions, yet credit and debit card fees are the only transaction costs singled out for non-recovery. In-person payments at Customer Service Centers are much more expensive than a mailed check, and sending a paper bill via mail is more expensive than receiving an email, yet PSE&G does not charge individually for these options. The different options are available to all customers who then choose the method that best works for them. The Company proposes treating credit card processing fees as it does the other payment and delivery fees within the billing process, thereby leveling the playing field – among the various payment options.

Q. What is the Company's proposal for credit card transaction fees?

A. The Company proposes to assume the cost for credit card transactions rather than requiring the payment from individuals using a credit or debit card. By assuming the payment, the Company anticipates the cost per transaction will be reduced from the current rate of $3.50 per payment to $2.60. However, this will result in a prudent cost to the utility (just as the cost to process all other forms of payment is prudent) that is not captured in the test year and would not represent the Company's go-forward expenses. Since it is unknown at this time how many customers will pay via credit card once the transaction fee is removed, the Company is proposing to defer those incremental expenses until the next base rate case as participation ramps up. After the conclusion of the next base rate case, the Company will stop the deferral mechanism and the costs would be recovered in the same manner as all other bill processing costs.

Q. Is there another significant cost the Company will occur outside this test year that requires deferral authority?

A. Yes. As discussed in the Direct Testimonies of Mr. Stephen Swetz and Company witness Ahmad Faruqui, the Company is proposing a Pilot Residential and Commercial Time of Use Rate. The TOU rates will utilize AMI to design a rate structure that will encourage customers to shift their usage to off-peak periods, lowering their bills and peak demand on the electric system, which will avoid the need for additional utility infrastructure and generation costs. This is particularly important with the growth in electric vehicles, which can have a significant impact on customer usage and peak demand. To encourage participation, the Company is also proposing a one-year pilot that will refund customers if TOU rates are higher than they would have been charged under RS Rates. However, implementing TOU rates and the ability to compare those rates to the RS rates and issue a refund will require significant changes to the existing billing system, resulting in significant incremental capital and O&M costs that will be incurred after approval of this proceeding.

Q. What is the Company's proposal for the expenditures necessary to implement TOU rates?

A. The Company proposes that the Board provide the Company approval to defer these costs and place them in a regulatory asset as separate and identifiable accounts for recovery of costs deemed prudent in the Company's next base rate case, in the same manner as costs related to the implementation of AMI in the CEF-EC Program. The regulatory asset will include capital costs inclusive of return on the average monthly rate base recorded at PSE&G's pre-tax overall WACC in effect at the time of the deferral. Incremental TOU-related O&M costs will be deferred separately without a return, for recovery in the Company's next base rate case.

The prudency of the TOU Pilot's costs, including those deferred and placed in the regulatory asset, will be reserved for review and determination in the Company's next base rate case.

XIV. TEST YEAR AND REVENUE REQUIREMENTS – ADJUSTMENTS TO BASE ELECTRIC AND GAS DISTRIBUTION RATES

Q. Please describe the test year that is being utilized in this proceeding.

A. The test year in this proceeding is the twelve-month period beginning June 1, 2023 and ending May 31, 2024. The filing consists of five months of actual data (through October 31, 2023) and seven months of estimated data. Actual data is supported by the Company's accounting records, while projected data is based on the Company's financial and capital budget for the period ending May 31, 2024. The Company will update for twelve months of actual data through May 31, 2024 in July 2024, which is consistent with the Company's anticipated rate effective date of September 1, 2024, and ensures the Board and the parties will be able to review twelve months of actual data sufficiently in advance of the estimated rate effective date.

Q. Please discuss the schedules that you are providing to support the revenue requirement.

A. The determination of revenue requirements is premised on the June 2023 through May 2024 test year described above with appropriate *pro forma* adjustments. *Pro forma* adjustments to the test year have been proposed to reflect the expense level of certain items for the twelve months ending August 30, 2025 (the "rate year"), which is the first full year that rates are proposed are anticipated to be effective on September 1, 2024. The costs to be recovered include expenses of running the business (including O&M expenses and taxes) as well as return of and on the capital invested that is necessary to run the business (*i.e.*, depreciation and amortizations, interest expense, and a fair return on equity invested). Plant additions that are expected to be in service within six months beyond the end of the test year (through November 30, 2024) have been included in rate base.

Set forth below is a description of the schedules identified in the introduction section of my testimony. The schedules reflect information for both electric distribution and gas distribution.

Determination of Revenue Requirements—Schedule MPM-02

Q. Are you presenting a schedule that shows the revenue requirement in this case?

A. Yes. Schedule MPM-02 shows the determination of the revenue requirement increase being requested in this proceeding. Based upon rate bases of $9.3 billion and $8.6 billion for electric distribution and gas distribution, respectively, *pro forma* operating income of $326.8 million and $349.6 million for electric and gas, respectively, and a required rate of return of 7.55%, the increase in required revenue requested is $522.1 million for electric distribution and $422.8 million for gas distribution.

Utility Rate Base—Schedule MPM-03

Q. Please describe the schedule depicting the Company's rate base.

A. Schedule MPM-03 presents projected total electric and gas utility rate bases as of May 31, 2024 and November 30, 2024. Electric rate base is expected to be $9.0 billion by May 31, 2024 and $9.3 billion as of November 30, 2024. Gas rate base is expected to be $8.5 billion by May 31, 2024 and $8.6 billion as of November 30, 2024. The rate bases consist primarily of the utility's investment in distribution plant, net of the accumulated provision for depreciation of utility plant plus distribution working capital, accumulated deferred income taxes, the consolidated tax adjustment, and the exclusion of IAP and GSMP II (as extended) investment that will be recovered in a separate rate adjustment proceeding in accordance with the orders in those matters. Rate base also includes the regulatory assets associated with the CEF-EC and CEF-EV investments as described below. Rate base represents the investment necessary to provide safe, adequate, proper, and reliable service to customers and is therefore a crucial factor in setting future distribution rates. The components of the Company's distribution rate bases are supported by Schedules MPM-07 through MPM-18 and will be addressed below.

Revenue Factor—Schedule MPM-06

Q. Are you presenting a schedule that depicts the revenue factor for the electric and the gas operation?

A. Yes. The electric revenue factor utilized by the Company in this proceeding is projected to be 1.3947. The factor includes the 9% State of New Jersey Corporate Business Tax, the 21% Federal income tax, and the assessments for the Board of 0.213045% and the Division of Rate Counsel (Rate Counsel) of 0.050234%. The gas revenue factor is the same rate assuming approval by the BPU of transitioning the gas bad debt from base rates to a new component of the gas SBC. If the recovery of gas bad debt expense through the SBC is not approved, the gas revenue factor should include the uncollectible rate at 1.80% (resulting in a revenue factor of 1.4203). This is the forecasted uncollectible expense as the historic rate has been skewed by the COVID-19 deferral and the significant increase in the reserve as a result of the moratorium on shutoffs.

Utility Plant in Service—Schedule MPM-07

Q. Please describe the schedule showing utility plant in service.

A. The electric utility and gas utility plant in service, as shown on Schedule MPM-07, is estimated to be $12.7 billion and $12.3 billion respectively on May 31, 2024 and $13.1 billion and $12.9 billion respectively on November 30, 2024.

Plant-In-Service Additions from May 31, 2023 through November 30, 2024—Schedule MPM-08

Q. Are you also presenting a schedule that shows additions to plant in service?

A. Yes. Schedule MPM-08 provides the direct additions to plant in-service from the actual June 1, 2023 balance projected through November 30, 2024. Additions are expected to total approximately $1.7 billion for electric and $1.7 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule MPM-09

Q. Please describe the schedule that presents Accumulated Depreciation.

A. Electric and gas plant in service have estimated useful lives, which normally extend over many operating periods. The systematic recovery of these investments is accomplished by the recognition in rates of annual depreciation charges, with the accumulated depreciation used to reduce rate base utility plant investments. This has been, and continues to be, an acceptable way of developing rate base because the accumulated depreciation balance recognizes that these amounts have already been charged to customers.

The accumulated depreciation balance reflects the recognition of annual depreciation charges projected through November 30, 2024 based upon the current BPU-approved electric and gas distribution depreciation rates. Please note that PSE&G is also presenting a study performed by Mr. John Spanos of Gannett Fleming that proposes changes to the existing depreciation rates. The Company has included the annualization of the depreciation expense, described in more detail in schedule MPM-41, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule MPM-10

Q. Is distribution rate base reduced to reflect advances by customers for construction?

A. Yes, it is. Because the costs of construction related to advances made by the Company's electric and gas utility customers are capitalized and included in the distribution rate bases, it is appropriate to reduce distribution plant costs for these advances. As shown on Schedule MPM-10, electric and gas distribution rate base has been reduced by $63.7 million and $24.9 million, respectively, based upon a 13-month average of the most current available actual advances—the period October 2022 through October 2023.

Working Capital

Q. What is "Working Capital?"

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The Company's proposed working capital allowance is $1.2 billion for electric rate base and $672.8 million for gas rate base. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments.

Cash (Lead/Lag) Working Capital

Q. Are the amounts shown for Working Capital supported by any analyses?

A. Yes, they are. The cash (Lead/Lag) working capital allowances reflected on Schedule MPM-03 of $925.7 million and $605.3 million that I have included in the electric and gas rate bases, respectively, are the result of detailed Lead/Lag studies supported by Mr. Michael Adams, in separate testimony and supporting schedules.

Materials and Supplies—Schedule MPM-11

Q. How are Materials and Supplies reflected in the filing?

A. I have included $227.2 million and $67.4 million of materials and supplies necessary for ongoing utility electric and gas operations, respectively, in rate base. This is a representative balance of general store items held in inventory for operating and maintenance and capital purposes. It is derived by taking a 13-month average of the most current available actual balances—the period October 2022 through October 2023.

Prepayments—Schedule MPM-12

Q. Does the Company's filing reflect an allowance for prepayments of costs?

A. Yes, it does. The Company is required to make advance payments for the BPU and Rate Counsel assessments, prior to their being charged to operating expenses. Such prepayments occur every year and therefore require a permanent, ongoing investment by the Company to fund them. Accordingly, I have included the average electric and gas utility prepayment requirements of $0.5 million and $0.1 million, respectively, in rate base. These levels are based upon a 13-month average as of October 2023.

Accumulated Deferred Taxes—Schedule MPM-13

Q. Have you incorporated Accumulated Deferred Income Taxes into your rate base calculation?

A. Yes. Company witness Mr. Pardo discusses Accumulated Deferred Taxes in his testimony. I have incorporated Mr. Pardo's Accumulated Deferred Tax Balance shown on Schedule CP-3. The net accumulated deferred taxes amount to a $1.8 billion reduction to electric rate base and a $1.8 billion reduction to gas rate base. These amounts are based upon the plant in service balances reflected in the respective rate bases as of November 30, 2024. For more details, please see the testimony of Mr. Pardo.

Consolidated Tax Adjustment—Schedule MPM-14

Q. Does the Company's filing recognize the Board's most recent policy concerning Consolidated Tax Adjustment ("CTA")?

A. Yes, it does. The Company believes that, as others representing PSE&G have testified in the past, the imposition of a CTA is a flawed and inappropriate regulatory adjustment. Nevertheless, Company witness Mr. Pardo has calculated a CTA and discusses the basis for that adjustment in his testimony. I have incorporated Mr. Pardo's CTA adjustment as shown on Confidential Schedule CP 5. This adjustment decreases electric distribution rate base by $3.4 million and results in no change to gas distribution rate base due to a cumulative tax loss. For details on the calculation of the Consolidated Tax Adjustment, please see the testimony of Mr. Pardo.

IAP Rate Base Adjustment-Schedule MPM-15

Q. Why is there an IAP Adjustment?

A. The IAP program was approved for recovery of investments through a separate mechanism outside of a base rate case. Because the Company has IAP investments that will occur during the test year but will be recovered through an IAP rate adjustment proceeding outside of the test year in accordance with the IAP Order, the IAP investments must be excluded from rate base to avoid double recovering the investment.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the IAP that will be recovered in a separate IAP rate adjustment proceeding, which is expected to be investment placed in service from February 1, 2024 through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric and gas rate base has been reduced by $27.9 million and $29.3 million, respectively, as of November 30, 2024.

CEF-EC Rate Base Adjustment-Schedule MPM-16

Q. What is the CEF-EC rate base adjustment?

A. The CEF-EC rate base adjustment accounts for the CEF-EC regulatory asset on CEF-EC related plant in-service that is or will be placed into service within six months of the end of the test year. Paragraph 22 of the CEF-EC stipulation approved by the Board states: "the Company will book a regulatory asset ("CEF-EC Regulatory Asset") comprised of: 1) its CEF-EC capital investment ("CEF-EC Investment Deferral"), and 2) the associated stranded costs

("Stranded Cost Deferral") on legacy meters in accordance with paragraphs 23 and 24 below."[21]

Q. How is the CEF-EC Regulatory Asset calculated?

A. Per paragraph 23 of the CEF-EC stipulation approved by the Board, the CEF-EC Investment Deferral is calculated as:

> *CEF-EC Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[22]

Paragraph 13 of the Stipulation authorized the two phases of AMI deployment, which incorporate a geographic strategic approach designed to maximize installation efficiency and customer satisfaction.[23] To minimize the inefficiencies of dispersed meter deployment, these phases have proceeded geographically regardless of the age of any particular legacy meter at the time of its removal. Paragraph 24 of the CEF-EC stipulation stated the Stranded Cost Deferral will be calculated as:

> *Stranded Cost Deferral = Accelerated Depreciation Expense associated with Legacy Meters – Depreciation Expense on Legacy Meters at the Approved Depreciation Rate as Determined in the 2018 Base Rate Case*[24]

Further, paragraph 28 of the CEF-EC Stipulation states,

> The CEF-EC Program investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance as described in paragraph 23 above. For ratemaking purposes, depreciation expense will not begin on CEF-EC Program investment until reflected in base rates in the Next Base Rate Case. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EC Program investment regulatory asset.[25]

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[21] CEF-EC Order at Stipulation ¶ 22.
[22] *Id.* ¶ 23.
[23] *Id.* ¶ 13.
[24] *Id.* ¶ 24.
[25] *Id.* ¶ 28.

Q. Did the CEF-EC Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 21 of the CEF-EC Stipulation states:

> The Parties also agree that reasonable and prudent costs associated with the CEF-EC Program investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the *Board's Elizabethtown* Water.[26]

Q. Does the CEF-EC Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 26 of the Stipulation approved by the Board states "The Parties agree that the revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EC Regulatory Asset defined in paragraphs 22-24 above to the extent that is deemed prudent."[27] The recovery "of" the CEF-EC Regulatory asset is described below in Schedule MPM-47. This adjustment to rate base is to account for the return "on" the CEF-EC Regulatory Asset derived from the CEF-EC investment in the same manner as Allowance for Funds Used During Construction ("AFUDC") is added to rate base when a project is placed into service.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $230.0 million as of November 30, 2024.

CEF-EV Rate Base Adjustment-Schedule MPM-17

Q. What is the CEF-EV Adjustment?

A. The CEF-EV rate base adjustment accounts for the CEF-EV regulatory asset on CEF-EV related plant in-service that is or will be placed into service within six months of the end of the test year. As stated in paragraph 22 of the CEF-EV Stipulation approved by the Board:

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[26] *Id.* ¶ 21 (internal footnote omitted).
[27] *Id.* ¶ 26.

> The Company will invest in EV infrastructure as described in paragraph 15 above. Until being rolled into base rates, as described further below, those CEF-EV related capital costs shall be deferred and placed in a regulatory asset, for recovery in the Company's next base rate case, to be filed no later than January 1, 2024 (the "Next Base Rate Case").[28]

Q. How is the CEF-EV Regulatory Asset calculated?

A. Per paragraph 26 of the CEF-EV stipulation approved by the Board, the CEF-EV Investment Deferral is calculated as:

> *CEF-EV Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[29]

Further, paragraph 30 of the CEF-EV Stipulation states,

> The CEF-EV investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance. For ratemaking purposes, depreciation expense will not begin on CEF-EV investment until reflected in base rates in the Next Base Rate Case or any subsequent base rate case or rate case reopener. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EV investment regulatory asset.[30]

Q. Did the CEF-EV Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 23 of the CEF-EV Stipulation states:

> The reasonable and prudent costs associated with the CEF-EV investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the Board's *Elizabethtown Water* standards.[31]

Q. Does the CEF-EV Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 28 of the Stipulation approved by the Board states

> The revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EV Regulatory Asset defined in paragraph 25 above. The return on the deferred investment will be based on the

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[28] CEF-EV Order at Stipulation ¶ 22.
[29] *Id.* ¶ 26.
[30] *Id.* ¶ 30.
[31] *Id.* ¶ 23 (internal footnote omitted).

approved WACC in the Next Base Rate Case, or subsequent base rate case, adjusted for income taxes and BPU and Rate Counsel assessment fees. The return of the deferred investment will be based on the Board approved depreciation/amortization rates determined in the Next Base Rate Case or any other appropriate period approved by the Board.[32]

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $43.2 million as of November 30, 2024.

Q. Does the CEF-EV Order discuss recovery for investment beyond the end of the six-month post-test-year period?

A. Yes. The CEF-EV Order allows for annual rate adjustment filings to recover investments placed into service more than six months after the end of the test year. The Company's proposal for the methodology and schedule of those annual rate adjustment filings is set forth in the testimony of Mr. Swetz.

GSMP II Extension Rate Base Adjustment-Schedule MPM-18

Q. Why is there a GSMP II Extension Adjustment?

A. The GSMP II Extension was approved for recovery of investments through a separate mechanism outside of a base rate case.[33] Because the Company has GSMP II Extension investments that will occur during the test year but will be recovered through a GSMP II Extension rate adjustment proceeding outside of the test year in accordance with the GSMP II Extension Order, the GSMP II Extension investments must be excluded from rate base to avoid double recovering the investment.

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[32] *Id.* ¶ 28.
[33] *See* GSMP II Extension Order.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the GSMP II Extension that will be recovered in a separate GSMP II Extension rate adjustment proceeding, which is expected to be investment placed in service through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, gas rate base has been reduced by $256.1 million as of November 30, 2024.

Electric and Gas Distribution Operating Income

Q. Please describe the schedules for Electric and Gas Operating Income.

A. Schedules MPM-19 through MPM-28 present a complete picture of PSE&G's electric and gas distribution operations. These schedules contain sales, distribution operating revenues, and number of billed customers by class of business for the electric and gas distribution businesses of the Company. Also included are O&M expenses by primary function, depreciation and amortization, taxes other than income taxes, and current and deferred income taxes. Schedule MPM-19 presents the income statements for these business segments. This information has been provided for the twelve-months ending May 31, 2024, which is the test year based on five months of actual data and seven months of forecast.

Pro-forma Distribution Operating Income—Schedule MPM-29

Q. Are you proposing to adjust Test Year Operating Income?

A. Yes. Schedule MPM-29 is a summary of *pro forma* adjustments to the test year electric and gas utility operating income. These *pro forma* adjustments adjust test period operating income for known or measurable changes to expense and income levels so as to reflect the expected expense and income levels for the rate year, which is the first twelve months after new rates are set as a result of this proceeding. Adoption of these adjustments by the Board will provide the Company with a realistic opportunity to earn a reasonable return on its electric and gas investment when the rates are in effect.

The Company's revenue requirements determination includes 21 adjustments to its test period electric distribution operating income. The *pro forma* adjustments reduce the test period electric operating income by $142.2 million after-tax. On the gas distribution side there are 19 adjustments that reduce the test period operating income by $110.3 million. There are 24 *pro forma* adjustments in total (16 combined electric and gas adjustments, 5 electric only and 3 gas only). Each of the *pro forma* adjustments will be discussed in more detail below.

Adjustment No. 1: Wages—Schedule MPM-30

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of $7.4 million and $6.7 million for electric and gas, respectively, represent the adjustment to the test year to reflect wage increases applicable to the rate year. These increases are to the labor costs applicable to Bargaining Unit employees; Management, Administrative, Secretarial, and Technical ("MAST") employees; and Service Company employees charged to PSE&G. The increases are based on labor charges to electric distribution and gas distribution during the test year.

The Company recently negotiated Bargaining Union increases for the twelve-month period ending May 31, 2024 as well as the Rate Year ending August 31, 2025. These contracts contain agreed-upon annual wage increases of 3.0% each year. The wage increases are effective on May 1, 2024 and May 1, 2025. For MAST employees, average wage increases of 3.5% were implemented in March of 2023. While no final decisions have been reached as to future years, best current projections based on benchmarking survey data are a 4% increase effective in March 2024 and a 4% increase in March of 2025.

The Board should continue its consistent practice of recognizing the importance of test year labor adjustments. The Company's employees are a critical element in meeting the service and reliability needs of our customers, and this adjustment to the test year ensures the Company's rates will reasonably reflect the cost of this workforce when rates are in effect.

Adjustment No. 2: Payroll Taxes—Schedule MPM-31

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.5 million and $0.5 million for electric and gas, respectively, result from the increase to operating expense associated with payroll taxes consistent with the wage adjustments made above. This adjustment reflects increases in the Federal Insurance Contribution Act Tax ("FICA") for increases in taxable wages and taxable wage ceiling levels. Based on the Company's historic average, additional payroll taxes for the wage adjustment in Schedule MPM-30 are calculated utilizing a composite 6.88% tax rate.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—MPM-32

Q. Please describe the Interest Synchronization Adjustment.

A. The Board, in the past, has adopted an adjustment to synchronize the Federal income tax savings associated with interest in the test year with the tax savings based on interest calculated using the weighted cost of debt in the capital structure utilized to support rate base.

As can be seen on Schedule MPM-32, the interest-bearing components of PSE&G's capitalization supporting rate base produce synchronized interest expenses of $3.7 million more than the interest expense in the test year for electric and $4.5 million more than interest expense in the test year for gas, resulting in tax savings of $1.0 million for electric and tax savings of $1.3 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule MPM-33

Q. Please describe the adjustment for Pension and Fringe Benefits.

A. The adjustments to test year operating income for pension costs and fringe benefits amount to a decrease of $20.9 million for electric and $15.6 million for gas, reflecting the expected change in these costs over the test period amounts. The adjustment encompasses expenses associated with pensions, OPEB, medical, dental, thrift, long-term disability, insurance, and workers compensation for employees providing support services to PSE&G.

As noted earlier, PSE&G has pension income that is increasing operating revenues and decreasing the revenue increase requested in this case, despite PSE&G not having access to the pension income. The pension and OPEB *pro forma* adjustments reflect the expected income for 2024, which will be known and measurable before the end of the test year. While the 2024 pension income is expected to be less than in the test year, pension and OPEB are still projected to be income, reducing the revenue requirement paid by customers.

While the Company has also previously described the numerous steps PSE&G has taken to reduce fringe benefit costs, these costs have continually increased, in particular medical costs. Other fringe benefit costs are escalated based primarily on contract renewals, including those for benefit administration costs, compliance, and consulting work.

The Board should continue to recognize that the Company's employees are critical to meeting the service and reliability needs of our customers. The ability to offer a package of wages and benefits will allow the Company to attract and retain the skilled employees that are needed. The revenue to cover those costs must be provided.

Adjustment No. 5: Electric / Gas Company Owned Life Insurance ("COLI") Interest Expense—Schedule MPM-34

Q. Please describe the adjustment required to reflect Company Owned Life Insurance.

A. In an effort to reduce a portion of the expenses associated with certain employee benefit plans, PSE&G has invested in COLI policies. COLI is a corporate owned investment in cash value life insurance, which provides an income stream to the Company.

A portion of the Company's workforce is covered by policies with the Company as owner and beneficiary. The cash value of the insurance contracts earns a return, which the Company utilizes to offset benefit expenses. The Company, as owner, is permitted to borrow against the policy during its life without interfering with the policy's accumulation of earnings. The policy provides life insurance proceeds upon the death of the insured sufficient to settle any outstanding loans.

The earnings associated with the growth in the policy's cash surrender value have produced a net credit to benefits expense. For the test year, the credit to Administrative and General Expense combined with tax savings is $4.1 million for electric distribution and $1.2 million for gas distribution. Interest expense on funds borrowed from the policies is directly related to the $2.1 million for electric distribution and $0.7 million for gas distribution in benefits attributable to the policies. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $2.1 million for electric and $0.7 million for gas, thereby reducing operating income to properly account for all aspects, both benefits and costs, of the COLI.

Adjustment No. 6: Weather Normalization —Schedule MPM-35

Q. Is an adjustment necessary to reflect the results of Weather Normalization?

A. Yes. This pro-forma adjustment is required to adjust test year actual results to reflect normal weather based on weather patterns over a 20-year period as measured at Newark Liberty International Airport. Because actual weather patterns during the time the rates will be in effect are assumed to be normal, this adjustment to the test year is an appropriate rate setting procedure. The use of unadjusted weather-related actual sales levels would result in overstating or understating the revenue requirement compared to normal. Schedule MPM-35 shows the adjustments necessary to reflect normal weather for the period June 2023 through May 2024. This schedule shows a comparison of the distribution revenue for the actual twelve months with that based upon normal weather. Distribution revenue represents the base rate revenue from the sale of a kWh, kW, or therm, excluding clauses and supply. In order to adjust the actual results to a normal sales level, a decrease to test period revenue of $3.5 million for electric is required since the first five months of the test year, June 2023 to October 2023, was warmer than normal. This is the same weather impact included in the billing determinants data in the testimony of Mr. Swetz. An increase to test period revenue of $4.4 million for gas, is required since the first five months of the test year, June 2023 to October 2023, was warmer than normal.

Adjustment No. 7: Gains/Losses on Sales of Property—Schedule MPM-36

Q. Please describe the adjustment to reflect Gains/Losses on Sales of Property.

A. This adjustment allocates one-half of the gain on sales of property, net of associated income taxes, to customers based on a five-year average. The use of a five-year average provides a representative amount of gains for ratemaking purposes, avoiding the distortion that would occur if an abnormally high or low level of gains is recognized in the test period. The Company has included the five-year average ending May 2024 as representative and appropriate for this proceeding. The adjustment to operating income for the customers' share of the five-year average gain is an increase of $42,000 for electric and $207,000 for gas.

Adjustment No. 8: Real Estate Taxes—Schedule MPM-37

Q. Is the Company presenting an adjustment for Real Estate Taxes?

A. Yes. This adjustment of $0.6 million decrease for electric and $0.3 million increase for gas adjusts the test year operating expense to be representative of the level of property tax expense that is expected to be accrued in the twelve-month period following the date new base rates go into effect. The increase in property tax expense between the rate year and the test year is consistent with actual experience. Accordingly, electric and gas operating income is reduced by the aforementioned amounts.

Adjustment No. 9: Insurance Premiums—Schedule MPM-38

Q. Please describe the adjustment necessary to reflect the Company's Insurance Expense.

A. There are items for which PSE&G carries outside insurance policies (*i.e.*, Corporate Property, Excess Liability Insurance, and Director's & Officers Insurance) for which it pays premiums of approximately $6.9 million for electric and $4.0 million for gas for the year. This adjustment before taxes of $671,000 for electric and $366,000 for gas increases the test year operating expense by $483,000 and $263,000 and is representative of the level of insurance expense that is expected to be accrued in the rate year. The increase in insurance expense between the rate year and the test year reflects input from our insurance carriers and actual experience.

Adjustment No. 10: ASB Margin—Schedule MPM-39

Q. Please describe the ASB margin adjustments that are necessary to reflect the proposed treatment of PSE&G's appliance service business.

A. For the reasons described in Section VI above, the Company is proposing that Gas ASB margins be accounted for as 50% above the line, in the same manner as is done for Electric ASB Margin. After adjusting for tax effect this results in a decrease to operating income of $14.8 million for gas.

Adjustment No. 11: TSG-NF Margin—Schedule MPM-40

Q. Please describe the adjustment for the TSG-NF Margin.

A. A reduction to gas operating income in the amount of $0.7 million is being made. This adjustment is discussed in the testimony of Mr. Swetz.

Adjustment No. 12: Depreciation Annualization and Proposed Rate Change — Schedule MPM-41

Q. Is the Company proposing adjustments related to Depreciation Annualization and to reflect a proposed change in depreciation rates?

A. Yes. This adjustment is to allow for the recovery of the depreciation expense associated with the total investment in Plant in Service in rate base approved in this proceeding. As described above, the Company is requesting rate base as of November 30, 2024. Essentially, the depreciation expense in the test year represents the depreciation expense on the average plant in service in the test year. The actual depreciation expense as a result of this rate case proceeding will be a full year's depreciation expense on the approved plant in service as of November 30, 2024. To arrive at the appropriate depreciation expense for the approved plant in-service, the depreciation expense in the last month used to determine rate base for this proceeding (November 30, 2024) is annualized by multiplying the balance by twelve. The difference between the annualized depreciation expense and the Test Year depreciation expense produces the pre-tax adjustment. It should be noted that the proposed annualization of depreciation expense is also incorporated in Accumulated Depreciation (Schedule MPM-09) as a rate base deduction using a mid-year convention. Therefore, this adjustment is simply to sync depreciation expense with the approved rate base balance. Accordingly, test year expense is increased $4.0 million for electric and $27.1 million for gas.

In addition, the Company has proposed new electric and gas distribution depreciation rates, including cost of removal, based on an Electric Depreciation Study and a Gas Depreciation Study, supported by the testimony of Mr. Spanos.

The proposed depreciation rates have also been annualized for estimated electric and gas plant balances for the month prior to the rate year. The difference between the annualized rate year expense based on the proposed rates versus the annualized expense based on current rates is an additional pre-tax adjustment, which increases depreciation expenses by $57.9 million for electric and by $72.2 million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $44.5 million for electric and $71.4 million for gas.

Adjustment No. 13: Test Year Amortization Adjustments - Schedule MPM-42

Q. Please describe the adjustment of Test Year Amortizations.

A. This schedule is to adjust operating income for amortizations that are ending during the test year. In the 2018 base rate case, the Signatory Parties agreed to an amortization of $65.605 million over a five-year period addressing all of the deferral recovery requests in that proceeding.[34] The 2018 base rate case was approved as effective November 1, 2018, so the five year amortization ended on October 31, 2023. This adjustment is to remove the amortization expense from the start of the test year through October 31, 2023 so that the test year operating income does not reflect any of this expense that will not occur going forward. In addition, test year operating income reflects amortization expense on IT capital. However, recovery of IT capital associated with the CEF-EE Program and Community Solar Program are recovered separately through the Green Program Recovery Charge. As a result, the IT amortization for these programs must be excluded from base rate recovery. The adjustment represents an increase in operating income of $17.3 million for electric and $5.9 million for gas.

Adjustment No. 14: Rate Case & Management Audit Expenses– Schedule MPM-43

Q. How does the Company propose to treat rate case expense?

A. This adjustment seeks recovery of all prudently incurred rate case and management audit expenses. As the Company was required to submit this rate case as a result of the GSMP II Order, among other Orders, it is appropriate for the Board to allow for recovery of the expenses required to complete the filing. The Company is seeking to remove all rate case expenses incurred during the test year and recover those expenses as a regulatory asset over a three-year period. In addition, regulated utilities are subject to Management and Affiliate Transaction audits and an audit of PSE&G commenced in 2021. The BPU awarded the audit contract to Overland Consulting for $1.6 million. The Company deferred the $1.6 million cost of the audit paid to Overland and is seeking recovery of the regulatory asset in this proceeding, also over a three-year period. The total adjustment for both rate case expenses and the recovery

[34] 2018 Rate Case Order at Stipulation ¶ 6.

of the management audit costs represents a decrease in operating income of $189,000 for electric and $150,000 for gas.

Adjustment No. 15: ES II / IAP Revenue Adjustment – Schedule MPM-44

Q. Please discuss the adjustment the Company proposes for ES II and IAP rate adjustments during and after the test year.

A. The Company proposes an adjustment to increase test year Operating Income so it reflects the full annual impact of the ES II and IAP rate adjustments rolled into rates during the test year.

Q. Why is this adjustment necessary?

A. When the ES II and IAP rate adjustments occur, base rates will be increased to collect the annual revenue requirement of the rate adjustment. The revenue increase will be added to current rates at the time this proceeding is concluded, which will include the annualized impact of the ES II and IAP adjustments in the test year. The revenue increase from the rate case will be based on the operating income during the test year. For the ES II and IAP rate adjustments that occur during the test year, base rates will be increased for the annual revenue requirement, but only a portion of the revenues from that rate increase will be captured in the test year operating revenue as these rate adjustments become effective. This adjustment is necessary to adjust test year operating revenue to coincide with base rates at the conclusion of the rate case.

Q. What are the ES II and IAP rate adjustments that have occurred and will occur during this proceeding?

A. In accordance with the ES II Order, rates changed November 1, 2023 as a result of the fourth rate adjustment filing (Rate Adjustment #4) based on investments through July 31, 2023.[35] The fifth rate adjustment filing (Rate Adjustment #5), was submitted on November 1, 2023 based on anticipated investment through December 31, 2023 for rates effective May 1, 2024.[36] Rate Adjustment #5 will be updated with actual investment through December 31, 2023 by February 21, 2024.

The first IAP rate adjustment was submitted on November 1, 2023 for rates effective May 1, 2024 based on plant in service through January 31, 2024.[37] The first Rate Adjustment will be updated with actual investment through January 31, 2024 by February 21, 2024.

Q. How was the adjustment calculated?

A. The goal of the adjustment is to ensure that test year Operating Income reflects the current rates in effect before the proposed rates from this proceeding are implemented. For the base rate changes implemented during the test year, this adjustment multiplies the rates for the adjustment by the billing determinants for the test year prior to the implementation date. Using IAP as an example, the adjustment would apply the increase in base rates from the IAP change effective May 1, 2024 to the actual weather normalized billing determinants from June 1, 2023 through April 30, 2024. An adjustment is not needed from May 1, 2024 forward as the revenue will already be included in the test year operating revenue as a result of the IAP rate adjustment.

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[35] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23050273, Decision and Order Approving Stipulation (October 25, 2023).

[36] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23110784 (filed November 1, 2023).

[37] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Infrastructure Advancement Program*, BPU Docket No. ER23110783 (filed November 1, 2023).

Q. Is an adjustment required for the rate adjustments prior to the start of the test year?

A. No. For all adjustments prior to the start of the test year, the full annual revenue associated with the adjustments will be reflected in the operating income in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $30.2 million for electric and $0.0 million for Gas.

Adjustment No. 16: BGS Administration Labor Costs to the BGS Charge Reconciliation Charge – Schedule MPM-45

Q. Why is the Company proposing an adjustment to O&M Expense related to labor costs for Basic Generation Service ("BGS") administration?

A. This adjustment is being made to remove labor costs associated with the administration of BGS from the Company's operations and maintenance expense as it will be recovered within the Company's reconciliation charge upon the conclusion of this proceeding.

Q. Why is this adjustment necessary?

A. On July 15, 2020, the BPU issued an Order of Implementation, effective July 25, 2020, requiring Electric Distribution Companies ("EDCs") to file a plan for implementation of the fourteen (14) accepted recommendations from the Final Report filed by Liberty Consulting Group, Inc.[38]. One of the accepted recommendations was to track direct administrative costs that are common across all EDCs and related to the provision of BGS, and recover those costs through their BGS Reconciliation charge(s) following their respective next base rate cases. As

[38] *I/M/O the Request for Proposal for a Financial Audit of the New Jersey Electric Distribution Companies' Basic Generation Administrative Expense and Other Related Expenses*, Docket No. EA17010004, Order of Implementation (July 15, 2020).

this is PSE&G's first base rate case since that Board Order, this adjustment is being made to remove these BGS related administrative expenses from the test year so that they can be recovered through the BGS reconciliation charge.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $220,000 for electric.

Adjustment No. 17: Gas Bad Debt in SBC – Schedule MPM-46

Q. Please discuss the adjustment the Company is proposing for gas bad debt.

A. As discussed in Section VIII above, the Company proposes to move base rate recovery for gas bad debt expenses from base rates to a new Social Programs component of the Gas SBC, the same recovery mechanism utilized for recovery of Electric bad debt expenses. As a result of the proposed adjustment, operating income will increase by $24.8 million for gas. This adjustment will be offset by the proposed gas bad debt SBC component discussed in further detail in the testimony of Mr. Swetz.

Adjustment No. 18: Clean Energy Future-Energy Cloud Amortization – Schedule MPM-47

Q. What is the CEF-EC regulatory asset?

A. As discussed above in Schedule MPM-16, the Company was authorized to record a regulatory asset comprised of its capital investment (CEF-EC Investment Deferral) and associated stranded costs (Stranded Cost Deferral).[39] In addition, as stated in paragraph 27 of the CEF-EC stipulation, "The Parties agree that the Company will defer incremental AMI-related O&M costs associated with the CEF-EC implementation into a separate regulatory

[39] CEF-EC Order at Stipulation ¶ 22.

asset ("CEF-EC O&M Regulatory Asset"), without a return, for recovery in the Company's Next Base Rate Case."[40]

Q. Is there any adjustment to the CEF-EC regulatory asset balances the Company wants to discuss?

A. Yes. Meter testing costs originally classified as part of the $707 million of estimated CEF-EC Program investment were determined not to qualify for capitalization and were recorded as an expense. The Company excluded the meter testing expenditures from the CEF-EC Program investment, so the Company is not earning a return on this investment, but the Company is seeking recovery of these prudently incurred expenditures that were always a component of the CEF-EC Program.

Q. How is the Company seeking to recover the CEF-EC regulatory assets?

A. For the CEF-EC Investment Deferral, the Company proposes to recover the regulatory asset over the life of the meter, which for AMI was set at 20 years in the CEF-EC Order.[41] For non-AMI meters, the depreciation rate (inclusive of cost of removal) is approximately 10%, so the Company proposes a 10 year recovery period for the Stranded Cost Deferral.[42] The Company will include the unamortized balance as a component of the Company's rate base in any future subsequent base rate case in accordance with the CEF-EC Order that allowed for a return of and on the regulatory asset.[43] The Company proposes to recover the Meter Testing expenses and CEF-EC O&M Regulatory Asset over a five-year period, the same period

[40] *Id.* ¶ 27.
[41] CEF-EC Order ¶ 23(c).
[42] See 2018 Rate Case Order at Stipulation Attachment B at 1 (showing total depreciation rate of 9.89 for electric account 370.00 ("Meters")).
[43] *Id.* ¶ 26.

proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $21.9 million for electric.

Adjustment No. 19: Clean Energy Future-Energy Cloud Revenue Reduction – Schedule MPM-48

Q. Is there an additional *pro forma* adjustment associated with the CEF-EC Program?

A. Yes. The implementation of AMI is forecasted to result in operational efficiencies and reductions in O&M. Some savings are reflected in the test year. See testimony of Mr. Johnson. However, the majority of these savings will occur after the AMI implementation is complete, which is not expected until after the end of the test year in this proceeding. In accordance with the CEF-EC Order, the Company is proposing an adjustment to its revenue request in this proceeding only to account for future O&M savings as a result of AMI that are not reflected in the test year.[44] This adjustment will not be implemented in a subsequent base rate case in which the actual O&M savings from the AMI implementation will be reflected in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income (after taxes) will increase by $5.1 million for electric.

[44] CEF-EC Order ¶ 19.

Adjustment No. 20: Clean Energy Future – Electric Vehicle Amortization – Schedule MPM-49

Q. What is the CEF-EV regulatory asset?

A. As discussed above in Schedule MPM-17, the Company was authorized to record a regulatory asset on its CEF-EV investment ("CEF-EV Regulatory Asset"). In addition, as stated in paragraph 29 of the CEF-EV Stipulation, "The Company will defer incremental CEF-EV-related O&M costs as described above in paragraph 15 ("CEF-EV O&M Regulatory Asset"), with a monthly carrying charge at the prior month 2-year treasury rate plus 60 basis points, for recovery in the Company's Next Base Rate Case."[45]

Q. How is the Company seeking to recover the CEF-EV Regulatory Asset?

A. For the CEF-EV Regulatory Asset, the Company proposes to recover the non-IT related expenditures over a 30-year life, the approved life in the deferral mechanism for Make-Ready – Service Upgrade Pole to Meter investment and the approximate weighted average life of the non-IT related investments. For the regulatory asset associated with the IT expenditures and the CEF-EV O&M Regulatory Asset, the Company proposes a five-year life, the same period proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

[45] CEF-EV Order at Stipulation ¶ 29.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $4.3 million for electric.

Adjustment No. 21: Conservation Incentive Program Accrual Adjustment – Schedule MPM-50

Q. Please discuss the adjustment the Company proposes for the Conservation Incentive Program Accrual Adjustment.

A. The Company proposes an adjustment to test year Operating Income so that it removes the impact of the CIP accrual recorded during the test year.

Q. Why is this adjustment necessary?

A. As discussed above, the CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $62.9 million for electric and $9.6 million for gas.

Adjustment No. 22: TAC Return Reset – Schedule MPM-51

Q. Please describe the need for the TAC Return adjustment being proposed.

A. Pursuant to the Order in PSE&G's last base rate case, PSE&G and the parties to that Order agreed that the return on the increase in rate base related excess deferred income taxes, including the ADIT associated with the Historic SHARE, will be reset at the conclusion of subsequent rate cases.[46] In accordance with that agreement, the Company will be resetting the return on the unamortized balances. The ADIT in the rate case will reflect all of the tax flowbacks that PSE&G has previously refunded to customers, resulting in increased rate base and return on rate base. Accordingly, the Company's operating revenue will reflect the earnings realized through the TAC flowbacks. The proposed adjustment will have a neutral effect as the adjustment will allow PSE&G to reduce the earnings in the TAC and move them to base rates through this proceeding.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $19.3 million for electric and $22.6 million for gas. However, this impact will be offset in the TAC.

Adjustment No. 23: Deferred Compensation & Severance Expense Adjustment – Schedule MPM-52

Q. Please discuss the adjustment the Company is proposing for Deferred Compensation & Severance Expense.

A. This adjustment is to increase operating income for the impact of deferred compensation and severance payments incurred during the test year. As noted in Section IV

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[46] 2018 Rate Case Order ¶ 20.

above, the Company initiated a Voluntary Exit Incentive Program for non-represented employees that will result in the voluntary retirement of 185 utility and service company employees by December 31, 2023. The Company offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks. In addition, there are non-recurring deferred compensation costs outside of the VIEP. This *pro forma* is to remove the severance and deferred compensation expense and any associated tax savings so that there is no impact to customers from the severance and deferred compensation payments.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $1.2 million for electric and $0.7 million for gas.

Adjustment No. 24: Tax Impact of Bad Debt – Schedule MPM-53

Q. Please discuss the adjustment the Company is proposing for the tax impact of bad debt.

A. This schedule is to adjust tax expense to remove the impact of the pandemic and the moratorium on bad debt expense. The tax impact on bad debt is calculated as the bad debt expense less write-offs, multiplied by the federal tax rate. In general, the bad debt expense and write-offs move in sync (such that the reserve will increase as write-offs increase and vice versa), resulting in a minimal impact to tax expense. However, this trend reversed during the pandemic when the reserve increased significantly, while write-offs declined, resulting in a tax expense increase. While the Company deferred its increase in the bad debt reserve during the moratorium for recovery in the COVID-19 proceeding, it did not defer the significant negative tax impact. The impact will reverse over time as the write-offs and bad debt reserve get back in sync. However, the test year does reflect a tax benefit from bad debt as the write-offs are forecasted to exceed the bad debt expense. This adjustment will ensure the tax impact of bad debt as a result of the moratorium is excluded from customer rates (since the negative impact during the moratorium was absorbed by the Company and excluded from the COVID-19 deferral request, and thus the offsetting positive benefit must be excluded from the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $8.7 million for electric and $4.9 million for gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CREDENTIALS
OF
MICHAEL P MCFADDEN
DIRECTOR OF SALES AND REVENUE FORECASTING

I have been employed at PSEG for 15 years, serving in a number of financial positions in the company and since June 2021 have been the Director of Sales and Revenue Forecasting. In this capacity, I am responsible for overseeing the development of the PSE&G's ("the Company") electric and gas sales and revenue forecast, including the forecasted electric and gas Conservation Incentive Program ("CIP") accrual, and supervising the development of the weather impacts on the sales and revenue forecast.

Prior to joining PSE&G, I held various positions at the New Jersey Board of Public Utilities as a Utility Rate Analyst and Administrative Analyst in the Bureaus of Rates and Tariffs, where I analyzed electric and gas utility filings on a variety of matters, including cost recovery proceedings, base rate cases, management audits and any other proceedings addressing electric and gas utility rates.

I joined PSE&G in 2008 as a Senior Regulatory Analyst before being promoted to a Principal Staff Regulatory Analyst in 2012. In my roles as an analyst, I supported the development of the electric and gas cost of service study in the 2009 base rate case as well as the update of numerous revenue requirement models in support of the Company's Solar Pilot Recovery Charge and Green program Recovery Charge components and was the lead analyst supporting the Energy Strong I Program.

In 2014 I was temporarily promoted to Manager of Pricing and Economics before being transitioned to the Manager of Revenue Requirements. In my role as manager of

Revenue Requirements, I managed over 20 rate orders applicable to PSE&G including infrastructure investments, renewable energy, energy efficiency programs and societal benefits programs, several of which I have designed complex financial cost recovery models. I also managed the calculation of revenue requirements and filing and settlement of the PSE&G 2018 base rate case. Additionally, I managed business responses to discovery, prepared written testimony and oversaw post-approval implementation activities. I also supported the Connecticut contract for differences on the New Haven Peaking plants, supporting the development of the cost of service revenue requirement.

In my role as manager of Revenue Requirements I submitted pre-filed direct cost recovery testimony, as well as oral testimony, before the State of Connecticut Public Utilities Regulatory Authority ("PURA" or the "Authority") in multiple dockets. In my current role as Director of Sales and Revenue Forecasting, I have provided written cost recovery testimony supporting the Company's electric and gas CIP filings.

I hold a Bachelor of Science degree in Finance from the Rutgers University School of Business, and a Master's in Business Administration from Excelsior College.

EXHIBIT P-2
SCHEDULE MPM-02

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 9,287,110	$ 8,646,212	$ 17,933,322
Rate of Return	7.55%	7.55%	7.55%
Operating Income Requirement	$ 701,177	$ 652,789	$ 1,353,966
Pro-Forma Operating Income	$ 326,842	$ 349,631	$ 676,473
Operating Income Deficiency	$ 374,334	$ 303,158	$ 677,493
Revenue Factor	1.3947	1.3947	
Revenue Requirements	**$ 522,084**	**$ 422,815**	**$ 944,899**

EXHIBIT P-2
SCHEDULE MPM-03

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,661,725	13,072,325
Plant Held for Future Use	495	495
Accumulated Depreciation Reserve	(3,203,264)	(3,300,289)
Customer Advances	(63,736)	(63,736)
Net Plant	9,395,220	9,708,796
Working Capital:		
Cash (Lead/Lag)	925,712	925,712
Materials and Supplies	227,212	227,212
Prepayments	500	500
Net Working Capital	1,153,424	1,153,424
Deferred Taxes	(1,776,640)	(1,817,082)
Consolidated Tax Adjustment	(3,394)	(3,394)
IAP	(14,816)	(27,894)
CEF-EC	174,420	230,037
CEF-EV	31,957	43,223
Total Electric Rate Base	**8,960,172**	**9,287,110**

GAS RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,322,346	12,883,854
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,724,785)	(2,838,624)
Customer Advances	(24,945)	(24,945)
Net Plant	9,572,712	10,020,381
Working Capital:		
Cash (Lead/Lag)	605,322	605,322
Materials and Supplies	67,365	67,365
Prepayments	116	116
Net Working Capital	672,803	672,803
Deferred Taxes	(1,736,979)	(1,761,557)
Consolidated Tax Adjustment	-	-
IAP	(314)	(29,283)
CEF-EC	-	-
CEF-EV	-	-
GSMP II EXT	(6,906)	(256,132)
Total Gas Rate Base	**8,501,315**	**8,646,212**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$ 13,661	44.29%	4.02% *	1.78%
Customer Deposits	66	0.21%	1.40%	0.00%
Common Equity	17,121	55.50%	10.40%	5.77%
Total	$ 30,848	100.00%		7.55%

* this is a forecasted rate as of May 31, 2024 due to the current interest rate environment, but will be replaced with the actual May 31, 2024 rate in the 12+0 update.

EXHIBIT P-2
SCHEDULE MPM-05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
10/31/2023
INCLUDING NET UNAMORTIZED PREMIUM - INCLUDING AMOUNT DUE WITHIN ONE YEAR

PSE&G LONG TERM DEBT	COST OF BOND YIELD BASIS	PRINCIPAL AMOUNT OUTSTANDING	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT)	PLUS NET UNAMORTIZED SELLING EXPENSE	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE	PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	WEIGHT IN % OF PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	COST IN PERCENT
SERIES DUE 6/1/37	8.053%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0546%	0.0044%
SERIES DUE 7/1/37	5.033%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0552%	0.0028%
SERIES D DUE 7/1/35	5.373%	$250,000,000.00	($306,250.00)	($834,457.60)	($1,140,707.60)	$248,859,292.40	1.8216%	0.0979%
SERIES D DUE 12/1/36	5.838%	$250,000,000.00	($463,005.88)	($950,037.44)	($1,413,043.32)	$248,586,956.68	1.8196%	0.1062%
SERIES E DUE 5/1/37	5.922%	$350,000,000.00	($307,494.76)	($1,340,363.04)	($1,647,857.80)	$348,352,142.20	2.5499%	0.1510%
SERIES G DUE 11/1/2039	5.501%	$250,000,000.00	($428,914.11)	($1,162,475.75)	($1,591,389.86)	$248,408,610.14	1.8183%	0.1000%
SERIES G DUE 3/1/2040	5.638%	$300,000,000.00	($782,873.36)	($1,405,578.46)	($2,188,451.82)	$297,811,548.18	2.1800%	0.1229%
SERIES H DUE 5/1/2042	4.076%	$450,000,000.00	($1,785,316.54)	($2,410,980.42)	($4,196,296.96)	$445,803,703.04	3.2633%	0.1330%
SERIES H DUE 9/1/2042	3.765%	$350,000,000.00	($1,070,939.82)	($2,000,109.65)	($3,071,049.47)	$346,928,950.53	2.5395%	0.0956%
SERIES H DUE 1/1/2043	3.924%	$400,000,000.00	($1,629,397.25)	($2,249,412.64)	($3,878,809.89)	$396,121,190.11	2.8996%	0.1138%
SERIES I DUE 3/15/2024	3.915%	$250,000,000.00	($796.96)	($66,280.56)	($67,077.52)	$249,932,922.48	1.8295%	0.0716%
SERIES I DUE 6/1/2044	4.147%	$250,000,000.00	($1,628,169.04)	($1,566,199.15)	($3,194,368.19)	$246,805,631.81	1.8066%	0.0749%
SERIES J DUE 8/15/2024	3.339%	$250,000,000.00	($35,397.76)	($150,860.94)	($186,258.70)	$249,813,741.30	1.8286%	0.0611%
SERIES J DUE 11/15/2024	3.275%	$250,000,000.00	($124,722.89)	($200,757.06)	($325,479.95)	$249,674,520.05	1.8276%	0.0598%
SERIES K DUE 5/15/2025	3.179%	$350,000,000.00	($55,530.33)	($156,374.45)	($211,904.78)	$349,788,095.22	2.5604%	0.0814%
SERIES K DUE 5/1/2045	4.172%	$250,000,000.00	($893,159.63)	($1,440,237.23)	($2,333,396.86)	$247,666,603.14	1.8129%	0.0756%
SERIES K DUE 11/1/2045	4.249%	$250,000,000.00	($187,103.67)	($1,478,963.41)	($1,666,067.08)	$248,333,932.92	1.8178%	0.0772%
SERIES K 3.80% DUE 2046	3.913%	$550,000,000.00	($1,818,438.28)	($3,609,683.28)	($5,428,121.56)	$544,571,878.44	3.9862%	0.1560%
SERIES L 2.25% DUE 2026	2.443%	$425,000,000.00	($401,773.97)	($885,528.83)	($1,287,302.80)	$423,712,697.20	3.1015%	0.0758%
SERIES L 3.00% DUE 2027	3.200%	$425,000,000.00	($439,804.20)	($1,136,377.26)	($1,576,181.46)	$423,423,818.54	3.0994%	0.0992%
SERIES L 3.60% DUE 2047	3.689%	$350,000,000.00	($205,204.79)	($2,486,005.53)	($2,691,210.32)	$347,308,789.68	2.5423%	0.0938%
SERIES M 3.70% DUE 2028	3.917%	$375,000,000.00	($641,963.24)	($1,267,991.72)	($1,909,954.96)	$373,090,045.04	2.7310%	0.1070%
SERIES M 4.05% DUE 2048	4.178%	$325,000,000.00	($1,643,538.20)	($2,391,141.83)	($4,034,680.03)	$320,965,319.97	2.3494%	0.0982%
SERIES M 3.65% DUE 2028	3.817%	$325,000,000.00	($25,182.15)	($1,128,313.74)	($1,153,495.89)	$323,846,504.11	2.3705%	0.0905%
SERIES M 3.20% DUE 2029	3.412%	$375,000,000.00	($810,563.35)	($1,545,930.19)	($2,356,493.54)	$372,643,506.46	2.7277%	0.0931%
SERIES M 3.85% DUE 2049	3.939%	$375,000,000.00	($54,222.55)	($2,856,979.94)	($2,911,202.49)	$372,088,797.51	2.7237%	0.1073%
SERIES M 3.20% DUE 2049	3.320%	$400,000,000.00	($2,491,704.45)	($3,045,893.77)	($5,537,598.22)	$394,462,401.78	2.8874%	0.0959%
SERIES N 2.45% DUE 2030	2.638%	$300,000,000.00	($427,471.00)	($1,409,414.80)	($1,836,885.80)	$298,163,114.20	2.1825%	0.0576%
SERIES N 3.15% DUE 2050	3.240%	$300,000,000.00	($403,265.59)	($2,378,567.26)	($2,781,832.85)	$297,218,167.15	2.1756%	0.0705%
SERIES N 2.70% DUE 2050	2.798%	$375,000,000.00	($1,352,376.39)	($3,017,591.86)	($4,369,968.25)	$370,630,031.75	2.7130%	0.0759%
SERIES N 2.05% DUE 2050	2.156%	$375,000,000.00	($2,672,893.72)	($2,950,553.33)	($5,623,447.05)	$369,376,552.95	2.7038%	0.0583%
SERIES N 0.95% DUE 2026	1.264%	$450,000,000.00	($466,847.03)	($1,382,574.10)	($1,849,421.13)	$448,150,578.87	3.2804%	0.0415%
SERIES N 3.00% DUE 2051	3.085%	$450,000,000.00	($401,911.65)	($3,697,312.72)	($4,099,224.37)	$445,900,775.63	3.2640%	0.1007%
SERIES N 1.90% DUE 2031	2.081%	$425,000,000.00	($808,606.21)	($2,421,466.07)	($3,230,072.28)	$421,769,927.72	3.0873%	0.0643%
SERIES P 3.10% DUE 2032	3.296%	$500,000,000.00	($786,115.43)	($3,420,147.31)	($4,206,262.74)	$495,793,737.26	3.6292%	0.1196%
SERIES P 4.90% DUE 2032	5.090%	$400,000,000.00	($236,324.39)	($2,786,491.71)	($3,022,816.10)	$396,977,183.90	2.9058%	0.1479%
SERIES P 4.650% DUE 2033	4.842%	$500,000,000.00	($437,265.89)	($3,578,198.44)	($4,015,464.32)	$495,984,535.68	3.6306%	0.1758%
SERIES P 5.125% DUE 2053	5.234%	$400,000,000.00	($231,318.54)	($3,624,300.22)	($3,855,618.75)	$396,144,381.25	2.8998%	0.1518%
SERIES P 5.200% DUE 2033	5.399%	$500,000,000.00	($634,808.01)	($3,613,620.21)	($4,248,428.22)	$495,751,571.78	3.6289%	0.1959%
SERIES P 5.450% DUE 2053	5.574%	$400,000,000.00	($984,280.15)	($3,553,707.79)	($4,537,987.94)	$395,462,012.06	2.8948%	0.1614%
TOTAL PSE&G LONG TERM DEBT		**$13,765,000,700.00**	**($28,074,951.18)**	**($75,600,879.70)**	**($103,675,830.89)**	**$13,661,324,869.11**	**100.0000%**	**3.8669%**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.213045	0.2130
Rate Counsel Assessment Rate	0.050234	0.0502
Income before State of NJ Bus. Tax	99.7367	99.7367
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7604	90.7604
Federal Income Taxes	19.0597	19.0597
Return	71.7007	71.7007
Revenue Factor	**1.3947**	**1.3947**

EXHIBIT P-2
SCHEDULE MPM-07

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,674,130	$ 12,661,725
Total Direct Additions	1,239,559	503,178
Total Transfers to Plant In-Service	(543)	0
Retirements:		
Distribution	(160,935)	(75,858)
General	(17,557)	(4,620)
Intangible	0	0
Common Plant	(72,929)	(12,100)
Total Retirements	(251,421)	(92,578)
Total Electric Utility Plant In-Service	**$ 12,661,725**	**$ 13,072,325**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,353,980	$ 12,322,346
Total Direct Additions	1,118,238	606,680
Total Transfers to Plant In-Service	(72)	0
Retirements:		
Production - Gas	0	0
Storage	0	0
Transmission	0	0
Distribution	(72,939)	(30,000)
General	(13,846)	(3,806)
Intangible	(3,345)	(1,466)
Common Plant	(59,670)	(9,900)
Total Retirements	(149,801)	(45,172)
Total Gas Utility Plant In-Service	**$ 12,322,346**	**$ 12,883,854**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-08

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADDITIONS TO ELECTRIC PLANT IN-SERVICE
($000)

	Test Year May 31, 2024		Six-Months Ending November 30, 2024	
Distribution	$	1,093,658	$	362,881
General		84,479		29,704
Intangible		23,456		98,456
Customer Operations		37,815		12,138
Land & Land Rights		151		-
Total Direct Additions	**$**	**1,239,559**	**$**	**503,178**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year May 31, 2024		Six-Months Ending November 30, 2024	
Production - Gas	$	1,029	$	-
Storage		492		-
Transmission		3,601		939
Distribution		1,025,170		558,725
General		56,677		23,639
Intangibles		329		13,446
Customer Operations		30,939		9,931
Land & Land Rights		1		0
Total Direct Additions	**$**	**1,118,238**	**$**	**606,680**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEPRECIATION OF ELECTRIC UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 3,165,769	$ 3,203,264
Distribution	278,111	137,039
General	27,212	14,178
Customer Operations	26,361	11,827
Total Charge to Depreciation Expense	331,684	163,044
Amortization of Intangibles	5,542	6,296
Total Depreciation Expense	337,225	169,340
Retirements	(251,421)	(92,578)
Cost of Removal (Net)	(110,068)	(46,563)
Other	61,759	35,845
Net Increase	37,495	66,044
Annualization of Depreciation		30,981
Balance - Accumulated Depreciation	**$ 3,203,264**	**$ 3,300,289**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 2,669,747	$ 2,724,785
Production - Gas	2	1
Storage	418	316
Transmission	1,362	748
Distribution	203,982	108,306
General	19,766	10,606
Customer Operations	21,569	9,676
Total Charge to Depreciation Expense	247,099	129,653
Amortization of Intangibles	2,362	2,121
Total Depreciation Expense	249,461	131,774
Retirements	(149,801)	(45,172)
Cost of Removal (Net)	(49,603)	(26,197)
Other	4,981	3,784
Net Increase	55,038	64,190
Annualization of Depreciation		49,649
Balance - Accumulated Depreciation	$ 2,724,785	$ 2,838,624

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ADVANCES FOR CONSTRUCTION - ELECTRIC DISTRIBUTION *
($000)

Extension of Electric Lines	$	(63,736)
Total Electric Customer Advances for Construction	**$**	**(63,736)**

CUSTOMER ADVANCES FOR CONSTRUCTION - GAS DISTRIBUTION *
($000)

Extensions/Deposits	$	(24,945)
Total Gas Customer Advances for Construction	**$**	**(24,945)**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 227,212	$ 67,365
Total Materials and Supplies	**$ 227,212**	**$ 67,365**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

EXHIBIT P-2
SCHEDULE MPM-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	500	116
Total Prepayments	**$ 500**	**$ 116**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year May 31, 2024		Balance Ending November 30, 2024	
Electric	$	(1,776,640)	$	(1,817,082)
Gas	$	(1,736,979)	$	(1,761,557)

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas	Total
CTA Adjustment	(3,394)	-	$ (3,394)

EXHIBIT P-2
SCHEDULE MPM-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

IAP RATE BASE ADJUSTMENT (ELECTRIC & GAS)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	13,218	25,291
Cost of Removal Expenditures	2,186	3,497
Accumulated Depreciation	51	241
Accumulated Deferred Taxes	(639)	(1,135)
Total	14,816	27,894
Rate Base Reduction	**(14,816)**	**(27,894)**
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	-	29,107
Cost of Removal Expenditures	437	437
Accumulated Depreciation	-	13
Accumulated Deferred Taxes	(123)	(274)
Total	314	29,283
Rate Base Reduction	**(314)**	**(29,283)**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EC RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
CEF-EC Investment Deferral:		
Deferred Depreciation	21,108	33,991
Deferred Interest	7,364	11,218
Carrying Charge Interest	838	1,492
Deferred Equity Return	29,405	44,792
Carrying Charge Return	2,406	4,282
Total	61,121	95,775
Stranded Cost Deferral:		
Accelerated Depreciation Expense	202,006	245,631
Depreciation Expense As Approved	(88,706)	(111,369)
Total	113,300	134,262
Rate Base Addition	**174,420**	**230,037**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EV RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Unamortized Investment	24,651	32,611
Depreciation & Amortization	3,491	4,744
Deferred Return	3,244	4,930
Carrying Charges	571	939
Total	31,957	43,223
Rate Base Addition	**31,957**	**43,223**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GSMPII EXT RATE BASE ADJUSTMENT (GAS ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	6,650	245,793
Cost of Removal Expenditures	350	12,936
Accumulated Depreciation	17	732
Accumulated Deferred Taxes	(111)	(3,330)
Total	6,906	256,132
Rate Base Reduction	**(6,906)**	**(256,132)**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC	**May 31, 2024**
Electric Operating Revenues	$ 4,218,045
Electric Operating Expenses:	
Operation Expense	$3,219,646
Maintenance Expense	$127,615
Depreciation Expense	$311,407
Amortization of Limited Term Plant	$22,160
Amortization of Property Losses	$17,686
Taxes Other Than Income Taxes	$25,686
Income Taxes	$24,851
Accretion Expense	$0
Total Electric Utility Operating Expenses	$3,749,050
Electric Utility Operating Income	$ 468,994

GAS	**May 31, 2024**
Gas Operating Revenues	$2,324,389
Gas Operating Expenses:	
Operation Expense	$1,559,327
Maintenance Expense	38,305
Depreciation Expense	233,901
Amortization of Limited Term Plant	14,209
Amortization of Regulatory Asset	7,835
Amortization of Property Losses	22,953
Amortization of Excess cost of removal	-
Taxes Other Than Income Taxes	17,288
Income Taxes	(29,384)
Total Gas Utility Operating Expenses	$1,864,434
Gas Utility Operating Income	$459,955
Net Utility Operating Income	$928,949

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DISTRIBUTION SALES BY CLASS OF BUSINESS
(KWh/Therms - 000)

Line		May 31, 2024 Electric	Gas
1	Residential	13,420,021	1,538,177
2	Commercial	21,847,389	964,063
3	Industrial	3,498,950	84,152
4	Firm Transportation Service		22,704
5	Non-Firm Transportation Service		128,549
6	Cogeneration Interruptible		25,942
7	Cogeneration Contracts		0
8	Contract Service Gas		684,425
9	Street Lighting	334,899	711
10	Total Sales to Customers	39,101,260	3,448,722
11	Interdepartmental	7,533	671
12	Total Sales	39,108,793	3,449,393

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

Line		Electric	May 31, 2024 Gas	Total
1	Residential	$ 2,508,564	$ 1,562,300	$ 4,070,864
2	Commercial	1,959,080	679,883	2,638,963
3	Industrial	219,388	44,702	264,090
4	Firm Transportation Service		3,876	3,876
5	Non-Firm Transportation Service		23,297	23,297
6	Cogeneration Interruptible		11,307	11,307
7	Cogeneration Contracts		-	0
8	Contract Service Gas		7,720	7,720
9	Street Lighting	84,809	601	85,410
10	Total Revenue from Sales to Customers	$ 4,771,841	$ 2,333,685	$ 7,105,526
11	Interdepartmental	1,127	384	1,511
12	Total Revenue from Sales	$ 4,772,968	$ 2,334,069	$ 7,107,036

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

Line		May 31, 2024 Electric	Gas
1	Residential	1,999,028	1,712,253
2	Commercial	302,889	154,037
3	Industrial	8,106	5,796
4	Firm Transportation Service		30
5	Non-Firm Transportation Service		153
6	Cogeneration Interruptible		11
7	Cogeneration Contracts		0
8	CSG		20
9	Street Lighting	10,919	16
10	Total Customers	2,320,943	1,872,316
11	Interdepartmental	1	1
12	Total Customers	2,320,944	1,872,317

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		May 31, 2024
Other Power Supply Expenses:		
Purchased Power	$	2,541,467
System Control/Load Dispatch	$	5
Total Other Power Supply Expenses	$	2,541,472
Distribution		
Operation	$	52,237
Maintenance		127,615
Total Distribution	$	179,852

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	1,148,595
Fuel Gas - Raw Materials		(46,078)
Other Gas Purchases		(208)
Other Gas Supply Expenses		273
Total Gas Supply	$	1,102,582
Gas Production		
Operation	$	-
Maintenance		1,574
Total Gas Production	$	1,574
Other Power Generation		
Liquefied petroleum gas expenses		485
Total Other Power Generation	$	485
Other Storage		
Operation	$	636
Maintenance		2,397
Total Other Storage	$	3,033
Total Production Expenses	$	1,107,674
Transmission		
Operation	$	137
Maintenance		4,087
Total Transmission	$	4,223
Distribution		
Operation	$	97,578
Maintenance		30,247
Total Distribution	$	127,825

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

	May 31, 2024		
	Electric	**Gas**	**Total**
Customer Accounts Expenses			
Operation:			
Meter Reading Expenses	$ 17,127	$ 12,790	$ 29,916
Customer Records and Collection Expenses	$ 82,663	$ 65,285	$ 147,948
Uncollectible Accounts	$ 93,118	$ 34,512	$ 127,630
Misc. Customer Accounts Expenses	$ 148,056	$ (2,166)	$ 145,890
Total Customer Accounts Expenses	$ 340,964	$ 110,421	$ 451,385
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 158,595	$ 136,311	$ 294,906
Misc. Cust. Service and Info. Expenses	$ 1,969	$ 1,564	$ 3,532
Total Cust. Service and Info. Expenses	$ 160,563	$ 137,874	$ 298,438
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 567	$ 453	$ 1,020
Misc. Sales Expenses	$ 105	$ 86	$ 190
Total Sales Expenses	$ 671	$ 539	$ 1,210
Total Customer Accounts and Information	$ 502,199	$ 248,834	$ 751,033

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

	May 31, 2024		
	Electric	**Gas**	**Total**
Salaries & Wages	$ 8,316	$ 8,624	$ 16,940
Supplies & Expenses	10,120	8,412	18,532
Outside Services	78,638	65,527	144,165
Property Insurance	1,714	292	2,007
Injuries and Damages	12,981	12,225	25,205
Pensions & Fringe Benefits	(9,139)	2,519	(6,620)
Regulatory Expenses	14,304	5,238	19,542
Duplicate Charge	(3,498)	(772)	(4,271)
General Advertising	2,364	1,854	4,218
Other Miscellaneous General	2,886	2,397	5,282
Rents	5,054	2,759	7,813
Maintenance	0	-	0
Total Administrative and General Salaries & Expenses	$ 123,738	$ 109,075	$ 232,813

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		May 31, 2024
	Depreciation	
1	Electric	$311,407
	Amortization	
2	Electric	$39,846
	Total Electric Depreciation and Amortization	**$351,252**

GAS

Line		May 31, 2024
	Depreciation	
1	Gas	$233,901
	Amortization	
2	Gas	$44,997
	Total Gas Depreciation and Amortization	**$278,898**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

Line		May 31, 2024		
		Electric	**Gas**	**Total**
1	Real Estate	$ 13,586	$ 4,607	$ 18,194
2	FICA	316	333	648
3	State Unemployment	11,406	11,950	23,356
4	Federal Unemployment	55	58	113
5	Miscellaneous Municipal and State Taxes	323	339	663
6	Total	$ 25,686	$ 17,288	$ 42,974

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

		May 31, 2024	
	Electric	**Gas**	**Total**
Net Income Taxes	$ 24,851	$ (29,384)	$ (4,533)

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#		Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 468,994**	**$ 459,955**	**$ 928,949**
#	**Pro-Forma Adjustments:**	**Schedule #**			
1	Wages	MPM-30	$ (7,362)	$ (6,747)	$ (14,109)
2	Payroll Taxes	MPM-31	(506)	(464)	(970)
3	Interest Synchronization (Tax Savings)	MPM-32	1,030	1,267	2,297
4	Pension & Fringe Benefits	MPM-33	(20,935)	(15,611)	(36,546)
5	COLI Interest Expense	MPM-34	(2,120)	(728)	(2,848)
6	Weather Normalization	MPM-35	(3,500)	4,424	924
7	Gains/Losses on Sales of Property	MPM-36	42	207	249
8	Real Estate Taxes	MPM-37	(617)	329	(288)
9	Insurance	MPM-38	(483)	(263)	(746)
10	ASB Margin	MPM-39	-	(14,762)	(14,762)
11	TSGNF Margin Sharing	MPM-40	-	(748)	(748)
12	Depreciation Rate Change	MPM-41	(44,544)	(71,386)	(115,930)
13	Test Year Amortization Adjustments	MPM-42	17,276	5,933	23,209
14	Rate Case & Management Audit Expenses	MPM-43	(189)	(150)	(339)
15	Energy Strong II / IAP Revenue Adjustment	MPM-44	30,209	-	30,209
16	BGS Admin Charge To Recon	MPM-45	220	-	220
17	Gas Bad Debt Adjustment	MPM-46	-	24,801	24,801
18	CEF-EC Amortization	MPM-47	(21,862)	-	(21,862)
19	CEF-EC Revenue Reduction	MPM-48	5,096	-	5,096
20	CEF-EV Amortization	MPM-49	(4,303)	-	(4,303)
21	CIP Revenue Accrual Adjustment	MPM-50	(62,862)	(9,597)	(72,460)
22	TAC Revenue Accrual Adjustment	MPM-51	(19,250)	(22,628)	(41,877)
23	Deferred Compensation & Severance	MPM-52	1,200	682	1,882
24	Tax Impact of Bad Debt Adjustment	MPM-53	(8,693)	(4,884)	(13,577)
	Total Pro-Forma Adjustments		**$ (142,152)**	**$ (110,324)**	**$ (252,476)**
Total Pro-Forma Distribution Operating Income			**$ 326,842**	**$ 349,631**	**$ 676,473**

EXHIBIT P-2
SCHEDULE MPM-30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 4,868	$ 4,651	$ 9,519
MAST Employees	3,115	2,976	6,091
Service Company Employees Charged to PSE&G	2,258	1,758	4,015
Operating Expense Increase before Taxes	$ 10,240	$ 9,385	$ 19,625
Income Taxes	2,879	2,638	5,517
Operating Income Increase (Decrease) After Taxes	**$ (7,362)**	**$ (6,747)**	**$ (14,109)**

EXHIBIT P-2
SCHEDULE MPM-31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 335	$ 320	$ 654
MAST Employees	214	205	419
Service Company	155	121	276
Operating Expense Increase before Taxes	$ 704	$ 645	$ 1,349
Income Taxes	198	181	379
Operating Income Increase (Decrease) After Taxes	**$ (506)**	**$ (464)**	**$ (970)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 3
Interest Synchronization (Tax Savings)
($000)

	Percent	Embedded Cost	Weighted Cost	
Electric Rate Base				$ 9,287,110
Debt Components:				
Long Term Debt	44.29%	4.02%	1.78%	
Customer Deposits	0.21%	1.40%	0.00%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 165,615
Less: Test Period Interest Expense				161,951
Net Interest Expense Increase / (Decrease)				$ 3,664
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,030

	Percent	Embedded Cost	Weighted Cost	
Gas Rate Base				$ 8,646,212
Debt Components:				
Long Term Debt	44.29%	4.02%	1.78%	
Customer Deposits	0.21%	1.40%	0.00%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 154,186
Less: Test Period Interest Expense				149,680
Net Interest Expense Increase / (Decrease)				$ 4,506
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,267

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 4
Pension and Fringe Benefits
($000)

	Electric	Gas	Total
Rate Year			
Pensions	$ (7,869)	$ (5,909)	$ (13,777)
Pensions - Service Company	$ 3,148	$ 2,669	$ 5,817
OPEB	$ (1,098)	$ (940)	$ (2,038)
OPEB - Service Company	$ 369	$ 322	$ 690
Medical	$ 20,197	$ 19,844	$ 40,041
Medical - Service Company	$ 3,999	$ 3,283	$ 7,282
Dental	$ 656	$ 644	$ 1,300
Dental - Service Company	$ 158	$ 130	$ 289
Thrift	$ 5,050	$ 4,961	$ 10,011
Thrift - Service Company	$ 1,350	$ 1,108	$ 2,458
Long Term Disability	$ 371	$ 364	$ 735
Long Term Disability - Service Company	$ 134	$ 110	$ 244
Group Life Insurance	$ 196	$ 192	$ 388
Group Life Insurance - Service Company	$ 71	$ 59	$ 130
Workers Compensation	$ 2,397	$ 2,355	$ 4,752
Workers Compensation - Service Company	$ 98	$ 81	$ 179
Benefits Other	$ 2,270	$ 2,230	$ 4,500
Benefits Other - Service Company	$ 475	$ 390	$ 865
	$ 31,972	$ 31,894	$ 63,866
Less: Test Year			
Pensions	$ (21,136)	$ (15,716)	$ (36,852)
Pensions - Service Company	$ 2,346	$ 1,899	$ 4,245
OPEB	$ (11,830)	$ (9,773)	$ (21,602)
OPEB - Service Company	$ 184	$ 159	$ 344
Medical	$ 17,914	$ 18,984	$ 36,897
Medical - Service Company	$ 3,840	$ 3,046	$ 6,886
Dental	$ 621	$ 649	$ 1,270
Dental - Service Company	$ 148	$ 118	$ 266
Thrift	$ 4,654	$ 4,855	$ 9,509
Thrift - Service Company	$ 1,221	$ 969	$ 2,190
Long Term Disability	$ 361	$ 379	$ 740
Long Term Disability - Service Company	$ 126	$ 100	$ 225
Group Life Insurance	$ 173	$ 182	$ 355
Group Life Insurance - Service Company	$ 58	$ 46	$ 104
Workers Compensation	$ 1,726	$ 1,808	$ 3,533
Workers Compensation - Service Company	$ 35	$ 28	$ 63
Benefits Other	$ 2,114	$ 2,215	$ 4,330
Benefits Other - Service Company	$ 295	$ 233	$ 528
	$ 2,851	$ 10,179	$ 13,030
Increase in Test Year Operating Expenses	$ 29,121	$ 21,715	$ 50,836
Income Taxes	$ 8,186	$ 6,104	$ 14,290
Operating Income Increase (Decrease) After Taxes	**$ (20,935)**	**$ (15,611)**	**$ (36,546)**

EXHIBIT P-2
SCHEDULE MPM-34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric	Gas	Total
Net Credit in Test Year			
Administrative & General Expenses	(3,737)	(1,063)	(4,800)
Tax Savings on COLI	(386)	(133)	(518)
Total Benefit	(4,123)	(1,196)	(5,318)
Interest Charges	2,120	728	2,848
Net Benefit	$ (2,003)	$ (468)	$ (2,470)
Operating Income Increase (Decrease) After Taxes	**$ (2,120)**	**$ (728)**	**$ (2,848)**

EXHIBIT P-2
SCHEDULE MPM-35

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas	Total
Actual Distribution Revenues	$ 984,919	$ 905,399	$ 1,890,317
Weather Normalized Distribution Revenues	$ 980,050	911,552	1,891,603
Increase (Decrease) in Test Year Margin Revenue	$ 4,869	$ (6,154)	$ (1,285)
Income Taxes	1,369	(1,730)	(361)
Operating Income Increase (Decrease) After Taxes	$ (3,500)	$ 4,424	$ 924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 7
Gains/Losses on Sales of Property
($000)

	Electric	Gas	Total
Five-Year Average - Book Gain/(Loss)	$ 116	$ 577	$ 693
Income Taxes	33	162	195
Net Income/(Loss)	$ 83	$ 415	$ 498
Operating Income Increase (Decrease) After Taxes	**$ 42**	**$ 207**	**$ 249**

EXHIBIT P-2
SCHEDULE MPM-37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 8
Real Estate Taxes
($000)

	Electric	Gas	Total
Rate Year Property Taxes	$ 14,444	$ 4,150	$ 18,594
Test Year Property Taxes	$ 13,586	$ 4,607	$ 18,194
Operating Expense Increase Before Taxes	$ 858	$ (457)	$ 400
Income Taxes	241	(129)	113
Operating Income Increase (Decrease) After Taxes	**$ (617)**	**$ 329**	**$ (288)**

EXHIBIT P-2
SCHEDULE MPM-38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 9
Insurance
($000)

	Electric	Gas	Total
Insurance Premium Expense	$ 6,933	$ 4,047	$ 10,981
Test Year Insurance Premium Expense	6,262	3,682	9,943
Operating Expense Increase Before Taxes	$ 671	$ 366	$ 1,037
Income Taxes	189	103	292
Operating Income Increase (Decrease) After Taxes	**$ (483)**	**$ (263)**	**$ (746)**

EXHIBIT P-2
SCHEDULE MPM-39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric		Gas		Total	
ASB Margin by Appliance	$	50,528	$	41,067	$	91,595
ASB Margin % Above-the-Line		50%		50%		
Above the Line ASB Margin	$	25,264	$	20,533	$	45,798
ASB Margin in Test Year	$	25,264	$	41,067	$	66,331
ASB Above-the-Line Margin	$	-	$	(20,533)	$	(20,533)
Income Taxes		-		(5,772)		(5,772)
Operating Income Increase (Decrease) After Taxes	**$**	**-**	**$**	**(14,762)**	**$**	**(14,762)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 11
TSG-NF Margin - Gas
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (1,041)	$ (1,041)
Income Taxes	-	293	293
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (748)**	**$ (748)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 315,435	$ 261,017	$ 576,451
Test Year Depreciation Expense	$ 311,407	$ 233,901	$ 545,308
Annualization of Current Depreciation Rates	$ 4,028	$ 27,115	$ 31,143
Depreciation Expense at Proposed Rates	$ 373,368	$ 333,200	$ 706,568
Operating Expense Increase (Decrease) for Proposed Rates	$ 57,933	$ 72,184	$ 130,117
Operating Income Increase (Decrease) Before Taxes	$ (61,961)	$ (99,299)	$ (161,260)
Income Taxes	$ (17,417)	$ (27,913)	$ (45,330)
Operating Income Increase (Decrease) After Taxes	**$ (44,544)**	**$ (71,386)**	**$ (115,930)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 13
Test Year Amortization Adjustments
($000)

	Electric	Gas	Total
Test Year Amortizations			
BRC Settlement	$ 20,040	$ 7,296	$ 27,335
Community Solar	$ 164	$ -	$ 164
CEF-EE IT	$ 3,828	$ 957	$ 4,784
Test Year Amortizations Total	$ 24,031	$ 8,253	$ 32,284
Operating Expense Increase Before Taxes	$ (24,031)	$ (8,253)	$ (32,284)
Income Taxes	$ (6,755)	$ (2,320)	$ (9,075)
Operating Income Increase (Decrease) After Taxes	**$ 17,276**	**$ 5,933**	**$ 23,209**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 14
Rate Case & Management Audit Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 244	$ 244	$ 488
Management Audit Expenses	$ 880	$ 720	$ 1,600
Amortization Period	3	3	3
Annual Amortization	$ 375	$ 321	$ 696
Test Year Rate Case Expense	$ 112	$ 112	$ 224
Operating Expense Decrease Before Taxes	$ (263)	$ (209)	$ (472)
Income Taxes	$ (74)	$ (59)	$ (133)
Operating Income Increase (Decrease) After Taxes	**$ (189)**	**$ (150)**	**$ (339)**

EXHIBIT P-2
SCHEDULE MPM-44

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 15
Energy Strong II / IAP Revenue Adjustment
($000)

	Electric	Gas	Total
ESII Roll-In #4 (Annualizing Revenue from Jun23 - Oct23)	8,792	-	8,792
IAP Roll-In #1 (Annualizing Revenue from Jun23 - Mar24)	6,256	-	6,256
ESII Roll-In #5 (Annualizing Revenue from Jun23 - Apr24)	26,973	-	26,973
Operating Revenue Increase Before Taxes	42,022	-	42,022
Income Taxes	(11,812)	-	(11,812)
Operating Income Increase (Decrease) After Taxes	**$ 30,209**	**$ -**	**30,209**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 16
BGS Administrative Expense Adjustment
($000)

	Electric	Gas	Total
BGS Administrative Expense	$ (307)	$ -	$ (307)
Operating Expense Decrease Before Taxes	$ (307)	$ -	$ (307)
Income Taxes	(86)	-	(86)
Operating Income Increase (Decrease) After Taxes	**$ 220**	**$ -**	**$ 220**

EXHIBIT P-2
SCHEDULE MPM-46

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 17
Gas Bad Debt Adjustment
($000)

	Electric	Gas	Total
Gas Bad Debt	$ -	$(34,499)	$ (34,499)
Operating Expense Decrease Before Taxes	$ -	$(34,499)	$ (34,499)
Income Taxes	-	(9,698)	(9,698)
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ 24,801**	**$ 24,801**

EXHIBIT P-2
SCHEDULE MPM-47

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Amortization of CEF-EC Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EC Regulatory Assets			
CEF-EC Monthly Investment Deferral	$ 95,775	$ -	$ 95,775
Meter Testing O&M	$ 18,250	$ -	$ 18,250
Stranded Cost Deferral	$ 134,262	$ -	$ 134,262
O&M Regulatory Asset	$ 35,440	$ -	$ 35,440
Total CEF-EC Regulatory Assets	$ 283,726	$ -	$ 283,726
Amortization Period			
CEF-EC Monthly Investment Deferral	20	0	20
Meter Testing O&M	5	0	5
Stranded Cost Deferral	10	0	10
O&M Regulatory Asset	5	0	5
Annual Amortization			
CEF-EC Monthly Investment Deferral	$ 4,789	$ -	$ 4,789
Meter Testing O&M	$ 3,650	$ -	$ 3,650
Stranded Cost Deferral	$ 13,426	$ -	$ 13,426
O&M Regulatory Asset	$ 7,088	$ -	$ 7,088
Total Annual Amortization	$ 28,953	$ -	$ 28,953
Carrying Charge:			
Average Deferred Balance During Test Year	$ 26,845	$ -	$ 26,845
Deferred Tax Benefit	$ (7,546)	$ -	$ (7,546)
Average Net of Tax Deferred Cost Balance	$ 19,299	$ -	$ 19,299
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 1,457	$ -	$ 1,457
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 30,410	$ -	$ 30,410
Income Taxes	$ 8,548	$ -	$ 8,548
Operating Income Increase (Decrease) After Taxes	**$ (21,862)**	**$ -**	**$ (21,862)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
CEF-EC Revenue Reduction
($000)

	Electric	Gas	Total
Future Savings Revenue Offset	$ (7,088)	$ -	(7,088)
Income Taxes	(1,992)	-	(1,992)
Operating Income Increase (Decrease) After Taxes	**$ 5,096**	**$ -**	**$ 5,096**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Amortization of CEF-EV Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EV Regulatory Assets			
Residential Smart Charging	$ 26,624	$ -	$ 26,624
Mixed Use	$ 5,809	$ -	$ 5,809
DCFC & C&I Rebate	$ 6,368	$ -	$ 6,368
IT Systems	$ 4,422	$ -	$ 4,422
O&M	$ 16,766	$ -	$ 16,766
Total CEF-EV Regulatory Assets	$ 59,989	$ -	$ 59,989
Amortization Period			
Residential Smart Charging	30	0	30
Mixed Use	30	0	30
DCFC & C&I Rebate	30	0	30
IT Systems	5	0	5
O&M	5	0	5
Annual Amortization			
Residential Smart Charging	$ 887	$ -	$ 887
Mixed Use	$ 194	$ -	$ 194
DCFC & C&I Rebate	$ 212	$ -	$ 212
IT Systems	$ 884	$ -	$ 884
O&M	$ 3,353	$ -	$ 3,353
Total Annual Amortization	$ 5,531	$ -	$ 5,531
Carrying Charge:			
Average Deferred Balance During Test Year	$ 8,383	$ -	$ 8,383
Deferred Tax Benefit	$ (2,357)	$ -	$ (2,357)
Average Net of Tax Deferred Cost Balance	$ 6,027	$ -	$ 6,027
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 455	$ -	$ 455
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 5,986	$ -	$ 5,986
Income Taxes	$ 1,683	$ -	$ 1,683
Operating Income Increase (Decrease) After Taxes	**$ (4,303)**	**$ -**	**$ (4,303)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 21
CIP Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
CIP Revenue Accrual in Test Year	$ 87,442	$ 13,350	$ 100,792
Operating Expense Decrease Before Taxes	$ 87,442	$ 13,350	$ 100,792
Income Taxes	24,580	3,753	28,333
Operating Income Increase (Decrease) After Taxes	**$ (62,862)**	**$ (9,597)**	**$ (72,460)**

EXHIBIT P-2
SCHEDULE MPM-51

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 22
TAC Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
TAC Revenue Accrual in Test Year	$ 26,846	$ 32,070	$ 58,916
Operating Expense Decrease Before Taxes	$ 26,846	$ 32,070	$ 58,916
Income Taxes	7,596	9,443	17,038
Operating Income Increase (Decrease) After Taxes	**$ (19,250)**	**$(22,628)**	**$ (41,877)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 23
Deferred Compensation & Severance Expense
($000)

		Electric		Gas		Total
Removal of Deferred Compensation in Test Year	$	3,726	$	3,465	$	7,191
Removal of Severance Expense in Test Year	$	(5,395)	$	(4,414)	$	(9,809)
Operating Expense Decrease Before Taxes	$	(1,669)	$	(949)	$	(2,618)
Income Taxes		(469)		(267)		(736)
Operating Income Increase (Decrease) After Taxes	**$**	**1,200**	**$**	**682**	**$**	**1,882**

EXHIBIT P-2
SCHEDULE MPM-53

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 24
Tax Impact of Bad Debt Adjustment
($000)

	Electric	Gas	Total
Tax Bad Debt in Test Year	$ 8,693	$ 4,884	$ 13,577
Operating Expense Decrease After Taxes	$ 8,693	$ 4,884	$ 13,577
Operating Income Increase (Decrease) After Taxes	**$ (8,693)**	**$ (4,884)**	**$ (13,577)**

Schedule MPM-54E

2023 Rate Case - Baseline Revenue / Customer				
Month	**RS & RHS**	**RLM**	**GLP**	**LPLS**
Jun	$19.2	$21.3	$86.8	$1,811.6
Jul	$48.7	$90.0	$177.7	$2,863.2
Aug	$61.6	$106.3	$192.7	$3,665.3
Sep	$58.8	$129.0	$200.5	$3,935.7
Oct	$39.9	$84.5	$190.7	$3,910.0
Nov	$19.0	$18.1	$53.1	$1,833.0
Dec	$19.1	$18.1	$40.4	$789.6
Jan	$24.3	$22.8	$41.3	$768.9
Feb	$26.4	$25.6	$41.9	$756.6
Mar	$21.8	$22.1	$40.0	$774.0
Apr	$22.0	$21.1	$41.7	$808.8
May	$17.8	$17.3	$39.5	$759.8
TOTAL ANNUAL	**$378.8**	**$576.3**	**$1,146.3**	**$22,676.5**

Schedule MPM-54G

	2023 Rate Case - Baseline Use / Customer			
		RSG	GSG	LVG
Oct-23	Oct	44.6	71.9	2,152.7
Nov-23	Nov	94.0	209.7	3,558.7
Dec-23	Dec	143.9	337.9	5,245.4
Jan-24	Jan	169.7	401.7	6,245.7
Feb-24	Feb	150.6	352.6	5,950.6
Mar-24	Mar	120.2	296.3	5,273.9
Apr-24	Apr	65.2	156.0	3,130.1
May-24	May	37.3	85.9	2,087.8
Jun-23	Jun	21.3	57.7	1,173.9
Jul-23	Jul	18.6	47.3	1,313.9
Aug-23	Aug	16.8	50.9	1,289.1
Sep-23	Sep	18.7	48.0	1,322.4
	Total	**900.9**	**2,115.9**	**38,744.2**

Interest Cost Reconciliation

$M

		Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**