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November 4, 2021

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Infrastructure Advancement Program
(IAP)

BPU Docket Nos. __________________

***VIA ELECTRONIC MAIL****

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

Dear Secretary Camacho-Welch:

Enclosed for filing is the Verified Petition of Public Service Electric and Gas Company ("PSE&G") in the above-entitled matter. Also attached and filed herewith are the Direct Testimonies and Schedules of the following witnesses in support of the Company's Petition.

| Attachment | Witness | Area of Responsibility |
|---|---|---|
| 1 | Wade E. Miller, Director – Gas Transmission and Distribution Engineering, PSE&G | Gas portion of PSE&G's proposed Infrastructure Investment Program |
| 2 | Edward F. Gray, Director – Electric Transmission and Distribution Engineering, PSE&G | Electric portion of PSE&G's proposed Infrastructure Investment Program |
| 3 | Stephen Swetz, Senior Director – Corporate Rates and Revenue Requirements, PSE&G | Revenue requirements, cost recovery methodology, and rate design |
| 4 | Electric and Gas Cost-Benefit Analysis Panel | Cost-benefit analyses of the electric and gas investments of the Infrastructure Advancement Program |
| 5 | Electric Vehicles Cost-Benefit Analysis Panel | Cost-benefit analysis of the electric EV Charging Infrastructure Subprogram of the Infrastructure Advancement Program |
| 6 | Legal Notice | |

PSE&G is filing this Petition seeking Board approval of its IAP by which the Company seeks to invest $848 million, over a four-year period, to further strengthen and modernize the utility's electric and gas systems. The Program is designed in a manner consistent with previous infrastructure investment programs that the Board has approved to modernize PSE&G's infrastructure, enhance and maintain the safety and reliability of the Company's electric and gas distribution systems, and provide a valuable stimulus to New Jersey's economy. The Company's previous economic stimulus infrastructure programs include those approved by Board orders dated July 14, 2011 in BPU Docket Nos. EO11020088 and GO10110862, and April 28, 2009 in BPU Docket Nos. EO09010049 and GO09010050. The IAP is also designed to comply with the Board's Infrastructure Investment Program rules, as set forth in N.J.A.C. 14:3-2A.

Additionally, the Company's filing contains multiple subprograms that respond directly to the need to enable faster grid modernization and higher levels of distributed energy resource ("DER") absorption, as identified and targeted by the Board in its Grid Modernization proceeding, Docket No. QO21010085. The goal of this this proceeding is facilitating the creation of "an optimized distribution grid infrastructure and related operational interconnection processes that drive efficient and effective hosting of increasing levels of DER needed to meet New Jersey's clean energy goals."

If approved, the proposed program will enable PSE&G to continue its momentum to modernize its infrastructure and allow for the proliferation of DERs in the state by launching an IAP that will:

- replace approximately 1,400 of the worst performing sections with new cable and single phase transformers, and, where needed, will add a second cable source to improve design and outage restorations times,
- replace approximately 60 miles of aging 3-phase open wire construction (cross arm and armless) with new spacer cable type construction,
- replace approximately 14 miles of lashed cable with spacer-cable construction,
- replace approximately 2,100 defective wood poles identified during periodic inspections with new poles designed to a higher and more resilient standard, bringing hardening and storm benefits,
- replace aging spacer units along approximately 300 miles of existing construction with new hardware that is designed to a higher and more resilient standard,
- replace approximately 34 miles of the poorest performing conventional underground cables that have reached end of life,
- replace approximately 1,300 secondary locations of existing open wire secondary with new secondary cable and services that have higher capacity and are also more resistant to storms and tree contacts,
- replace approximately 1,600 aging 13kV pole top capacitors and switches that are increasingly failing and providing poor voltage regulation,
- replace 40 existing 26kV oil circuit breakers with newer gas circuit breakers at various

switching and substations across the Company's system,

- replace an existing 92-year old 26kV air insulated station at West Orange with new sheltered aisle switchgear,
- modernize 4kV switchgear at five electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure,
- install electric vehicle infrastructure at 65 existing PSE&G reporting locations to support PSE&G's transition to an electric fleet,
- modernize seven metering and regulating stations, including upgrading carrying equipment and facilities, modernizing supply configurations to enhance reliability and reduce potential methane emissions, and installing enhanced physical security measures, and
- improve PSE&G's already strong customer service.

Included in the testimony of Wade Miller (Attachment 1) and Edward Gray (Attachment 2), concerning, respectively, the gas and electric portions of the IAP, are several schedules that contain confidential information. This material will be furnished to the Board of Public Utilities Staff and the Division of Rate Counsel upon execution of the attached Confidentiality Agreement. Copies of the Petition and supporting documentation will be served upon all entities legally required to be noticed.

In compliance with the Board's Order in Docket No. EO20030254, dated March 19, 2020, the Company hereby submits this filing via electronic delivery only to the Board Secretary, and will suspend submitting such filings as paper documents until the Board directs otherwise.

Very truly yours,

* **Hard copies, if requested, can be provided at a later date.**

Attachment
C Attached Service List (E-Mail Only)

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**STATE OF NEW JERSEY**
**BOARD OF PUBLIC UTILITIES**

| | | |
|---|---|---|
| IN THE MATTER OF THE PETITION OF | ) | |
| PUBLIC SERVICE ELECTRIC AND GAS | ) | PETITION |
| COMPANY FOR APPROVAL OF AN | ) | BPU DOCKET NOS. |
| INFRASTRUCTURE ADVANCEMENT | ) | EO________ |
| PROGRAM | ) | GO________ |

## VERIFIED PETITION

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

## INTRODUCTION AND OVERVIEW OF THE FILING

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service ("BGS"), and distribution of gas and the provision of Basic Gas Supply Service ("BGSS"), for residential, commercial and industrial customers within the State of New Jersey. PSE&G provides service to approximately 2.4 million electric and 1.8 million gas customers in an area having a population in excess of 6.2 million persons that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton, and south to Camden, New Jersey.

2. Petitioner is subject to Board regulation for the purposes of setting its retail distribution rates and to assure safe, adequate, and reliable electric distribution and natural gas distribution service pursuant to N.J.S.A. 48:2-13 *et seq*.

3. PSE&G is filing this Petition seeking Board approval of an Infrastructure Advancement Program ("IAP" or "Program") and associated cost recovery mechanism for a four-year period. The Program is designed in a manner consistent with previous infrastructure

investment programs that have been approved by the Board in an effort to modernize PSE&G's infrastructure, and enhance and maintain the safety and reliability of the Company's electric and gas distribution systems, and enable the penetration of distributed energy resources and electric vehicles consistent with New Jersey's policy goals, while also providing a valuable stimulus to New Jersey's economy. The Company's previous economic stimulus infrastructure programs include those approved by Board orders dated July 14, 2011 in BPU Docket Nos. EO11020088 and GO10110862,[1] and April 28, 2009 in BPU Docket Nos. EO09010049 and GO09010050.

4. The IAP is also designed to comply with the Board's rules on Infrastructure Investment Programs ("IIPs"), as set forth in N.J.A.C. 14:3-2A. Consistent with the IIP regulations, the IAP proposes infrastructure investments to enhance safety, reliability, and/or resiliency, and modernize the Company's electric and gas delivery systems through twelve electric projects and one gas project. PSE&G anticipates the Program will be conducted over the four-year period commencing on the first of the month following the effective date of a Board order of approval, with certain limited close out expenses to follow the four-year period. The Program proposes estimated investments of $708 million in electric infrastructure over 4 years and $140 million in gas infrastructure over 4 years, with cost recovery based upon the Board's IIP rules and consistent with the recovery of electric and gas investments that have previously been approved for the Company's Energy Strong Programs as approved by Board orders dated May 21, 2014 in

[1] *I/M/O The Petition Of Public Service Electric And Gas Company For Approval Of An Extension Of The Electric Capital Economic Stimulus Infrastructure Investment Program And Associated Cost Recovery Mechanism*, BPU Docket Nos. EO11020088 and GO10110862, "Decision and Order Approving Stipulation" (July 14, 2011); *I/M/O The Proceeding For Infrastructure Investment And Cost Recovery Mechanisms For All Gas And Electric Utilities, And I/M/O The Petition Of Public Service Electric & Gas Company For Approval Of A Capital Economic Stimulus Infrastructure Investment Program And An Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48-2-21.1*, BPU Docket Nos. EO09010049 and GO09010050, "Decision and Order Approving Stipulation" (April 28, 2009).

BPU Docket Nos. EO13020155 and GO13020156 and September 11, 2019 in BPU Docket Nos. EO18060629 and GO18060630.

## THE PROPOSED PROGRAM

5. As noted above, this IAP filing has been designed to be consistent with the Board's IIP regulations. Appendix 1 attached to this Petition sets forth the location in this filing of all requirements of the Board's IIP regulations. The Program includes the following proposed electric subprograms, with summaries and investment totals as listed below:

### I. Electric Outside Plant Subprogram

The Electric Outside Plant Subprogram consists of eight projects that address service reliability, storm hardening and resiliency and also support the goals of the New Jersey Energy Master Plan. This subprogram focuses on overhead and underground facilities that supply customers from the substation to the customers' meters. This subprogram consists of the following projects:

**(i) Buried Underground Distribution Cable Replacement Project**. Since 1973 all new residential developments greater than three homes have required underground electric supply facilities. Cables and associated transformers in the older developments that were subject to these requirements have reached their end of life and are experiencing increasing failure rates. This program will replace approximately 1,400 of the worst performing sections with new cable and single phase transformers, and, where needed, will add a second cable source to improve design and outage restorations times. The projected cost of this project is $80 million.

**(ii) Spacer Cable Construction Project**. This project will replace approximately 60 miles of aging 3-phase open wire construction (cross arm and armless) with new spacer cable type construction. Spacer cable is a more compact and reliable design that incorporates a conductor with a thick polymer covering, thereby making it especially resilient to branch and tree contacts. Where necessary, undersized or aged poles will also be replaced. The projected cost of this project is $42 million.

**(iii)** **Lashed Cable Replacement Project**. Lashed primary cable consists of three conductors that are wrapped together with a bonding ribbon and suspended from pole to pole with clamps. This construction type is used for 4kV applications primarily in urban areas, backyards, or right of ways with limited construction space. Lashed cable is one of the oldest distribution assets on PSE&G's system and suffers from increasingly poor reliability. This program will replace approximately 14 miles of lashed cable with spacer-cable construction. The projected cost of this project is $14 million.

**(iv)** **Pole Upgrade Project**. This project will replace approximately 2,100 defective wood poles identified during periodic inspections with new poles designed to a higher and more resilient standard, bringing hardening and storm benefits. The projected cost of this project is $32 million.

**(v)** **Spacer Cable Upgrade Project**. This project will replace aging spacer units along approximately 300 miles of existing construction with new hardware that is designed to a higher and more resilient standard. The new spacer standard has higher insulation values, improved material properties and better mechanical performance, and will improve the reliability on these circuits at a relatively low cost compared to circuit reconstruction. The projected cost of this project is $15 million.

**(vi)** **Conventional Underground Cable Replacement Project**. Conventional underground cable systems are most common in urban environments, and this asset class includes cable, splices, and terminations. This program will replace approximately 34 miles of the poorest performing cables that have reached end of life. The projected cost of this project is $23 million.

**(vii) Open Wire Secondary Upgrade Project**. Open wire secondary (OWS) is an older, lower capacity construction type that has deteriorated over time and is increasingly experiencing short circuits and outages. This project will replace approximately 1,300 secondary locations of existing OWS with new secondary cable and services that have higher capacity and are also more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVa transformers in place, new larger capacity units will be installed. This project will also provide enhanced capacity to support increased EV penetration consistent, with the State's policy goals. The projected cost of this project is $36 million.

**(viii) Voltage Optimization Project**. This project will replace approximately 1,600 aging 13kV pole top capacitors and switches that are increasingly failing and providing poor voltage regulation. The existing units also lack communication functionality, so failures cannot be detected without a visual inspection. Replacement systems will be equipped with advanced switches, voltage and current sensing, and the ability to communicate back to the DSCADA system, providing significant improvements in voltage regulation as distributed energy resources ("DERs") becomes more commonplace. The projected cost of this project is $55 million.

## II. Substation Modernization Subprogram

The Substation Modernization Subprogram will modernize 26kV and 4kV substations and consists of the following projects:

**(i)** **26kV Station Upgrade Project**. This project will replace 40 existing 26kV oil circuit breakers (OCBs) with newer gas circuit breakers at various switching and substations across the Company's system. The OCBs have an average age of 60 years, require significant corrective maintenance, and pose environmental challenges. The projected cost of this project is $33 million.

**(ii)** **West Orange Switching Station Project**. This project will replace an existing 92-year old 26kV air insulated station at West Orange with new sheltered aisle switchgear. The project will also reconfigure existing 26kV cables, eliminate low pressure gas filled cables, and install a bulk nitrogen system. The projected cost of this project is $72 million.

**(iii)** **4kV Substation Modernization Project**. This subprogram will modernize 4kV switchgear at five electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure. The projected cost of this project is $172 million.

## III. Electric Vehicle ("EV") Charging Infrastructure Subprogram

The EV Charging Infrastructure subprogram consists of a single project that will install EV infrastructure at 65 existing PSE&G reporting locations to support PSE&G's transition to an electric fleet. Approximately 2,000 EV chargers and associated infrastructure will be installed at field division and district operating facilities, switching stations, service centers, and various office locations. The projected cost of this project is $134 million. While this project is being constructed and implemented by the Company's electric business, the project will benefit both the electric and gas businesses. Therefore, the costs of the project will be assigned to both the electric and gas businesses.

6. The IAP also includes the following gas subprogram:

**(i) Gas Metering and Regulating Station Modernization Subprogram**. This subprogram consists of a single project that will modernize seven metering and regulating stations, including upgrading equipment and facilities, modernizing supply configurations to enhance reliability and reduce potential methane emissions, and installing enhanced physical security measures. The projected cost of this project is $140 million.

7. The Company commits to capital expenditures on projects similar to those proposed in the Program in an amount of at least ten (10) percent of the Program expenditures. These capital expenditures will be recovered in a base rate proceeding, and will not be subject to the cost recovery mechanism set forth herein.

## BENEFITS TO CUSTOMERS AND THE NEW JERSEY ECONOMY

8. The proposed IAP, like the prior PSE&G Capital Infrastructure Programs, will produce many benefits for customers served by PSE&G's electric and gas distribution systems, and for the State of New Jersey. Customers will benefit from a safer, more modern system that accommodates new technologies, providing an electric system that can integrate and manage larger quantities of DERs, and other innovations. When catastrophic events occur, the electric systems will have increased ability to withstand and recover from those events with associated lower extraordinary restoration costs, if any, and less disruption, if any, to customers and the New Jersey economy. The Program will provide higher levels of reliability in the PSE&G electric and gas distribution systems.

9. In addition, the Program will provide a significant stimulus to a New Jersey economy that is slowly emerging from the COVID-19 pandemic. Using the methodology for job creation from the introductory materials to the Board's August 7, 2017 proposal for the IIP regulations that the BPU has relied upon most recently in the Company's Energy Strong II

proceeding, the IAP will create approximately 80-100 full-time equivalent ("FTE") positions in the first year of the Program and 780-800 FTE positions in years three and four. The Program will also create approximately 80 to 100 indirect jobs in the first year and 800 to 900 in years three and four. The multi-year nature of the Program will provide stability and permanence to the jobs created and supported by the Program.

10. To support job creation and help ensure success of the stimulus efforts, PSE&G will develop a jobs program drawing on the models created by the Company in connection with significant urban infrastructure work at the Company's McCarter and Newark Switching station projects, and incorporating certain components of the new jobs program currently supporting the Company's Clean Energy Future – Energy Efficiency program. The program will focus on union jobs and developing diverse apprenticeships, targeting linepersons represented by the International Brotherhood of Electric Workers, electricians, laborers, and operating engineers, as well as carpenters and opportunities for pipefitters for certain gas work.

11. A four-year period is necessary for the Program because the vast majority of the construction projects proposed require four years to complete. Various aspects of permitting, planning, and coordinating the projects, cannot be reasonably planned for and executed in less than a four year period. In addition, the multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

12. The Cost Benefit Analyses attached to the Direct Testimony of the Electric and Gas Cost-Benefit Analysis Panel and the Direct Testimony of the Electric Vehicles Charging Infrastructure Cost-Benefit Analysis Panel further support the approval of the Program.

## COST RECOVERY

13. PSE&G is proposing a cost recovery mechanism for the IAP that is consistent with the BPU' s IIP regulations, as addressed in detail in the attached Direct Testimony of Stephen Swetz. The cost recovery method will involve proposed new electric and gas IAP rate components of the Company's Infrastructure Investment Program Charges ("IIPCs") with the potential for semi-annual rate adjustment filings. This method is consistent with the IIP regulations, and the same approach used for PSE&G's Energy Strong II program. The proposed schedule for these potential filings are shown in the chart below:

| **Proposed Rate Adjustment Schedule** | | | | |
|---|---|---|---|---|
| **Rate Adj#** | **Initial Filing** | **Investment as Of** | **Update for Actuals Filing** | **Rates Effective** |
| 1 | 10/31/22 | 12/31/22 | 1/31/23 | 4/1/23 |
| 2 | 4/30/23 | 6/30/23 | 7/31/23 | 10/1/23 |
| 3 | 10/31/23 | 12/31/23 | 1/31/24 | 4/1/24 |
| 4 | 4/30/24 | 6/30/24 | 7/31/24 | 10/1/24 |
| 5 | 10/31/24 | 12/31/24 | 1/31/25 | 4/1/25 |
| 6 | 4/30/25 | 6/30/25 | 7/31/25 | 10/1/25 |
| 7 | 10/31/25 | 12/31/25 | 1/31/26 | 4/1/26 |
| 8 | TBD* | TBD + 2 mo | TBD + 3 mo | TBD + 5 mo + 1 Day |

14. Because the IIP rules limit each electric and gas base rate adjustment request to a minimum investment level of 10 percent of each respective electric and gas program, PSE&G projects that its filings for such increases may be less often than the semi-annual filings noted above.

15. Assuming Board approval by June 2022, the IAP is estimated to be complete June 30, 2026, except for certain close out work that may occur 3 to 6 months following the conclusion of the Program. Without a firm date for completion of this close out work, the Company is proposing a rate filing no later than December 31, 2026 comprised of all actual cost data (as

opposed to projected) for rates effective April 1, 2027. Given the nature of the close out work, the final roll-in may be less than 10% of the Program, but is appropriate to provide completion of the Program.

16. Consistent with previous accelerated infrastructure programs, PSE&G proposes that the costs to be included in rates will include: depreciation/amortization expense providing for the recovery of the invested capital over its useful book life; return on the net investment, where net investment is the capital expenditures less accumulated depreciation/amortization, less associated accumulated deferred income taxes; and the impact of any tax adjustments applicable to the Program. The return on net investment will be based upon a weighted average cost of capital ("WACC"). The Company proposes a WACC for the Program based upon the most recent WACC for base rates approved by the Board. PSE&G further proposes that any change in the WACC authorized by the Board in any subsequent base rate case be reflected in the subsequent revenue requirement calculations.

17. BPU Staff and Rate Counsel will have an opportunity to review each rate adjustment filing to ensure that the revenue requirements and proposed rates are calculated in accordance with the BPU Order approving the Program and the IIP rules. The changes to IAP rates made through these rate adjustment filings would be subject to refund if the Board finds that PSE&G imprudently incurred capital expenditures in its implementation of the IAP. The prudence of the Company's actual expenditures in IAP will be reviewed as part of PSE&G's subsequent base rate case(s) following the rate adjustments. This is identical to the approach under the Energy Strong II program, and the Board's regulation at <u>N.J.A.C.</u> 14:3-2A.6(e). The Company is presently required to file its next base rate case no later than January 1, 2024.

18. In addition to limiting the base rate adjustment requests to a minimum investment level of ten (10) percent of the total program investment, PSE&G is also proposing an earnings test that would serve to limit the amount of investment to be included in the rate base adjustments. Consistent with the IIP regulations, if the Company exceeds the allowed Return-on-Equity from the utility's last base rate case by fifty basis points or more for the most recent twelve month period, the pending base rate adjustment will not be allowed for the applicable filing period. Details regarding application of the earnings test are set forth in the Direct Testimony of Stephen Swetz, submitted herewith.

19. This Petition does not propose any rate increase and, for that reason, no public comment hearings are required. Nevertheless, PSE&G proposes public comment hearings similar to those that are held when rate increases are proposed. Thus, a proposed form of public notice of filing and public hearings, including the proposed rates and bill impacts attributable to the proposed implementation of the Program, is attached to this Petition. PSE&G proposes this Form of Notice will be placed in newspapers having a circulation within the Company's electric and gas service territory once public hearings have been scheduled. As with petitions that propose rate increases, PSE&G proposes public hearings to allow members of the public the opportunity to present their views on the Company's filing. PSE&G also proposes that it provide notice to the County Executives and Clerks of all municipalities within the Company's electric and gas service territories upon receipt of public hearing dates.

20. The typical annual bill impacts for a typical residential customer as well as rate class average customers compared to rates as of October 1, 2021 are set forth in the testimony of Mr. Stephen Swetz. The forecast cumulative impact (impact from the entire Program) on the typical residential electric customer is an increase of approximately 2.08% on an average annual bill or

about a $2.30 increase in their average monthly bill. The forecast cumulative impact (impact from the entire Program) on the typical residential gas heating customer is an increase of approximately 1.25% on an average annual bill or about a $0.95 increase in their average monthly bill. The total impact for a combined typical electric and gas residential customer would average about 0.43% per year over the four year period.

**ATTACHED DIRECT TESTIMONY AND PROPOSED PROCEDURAL SCHEDULE**

21. Given the importance of this Program to continuing safety and reliability of the Company's electric and gas distribution systems and the economy of the State, it is important for PSE&G to receive Board approval by June, 2022to begin planning for, designing and making the capital investments described herein. Therefore, the Company respectfully requests that the Board retain this matter and utilize a schedule similar to the following procedural schedule:

| | |
|---|---|
| Petition and Direct Testimony filed | November 4, 2021 |
| Prehearing Conference | December 7, 2021 |
| Discovery/Technical Conferences | December 8, 2021, January 11 & 12, 2022 |
| Non-Petitioner Direct Testimony Due | February 8, 2022 |
| Rebuttal Testimony – All Parties | March 8, 2022 |
| Settlement Conferences | February 1 & 3 |
| | March 1, 3, 22 & 24 |
| Hearings | April 5-7, 12-14 |
| Initial Briefs | May 17, 2022 |
| Reply Briefs | May 31, 2022 |
| BPU Order | June, 2022 |

22. Attached are the following direct testimony with schedules and other attachments in support of the proposal in this petition:

Appendix 1 - Location of requirements per the IIP regulations at N.J.A.C. 14:3-2A

Non-Disclosure Agreement

Attachment 1 - Prepared Direct Testimony of Wade E. Miller

Attachment 2 - Prepared Direct Testimony of Edward F. Gray

Attachment 3 - Prepared Direct Testimony of Stephen Swetz

Attachment 4 - Prepared Direct Testimony of the Electric and Gas Cost-Benefit Analysis Panel

Attachment 5 - Prepared Direct Testimony of the Electric Vehicles Charging Infrastructure Cost-Benefit Analysis Panel

Attachment 6 – Legal Notice

## COMMUNICATIONS

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

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**CONCLUSION AND REQUESTS FOR APPROVAL**

For all the foregoing reasons, PSE&G respectfully requests that the Board issue an Order approving this Petition no later than June 2022 specifically finding that:

1. The Infrastructure Advancement Program is in the public interest;

2. The Infrastructure Advancement Program as described herein is reasonable and prudent;

3. PSE&G is authorized to implement and administer the Program under the terms set forth in this Petition and accompanying Attachments;

4. The cost recovery proposal and mechanism set forth in this Petition will provide for implementation of just and reasonable rates and is approved; and

5. PSE&G may recover all prudently-incurred Program costs, on a full and timely basis, under the cost recovery mechanism set forth herein.

Respectfully submitted,

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**

Danielle Lopez

By: Danielle Lopez, Esq.

DATED: November 4, 2021

STATE OF NEW JERSEY )
COUNTY OF ESSEX )

I, David Zarra, of full age, being duly sworn according to law, on his oath deposes and says:

1. I am Manager of Revenue Requirements of PSEG Services Corporation.

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

BY: ________________________________

David Zarra

Sworn and subscribed before me
this 4th day of November, 2021

Michele D. Falcao

MICHELE D. FALCAO
Notary Public, State of New Jersey
My Commission Expires
November 14, 2021

| PUBLIC SERVICE ELECTRIC AND GAS<br><br>Minimum Filing Requirements – Infrastructure Advancement Program | |
|---|---|
| **Minimum Filing Requirement** | **Location in Filing** |
| **14:3-2A.2 Project eligibility** | |
| a) Eligible projects within an Infrastructure Investment Program shall be:<br>1. Related to safety, reliability, and/or resiliency;<br>2. Non-revenue producing;<br>3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and<br>4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition. | See Attachment 1, Direct Testimony of Wade E. Miller;<br>See Attachment 2, Direct Testimony of Edward F. Gray |
| b) Projects within an Infrastructure Investment Program may include:<br>5. The replacement of gas Utilization Pressure Cast Iron mains with elevated pressure mains and associated services;<br>6. The replacement of mains and services that are identified as high risk in a gas utility's Distribution Integrity Management Plan;<br>7. The installation of gas Excess Flow Valves where existing gas service line replacements require them, excluding Excess Flow Valves installed upon customer request pursuant to 49 CFR 192.383;<br>8. Electric distribution automation investments, including, but not limited to, Supervisory Control and Data Acquisition equipment, cybersecurity investments, relays, reclosers, Voltage and Reactive Power Control, communications networks, and Distribution Management System Integration;<br>9. The installation of break-predictive water sensors and wastewater sensors to curtail combined sewer overflows; and<br>10. Other projects deemed appropriate by the Board | See Attachment 1, Direct Testimony of Wade E. Miller;<br>See Attachment 2, Direct Testimony of Edward F. Gray |

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| c) A utility shall maintain its capital expenditures on projects similar to those proposed within the utility's Infrastructure Investment Program. These capital expenditures shall amount to at least ten (10) percent of any approved Infrastructure Investment Program. These capital expenditures shall be made in the normal course of business and recovered in a base rate proceeding, and shall not be subject to the recovery mechanism set forth in N.J.A.C. 14:3-2A.6. | See Attachment 1, Direct Testimony of Wade E. Miller, Schedule WEM-IAP-2B;<br>See Attachment 2, Direct Testimony of Edward F. Gray, Schedule EFG-IAP-2B |
| **14:3-2A.3 Annual baseline spending levels** | |
| a) A utility seeking to establish an Infrastructure Investment Program shall, within its petition, propose annual baseline spending levels to be maintained by the utility throughout the length of the proposed Infrastructure Investment Program. These expenditures shall be recovered by the utility in the normal course within the utility's next base rate case. | See Attachment 1, Direct Testimony of Wade E. Miller, Schedule WEM-IAP-2B;<br>See Attachment 2, Direct Testimony of Edward F. Gray, Schedule EFG-IAP-2B |
| b) In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level | See Attachment 1, Direct Testimony of Wade E. Miller;<br>See Attachment 2, Direct Testimony of Edward F. Gray |
| **14:3-2A.4 Infrastructure Investment Program length and limitations** | |
| a) Allowance for Funds Used During Construction (AFUDC) shall be permitted under an Infrastructure Investment Program, but a utility shall not utilize AFUDC once Infrastructure Investment Program facilities are placed in service. | See Attachment 3, Direct Testimony of Stephen Swetz |
| **14:3-2A.5 Infrastructure Investment Program minimum filing and reporting requirements** | |
| 1) Projected annual capital expenditure budgets for a five (5) year period, identified by major categories of expenditures | See Attachment 1, Schedule WEM-IAP-2B, of the Direct Testimony of Wade E. Miller;<br>See Attachment 2, Schedule EFG-IAP-2B, of the Direct Testimony of Edward F. Gray |

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| 2) Actual annual capital expenditures for the previous five (5) years, identified by major categories of expenditures | See Attachment 1, Schedule WEM-IAP-2A, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-IAP-2A, of the Direct Testimony of Edward F. Gray |
| 3) An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives, detailed cost estimates, in-service dates, and any applicable cost-benefit analysis for each project | See Attachment 1, Direct Testimony of Wade E. Miller; Schedule WEM-IAP-4 See Attachment 2, Direct Testimony of Edward F. Gray; Schedule EFG-IAP-4 See Attachment 4, and Attachment 5, Direct Testimony of the IAP Electric and Gas Cost-Benefit Analysis Panel; See Attachment 6, Direct Testimony of the Fleet Electrification Program Cost-Benefit Analysis Panel |
| 4) An Infrastructure Investment Program budget setting forth annual budget expenditures | See Attachment 1, Schedule WEM-IAP-3, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-IAP-3, of the Direct Testimony of Edward F. Gray |
| 5) A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f) | See Attachment 3, Direct Testimony of Stephen Swetz |
| 6) Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b) | See Attachment 1, Schedule WEM-IAP-2B, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-IAP-2B, of the Direct Testimony of Edward F. Gray |

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| 7) | The maximum dollar amount, in aggregate, the utility seeks to recover through the Infrastructure Investment Program; and | See Attachment 1, Schedule WEM-IAP-3, of the Direct Testimony of Wade E. Miller;<br>See Attachment 2, Schedule EFG-IAP-3, of the Direct Testimony of Edward F. Gray |
| 8) | The estimated rate impact of the proposed Infrastructure Investment Program on customers | See Attachment 3, Schedule SS-IAP-8, and Schedule SS-ISP-9 of the Direct testimony of Stephen Swetz |
| **14:3-2A.6** | **Infrastructure Investment Program Recovery** | |
| a) | Each filing made by a utility seeking accelerated recovery under an Infrastructure Investment Program shall seek recovery, at a minimum, of at least ten (10) percent of overall Infrastructure Investment Program expenditures. | See Attachment 3, the Direct testimony of Stephen Swetz |
| b) | A utility's expenditures made prior to the Board's approval of an Infrastructure Investment Program shall not be eligible for accelerated recovery. | N/A |
| c) | Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be accelerated, and recovered through a separate clause of the utility's Board-approved tariff. | See Attachment 3, the Direct testimony of Stephen Swetz |
| d) | Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest. Prudence of Infrastructure Investment Program expenditures shall be determined in the utility's next base rate case. | See Attachment 3, the Direct testimony of Stephen Swetz |
| e) | A utility shall file its next base rate case not later than five (5) years after the Board's approval of the Infrastructure Investment Program, although the Board, in its discretion, may require a utility to file its next base rate case within a shorter period | See Attachment 3, the Direct testimony of Stephen Swetz |
| f) | An earnings test shall be required, where Return on Equity (ROE) shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period. | See Attachment 3, the Direct testimony of Stephen Swetz |

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| g) For any Infrastructure Investment Program approved by the Board, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more, accelerated recovery shall not be allowed for the applicable filing period. | See Attachment 3, the Direct testimony of Stephen Swetz |

**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 INFRASTRUCTURE ADVANCEMENT PROGRAM | AGREEMENT OF NON-DISCLOSURE OF INFORMATION CLAIMED TO BE CONFIDENTIAL<br><br>BPU DOCKET NOS.<br>EO__________<br>GO__________ |
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It is hereby AGREED, as of the 4th day of November 2021 by and among Public Service Electric and Gas Company ("**PETITIONER**"), the Staff of the New Jersey Board of Public Utilities ("Board Staff') and the New Jersey Division of the Rate Counsel ("Rate Counsel"), (collectively, the "Parties"), who have agreed to execute this Agreement of Non-Disclosure of Information Claimed to be Confidential ("Agreement"), and to be bound thereby that:

WHEREAS, in connection with the above-captioned proceeding before the Board of

Public Utilities (the "Board"), **PETITIONER** and/or another party ("Producing Party") may be requested or required to provide petitions, prefiled testimony, other documents, analyses and/or other data or information regarding the subject matter of this proceeding that the Producing Party may claim constitutes or contains confidential, proprietary or trade secret information, or which otherwise may be claimed by the Producing Party to be of a market-sensitive, competitive, confidential or proprietary nature (hereinafter sometimes referred to as "Confidential Information" or "Information Claimed to be Confidential"); and

WHEREAS, the Parties wish to enter into this Agreement to facilitate the exchange of information while recognizing that under Board regulations at N.J.A.C. 14:1-12 et seq., a request for confidential treatment shall be submitted to the Custodian who is to rule on requests made pursuant to the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-l et seq., unless such information is to be kept confidential pursuant to court or administrative order (including, but not limited to, an Order by an Administrative Law Judge sealing the record or a portion thereof pursuant to N.J.A.C. 1:1-14.1, and the parties acknowledge that an Order by an Administrative Law Judge to seal the record is subject to modification by the Board), and also recognizing that a request may be made to designate any such purportedly confidential information as public through the course of this administrative proceeding; and

WHEREAS, the Parties acknowledge that unfiled discovery materials are not subject to public access under OPRA; and

WHEREAS, the Parties acknowledge that, despite each Party's best efforts to conduct a thorough pre-production review of all documents and electronically stored information ("ESI"), some work product material and/or privileged material ("protected material") may be inadvertently disclosed to another Party during the course of this proceeding; and

WHEREAS, the undersigned Parties desire to establish a mechanism to avoid waiver of privilege or any other applicable protective evidentiary doctrine as a result of the inadvertent disclosure of protected material;

NOW, THEREFORE, the Parties hereto, intending to be legally bound thereby, DO HEREBY AGREE as follows:

1. The inadvertent disclosure of any document or ESI which is subject to a legitimate claim that the document or ESI should have been withheld from disclosure as protected material shall not waive any privilege or other applicable protective doctrine for that document or ESI or for the subject matter of the inadvertently disclosed document or ESI if the Producing Party, upon

becoming aware of the disclosure, promptly requests its return and takes reasonable precautions to avoid such inadvertent disclosure.

2. Except in the event that the receiving party or parties disputes the claim, any documents or ESI which the Producing Party deems to contain inadvertently disclosed protected material shall be, upon written request, promptly returned to the Producing Party or destroyed at the Producing Party's option. This includes all copies, electronic or otherwise, of any such documents or ESI. In the event that the Producing Party requests destruction, the receiving party shall provide written confirmation of compliance within thirty (30) days of such written request. In the event that the receiving party disputes the Producing Party's claim as to the protected nature of the inadvertently disclosed material, a single set of copies may be sequestered and retained by and under the control of the receiving party until such time as the Producing Party has received final determination of the issue by the Board of Public Utilities or an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge.

3. Any such protected material inadvertently disclosed by the Producing Party to the receiving party pursuant to this Agreement shall be and remain the property of the Producing Party.

4. Any Information Claimed to be Confidential that the Producing Party produces to any of the other Parties in connection with the above-captioned proceeding and pursuant to the terms of this Agreement shall be specifically identified and marked by the Producing Party as Confidential Information when provided hereunder. If only portions of a document are claimed to be confidential, the producing party shall specifically identify which portions of that document are claimed to be confidential. Additionally, any such Information Claimed to be Confidential shall be provided in the form and manner prescribed by the Board's regulations at N.J.A.C. 14:1-12 et seq., unless such information is to be kept confidential pursuant to court or administrative order.

However, nothing in this Agreement shall require the Producing Party to file a request with the Board's Custodian of Records for a confidentiality determination under N.J.A.C. 14:1-12 et seq. with respect to any Information Claimed to be Confidential that is provided in discovery and not filed with the Board.

5. With respect to documents identified and marked as Confidential Information, if the Producing Party's intention is that not all of the information contained therein should be given protected status, the Producing Party shall indicate which portions of such documents contain the Confidential Information in accordance with the Board's regulations at N.J.A.C. 14:1-12.2 and 12.3. Additionally, the Producing Party shall provide to all signatories of this Agreement full and complete copies of both the proposed public version and the proposed confidential version of any information for which confidential status is sought.

6. With respect to all Information Claimed to be Confidential, it is further agreed that:

(a) Access to the documents designated as Confidential Information, and to the information contained therein, shall be limited to the Party signatories to this Agreement and their identified attorneys, employees and consultants whose examination of the Information Claimed to be Confidential is required for the conduct of this particular proceeding.

(b) Recipients of Confidential Information shall not disclose the contents of the documents produced pursuant to this Agreement to any person(s) other than their identified employees and any identified experts and consultants whom they may retain in connection with this proceeding, irrespective of whether any such expert is retained specially and is not expected to testify, or is called to testify in this proceeding. All consultants or experts of any Party to this

Agreement who are to receive copies of documents produced pursuant to this Agreement shall have previously executed a copy of the Acknowledgement of Agreement attached hereto as "Attachment I," which executed Acknowledgement of Agreement shall be forthwith provided to counsel for the Producing Party, with copies to counsel for Board Staff and Rate Counsel.

(c) No other disclosure of Information Claimed to be Confidential shall be made to any person or entity except with the express written consent of the Producing Party or their counsel, or upon further determination by the Custodian, or order of the Board, the Government Records Council or of any court of competent jurisdiction that may review this matter.

7. The undersigned Parties have executed this Agreement for the exchange of Information Claimed to be Confidential only to the extent that it does not contradict or in any way restrict any applicable Agency Custodian, the Government Records Council, an Administrative Law Judge of the State of New Jersey, the Board, or any court of competent jurisdiction from conducting appropriate analysis and making a determination as to the confidential nature of said information, where a request is made pursuant to OPRA, N.J.S.A. 47:1A-l et seq. Absent a determination by any applicable Custodian, Government Records Council, an Administrative Law Judge, the Board, or any court of competent jurisdiction that a document is to be made public, the treatment of the documents exchanged during the course of this proceeding and any subsequent appeals is to be governed by the terms of this Agreement.

8. In the absence of a decision by the Custodian, Government Records Council, an

Administrative Law Judge, or any court of competent jurisdiction, the acceptance by the undersigned Parties of information which the Producing Party has identified and marked as Confidential Information shall not serve to create a presumption that the material is in fact entitled to any special status in these or any other proceedings. Likewise, the affidavit submitted pursuant to N.J.A.C. 14:1-12.8 shall not alone be presumed to constitute adequate proof that the Producing Party is entitled to a protective order for any of the information provided hereunder.

9. In the event that any Party seeks to use the Information Claimed to be Confidential in the course of any hearings or as part of the record of this proceeding, the Parties shall seek a determination by the trier of fact as to whether the portion of the record containing the Information Claimed to be Confidential should be placed under seal. Furthermore, if any Party wishes to challenge the Producing Party's designation of the material as Confidential Information, such Party shall provide reasonable notice to all other Parties of such challenge and the Producing Party may make a motion seeking a protective order. In the event of such challenge to the designation of material as Confidential Information, the Producing Party, as the provider of the Information Claimed to be Confidential, shall have the burden of proving that the material is entitled to protected status. However, all Parties shall continue to treat the material as Confidential Information in accordance with the terms of this Agreement, pending resolution of the dispute as to its status by the trier of fact.

10. Confidential Information that is placed on the record of this proceeding under seal pursuant to a protective order issued by the Board, an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge, or any court of competent jurisdiction shall remain with the Board under seal after the conclusion of this proceeding. If such Confidential Information is provided to appellate courts for the purposes of an

appeal from this proceeding, such information shall be provided, and shall continue to remain, under seal.

11. This Agreement shall not:

(a) Operate as an admission for any purpose that any document or information produced pursuant to this Agreement is admissible or inadmissible in any proceeding;

(b) Prejudice in any way the right of the Parties, at any time, on notice given in accordance with the rules of the Board, to seek appropriate relief in the exercise of discretion by the Board for violation of any provision of this Agreement.

12. Within forty five (45) days of the final Board Order resolving the above-referenced proceeding, all documents, materials and other information designated as "Confidential Information," regardless of format, shall be destroyed or returned to counsel for the Producing Party. In the event that such Board Order is appealed, the documents and materials designated as "Confidential Information" shall be returned to counsel for the Producing Party or destroyed within forty-five (45) days of the conclusion of the appeal. Notwithstanding the above return requirement, Board Staff and Rate Counsel may maintain in their files copies of all pleadings, briefs, transcripts, discovery and other documents, materials and information designated as "Confidential Information," regardless of format, exchanged or otherwise produced during these proceedings, provided that all such information and/or materials that contain Information Claimed to be Confidential shall remain subject to the terms of this Agreement. The Producing Party may request consultants who received Confidential Information who have not returned such material to counsel

for the Producing Party as required above to certify in writing to counsel for the Producing Party that the terms of this Agreement have been met upon resolution of the proceeding.

13. The execution of this Agreement shall not prejudice the rights of any Party to seek relief from discovery under any applicable law providing relief from discovery.

14. The Parties agree that one original of this Agreement shall be created for each of the signatory parties for the convenience of all. The signature pages of each original shall be executed by the recipient and transmitted to counsel of record for PETITIONER, who shall send a copy of the fully executed document to all counsel of record. The multiple signature pages shall be regarded as, and given the same effect as, a single page executed by all Parties.

IN WITNESS THEREOF, the undersigned Parties do HEREBY AGREE to the form and execution of this Agreement.

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**

By:______________________________
Danielle Lopez
Associate Counsel – Regulatory

**GURBIR S. GREWAL**
**ATTORNEY GENERAL OF THE STATE OF NEW JERSEY, ATTORNEY FOR THE STAFF OF THE BOARD OF PUBLIC UTILITIES**

By:______________________________

**BRIAN LIPMAN**
**ACTING DIRECTOR, DIVISION OF RATE COUNSEL**

By:______________________________

DATED:

**ATTACHMENT I**

**STATE OF NEW JERSEY**
**BOARD OF PUBLIC UTILITIES**

| | | |
|---|---|---|
| IN THE MATTER OF THE PETITION OF | ) | |
| PUBLIC SERVICE ELECTRIC AND GAS | ) | PETITION |
| COMPANY FOR APPROVAL OF AN | ) | BPU DOCKET NOS. |
| INFRASTRUCTURE ADVANCEMENT | ) | EO________ |
| PROGRAM | ) | GO________ |

## ACKNOWLEDGEMENT OF AGREEMENT

The undersigned is an attorney, employee, consultant and/or expert witness for Division of the Rate Counsel, Board Staff, or an intervenor, who has received, or is expected to receive, Confidential Information provided by PSE&G or by another party (Producing Party) which has been identified and marked by the Producing Party as "Confidential Information." The undersigned acknowledges receipt of the Agreement of Non-Disclosure of Information Claimed to be Confidential and agrees to be bound by the terms of the Agreement.

Dated: __________________ By: _______________________________

(Name, Title and Affiliation)

# 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 Infrastructure Advancement Program

**BPU Docket No. ______________**

## DIRECT TESTIMONY

## OF

## WADE E. MILLER
## DIRECTOR – GAS TRANSMISSION AND DISTRIBUTION ENGINEERING
## INFRASTRUCTURE ADVANCEMENT PROGRAM - GAS

**November 4, 2021**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**
**DIRECT TESTIMONY**
**OF**
**WADE E. MILLER**
**DIRECTOR – GAS TRANSMISSION AND DISTRIBUTION ENGINEERING**
**INFRASTRUCTURE ADVANCEMENT PROGRAM - GAS**

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

A. My name is Wade E. Miller, and I am Director - Gas Transmission and Distribution (T&D) Engineering of Public Service Electric and Gas Company (PSE&G, or the Company), the Petitioner in this matter.

**Q. Please describe your responsibilities as Director of Gas Transmission and Distribution Engineering.**

A. As the Director of Gas T&D Engineering, I have the responsibility and accountability for three core functions of PSE&G's gas business. The first core function is delivering the natural gas. This includes gas control and system reliability to over 1.8 million customers. Delivering the gas also includes the operation and maintenance of 58 Metering and Regulating (M&R) stations, one Liquefied Natural Gas (LNG) plant, three Liquid Propane Air (LPA) plants, and one Liquid Propane (LP) storage facility. The second core function is gas asset management. This includes the safe and efficient engineering and design of PSE&G's gas transmission and distribution assets, capacity planning, corrosion control, replacement facility identification and prioritization, transmission pipeline maintenance, and the management of the Transmission and Distribution Integrity Management Programs. The third core function is business support and technical services. This includes the development of operating standards and procedures, material evaluation and specification, operator qualification and other programs.

**Q. Please describe your educational and professional background and qualifications.**

A. That information is provided in Schedule WEM-IAP-1, which is attached hereto.

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

A. My testimony supports the gas portion of PSE&G's proposed New Jersey Infrastructure Advancement Program (the Program or IAP) as it relates to the natural gas delivery system. The gas portion of the Program involves rebuilding seven gas M&R stations for needed modernization.

**Q. Are there other witnesses supporting the proposed IAP- Gas?**

A. The benefits associated with the M&R Upgrade Program are addressed in a cost benefit analysis being submitted on behalf of PSE&G by Ralph Zarumba and Trent Winstone – the Infrastructure Advancement Program – Electric and Natural Gas Cost-Benefit Panel, a group from Black & Veatch Management Consulting, LLC (Black & Veatch). This panel is referred to as the Electric and Natural Gas Cost-Benefit Panel.

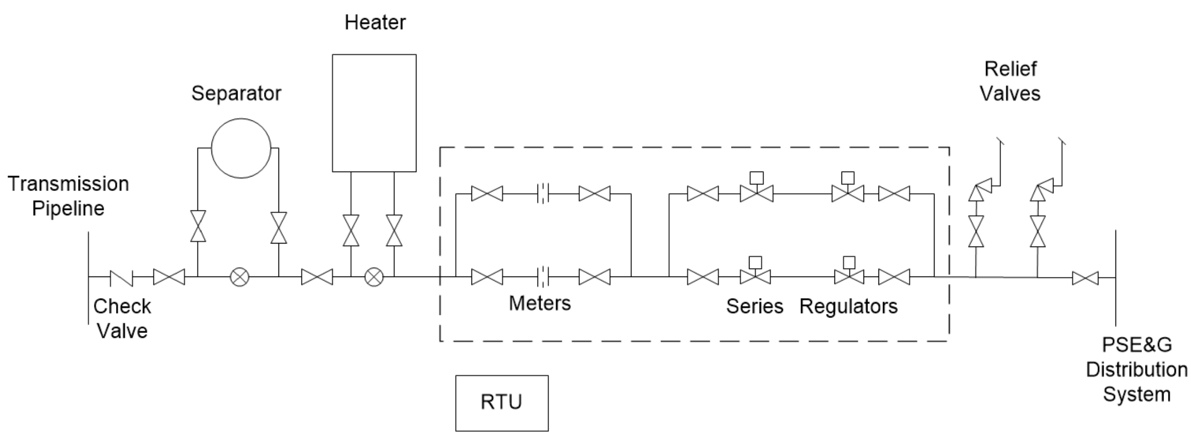
**Q. Please provide an overview of PSE&G gas operations.**

A. PSE&G provides gas distribution service and Basic Gas Supply Service (BGSS), under regulation by the New Jersey Board of Public Utilities (Board or BPU). PSE&G serves approximately 1.8 million gas customers in an area that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to West Deptford, New Jersey.

**Q. Please describe the functions performed at M&R stations and the circumstances that create a need to modernize these stations.**

A. A M&R station is a joint facility interconnecting an interstate pipeline system to PSE&G's

local distribution system and includes the land occupied and buildings, piping, equipment, controls, facilities and appurtenances owned by both parties. At an M&R station, custody of the gas is transferred from the pipeline company to PSE&G through piping and facilities designed to safely deliver the gas from the transmission system operating at hundreds of pounds per square inch (psi) pressure to the distribution system operating at tens of psi. The equipment at an M&R station typically includes a separator to remove any liquids that might be present in the gas stream before they can reach the other M&R equipment or the distribution system. A heater is required to raise the temperature of the flowing gas prior to reducing the pressure to avoid potential freezing conditions in and around the downstream gas piping. Meters measure the flow of gas through the station and regulators provide the controlled pressure reduction from transmission pressure to distribution pressure. Overpressure protection devices are safety devices installed downstream of the pressure regulators to ensure the safety of the distribution system in the unlikely event of a failure of the primary regulator to control the pressure reduction. Typical means of overpressure protection is through relief valves that will release gas to the atmosphere to keep the downstream pressure from rising too high. The station operation is controlled from PSE&G's Gas System Operations Center (GSOC) through a Remote Terminal Unit (RTU) located at the station. The following figure illustrates a generic M&R station:




PSE&G is proposing modernization of seven M&R stations with an average age of 58 years of service. All seven were designed to a former standard and have single regulation with downstream relief valves and three stations have upstream relief valves as well for PSE&G piping that is not rated for transmission line pressure. In an era of heightened awareness of the safe operation of the gas distribution system and the potential consequences of over-pressurizing the distribution system as well as the environmental consequences of methane releases to atmosphere it is important to take advantage of advancements in M&R station design.

**Q. Please provide an overview of the proposed investments.**

A. In the M&R Upgrade program, PSE&G seeks to modernize certain M&R stations by phasing out outdated designs, upgrading stations to series regulation design with a second level of overpressure protection for enhanced safety and reliability, and replacing aging equipment and facilities. Larger structures would be installed to house the regulating equipment and energy efficient heating equipment. Physical site security enhancements would also be installed at all stations. The proposed gas Program is consistent with the BPU's Infrastructure Investment Program (IIP) rules.

**Q. Why is PSE&G recommending the proposed investments now?**

A. The M&R Upgrade Program is being proposed to modernize the operation of M&R stations placed in service decades ago. These proposed M&R projects will maintain service reliability and reduce the potential for a large volume release of methane, a potent greenhouse gas. This Program, like the prior gas system modernization and reliability/resiliency programs—Gas System Modernization Program II (GSMP II) and Energy Strong II—will not only produce benefits for the environment, but for the Company's distribution system and for PSE&G customers alike. Reliability and modernization of distribution systems, particularly during this time when the pandemic has forced many to work from home, is imperative to meet the evolving needs of PSE&G's customers. This modernization program is fully justified at this time by the Company's risk analysis and consideration of the benefits to be realized coupled with the need to provide economic development to overcome the severe impact that the Covid-19 pandemic has had on New Jersey's economy by proposing projects that will provide much needed job opportunities.

**Q. Please summarize your conclusions and recommendations.**

A. For reasons noted above, PSE&G is requesting that the Board approve the M&R Upgrade Program. This Program involves an investment of approximately $140 million. The proposal will help revive the State's economy and stimulate job growth through capital expended on the projects, creating new employment opportunities while enhancing service and reliability and reducing potential emissions of methane, a potent greenhouse gas.

The M&R components of PSE&G's approved Energy Strong II filing were important investments to modernize the station design and upgrade equipment. As part of the ESII Program, the Company is modernizing six of its M&R stations that have an outdated design. The proposed M&R Upgrade Program continues this work. Analogous to the PSE&G Gas System Modernization program for our infrastructure of main and services, it is important to modernize the designs of M&R stations, which are the critical sources of gas supply into PSE&G's distribution system. The modernization enhances the safety and reliability of the system and delivers many specific benefits, including reducing the likelihood and consequence of equipment failure through the replacement of aging equipment, implementing modern design practices to reduce the potential for methane emissions, and enhancing physical security measures and noise abatement. New station design features and piping layout will enhance employee safety for performing operations and maintenance activities. The Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020 (signed into law on December 27, 2020) requires operators to update their inspection and maintenance plans to address minimizing releases of natural gas from pipeline facilities and the protection of the environment. The proposed design enhancements eliminate intermediate relief valves where applicable and dictate installation of two regulators in series as the primary means of overpressure protection, greatly reducing the likelihood of a gas release due to a regulator failure.

Lastly, as each project is completed, the safety, reliability and environmental performance benefits associated with that location are realized. Thus, customers do not need to wait for the conclusion of the program to receive benefits of the program.

**Q. How is the remainder of your testimony organized?**

A. My testimony is organized into five sections: (1) the alignment of Program with the Board's IIP rules; (2) a more detailed explanation of the M&R Upgrade Program projects; (3)

identification of the cost-benefit analysis submitted with this filing; (4) the significant benefits to New Jersey created by PSE&G's gas distribution system Program; and (5) reporting requirements.

## I. INFRASTRUCTURE INVESTMENT PROGRAM

**Q. Please describe the BPU's IIP rules.**

A. The IIP rules were adopted by the BPU "to allow a utility to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to provide safe and adequate service." The regulatory initiative is intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety.

**Q. Are the projects in the IAP - Gas eligible under the IIP rules?**

A. Yes. The IIP rules include projects that are related to safety, reliability, and/or resiliency, and that are non-revenue producing. The IAP gas projects all are related to safety and reliability and represent incremental capital spending, all of which would otherwise be completed beyond 2022 and all of which are non-revenue producing.

**Q. Are there minimal filing requirements associated with seeking accelerated rate recovery of infrastructure investments under the IIP rules?**

A. Yes. The location of all requirements under the IIP rules in the IAP – Gas filing is provided in Appendix 1 to the Petition. I will address the requirements related to program eligibility, capital expenditures, selection criteria, and reporting. Mr. Swetz will address requirements associated with cost recovery. Witnesses from Black & Veatch will address the benefits of the Program.

**Q. Is the Company proposing base capital expenditures on similar gas distribution projects as proposed for the IAP?**

A. Yes. The Company commits to spending at least 10 percent of the capital expenditures proposed for the IAP - Gas to be recovered in a base rate proceeding.

**Q. Is the Company proposing annual baseline spending levels over the life of the Program?**

A. Yes. Please see Schedule WEM- IAP -2 for the annual minimum baseline spending levels for gas delivery projects over the Program period.

**Q. What is the justification for the annual baseline budget spending levels?**

A. The annual minimum baseline spending levels proposed in Schedule WEM- IAP -2 are based on the 2022 gas capital depreciation level.

**Q. Is the Company proposing any limit to variations in annual spending?**

A. Yes. Consistent with the IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the Program. The Company will seek Board approval for any year-to-year variances from the BPU approved annual expenditure level that are expected to be greater than 10 percent.

**Q. Have you included the Company's actual gas delivery capital expenditures over the past five years and projected capital expenditures over the next five years by major category?**

A. Yes. Please see Schedule WEM-IAP-2 for the actual and projected gas delivery capital expenditures by major category from 2016 through 2026.

**Q. Has an engineering evaluation been done to determine the projects, in-service dates, costs and benefits of the proposed Program?**

A. Yes. PSE&G has conducted engineering evaluations of the various projects that comprise the M&R Upgrade Program. These analyses have helped determine specific projects, in service dates, and costs. Please see Schedule WEM-IAP-4. Furthermore, Black & Veatch has prepared a cost–benefit analysis for the Program as discussed in the testimony of the Electric and Gas Cost Benefit Analysis Panel.

**Q. Have you developed an annual budget for the gas portion of the Program?**

A. Yes. Please see Schedule WEM-IAP-3 for the monthly and annual capital expenditures for the Program. As shown in that schedule, the estimated capital expenditure dollar amount is approximately $140 million.

**Q. Is the Company proposing any reporting requirements associated with the gas portion of the Program?**

A. Yes. Consistent with the IIP rules, the Company is proposing semi-annual status reports on the Program. The reporting requirements are detailed later in my testimony.

## II. M&R UPGRADE PROGRAM

**Q. Please provide a more complete description of PSE&G's proposed M&R Upgrade Program.**

A. PSE&G is proposing to implement a program to systematically upgrade seven M&R stations. The purpose is to modernize M&R Station designs, reducing the likelihood and consequence of equipment failure. PSE&G has analyzed asset demographics, failure curves, and risk scoring for all of its M&R assets.

**Q. Which of PSE&G's M&R stations are included in this subprogram?**

A. The Brooklawn, Hillsborough, Hanover, Roseland, Hamilton, Trenton, and West Deptford M&R stations are included in the proposed program.

**Q. Why have these M&R stations been chosen for inclusion in this subprogram?**

A. These M&R stations were chosen for several reasons. All of these stations have an outdated design with single regulation runs. Three of the stations have upstream relief valves. This arrangement can lead to a methane emission release through the relief valves in the event of a single regulator failure.

In addition, all of these stations have a number of aging components, which in some cases contain parts that are unavailable or are no longer supported by the manufacturer.

The Brooklawn, Hillsborough, Hanover, Roseland, Hamilton, Trenton and West Deptford regulating buildings are not large enough to accommodate a modern design. In addition, the Hillsborough, Hamilton and Trenton stations are in proximity to residential neighborhoods. A release of gas from a relief valve at these locations could result in disruption to the locality given the sensitive surroundings. Upgrading to a modern design will greatly reduce the likelihood of a relief valve event.

These stations were prioritized using the PSE&G Asset Management Risk model as well as considering factors outside the scope of the model such as style and type of regulator and transmission piping that cannot be internally inspected. This model prioritizes stations using a risk matrix. The two main components of the matrix are consequence of failure and likelihood of failure. Consequence of failure is comprised of the following factors: safety impact, customer impact, asset reliability impact, and environmental impact. Each factor has specific criteria to calculate station consequence of failure, with examples such as stations located in sensitive areas, replacement part availability, and redundancy. Likelihood of failure is based upon equipment age, structural integrity, and station design. Equipment age and maintenance practices are used to plot assets along depreciation curves in order to calculate the likelihood of failure. The stations are organized in the risk matrix based upon their calculated likelihood of failure.

**Q. Are there other M&R stations that have the same outdated design as the ones included in the IAP?**

A. Yes. There are five additional stations with the same outdated design that have been prioritized for future modernization upgrades.

**Q. What advantage does the new design offer?**

A. The new design eliminates upstream relief valves where present, and calls for installation of two regulators in series as the primary means of overpressure protection, greatly reducing the likelihood of a gas release due to a regulator failure. The new design would employ an additional overpressure protection mode, which would operate in the event both the regulator and monitor were to fail, greatly improving safety. The new design also replaces aging equipment and facilities, provides noise abatement, locates pressure regulation within a controlled environment, and provides greater working access to equipment. In addition, modern heater technologies for higher efficiency and lower emissions would be installed. The upgrade also replaces piping subject to high pressure with lower stress pipe (less than 20% Specified Minimum Yield Strength (SMYS)). Taken together, these characteristics ultimately result in improved reliability, enhanced safety, and improved environmental performance. As part of the Program, major equipment that is near end of life condition would be replaced. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.

**Q. Please describe the proposed M&R modernization projects in prioritized order.**

A. The following table summarizes the proposed M&R modernization projects in prioritized order:

| M&R Station Modernization | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| M&R Station Priority | New Station | Proposed Construction Adjacent to Existing Station | Consolidate Existing Stations into New Building | Physical Security Enhancements | Replace Transmission pipe in HCA/MCA with higher strength pipe (< 20% SMYS at MAOP) | Remove Upstream Relief Valves - New Piping Rated at MAOP of Pipeline Company | New Design - Series Regulators with a Working Regulator and Monitor Regulator for Overpressure Protection | Downstream Relief Valves - 2nd Line of Overpressure Protection | Replacement of Obsolete Equipment - Hard to Repair - Hard to Find Suitable Replacement Parts | Reduces Methane Release Likelihood |
| Brooklawn | x | x | x | x | x | | x | x | x | x |
| Hillsborough | x | x | | x | x | x | x | x | x | x |
| Hanover | x | x | | x | | x | x | x | x | x |
| Roseland | x | x | | x | | x | x | x | x | x |
| Hamilton | x | x | x | x | | | x | x | x | x |
| Trenton | x | x | x | x | | | x | x | x | x |
| West Deptford | x | x | | x | x | | x | x | | x |

At all locations the new modernized station would be constructed adjacent to the existing station with physical site security enhancements installed. The Hamilton M&R site is a newly identified TSA critical site in accordance with the recently published TSA physical security guidelines in 2021 and physical site security enhancements would be installed in accordance with TSA critical site standards.

All stations would have the new PSE&G standard design of series regulators with a working regulator and monitor regulator for overpressure protection and downstream relief valves as a second line of overpressure protection. The new design would reduce the likelihood of a methane release at all the stations.

The Brooklawn, Hamilton and Trenton stations each currently have pressure regulation for two distribution systems in two separate buildings, these would be consolidated into a single new building at each station.

At the Brooklawn, Hillsborough, and West Deptford stations existing transmission piping that cannot be internally inspected would be replaced with piping designed to operate below 20% SMYS at the full pipeline company Maximum Allowable Operating Pressure (MAOP). The replacement of buried transmission piping with higher strength and/or thicker wall pipe that is below 20% SMYS within the station will have several benefits. It will eliminate the need for certain assessments that are required as part of the Federal code for pipelines in high consequence and moderate consequence areas. High consequence areas and moderate consequence areas require assessments every 7 and 10 years respectively. Standard assessment techniques such as In Line Inspection (ILI) or Direct Assessment (DA) within M&R stations are typically not feasible due to the configurations of the piping in the station. Eliminating such assessment requirements would result in long term O&M savings. In addition, the higher strength and/or thicker wall pipe has the added benefit of enhancing the overall safety and integrity of the lines within the station as a result of the pipe's improved strength and toughness characteristics.

The Hillsborough, Hanover and Roseland station upgrades would eliminate upstream relief valves and the potential for a high pressure, large volume, methane emission release through the relief valves in the event of a single regulator failure.

At the Trenton M&R station boot-style regulators would be replaced with control valve style regulators for improved performance.

**Q. Have you prepared cost estimates for these proposed projects?**

A. Yes, we have prepared class 5 level estimates for each project. These costs have been developed using the actual cost and construction experience from Energy Strong and other PSE&G construction projects of this type and are considered office estimates. They are summarized in Schedule WEM- IAP -3.

**Q. What resources are required to complete the M&R Upgrade Program?**

A. The proposed M&R Upgrade program requires $140 million over four years for full implementation. The IIP regulations require capital expenditures on projects similar to those proposed within the Program in an amount of at least 10 percent of the Program. In the IAP - Gas, the Company will meet the 10 percent requirement of $14 million by not seeking recovery through the Program rate adjustments for that portion of the investment that will be recovered through a base rate proceeding.

## IV. COST-BENEFIT ANALYSIS

**Q Did the Company prepare a cost-benefit analysis of this gas portion of the Program?**

A. Yes. Black & Veatch has completed a cost-benefit analysis for PSE&G of the proposed IAP - Gas. The Black & Veatch report is the result of analysis of both quantifiable and qualitative benefits of the gas portion of the Program. Their report is being submitted as part of the Electric and Natural Gas Cost-Benefit Panel's testimony.

## V. BENEFITS TO NEW JERSEY'S ECONOMY

**Q. How will the infrastructure investments proposed herein benefit New Jersey's economy?**

A. The gas portion of the IAP will provide benefits to both PSE&G's customers and New Jersey's economy. This component of the proposed Program will result in additional skilled jobs. Using the methodology for job creation from the introductory materials to the Board's August 7, 2017 proposal for the IIP regulations, this portion of the proposed program would create an estimated 405 fulltime direct full-year jobs and 503 indirect full-year jobs over the course of the Program.

**Q. Please elaborate on the labor and other resources required to successfully complete this Program.**

A. The Company anticipates an increase in staffing for engineering, project management, and construction oversight in order to carry out the Program each year. As was the case for the Energy Strong and GSMP Programs, PSE&G will continue to utilize a combination of internal labor and outside contractors for the Program. The Program will support employment opportunities for suppliers as well.

**Q. How does a multi-year program affect the work effort involved with the Program?**

A. The construction projects proposed in the gas portion of Program require between eighteen months and four years to complete. The multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

## VI. PROGRAM REPORTING

**Q. Does the Company intend to provide regular reporting on its progress?**

A. Yes. PSE&G proposes to provide semi-annual reports consistent with the requirements of the IIP rule. The rule requires the following:

1. Forecasted and actual costs of the Infrastructure Investment Program for the applicable reporting period, and for the Program to date, where Program projects are identified by major category;
2. The estimated total quantity of work completed under the Program identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided;

3. Estimated completion dates for the Infrastructure Investment Program as a whole, and estimated completion dates for each major Program category;
4. Anticipated changes to Infrastructure Investment Program projects, if any;
5. Actual capital expenditures made by the utility in the normal course of business on similar projects, identified by major category; and
6. Any other performance metrics concerning the Infrastructure Investment Program required by the Board.

**Q. Is it correct that PSE&G is proposing a cost recovery mechanism for the Program, including the gas portions of the Program that you are supporting?**

A. Yes. The Direct Testimony of Stephen Swetz explains the cost recovery mechanism proposed by the Company.

**Q. Please summarize your recommendations.**

A. Even as PSE&G continues to provide safe and reliable service to customers, I recommend approval of the proposed M&R Upgrade Program to rebuild the seven specified M&R stations to modern design practices, greatly reducing the potential for gas release; maintaining the reliability and enhancing the safety of operation; and promoting job creation in New Jersey that is vital to our state's economy.

**Q. Does this conclude your prepared direct testimony?**

A. Yes.

# CREDENTIALS OF WADE E. MILLER DIRECTOR – GAS TRANSMISSION & DISTRIBUTION ENGINEERING

I received a Bachelor of Science Degree in Mechanical Engineering from The College of New Jersey in 2000. I also received my Engineer-In-Training certification in 2000. I became licensed as a Professional Engineer with the State of New Jersey in 2006. I also received my certification as a Project Management Professional with the Project Management Institute in 2006. In 2007, I earned the designation of Registered Gas Distribution Professional from the Gas Technology Institute.

I was employed by PSE&G in June 2000 as an Associate Engineer in the Trenton Gas Distribution District where I began my training program and was mentored under a senior engineer. In 2001, I was relocated from Trenton District to Burlington District where I acted as the sole engineer. In 2003, I was promoted to the position of Lead Engineer. During my first four years, I provided engineering and managerial support for all phases of planning, design, construction, and maintenance of the gas distribution system while adhering to the established capital and O&M budgets.

In 2004, I was promoted to the position of Supervising Engineer in the Asset Management department and given the responsibility for the approval of all engineering designs associated with new and replacement main requisitions, district and pound to pound regulator installations, large volume meter sets, higher than normal delivery pressure requests, gas load increase submittals, and written gas out procedures covering six of the twelve gas districts. In addition, I was also responsible for developing the replacement main plans for these same six districts including identification and prioritization.

In 2007, I was promoted to the position of Planning & Design Manager in the Asset Management department overseeing a team of engineers and given the responsibility for developing and maintaining Company design standards for the Gas system, maintaining system integrity, and providing technical support to gas field operations. I was also responsible for developing the annual replacement main, regulator, and system reinforcement programs for the Company.

In April 2014, I assumed my current position, which involves overall responsibility for system planning and reliability as well as the safe and efficient engineering, design, and operating procedures of PSE&G's gas transmission and distribution assets. I am also responsible for the management of the Transmission and Distribution Integrity Management Programs, operation and maintenance of 58 metering & regulating stations, four gas plants, and gas control to over 1.8 million customers.

I am the Committee sponsor for PSE&G's Gas Engineering Committee which is responsible for approval of action items due to regulatory changes and changes to Company technical manuals, the Operator Qualification program, Integrity Management programs, and new technology and materials.

I am a member of the Operations Safety Regulatory Action committee and the Engineering committee of the American Gas Association. In addition, I am a member of the Executive Committee of the Society of Gas Operators.

**PSE&G INFRASTRUCTURE ADVANCEMENT PROGRAM - GAS**

Attachment 1

## Gas Delivery Capital Summary (2012 - 2021)

Schedule WEM-IAP-2A

| Capital Category ($M) | 2016 Full Year Actual | 2017 Full Year Actual | 2018 Full Year Actual | 2019 Full Year Actual | 2020 Full Year Actual | 2021 Full Year Forecast |
|---|---|---|---|---|---|---|
| **Total Base** | **210** | **352** | **436** | **219** | **202** | **237** |
| | | | | | | |
| **New Business** | 79 | 74 | 95 | 90 | 100 | 97 |
| **GSMP I** | | | | | | |
| Recovery Mechanism | 159 | 245 | 201 | 48 | | |
| Stipulated Base | 95 | 100 | 94 | | | |
| **Energy Strong I** | 70 | 5 | 0 | | | |
| **GSMP II** | | | | | | |
| Recovery Mechanism | | | | 288 | 407 | 480 |
| Stipulated Base | | | | 60 | 46 | 53 |
| **Energy Strong II** | | | | 0 | 4 | 30 |
| **Total Capital $** | **$ 613** | **$ 774** | **$ 826** | **$ 703** | **$ 759** | **$ 897** |

### Base Breakdown by Major Category

| | | | | | | |
|---|---|---|---|---|---|---|
| Replace Facilities | $ 77 | $ 174 | $ 229 | $ 64 | $ 57 | $ 53 |
| System Reinforcement | $ 60 | $ 71 | $ 73 | $ 53 | $ 60 | $ 71 |
| Environmental Regulatory | $ 27 | $ 36 | $ 38 | $ 34 | $ 30 | $ 31 |
| Replace Meters | $ 37 | $ 57 | $ 61 | $ 60 | $ 40 | $ 61 |
| Support Facilities | $ 9 | $ 13 | $ 35 | $ 8 | $ 15 | $ 22 |
| **Total Base $** | **$ 210** | **$ 352** | **$ 436** | **$ 219** | **$ 202** | **$ 237** |

**PSE&G INFRASTRUCTURE ADVANCEMENT PROGRAM - GAS** Attachment 1

## Gas Delivery Capital Summary (2022 - 2026)

Schedule WEM-IAP-2B

| Capital Category ($M) | 2022 Full Year Plan | 2023 Full Year Plan | 2024 Full Year Plan | 2025 Full Year Plan | 2026 Full Year Plan |
|---|---|---|---|---|---|
| **Total Base** | **176** | **176** | **176** | **176** | **176** |
| | | | | | |
| **New Business** | 99 | 101 | 103 | 106 | 98 |
| **GSMP II** | | | | | |
| Recovery Mechanism | 365 | 36 | | | |
| Average Projected Stipulated Base | 70 | 71 | | | |
| **Energy Strong II** | | | | | |
| Recovery Mechanism | 40 | 1 | | | |
| Projected Stipulated Base | 18 | 9 | | | |
| **IAP - Gas M&R** | | | | | |
| Recovery Mechanism | 1 | 15 | 76 | 31 | 4 |
| Projected Stipulated Base | 0 | 2 | 8 | 3 | 0 |
| **IAP - Electric Vehicle** | | | | | |
| Recovery Mechanism | 1 | 17 | 21 | 10 | 2 |
| Projected Stipulated Base | 0 | 2 | 2 | 1 | 0 |
| **Total Capital $** | **$ 770** | **$ 428** | **$ 386** | **$ 327** | **$ 281** |

### Base Breakdown by Major Category

| | | | | | |
|---|---|---|---|---|---|
| Replace Facilities | $ 36 | $ 47 | $ 33 | $ 41 | $ 39 |
| System Reinforcement | $ 41 | $ 50 | $ 51 | $ 53 | $ 54 |
| Environmental Regulatory | $ 27 | $ 31 | $ 31 | $ 31 | $ 31 |
| Replace Meters | $ 71 | $ 46 | $ 58 | $ 49 | $ 50 |
| Support Facilities | $ 2 | $ 2 | $ 2 | $ 2 | $ 2 |
| **Total Base $*** | **$ 176** | **$ 176** | **$ 176** | **$ 176** | **$ 176** |

*The Company proposes to maintain minimum base level spending from 2022-2026 at the level shown above.

**PSE&G INFRASTRUCTURE ADVANCEMENT PROGRAM - GAS** ATTACHMENT 1

**Gas Metering and Regulating (M&R) Upgrade Subprogram Cash Flows** Schedule WEM-IAP-3

| Cash Flows ($000s) | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program Year - 2022** | | | | | | | | | | | | | |
| Direct In-Service | | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| CWIP Spending | | | | | | | $ 64,334 | $ 64,334 | $ 64,334 | $ 164,566 | $ 167,756 | $ 169,252 | $ 694,573 |
| COR | | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 64,334** | **$ 64,334** | **$ 64,334** | **$ 164,566** | **$ 167,756** | **$ 169,252** | **$ 694,573** |
| **Program Year - 2023** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 539,771 | $ 442,480 | $ 982,251 |
| CWIP Spending | $ 615,953 | $ 679,753 | $ 771,238 | $ 978,649 | $ 1,027,295 | $ 1,267,455 | $ 2,020,330 | $ 2,115,240 | $ 1,954,664 | $ 1,785,733 | $ 938,405 | $ 938,405 | $ 15,093,119 |
| COR | $ 3,210 | $ 3,210 | $ 3,374 | $ 3,374 | $ 3,865 | $ 6,486 | $ 8,124 | $ 11,399 | $ 11,399 | $ 8,124 | $ 4,848 | $ 3,865 | $ 71,277 |
| **Total** | **$ 619,163** | **$ 682,963** | **$ 774,612** | **$ 982,023** | **$ 1,031,160** | **$ 1,273,941** | **$ 2,028,453** | **$ 2,126,639** | **$ 1,966,063** | **$ 1,793,856** | **$ 1,483,024** | **$ 1,384,750** | **$ 16,146,647** |
| **Program Year - 2024** | | | | | | | | | | | | | |
| Direct In-Service | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 14,960 | $ 3,582,313 | $ 2,935,349 | $ 6,667,261 |
| CWIP Spending | $ 3,640,985 | $ 3,975,935 | $ 4,538,401 | $ 5,924,623 | $ 6,248,105 | $ 8,466,828 | $ 13,146,633 | $ 12,909,419 | $ 11,233,786 | $ 6,206,799 | $ 489,830 | $ 489,830 | $ 77,271,173 |
| COR | $ 24,226 | $ 24,226 | $ 25,315 | $ 25,315 | $ 28,583 | $ 46,009 | $ 56,901 | $ 78,684 | $ 78,684 | $ 56,901 | $ 35,118 | $ 28,583 | $ 508,544 |
| **Total** | **$ 3,680,171** | **$ 4,015,121** | **$ 4,578,676** | **$ 5,964,898** | **$ 6,291,647** | **$ 8,527,797** | **$ 13,218,494** | **$ 13,003,063** | **$ 11,327,430** | **$ 6,278,660** | **$ 4,107,260** | **$ 3,453,761** | **$ 84,446,978** |
| **Program Year - 2025** | | | | | | | | | | | | | |
| Direct In-Service | $ 36,287 | $ 36,287 | $ 36,287 | $ 36,287 | $ 27,215 | $ 27,215 | $ 27,215 | $ 27,215 | $ 27,215 | $ 27,215 | $ 1,467,220 | $ 1,467,220 | $ 3,242,878 |
| CWIP Spending | $ 1,505,507 | $ 1,644,107 | $ 1,887,217 | $ 2,445,379 | $ 2,593,448 | $ 3,643,627 | $ 5,736,369 | $ 5,126,851 | $ 4,354,695 | $ 1,637,430 | $ - | $ - | $ 30,574,628 |
| COR | $ 9,072 | $ 9,072 | $ 9,571 | $ 9,571 | $ 11,066 | $ 19,043 | $ 24,029 | $ 29,014 | $ 29,014 | $ 16,052 | $ 14,058 | $ 14,058 | $ 193,620 |
| **Total** | **$ 1,550,866** | **$ 1,689,466** | **$ 1,933,075** | **$ 2,491,237** | **$ 2,631,729** | **$ 3,689,885** | **$ 5,787,613** | **$ 5,183,080** | **$ 4,410,924** | **$ 1,680,697** | **$ 1,481,278** | **$ 1,481,278** | **$ 34,011,126** |
| **Program Year - 2026** | | | | | | | | | | | | | |
| Direct In-Service | $ 1,406,202 | $ 1,406,202 | $ 1,406,202 | $ 14,487 | $ 9,658 | $ 9,658 | | | | | | | $ 4,252,408 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | | $ - |
| COR | $ 14,058 | $ 14,058 | $ 14,058 | $ - | $ - | $ - | | | | | | | $ 42,173 |
| **Total** | **$ 1,420,260** | **$ 1,420,260** | **$ 1,420,260** | **$ 14,487** | **$ 9,658** | **$ 9,658** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 4,294,582** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ 1,457,449 | $ 1,457,449 | $ 1,457,449 | $ 65,734 | $ 51,833 | $ 51,833 | $ 42,175 | $ 42,175 | $ 42,175 | $ 42,175 | $ 5,589,304 | $ 4,845,048 | $ 15,144,798 |
| CWIP Spending | $ 5,762,445 | $ 6,299,795 | $ 7,196,855 | $ 9,348,651 | $ 9,868,847 | $ 13,377,910 | $ 20,967,665 | $ 20,215,843 | $ 17,607,478 | $ 9,794,527 | $ 1,595,990 | $ 1,597,486 | $ 123,633,493 |
| COR | $ 50,566 | $ 50,566 | $ 52,317 | $ 38,260 | $ 43,514 | $ 71,538 | $ 89,053 | $ 119,098 | $ 119,098 | $ 81,076 | $ 54,023 | $ 46,505 | $ 815,614 |
| **Total** | **$ 7,270,459** | **$ 7,807,809** | **$ 8,706,621** | **$ 9,452,645** | **$ 9,964,195** | **$ 13,501,281** | **$ 21,098,893** | **$ 20,377,115** | **$ 17,768,751** | **$ 9,917,778** | **$ 7,239,317** | **$ 6,489,040** | **$ 139,593,905** |

* The M&R Subprogram Cash Flow reflects 100% of the program's cash flow, some of which will be invested in base capital - pursuant to the BPU's regulations entitled Infrastructure Investment And Recovery

# ATTACHMENT 1
# Schedule WEM-IAP-4

# CONFIDENTIAL

**TO BE PROVIDED UPON EXECUTION OF THE NON-DISCLOSURE AGREEMENT**

# 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 Infrastructure Advancement Program

**BPU Docket No. _______________**

## DIRECT TESTIMONY

## OF

## EDWARD F. GRAY
## DIRECTOR – TRANSMISSION AND DISTRIBUTION ENGINEERING
## INVESTMENT ADVANCEMENT PROGRAM

**November 4, 2021**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**
**DIRECT TESTIMONY**
**OF**
**EDWARD F. GRAY**
**DIRECTOR – TRANSMISSION AND DISTRIBUTION ENGINEERING**
**INVESTMENT ADVANCEMENT PROGRAM**

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

A. My name is Edward F. Gray, and I am the Director of Transmission and Distribution Engineering for Public Service Electric and Gas Company (PSE&G, or the Company), the Petitioner in this matter. My educational and professional background and experience are set forth in the attached Schedule EFG-IAP-1.

**Q. Please describe your responsibilities as Director of Transmission and Distribution Engineering as it relates to electric delivery.**

A. I am responsible for the plant design, reliability, and asset life cycles for PSE&G's electric distribution and transmission system, serving 2.4 million electric customers. I am responsible for ensuring the reliability of PSE&G's electric delivery assets and overseeing various functions that support the provision of safe, adequate, proper, and reliable electric delivery service.

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

A. My testimony will support the electric portion of PSE&G's proposed Infrastructure Advancement Program (the Program or IAP). PSE&G seeks Board approval for an infrastructure program that will harden the electric infrastructure from the effects of major storm events, improve reliability for customers, support the adoption of electric vehicles (EV) for both customers and PSE&G's fleet, and ensure safe and reliable service by proactive replacement of facilities near the end-of-life. These investments will improve the Distribution system from the substation to the customer meter, including significant work impacting the “last mile” of the Distribution system. By accelerating investments and making improvements, the Program also supports economic stimulus and job creation both internal to PSE&G and to external organizations that will be utilized to execute the various aspects of the program.

**Q. Please provide an overview of the IAP Electric program**

A. The IAP for electric is a four year $708 million program comprised of three subprograms:

1. Electric Outside Plant: Overhead and Underground facilities that supply customers from the substation to the customer’s meter.
2. Substation Modernization: Upgrading and modernizing of 26kV and 4kV substation facilities
3. Electric Vehicle (EV) Charging Instructure: Construction of charging infrastructure at PSE&G facilities required to support the electrification of PSE&G’s vehicle fleet.

Each of these subprograms is discussed more fully below.

**Q. Why is PSE&G recommending the proposed investments now?**

A. In alignment with the Board’s Infrastructure Investment Program (IIP) regulations, this program provides for investments related to reliability, resiliency, and/or the provision of safe and adequate service. Mitigating the economic impacts of COVID-19 and satisfying the goals outlined in the NJ Energy Master Plan (EMP) represent unique challenges for the electric distribution system that this program addresses.

COVID-19 has been unprecedented in both its impacts on customer behavior and economic activity. For customers, working from home increases the focus on reliability, as the home now doubles as a place of business. Service interruptions can now directly affect our customers’ home life and work days. Unlike many downtown or other office arrangements, where redundancy is provided through either utility network service or back-up generation provided at the place of work, redundancy is not built into PSE&G's residential distribution system. This "new normal", with 45%[1] of employers moving towards either a permanent or hybrid work-from-home arrangement, requires that electric distribution companies like PSE&G provide additional levels of reliability. In addition, the EMP and New Jersey's statutory goals for EV adoption will further increase the need for higher levels of home based reliability, as power outages will now also impact customers' ability to charge their vehicles and thus their ability to travel. The Plug In Vehicle Act (PIV), signed by Governor Murphy on January 17, 2020 calls for the adoption of 330,000 EV light duty vehicles (LDV) by 2025, representing 5% of all LDV's. By 2035, the PIV calls for the adoption of 2,000,000 EV LDV's, and by 2040 the PIV calls for 85% of all new registrations to be EV.

The Electric Outside Plant, Substation Modernization, and EV Charging Infrastructure subprograms proposed in the IAP serve to address the "new normal" of PSE&G's customers and to advance the state's energy goals.

Electric Outside Plant

The Electric Outside Plant projects outlined in this program will improve reliability for both blue sky and storm conditions by upgrading facilities across the service territory and include both overhead and underground infrastructure. The projects complement the Contingency Reconfiguration (CR) program being executed as part of PSE&G's Energy

[1] "Remote Work Persistent and Trending" by Lydia SAAD and Ben Wigert, PH. D. Gallup Data, October 13, 2021. https://news.gallup.com/poll/355907/remote-work-persisting-trending-permanent.aspx

Strong II program. The CR subprogram focuses on limiting the number of customers impacted by an outage and enabling faster restoration once an outage occurs. These IAP Electric Outside Plant projects focus primarily on preventing outages from occurring through upgraded facilities or reducing the damage experienced, thus reducing restoration times. Proactive upgrades will be more cost effective in the long run by avoiding future corrective maintenance costs and customer outages, and will support economic and job growth immediately.

EV charging will introduce high demand loads in existing areas and place new challenges on the electric system, and the Electric Outside Plant subprogram is a significant step to support the adoption of this technology. Traditionally, new loads have been forecasted by predicting new customer additions through new construction and/or redevelopment. EV adoption, however, will increase the peak demands of existing customers in both residential and commercial areas in relatively short time frames compared to new building construction. For example, a new level 2 charger at a residential home has a peak demand ranging from 7kW to 10kW. This effectively doubles the load of residential customers and can stress the local overhead transformers, secondary and service wiring. PSE&G is proposing investments to support EV adoption in areas where the local design is highly likely to be impacted by EV adoption.

These new higher loads from EV and the Distributed Energy Resource (DER) goals outlined in the EMP will also impact the voltage profile of PSE&G's circuits by: (1) creating new loads that did not exist previously, and (2) introducing new intermittent generation sources. These goals will require a significant upgrades to PSE&G's system in the form of enhanced voltage control through upgraded system capacitors. PSE&G is proposing the installation of new capacitors, new vacuum switches to replace oil filled switches, and a modern controller with remote communication that can be integrated with the new communication system and Advanced Distribution Management System (ADMS) being implemented as part of Energy Strong II.

Substation Modernization Subprogram

The Substation Modernization Subprogram is being proposed to maintain service reliability, resiliency and safety through planned replacements, and to reduce service interruptions and emergent replacements due to equipment failure. The subprogram focuses on upgrades of both 4kV stations as well as 26kV switchyards, which supply stations and customers throughout the PSE&G service territory. This proposed work represent projects that need to be executed at some point in the future, and thus accelerating the project timelines supports economic stimulus through a program that can be efficiently planned and executed while avoiding unplanned or emergency repairs.

EV Charging Infrastructure Subprogram

Finally, the EV Charging Infrastructure Subprogram is being proposed to support both economic stimulus and the EMP goals by accelerating the installation of charging facilities at PSE&G locations to charge PSE&G fleet vehicles for Electric, Gas and Customer Operations. These facilities are needed to support the electrification of PSE&G's fleet and also offer the benefits of economic expansion by way of outsourcing construction of all behind the meter work.

**Q. Please summarize your conclusions and recommendations.**

A. PSE&G has continued to invest in its delivery system over its 118-year history. Those investments have allowed PSE&G to meet its obligations as well as win numerous awards for reliability.[2] PSE&G is proud of the system it has built and the decisions made over the years to invest in the current system. The impacts of COVID-19 on customer behavior and the goals outlined in the EMP require greater reliability and additional system investment, and PSE&G believes it is at a critical decision point where choices need to be made. PSE&G can continue to invest prudently in the existing electric system and current designs, or PSE&G can take more comprehensive action and proactively make investments in the electric delivery systems in alignment with the Board's proposed IIP regulatory initiative. Through the IAP, PSE&G proposes to make infrastructure investments that will have significant impacts for system-wide reliability, hardening and resiliency, supporting economic growth while looking towards the future needs of an evolving grid to support EMP goals.

The programs proposed improve customer reliability programs across the system for both blue sky and storm conditions. The programs include a comprehensive approach to reliability improvement including underground, overhead and service upgrades with targeted programs. This approach will allow for proactive replacement at lower costs and avoid outages that occur during a normal "run to failure" mode of operation.

The EMP program goals require investments that are "make ready" for EV adoption, particularly in older service areas and for improved technology to monitor and control voltage through the system. By making these investments proactively, PSE&G will start making the

[2] PSE&G has consistently been ranked as the most reliable electric utility in the mid-Atlantic region, as well as the most reliable utility the United States. PA Consulting, the industry's benchmarking group, has awarded PSE&G the most reliable electric utility in America five times, most recently in November 2012, when PSE&G was recognized as the most reliable electric utility in America in 2011. In addition, PSE&G has been named by PA Consulting as the most reliable electric utility in the mid-Atlantic region for the last 19 years (2001-2019). PSE&G also won PA Consulting's 2011 Outstanding Response to a Major Outage Event award for its performance during Hurricane Irene and the October 2011 snowstorm.

necessary upgrades to ensure that the Distribution system can support the EMP goals and position PSE&G for increased DER and EV adoption. PSE&G is aggressively working to add capacity to the system to address existing load issues; however, in anticipation of the impacts of electrification and to support the EMP, these proposed investments are a necessary addition to work PSE&G is already undertaking.

Finally, the substation modernization investments are being proposed to address assets that are near end-of-life, where the primary mode of failure is the result of age. These facilities are typically not impacted by storms or external factors (i.e., vegetation, animal contacts) and have high replacement costs. PSE&G has significant numbers of assets in this category, where an ongoing program of replacement well beyond historical investment can help ensure and enhance the provision of safe and reliable service that the BPU requires and customers currently receive and expect from PSE&G. These assets have performed well, as demonstrated by PSE&G's sustained reliability performance, and keeping them in service for long durations has helped keep customer rates down. The average age of these PSE&G facilities is typically higher than the industry average, which reflects the age of PSE&G's service territory. In most circumstances, this equipment has exceeded its book depreciation life. The substation projects that I will describe later include substations and switching stations investments in stations with age ranges from 50 years to 92 years.

All of these subprograms, including the EV Charging Infrastructure subprogram, support one of the overriding goals of this filing: to support job growth and economic activity in New Jersey. PSE&G is requesting the Board approve the proposed Electric Stimulus program for a four year (48 month) term, permitting investment of approximately $708 million for electric delivery.

**Q. How is the remainder of your testimony organized?**

A. My testimony is organized into six main sections: (1) the alignment of Electric IAP with the Board's Infrastructure Investment Program regulations; (2) Electric Outside Plant Subprogram; (3) Substation Modernization Subprogram; (4) EV Charging Infrastructure Subprogram; (5) benefits to New Jersey created by PSE&G's IAP, and (6) reporting. Within the Electric Outside Plant subprogram I will discuss how the individual projects will support improved reliability and EMP goals and objectives. Within the Substation Modernization Subprogram I will discuss the West Orange project, 26kV switching station upgrades and 4kV substation modernization projects. In the EV Charging Infrastructure subprogram I will discuss the facility upgrades proposed to enable EV charging at all PSE&G reporting facilities.

## <u>INFRASTRUCTURE INVESTMENT PROGRAM REGULATIONS</u>

**Q. What are the Infrastructure Investment Program ("IIP") regulations?**

A. They are regulations adopted by the BPU in 2018 "to provide a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment."

**Q. Are the projects in the Investment Advancement Program eligible under the IIP proposal?**

A. Yes. As stated in the IIP regulations, specifically in N.J.A.C. 14:3-2A.2(a):

(a) Eligible projects within an Infrastructure Investment Program shall be:

1. Related to safety, reliability, and/or resiliency;

2. Non-revenue producing;
3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and
4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition.

The IAP subprograms all meet these criteria. PSE&G is requesting Board approval to implement this program as consistent with the IIP policy and in the best interests of PSE&G's customers.

**Q. Are there minimum filing requirements associated with seeking accelerated recovery of infrastructure investments under the IIP regulations?**

A. Yes. The location of all requirements under the IIP regulations in the IAP filing is provided in Appendix 1 to the Company's Petition. I will address the requirements related to program eligibility, capital expenditures, selection criteria, and reporting for the proposed electric investments. Mr. Swetz will address requirements associated with cost recovery. Cost benefit analysis are also being submitted on behalf of PSE&G by groups from Black & Veatch and 1898 & Co. part of Burns and McDonnell.

**Q. Is the Company proposing base capital expenditures on similar electric distribution projects as proposed for the IAP Program?**

A. Yes. Consistent with the IIP rules, the Company commits to base rate treatment of investments in an amount at least 10 percent of the capital expenditures recovered through the recovery mechanism proposed for the electric IAP Program. These capital expenditures will be on work similar to that proposed to be recovered under the IAP cost recovery mechanism.

**Q. Is the Company proposing annual baseline spending levels over the life of the Program?**

A. Yes. Please see Schedule EFG-IAP-2B for the annual baseline spending levels for electric projects over the IAP period.

**Q. What is the justification for the annual baseline budget spending levels?**

A. The annual baseline spending levels proposed in Schedule EFG-IAP-2B are the Company's projected baseline capital budget, along with an additional amount of proposed base rate recovery spending on work that is similar to that which is being proposed for the IAP cost recovery mechanism. The annual base line spend total plus the proposed additional "similar work" provides for the capital expenditures required to satisfy PSE&G's obligation to provide safe and adequate utility service.

**Q. Is the Company proposing any limit to variations in annual spending?**

A. Yes. Consistent with the IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the Program. The Company will seek Board approval for any year-to-year variances that are expected to be greater than 10 percent.

**Q. Have you included the Company's actual capital expenditures over the past five years and projected capital expenditures over the next five years by major category?**

A. Yes. Please see Schedule EFG-IAP-2A for the actual capital expenditures by major category from 2016-2021, and Schedule EFG-IAP-2B for the projected capital expenditures by major category from 2022 through 2026.

**Q. Has an engineering evaluation been done to determine the projects, in-service dates, costs and benefits of the proposed Program?**

A. Yes. My testimony below details the projects proposed for the Program, how and why they were selected, the monthly forecasted capital expenditures and the cost estimates, including how those cost estimates were developed. A cost benefit analysis of the Electric Outside Plant and Substation Modernization subprograms is being provided in testimony provided by Black & Veatch. The cost benefit analysis of the EV Charging Infrastructure Subprogram is being provided in testimony by 1898 & Co. These cost benefit analyses are being sponsored by the Electric and Gas Cost Benefit Analysis Panel and the EV Charging Infrastructure Cost Benefit Analysis Panel.

**Q. Have you developed an annual budget for the IAP Electric Program?**

A. Yes. Please see Schedule EFG-IAP-3 for the monthly and annual capital expenditures for the Program. As shown in Schedule EFG-IAP-3, the maximum capital expenditure dollar amount the Company seeks to recover through the Electric IAP is $707 million.

**Q. Is the Company proposing any reporting requirements associated with IAP?**

A. Yes. Consistent with the IIP, the Company is proposing semi-annual status reports on the Program. The reporting requirements are detailed later in my testimony.

## SUBSTATION MODERNIZATION SUBPROGRAM

**Q. Please provide an overview of PSE&G's proposed Substation Modernization Subprogram.**

A. The Company proposes the following three projects within the Substation Modernization Subprogram:

- The West Orange Switching Station project is a proposed upgrade to the largest 26kV switching station in PSE&G's service territory.
- The 26kV switchyard upgrade project represents a list of prioritized upgrades at 14 stations across the service territory. This project proposes to replace breakers, relays and associated equipment to improve performance.
- The 4kV substation modernization project proposes replacement of aged substation facilities for five stations.

The 4 kV substation modernization projects were identified through the risk model and scoring outlined as part of the Energy Strong II program, which has been utilized along with engineering studies to identify and prioritize this work. Replacement of these facilities will enhance PSE&G's continued provision of safe and reliable service.

**1. West Orange Switching Station**

**Q. Please provide an overview of PSE&G's proposal with respect to West Orange Switching Station.**

A. The West Orange 26kV Replacement Project will replace the existing, 92 year old, 26kV Air Insulated Station (AIS) with new sheltered aisle switchgear. West Orange is a 26kV switching station and will not be replaced with 69kV. Switching stations are designed to supply power to multiple substations and 26kV customers. West Orange is the largest switchyard in PSE&G's service territory and is required to supply service to 82,956 customers. The project will include the reconfiguration, as required, of existing 26kV cables, and the elimination of 26 kV Low Pressure Gas Filled (LPGF) Cables and any additional 26kV equipment that may be required. This project will address the oldest and largest 26kV switchyard in the service territory, thereby reducing exposure to outages, reducing maintenance costs and providing a better substation design for enhanced reliability.

PSE&G has executed several similar projects in the past as part of the Energy Strong program including the Essex 26kV, South Waterfront 26kV and Sewaren 26kV projects.

**Q. What resources are required to complete the West Orange Switching Station portion of the Substation Modernization Subprogram?**

A. The West Orange Switching Station requires $71.4 million over 4 years for full implementation. These costs have been developed through a feasibility analysis including construction sequencing. An engineering evaluation and estimate are included in confidential Schedule EFG-IAP-4 of this testimony.[3] A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

### 2. 4kV Substation Modernization Projects

**Q. Please provide an overview of PSE&G's proposal with respect to the 4kV substation modernization project.**

A. The 4kV substation modernization projects address five stations that have upgraded 69kV supply equipment. However, the 4kV distribution equipment at these stations is near end of life. The purpose of these replacements is to avoid a future large scale volume of assets reaching end of life at or around the same time and creating significant reliability and/or safety concerns related to workers operating this equipment. Beyond the personnel safety issues,

[3] Confidential Schedule EFG-IAP-4 consists of 6 separate Feasibility Analysis Reports ("Reports") for the West Orange Switching Station project and the 4kV Substation Modernization project. Additionally, Schedule EFG-IAP-4 includes a spreadsheet summarizing cost estimates and number of customers served for each of the locations.

failure to proactively address these facility needs will result in operational changes requiring increased customer outages to perform work as it becomes necessary.

**Q. Please describe how PSE&G selected the five stations that is proposes to modernize as a part of this subprogram.**

A. The Company proposes to replace 4kV assets that are either at or close to end-of-life. PSE&G has approximately 74 stations with these assets, with Class A and B station designs including 4kV facilities in a masonry building and Class C station designs having all facilities outdoors with 4kV equipment in metal-clad switchgear. Class A and B stations were constructed from PSE&G's inception in 1903 until approximately 1952. The first Class C station was constructed in 1938 and phased out as a standard for new stations in 1970. Excluding the stations that are being addressed in Energy Strong II through flood mitigation or stipulated base investment, a breakdown of the stations that are considered candidates for modernization or retirement are listed below:

<u>Class A and B substations</u>

- Number of stations - 32
- Average age - 95
- Total Customers Served: 278,801

<u>Class C substations</u>

- Number of stations - 42
- Average age – 64
- Total Customers Served: 215,903

The majority of the 4kV equipment in these facilities is the original equipment installed at the time the station was in service. PSE&G has prioritized Class C stations for replacement;

these stations have significantly higher risk scores than the Class A and B stations, in part due to the fact that the 4kV equipment is in outdoor switchgear and is exposed to the elements. Due to the outdated (circa 1940) design and condition of the 4kV equipment in the Class C stations, PSE&G is proposing that this equipment be completely replaced with modern insulation, equipment, and protection schemes. PSE&G has prioritized work at existing 4kV stations based on the rationale outlined below.

1. Class C stations that are located where 69kV upgrades are completed or are in progress. These facilities are necessary to supply customers and are not anticipated to be eliminated in the future, so the upgrade of the 4kV will provide long term risk reduction. (10 stations)
2. Class C stations identified for elimination and where there is capacity available for 13kV conversion. While these stations also provide long term risk reduction at a lower cost, they are given a lower priority due to the lower risk reduction than for the ten stations under number 1. (21 stations)
3. Class C stations where a full station upgrade is required. These projects will be higher costs than the earlier priorities. (11 Stations)
4. Class A and B stations for potential elimination (9 Stations) or rebuilding where it is required for the station to supply customers while remaining in its current location (23 stations).

Based on the priority above PSE&G is proposing to upgrade five of the stations that fall into the top priority group; these stations are listed below:

| Station Name | Station Class | Recommendation | Customers Served |
|---|---|---|---|
| FOURTIETH ST | C | Rebuild 4kV | 6,590 |
| MCLEAN BLVD | C | Rebuild 4kV | 11,359 |
| TEANECK | C | Rebuild 4kV | 4,658 |
| TONNELLE AVENUE | C | Rebuild 4kV | 3,681 |
| TOTOWA | C | Rebuild 4kV | 1,464 |
| | | Totals | 27,752 |

**Q. What resources are required to complete the 4kV replacements of the Substation subprogram?**

A. PSE&G is requesting approval of $172 million for this subprogram. An outline of the project scope and cost estimate is included in Schedule EFG-IAP-4.

### 3. 26kV Station Upgrades

**Q. Please provide an overview of PSE&G's proposal with respect to 26kV Station Upgrades**

A. This project will replace 40 existing 26kV oil circuit breakers (OCBs) with newer gas circuit breakers (GCBs) at various switching and substations across our system. The OCBs have an average age of 60 years, require significant corrective maintenance, and pose environmental challenges. The program will also modernize the existing protection system with microprocessor relays, the associated auxiliary equipment including disconnect switches.

PSE&G currently has 233 OCBs out of 1084 26kV breakers on the system. PSE&G has not purchased OCBs since the early 1980s, since OCBs are slower and less reliable than current breaker designs. PSE&G did a comprehensive review of the breakers in the system and selected the 26 kV facilities with the highest risk scores of the devices considered.

These circuit breakers are major components of the 26kV system which supplies PSE&G and customer substations, and is critical infrastructure needed to support electrification moving forward. While the supply of some PSE&G substations is being upgraded to 69kV for improved capacity and reliability, 26kV still represents a preferred supply voltage for many customers with higher demands, because metal clad switchgear can be implemented at significantly lower cost and within a smaller footprint than 69kV equipment. This system has the potential to provide an important supply source for large demand EV charging locations in the future such as fleet locations.

**Q. What resources are required to complete the 26kV Substation Upgrade subprogram?**

A. PSE&G is requesting approval of $33 million for this subprogram. An outline of the project scope and cost estimate is included in Schedule EFG-IAP-5.

## III. OUTSIDE PLANT SUBPROGRAM

**Q. Please provide an overview of PSE&G's proposed Outside Plant Subprogram.**

A. The Outside Plant Subprogram consists of eight projects that address service reliability, storm hardening and resiliency and also support EMP goals. Reliability specific projects include Buried Underground Distribution (BUD) Cable, Underground Cable and Lashed Cable replacement projects. Projects that support reliability and also improve storm performance include the Pole Upgrade, Spacer Upgrade, Open Wire Secondary Upgrade and Spacer Cable Conversion projects. The Voltage Optimization project is specifically proposed to support the

EMP, and the Open Wire Secondary Upgrade project also supports EV adoption by upgrading location service areas to higher capacity.

### 1. BUD Cable Replacement Project

**Q. Please provide an overview of PSE&G's proposal with respect to BUD Cable Replacement Project.**

A. Since 1973 all new residential developments greater than three homes have required underground electric supply facilities. Cables and associated transformers in these older developments are reaching their end of life and are experiencing increasing failure rates. This project will replace approximately 1,400 of the worst performing sections with new cable and single phase transformers and, where needed, will add a second cable source to improve design and outage restorations times. The proposed project is targeted to address 2.4% of the system that represents an estimated 26% of the total outage minutes caused by BUD system issues. PSE&G executed similar programs between 2009 and 2011 during the CIP programs authorized by the Board. These programs supported a 44% reduction in BUD incidents from 2010 to 2013.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $80 million. A list of developments proposed for this project and associated mileage is shown in Schedule EFG-IAP-6.

**Lashed Cable Replacement Project**

**Q. Please provide an overview of PSE&G's proposed Lashed Cable Replacement Project.**

A. Lashed primary cable is comprised of three conductors that are wrapped together with a bonding ribbon and are suspended from pole to pole with clamps. This construction type is used for 4kV applications primarily in urban areas, backyards, or rights of way with limited construction space. Lashed cable is one of the oldest distribution assets on our system and has increasing reliability issues. This project will replace approximately 14 miles of lashed cable with spacer-cable construction.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $14 million. There will be incremental benefits as projects are completed during the program. A list of circuits proposed for this project and associated mileage is shown in Schedule EFG-IAP-7.

**Pole Upgrade Project**

**Q. Please provide an overview of PSE&G's proposed Pole Upgrade Project.**

A. This project will replace approximately 2,100 wood poles identified during periodic inspections with new poles designed to a higher and more resilient standard, bringing hardening and storm benefits. PSE&G has approximately 861,348 wood poles in its system that support all circuit voltages up to 69kV. The annual inspection program identifies poles that have lost approximately 33% or more of their initial strength, indicating that either replacement or a base reinforcement is required. A base reinforcement involves the installation of steel brackets and bands around the pole base to restore pole base to its original strength. These reinforcements provide no benefit to the portions of the pole above the base or the equipment mounted on the pole. Priority for this project will include poles along circuit mainlines and the potential customer interruptions related to the pole condition. The prioritization will consider the results of new pole inspections during project execution to ensure the highest priority poles are completed. As such, the pole list provided for this project may be modified as it is implemented. This project provides a blue sky reliability benefit since these poles are generally over 52 years of age and the facilities on the pole are typically aged as well. Upgrading the facilities on these poles with new construction will reduce the risk of equipment related failures. This project also provides a storm hardening benefit as the upgrades to larger diameter and new poles will represent a significant increase in pole strength.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this portion of the project will take four years for full implementation with an investment of $32 million. There will be incremental benefits as projects are completed during the project. A list of poles proposed for this project are shown in Schedule EFG-IAP-8.

**4. Conventional Underground Cable Replacement Project**

**Q. Please provide an overview of PSE&G's proposed Underground Cable Project.**

A. Conventional underground (UG) cable systems are most common in urban environments, and this asset class includes cable, splices, and terminations. This project will replace approximately 34 miles of the poorest performing three-phase primary distribution cables that are near end of life. The proposed upgrades account for 1.7% of the total in-service population, while representing approximately 23% of the total Customers Interrupted ("CI") related to underground cable issues. Planned replacements of underground cable are significantly less costly than replacing cable sections as they fail. Cable failures require significant effort to locate the failed section, which is avoided with planned replacements. In addition, planned replacements can be coordinated to limit overtime and work during peak traffic times, thus avoiding these incremental costs.

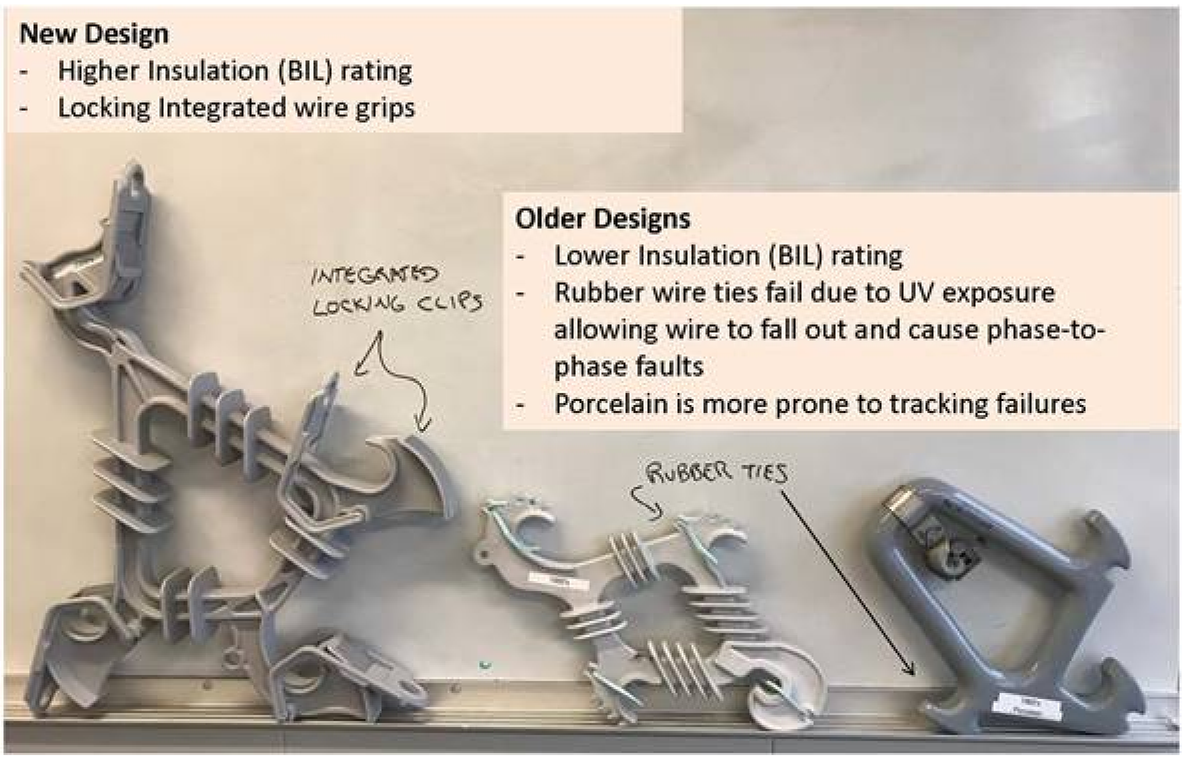
**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $23 million. There will be incremental benefits as projects are completed during the program. A list of circuits proposed for this project and associated mileage is shown in Schedule EFG-IAP-9.

**Spacer Upgrade Project**

**Q. Please provide an overview of PSE&G's proposed Spacer Upgrade Project.**

A. This project will replace aging spacer units along approximately 300 miles of existing construction with new hardware that is designed to a higher and more resilient standard. The new spacer standard has higher insulation values, improved material properties, better mechanical performance, and will improve the reliability on these circuits at a significantly lower cost compared to circuit reconstruction. The project targets approximately 9% of the poorest performing units that represent 29%of the total CI attributed to spacer cable. The picture below shows the difference between the new design and the older designs on the system. PSE&G has been utilizing spacer cable since the 1960s and the older designs have lower insulations values, lower tracking resistance and less reliable connections than the clamping locks in the new design. In the photo below the upgraded design is shown on the left, the middle spacer represents a design from the 1980s and the one on the right a design from the 1960s.




These upgrades will improve the performance of these circuits without the significantly higher costs associated with wire replacements. This project also has limited material requirements so the costs are almost all labor related, which should result in more job creation.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $14 million. There will be incremental benefits as projects are completed during the project. A list of circuits proposed for this project and associated mileage is shown in Schedule EFG-IAP-10.

**Open Wire Secondary Upgrade Project**

**Q. Please provide an overview of PSE&G's proposed Open Wire Secondary Upgrade Project.**

A. Open wire secondary (OWS) is an older, lower capacity construction type that has deteriorated over time and is less reliable than the current triplex standard. This project will replace approximately 1,300 secondary locations of existing OWS with new secondary wire and services that have higher capacity and are also more resistant to storms and tree contacts. This project is focused on potential EV penetration as well as improving reliability. PSE&G eliminated open wire secondary as a design standard in the late 1970s. As a consequence, open wire construction is in areas with older facilities. Areas with open wire secondary and lower capacity (25kVA transformers) will likely be overloaded with only 1 or 2 EVs additions to these locations. This will require emergent action to address customer voltage or possible equipment failure due to overloads. This program will target areas with lower rated 25kVA transformers and open wire secondary. PSE&G proposes to upgrade the secondary arrangement, install higher capacity transformers and upgrade services as needed. For these areas there will be reliability improvement, a capacity increase to allow EV adoption, and a planned project that can be executed more cost effectively than reactive replacement after a failure or customer issue. This project also supports the development of overhead line resources by providing low voltage work that can be done by lineworkers that are still in the apprentice classification and unable to work on primary voltages.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $36 million. There will be incremental benefits as projects are completed during the project.

### 7. Voltage Optimization Project

**Q. Please provide an overview of PSE&G's proposed Voltage Optimization Project.**

A. This project will replace approximately 1,600 13kV pole top capacitors and switches on approximately 269 circuits from 20 stations with new devices that will include remote communications integration into the DSCADA system implemented as part of Energy Strong and the communication and ADMS systems being implemented as part of Energy Strong II. Existing capacitor banks provide no remote indication of existing circuit voltages and failures can only be found by visual inspections. Increasing levels of EV and DER penetration will require a more dynamic and coordinated system to manage and regulate system voltages. For the 13kV system, voltage profiles are regulated by substation equipment and pole top capacitors.. The current system was designed based on a traditional utility arrangement with centralized generation, and power flowing from the transmission system, through the substation, along circuits and to customers. In this design, PSE&G has been successful in using capacitors utilizing standard settings but with static coordination between devices.

Increased dispersed generation along the circuits of this type of static system will lead to voltage regulation issues. Therefore a more dynamic system is required. The new capacitors will be equipped with advanced switches, voltage and current sensing, the ability to communicate back to the DSCADA system, and the capacity for autonomous or centralized control. These new devices can be integrated into the ADMS system to allow for dynamic voltage control or remote operator action when necessary. This project represents a first step in transforming the voltage control system across the distribution system. Priority will be given to longer circuits with higher DER penetration.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years for full implementation with an investment of $55 million. There will be incremental benefits as projects are completed during the project. A list of stations proposed for this project and associated capacitors are shown in Schedule EFG-IAP-11.

**8. Spacer Cable Conversion Project**

**Q. Please provide an overview of PSE&G's proposal with respect to the Spacer Cable Conversion Project.**

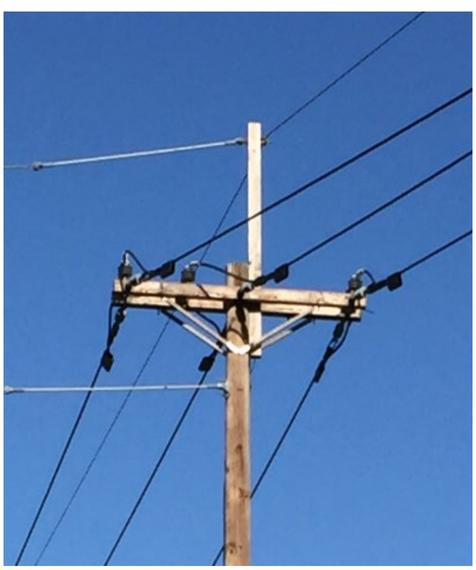
A. The Company proposes to convert existing open wire construction on 13kV circuits to spacer cable on circuits with poor storm performance. The construction change consists of replacement of cross-arm open wire construction with a more compact spacer cable configuration. Approximately 43% of PSE&G's overhead 13kV mainline electrical system is composed of wires installed on cross-arms. A picture of typical cross arm construction is shown in picture #1 below.

A spacer cable system is composed of rugged weatherproofed wire, compacted into a bundle with a steel cable support. It is resistant to tree and limb damage because of its high strength and smaller profile. A picture of a typical spacer cable system is shown in picture #2 below.

On cross-arm construction, approximately 8 feet of 13kV open wire is placed on cross arms and is exposed to harm from tree limbs and other debris compared to approximately 18 inches on spacer cable. PSE&G has analyzed the performance of spacer cable in major events and has found that on a per mile basis spacer cable had 39% to 81% fewer damage locations attributed to tree contacts that caused customer interruptions, compared with cross arm construction. Fewer damage locations will result in fewer outages and faster restoration of service. This is due to the smaller profile and the presence of a steel supporting wire that supplies additional strength and protects the conductors from tree contacts. As vegetation related damage accounts for up to 80% of damage during a storm event, this reduction in damage will have significant hardening benefits for customers for all types of storm events. Better overvoltage protection is also obtained by the installation of supporting wire, offering protection from lightning strikes that are also more prevalent during storm conditions.

The proposed project will upgrade approximately 60 miles of circuits. As part of this project PSE&G also proposes the replacement of approximately 841 poles on these circuits along with additional storm guying along these circuits. The pole replacements will target smaller diameter poles that are greater than 30 years of age. Due to the age of the existing poles the spacer cable upgrades require the pole to be replaced where pole tops cannot support spacer construction. In addition, by replacing the existing poles with larger diameter (Class 2) poles the strength of the pole will be increased significantly. A structural analysis of typical pole configurations, along with the age of the pole, shows the replacement of a typical 40 foot Class 4 (smaller diameter) pole with a Class 2 pole results in an overall strength gain of 53%. PSE&G will also enhance storm guying for the poles along these circuits. Pole guying refers to the use of cables and earth embedded anchors to strengthen poles and support the overhead electrical distribution system. The tension on guy wires from wind forces and tree impact will significantly reduce the shear and bending forces on pole lines. Appropriate placement of additional pole guys would reduce overall storm damage significantly by increasing pole strength and reducing cascading pole failures. This is required where spacer cable is being installed, as the additional strength of the conductor construction (steel support cable) will typically hold up large trees provided the supporting poles are of sufficient strength. The additional strength provided by pole upgrades and storm guying aligns with the need for upgrading to spacer cable.

Picture #1 - Open Wire Construction – Phases Spread over Wood Cross Arms



Picture #2 - Spacer Cable – Phases across spacer supported by steel cable with metal bracket at pole.

**Q. What resources are required to complete this project?**

A. PSE&G estimates this project will take four years to implement with an investment of $42 million. There will be incremental benefits as circuit miles are energized with spacer cable throughout the project. A list of the circuits proposed for this project with associated mileage is shown in Schedule EFG-IAP-12.

## IV. EV CHARGING INFRASTRUCTURE SUBPROGRAM

**Q. Please provide an overview of PSE&G's proposal with respect to implementing EV Charging Infrastructure Subprogram.**

A. This subprogram, which proposes the addition of EV infrastructure to existing PSE&G reporting locations, will make way for the Company's electrification of its fleet in support of the New Jersey Energy Master Plan, New Jersey's Global Warming Response Act, the State

Zero-Emission Vehicles Program and the Plug-In Vehicles Act. The subprogram will accelerate the installation of necessary EV charging infrastructure across PSEG facilities and will have an immediate impact on job creation.

In this subprogram PSE&G proposes to install approximately 2,000 EV chargers and associated behind the meter electric infrastructure at 65 locations.

- The locations include company-reporting locations (i.e. Electric Division Headquarters, Gas District Headquarters, switching stations, service centers, and offices).
- The locations chosen are either where PSEG vehicles are stored or where PSE&G personnel travel to perform job functions.
- Building this infrastructure will allow PSEG to charge vehicles both overnight and during working hours.
- Installation of equipment at each location will include EV chargers, cable, conduit, and electrical upgrades such as switchboards and transformers.
- Standby generators will be installed at primary reporting locations where the majority of EVs will be parked overnight for charging.
- Standby charging will enable PSEG to continue critical operations in the event of a grid outage or during storm restoration efforts.

**Q. What resources are required to implement the subprogram?**

A. PSE&G estimates this subprogram will take four years for full implementation with an investment of $134 million. The investments associated with this subprogram will be recovered from electric and gas customers through their respective IAP recovery mechanisms.

There will be incremental benefits as phases of the subprogram are executed.

## V. BENEFITS TO NEW JERSEY'S ECONOMY

**Q. How will the infrastructure investments proposed herein benefit New Jersey's economy?**

A. The electric portion of the IAP Program will provide benefits to both PSE&G's customers and New Jersey's economy. This component of the proposed IAP Program will result in additional skilled jobs. Using the methodology from the introductory material to the Board's IIP proposal for job creation in New Jersey, this portion of the proposed program would create an estimated 1,150 full-time jobs per year for the duration of the Program.

**Q. Please elaborate on the labor and other resources required to successfully complete this Program.**

A. The Company anticipates an increase in staffing for engineering, construction and construction management, and records management in order to carry out the Program each year. PSE&G will continue to utilize a combination of internal labor and outside contractors for the Program. The Program will support employment opportunities for suppliers as well.

**Q. How does a multi-year program affect the work effort involved with the IAP?**

A. The substation projects proposed typically require multiple years to complete. In the case of West Orange and 4kV stations upgrades this will require the full four years for execution. Various aspects of permitting, planning, and coordinating the projects, many of which are interdependent, cannot be reasonably planned for and executed in less than a four-year period. In addition, the multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

## VI. PROGRAM REPORTING

**Q. Does the Company intend to provide regular reporting on its progress?**

A. Yes. Consistent with the IIP regulations, the Company proposes to submit semi-annual status reports to Board Staff and the Division of Rate Counsel that contain the following information:

1. Forecasted and actual costs of the Infrastructure Investment Program for the applicable reporting period, and for the Program to date, where Program projects are identified by major category.
2. The estimated total quantity of work completed under the Program identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided.
3. Estimated completion dates for the Infrastructure Investment Program as a whole, and estimated completion dates for each major Program category.
4. Anticipated changes to Infrastructure Investment Program projects, if any.
5. Actual capital expenditures made by the utility in the normal course of business on similar projects, identified by major category.

**Q. Does this conclude your testimony?**

A. Yes.

# CREDENTIALS
# OF
# EDWARD F GRAY
# DIRECTOR-TRANSMISSION AND DISTRIBUTION ENGINEERING

My name is Edward F. Gray and I am employed by Public Service Electric and Gas. I am the Director – Transmission and Distribution Engineering where I am responsible for reliability and maintenance programs for Electric Transmission and Distribution.

## EDUCATIONAL BACKGROUND

I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Civil Engineering. I also earned a Master's in Civil Engineering from Rutgers University and a Master's in Management from New Jersey Institute of Technology. I am a Licensed Professional Engineer in the State of New Jersey.

## WORK EXPERIENCE

I have over 32 years' experience in Engineering and Asset Management at PSE&G. I have had various positions at PSE&G in Substation Engineering, System development for Electric and Gas work management, New Business Policy, Solar Interconnections, Resource Planning and Financial Management. I am presently the Director – Transmission and Distribution Engineering with oversight of electric reliability and maintenance programs.

I have been actively involved in Electric programs implemented since 2009. I was the program lead for Electric Distribution for both Capital Economic Stimulus Infrastructure Investment Programs responsible for the project implementation including cost and scheduling for each sub-program. For both programs developed discovery responses and was involved in various settlement and review meetings with BPU Staff and Rate Council. I was directly involved in the development of the Energy Strong program. I was actively involved in the preparation of testimony, project estimates, discovery responses and settlement meetings during the project approval. After approval was directly involved with project implementation on engineering and design of projects as well as working with the Independent Monitor on various process and data requests. I was the Company’s witness for the Energy Strong II program filing and was involved in all the testimony, discovery and settlement activities and now provide oversight to the program implementation.

In addition to these programs I have been involved with various items with Board Staff including storm cost recovery filings and the PVSC substation petition as well as other items related to Smart Growth and solar policy.

**PSE&G INFRASTRUCTURE ADVANCEMENT PROGRAM - Electric**

Attachment 2

## Electric Delivery Capital Summary (2016 - 2021)

Schedule EFG-IAP-2A

| Capital Category ($M) | 2016 Full Year Actual | 2017 Full Year Actual | 2018 Full Year Actual | 2019 Full Year Actual | 2020 Full Year Actual | 2021 Full Year Forecast |
|---|---|---|---|---|---|---|
| **Total Base** | **$ 226** | **$ 358** | **$ 527** | **$ 302** | **$ 319** | **$ 338** |
| | | | | | | |
| **New Business** | $ 119 | $ 125 | $ 144 | $ 141 | $ 126 | $ 129 |
| **Energy Strong I** | | | | | | |
| Recovery Mechanism | $ 252 | $ 109 | $ 28 | | | |
| Stipulated Base | | | | | | |
| **Energy Strong II** | | | | | | |
| Recovery Mechanism | | | | $ 12 | $ 138 | $ 164 |
| Stipulated Base | | | | $ - | $ 2 | $ 19 |
| **Total Capital $** | **$ 597** | **$ 591** | **$ 700** | **$ 455** | **$ 586** | **$ 650** |

### Base Breakdown by Major Category

| | | | | | | |
|---|---|---|---|---|---|---|
| Replace Facilities | $ 123 | $ 172 | $ 329 | $ 181 | $ 211 | $ 202 |
| System Reinforcement | $ 74 | $ 147 | $ 142 | $ 90 | $ 77 | $ 108 |
| Environmental Regulatory | $ 8 | $ 7 | $ 6 | $ 6 | $ 10 | $ 8 |
| Replace Meters | $ 15 | $ 16 | $ 15 | $ 13 | $ 10 | $ 5 |
| Support Facilities | $ 5 | $ 15 | $ 35 | $ 12 | $ 11 | $ 16 |
| **Total Base $** | **$ 226** | **$ 358** | **$ 527** | **$ 302** | **$ 319** | **$ 338** |

## PSE&G INFRASTRUCTURE ADVANCEMENT PROGRAM - Electric

Attachment 2

## Electric Delivery Capital Summary (2022 - 2026)

Schedule EFG-IAP-2B

| Capital Category ($M) | 2022 Full Year Plan | 2023 Full Year Plan | 2024 Full Year Plan | 2025 Full Year Plan | 2026 Full Year Plan |
|---|---|---|---|---|---|
| **Total Base** | **$ 248.0** | **$ 248.0** | **$ 248.0** | **$ 248.0** | **$ 248.0** |
| | | | | | |
| **New Business** | $ 124 | $ 124 | $ 124 | $ 126 | $ 128 |
| **Energy Strong I** | | | | | |
| Recovery Mechanism | | | | | |
| Stipulated Base | | | | | |
| **Energy Strong II** | | | | | |
| Recovery Mechanism | $ 137 | $ 167 | $ 21 | | |
| Stipulated Base | 65 | 45 | 1 | | |
| **IAP** | | | | | |
| Recovery Mechanism | 21 | 97 | 196 | 161 | 42 |
| Stipulated Base | 2 | 11 | 22 | 18 | 5 |
| **IAP - EV Charging Infrastructure** | | | | | |
| Recovery Mechanism | 2 | 23 | 29 | 14 | 3 |
| Stipulated Base | 0 | 3 | 3 | 2 | 0 |
| **Total Capital $** | **$ 597** | **$ 691** | **$ 613** | **$ 553** | **$ 422** |

### Base Breakdown by Major Category

| | | | | | |
|---|---|---|---|---|---|
| Replace Facilities | $ 154 | $ 154 | $ 154 | $ 154 | $ 154 |
| System Reinforcement | $ 71 | $ 71 | $ 71 | $ 71 | $ 71 |
| Environmental Regulatory | $ 6 | $ 6 | $ 6 | $ 6 | $ 6 |
| Replace Meters | $ 7 | $ 7 | $ 7 | $ 7 | $ 7 |
| Support Facilities | $ 10 | $ 10 | $ 10 | $ 10 | $ 10 |
| **Total Base $*** | **$ 248** | **$ 248** | **$ 248** | **$ 248** | **$ 248** |

*The Company proposes to maintain base level spending from 2022-2026 at the level shown above.

# PSE&G Energy Strong Program II
# Electric Summary Cash Flows



| Cash Flows ($000s) | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program Year - 2022** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,483 | $ 1,483 | $ 2,382 | $ 4,180 | $ 4,180 | $ 4,180 | $ 17,887 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,554 | $ 926 | $ 1,069 | $ 1,162 | $ 1,371 | $ 1,162 | $ 7,243 |
| COR | $ - | $ - | $ - | $ - | $ - | $ - | $ 137 | $ 137 | $ 218 | $ 373 | $ 379 | $ 373 | $ 1,616 |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 3,174** | **$ 2,546** | **$ 3,669** | **$ 5,714** | **$ 5,930** | **$ 5,714** | **$ 26,746** |
| **Program Year - 2023** | | | | | | | | | | | | | |
| Direct In-Service | $ 4,180 | $ 7,941 | $ 7,941 | $ 7,941 | $ 8,076 | $ 7,941 | $ 7,941 | $ 7,941 | $ 7,941 | $ 7,941 | $ 7,941 | $ 7,941 | $ 91,665 |
| CWIP Spending | $ 1,270 | $ 2,486 | $ 2,878 | $ 2,894 | $ 1,357 | $ 1,294 | $ 8,072 | $ 5,170 | $ 6,621 | $ 5,998 | $ 6,089 | $ 6,344 | $ 50,473 |
| COR | $ 376 | $ 658 | $ 837 | $ 838 | $ 675 | $ 659 | $ 832 | $ 742 | $ 787 | $ 707 | $ 914 | $ 921 | $ 8,948 |
| **Total** | **$ 5,826** | **$ 11,085** | **$ 11,656** | **$ 11,673** | **$ 10,109** | **$ 9,893** | **$ 16,845** | **$ 13,853** | **$ 15,349** | **$ 14,646** | **$ 14,943** | **$ 15,206** | **$ 151,085** |
| **Program Year - 2024** | | | | | | | | | | | | | |
| Direct In-Service | $ 8,076 | $ 11,403 | $ 11,403 | $ 11,403 | $ 11,538 | $ 11,403 | $ 11,403 | $ 11,403 | $ 11,403 | $ 11,403 | $ 11,403 | $ 11,403 | $ 133,647 |
| CWIP Spending | $ 6,454 | $ 8,470 | $ 10,946 | $ 13,901 | $ 30,501 | $ 7,741 | $ 6,550 | $ 8,650 | $ 6,419 | $ 6,333 | $ 6,960 | $ 6,393 | $ 119,319 |
| COR | $ 783 | $ 1,601 | $ 1,845 | $ 1,900 | $ 1,789 | $ 1,597 | $ 1,569 | $ 1,608 | $ 1,594 | $ 1,554 | $ 1,741 | $ 1,723 | $ 19,304 |
| **Total** | **$ 15,313** | **$ 21,474** | **$ 24,194** | **$ 27,205** | **$ 43,828** | **$ 20,742** | **$ 19,523** | **$ 21,661** | **$ 19,416** | **$ 19,290** | **$ 20,103** | **$ 19,520** | **$ 272,270** |
| **Program Year - 2025** | | | | | | | | | | | | | |
| Direct In-Service | $ 11,538 | $ 9,031 | $ 9,031 | $ 9,031 | $ 9,166 | $ 9,031 | $ 9,031 | $ 9,031 | $ 9,031 | $ 9,089 | $ 10,310 | $ 10,350 | $ 113,671 |
| CWIP Spending | $ 7,348 | $ 7,309 | $ 6,696 | $ 8,395 | $ 8,085 | $ 6,320 | $ 3,731 | $ 6,636 | $ 6,531 | $ 5,112 | $ 2,238 | $ 2,938 | $ 71,339 |
| COR | $ 1,610 | $ 1,411 | $ 1,587 | $ 1,612 | $ 1,496 | $ 1,454 | $ 1,401 | $ 1,396 | $ 1,393 | $ 2,267 | $ 2,383 | $ 2,406 | $ 20,416 |
| **Total** | **$ 20,496** | **$ 17,751** | **$ 17,314** | **$ 19,037** | **$ 18,747** | **$ 16,804** | **$ 14,164** | **$ 17,063** | **$ 16,955** | **$ 16,469** | **$ 14,932** | **$ 15,694** | **$ 205,425** |
| **Program Year - 2026** | | | | | | | | | | | | | |
| Direct In-Service | $ 11,819 | $ 6,992 | $ 6,777 | $ 6,891 | $ 6,626 | $ 5,459 | $ - | $ - | $ - | $ - | $ - | $ - | $ 44,564 |
| CWIP Spending | $ - | $ 800 | $ 1,080 | $ 1,080 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,960 |
| COR | $ 1,383 | $ 675 | $ 789 | $ 792 | $ 671 | $ 628 | $ - | $ - | $ - | $ - | $ - | $ - | $ 4,937 |
| **Total** | **$ 13,202** | **$ 8,467** | **$ 8,645** | **$ 8,763** | **$ 7,297** | **$ 6,087** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 52,462** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ 35,613 | $ 35,367 | $ 35,152 | $ 35,266 | $ 35,406 | $ 33,834 | $ 29,859 | $ 29,859 | $ 30,757 | $ 32,613 | $ 33,834 | $ 33,874 | $ 401,434 |
| CWIP Spending | $ 15,072 | $ 19,064 | $ 21,600 | $ 26,270 | $ 39,943 | $ 15,355 | $ 19,908 | $ 21,382 | $ 20,640 | $ 18,605 | $ 16,658 | $ 16,836 | $ 251,333 |
| COR | $ 4,152 | $ 4,346 | $ 5,057 | $ 5,142 | $ 4,631 | $ 4,337 | $ 3,939 | $ 3,883 | $ 3,992 | $ 4,901 | $ 5,417 | $ 5,423 | $ 55,220 |
| **Total** | **$ 54,837** | **$ 58,777** | **$ 61,810** | **$ 66,679** | **$ 79,980** | **$ 53,526** | **$ 53,706** | **$ 55,124** | **$ 55,389** | **$ 56,119** | **$ 55,908** | **$ 56,133** | **$ 707,988** |

**PSE&G Energy Strong Program II**
**Electric Substation Subprogram Cash Flows**

| Cash Flows ($000s) | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program Year - 2022** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,554 | $ 926 | $ 1,069 | $ 1,162 | $ 1,371 | $ 1,162 | $ 7,243 |
| COR | $ - | $ - | $ - | $ - | $ - | $ - | $ 23 | $ 23 | $ 27 | $ 30 | $ 36 | $ 30 | $ 168 |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | $ 1,576 | $ 949 | $ 1,096 | $ 1,191 | $ 1,407 | $ 1,191 | **$ 7,412** |
| **Program Year - 2023** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ 135 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 135 |
| CWIP Spending | $ 1,270 | $ 2,486 | $ 2,878 | $ 2,894 | $ 1,357 | $ 1,294 | $ 8,072 | $ 5,170 | $ 6,621 | $ 5,998 | $ 6,089 | $ 6,344 | $ 50,473 |
| COR | $ 33 | $ 33 | $ 213 | $ 213 | $ 51 | $ 34 | $ 207 | $ 118 | $ 162 | $ 82 | $ 289 | $ 297 | $ 1,732 |
| **Total** | **$ 1,303** | **$ 2,519** | **$ 3,091** | **$ 3,107** | **$ 1,543** | **$ 1,328** | **$ 8,280** | **$ 5,287** | **$ 6,784** | **$ 6,081** | **$ 6,377** | **$ 6,640** | **$ 52,340** |
| **Program Year - 2024** | | | | | | | | | | | | | |
| Direct In-Service | 135.00 | - | - | - | 135.00 | - | - | - | - | - | - | - | $ 270 |
| CWIP Spending | 6,454.45 | 8,469.51 | 10,946.11 | 13,901.37 | 30,501.17 | 7,741.06 | 6,550.39 | 8,650.15 | 6,418.81 | 6,332.75 | 6,959.51 | 6,393.32 | $ 119,319 |
| COR | 157.83 | 168.03 | 411.64 | 467.03 | 355.22 | 164.15 | 135.75 | 174.72 | 160.71 | 120.94 | 307.33 | 289.82 | $ 2,913 |
| **Total** | **$ 6,747** | **$ 8,638** | **$ 11,358** | **$ 14,368** | **$ 30,991** | **$ 7,905** | **$ 6,686** | **$ 8,825** | **$ 6,580** | **$ 6,454** | **$ 7,267** | **$ 6,683** | **$ 122,502** |
| **Program Year - 2025** | | | | | | | | | | | | | |
| Direct In-Service | $ 135 | $ - | $ - | $ - | $ 135 | $ - | $ - | $ - | $ - | $ 58 | $ 1,279 | $ 1,319 | $ 2,926 |
| CWIP Spending | $ 7,348 | $ 7,309 | $ 6,696 | $ 8,395 | $ 8,085 | $ 6,320 | $ 3,731 | $ 6,636 | $ 6,531 | $ 5,112 | $ 2,238 | $ 2,938 | $ 71,339 |
| COR | $ 177 | $ 124 | $ 299 | $ 324 | $ 208 | $ 166 | $ 114 | $ 108 | $ 105 | $ 980 | $ 1,096 | $ 1,119 | $ 4,820 |
| **Total** | **$ 7,660** | **$ 7,432** | **$ 6,995** | **$ 8,719** | **$ 8,428** | **$ 6,486** | **$ 3,845** | **$ 6,744** | **$ 6,637** | **$ 6,150** | **$ 4,613** | **$ 5,375** | **$ 79,085** |
| **Program Year - 2026** | | | | | | | | | | | | | |
| Direct In-Service | $ 2,788 | $ 2,228 | $ 2,014 | $ 2,128 | $ 1,863 | $ 696 | $ - | $ - | $ - | $ - | $ - | $ - | $ 11,716 |
| CWIP Spending | $ - | $ 800 | $ 1,080 | $ 1,080 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,960 |
| COR | $ 95 | $ 67 | $ 180 | $ 184 | $ 63 | $ 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ 610 |
| **Total** | **$ 2,883** | **$ 3,095** | **$ 3,274** | **$ 3,392** | **$ 1,926** | **$ 716** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 15,286** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ 3,058 | $ 2,228 | $ 2,014 | $ 2,128 | $ 2,268 | $ 696 | $ - | $ - | $ - | $ 58 | $ 1,279 | $ 1,319 | $ 15,048 |
| CWIP Spending | $ 15,072 | $ 19,064 | $ 21,600 | $ 26,270 | $ 39,943 | $ 15,355 | $ 19,908 | $ 21,382 | $ 20,640 | $ 18,605 | $ 16,658 | $ 16,836 | $ 251,333 |
| COR | $ 463 | $ 392 | $ 1,104 | $ 1,188 | $ 677 | $ 384 | $ 479 | $ 424 | $ 456 | $ 1,213 | $ 1,728 | $ 1,735 | $ 10,243 |
| **Total** | **$ 18,594** | **$ 21,685** | **$ 24,718** | **$ 29,586** | **$ 42,888** | **$ 16,434** | **$ 20,387** | **$ 21,805** | **$ 21,096** | **$ 19,876** | **$ 19,665** | **$ 19,890** | **$ 276,624** |

**PSE&G Energy Strong Program II**
**Electric Outside Plant Subprogram Cash Flows**



| Cash Flows ($000s) | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program Year - 2022** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | $ 899 | $ 899 | $ 1,798 | $ 3,595 | $ 3,595 | $ 3,595 | $ 14,380 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ - | $ - | $ - | $ - | $ - | $ - | $ 76 | $ 76 | $ 153 | $ 305 | $ 305 | $ 305 | $ 1,220 |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 975** | **$ 975** | **$ 1,950** | **$ 3,900** | **$ 3,900** | **$ 3,900** | **$ 15,600** |
| **Program Year - 2023** | | | | | | | | | | | | | |
| Direct In-Service | $ 3,595 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 4,279 | $ 50,666 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 305 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 388 | $ 4,568 |
| **Total** | **$ 3,900** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 4,667** | **$ 55,233** |
| **Program Year - 2024** | | | | | | | | | | | | | |
| Direct In-Service | $ 4,279 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 7,096 | $ 82,333 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 388 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 1,154 | $ 13,083 |
| **Total** | **$ 4,667** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 8,250** | **$ 95,417** |
| **Program Year - 2025** | | | | | | | | | | | | | |
| Direct In-Service | $ 7,096 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 7,167 | $ 85,929 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 1,154 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 1,167 | $ 13,988 |
| **Total** | **$ 8,250** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 8,333** | **$ 99,917** |
| **Program Year - 2026** | | | | | | | | | | | | | |
| Direct In-Service | $ 7,167 | $ 3,945 | $ 3,945 | $ 3,945 | $ 3,945 | $ 3,945 | $ - | $ - | $ - | $ - | $ - | $ - | $ 26,892 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 1,167 | $ 555 | $ 555 | $ 555 | $ 555 | $ 555 | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,942 |
| **Total** | **$ 8,333** | **$ 4,500** | **$ 4,500** | **$ 4,500** | **$ 4,500** | **$ 4,500** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 30,833** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ 22,137 | $ 22,487 | $ 22,487 | $ 22,487 | $ 22,487 | $ 22,487 | $ 19,440 | $ 19,440 | $ 20,339 | $ 22,137 | $ 22,137 | $ 22,137 | $ 260,200 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 3,013 | $ 3,263 | $ 3,263 | $ 3,263 | $ 3,263 | $ 3,263 | $ 2,785 | $ 2,785 | $ 2,861 | $ 3,013 | $ 3,013 | $ 3,013 | $ 36,800 |
| **Total** | **$ 25,150** | **$ 25,750** | **$ 25,750** | **$ 25,750** | **$ 25,750** | **$ 25,750** | **$ 22,225** | **$ 22,225** | **$ 23,200** | **$ 25,150** | **$ 25,150** | **$ 25,150** | **$ 297,000** |

**PSE&G Energy Strong Program II**
**Electric Vehicle Charging Infrastructure Subprogram Cash Flows**



| Cash Flows ($000s) | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program Year - 2022** | | | | | | | | | | | | | |
| Direct In-Service | $ - | $ - | $ - | $ - | $ - | $ - | 584.58 | 584.58 | 584.58 | 584.58 | 584.58 | 584.58 | $ 3,507 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | - | - | - | - | - | - | $ - |
| COR | $ - | $ - | $ - | $ - | $ - | $ - | 37.88 | 37.88 | 37.88 | 37.88 | 37.88 | 37.88 | $ 227 |
| **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 622** | **$ 622** | **$ 622** | **$ 622** | **$ 622** | **$ 622** | **$ 3,735** |
| **Program Year - 2023** | | | | | | | | | | | | | |
| Direct In-Service | $ 585 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 3,662 | $ 40,864 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 38 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 237 | $ 2,648 |
| **Total** | **$ 622** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 3,899** | **$ 43,512** |
| **Program Year - 2024** | | | | | | | | | | | | | |
| Direct In-Service | $ 3,662 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 4,307 | $ 51,044 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 237 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 279 | $ 3,308 |
| **Total** | **$ 3,899** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 4,587** | **$ 54,351** |
| **Program Year - 2025** | | | | | | | | | | | | | |
| Direct In-Service | $ 4,307 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 1,864 | $ 24,815 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 279 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 121 | $ 1,608 |
| **Total** | **$ 4,587** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 1,985** | **$ 26,423** |
| **Program Year - 2026** | | | | | | | | | | | | | |
| Direct In-Service | $ 1,864 | $ 818 | $ 818 | $ 818 | $ 818 | $ 818 | | | | | | | $ 5,956 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | | $ - |
| COR | $ 121 | $ 53 | $ 53 | $ 53 | $ 53 | $ 53 | | | | | | | $ 386 |
| **Total** | **$ 1,985** | **$ 871** | **$ 871** | **$ 871** | **$ 871** | **$ 871** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 6,342** |
| **Totals** | | | | | | | | | | | | | |
| Direct In-Service | $ 10,418 | $ 10,652 | $ 10,652 | $ 10,652 | $ 10,652 | $ 10,652 | $ 10,418 | $ 10,418 | $ 10,418 | $ 10,418 | $ 10,418 | $ 10,418 | $ 126,187 |
| CWIP Spending | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| COR | $ 675 | $ 690 | $ 690 | $ 690 | $ 690 | $ 690 | $ 675 | $ 675 | $ 675 | $ 675 | $ 675 | $ 675 | $ 8,177 |
| **Total** | **$ 11,093** | **$ 11,342** | **$ 11,342** | **$ 11,342** | **$ 11,342** | **$ 11,342** | **$ 11,093** | **$ 11,093** | **$ 11,093** | **$ 11,093** | **$ 11,093** | **$ 11,093** | **$ 134,363** |

# ATTACHMENT 2
# Schedule EFG-IAP-4

# CONFIDENTIAL

**TO BE PROVIDED UPON EXECUTION OF THE NON-DISCLOSURE AGREEMENT**

**Schedule EFG-IAP-5 26kV Station Upgrades**

| Station | Breakers |
|---|---|
| Arcola Substation | 1 |
| Athenia Switching Stations | 5 |
| Bloomfield Substation | 8 |
| Brunswich Switching Station | 1 |
| Burlington Switching Station | 1 |
| Camden Switching Station | 4 |
| Cherry Hill Substation | 1 |
| Chester Substation | 1 |
| Culver Avenue Substation | 2 |
| Haddon Heights Substation | 1 |
| Lawrence Switching Station | 6 |
| Metuchen Switching Station | 6 |
| Princeton Substation | 2 |
| Westwood Substation | 1 |

**Schedule EFG-IAP-6 - BUD Cable Replacement Project**

| Division | BUD | Name | Municipality | Estimated Footage |
|---|---|---|---|---|
| Southern | 113 | Willow Ridge | Evesham | 28,937 |
| Southern | 202 | Lantern Heights | Cherry Hill | 4,213 |
| Southern | 1 | Surrey Place East | Cherry Hill | 17,348 |
| Southern | 366 | Homestead at Mansfield | Mansfield | 34,011 |
| Southern | 1202 | Wynwood | South Brunswick | 9,872 |
| Southern | 95 | Ramblewood Village Apartments | Mount Laurel | 10,536 |
| Southern | 1102 | White Pine | Lawrence | 1,716 |
| Southern | 1110 | Pheasant Hollow | Plainsboro | 3,173 |
| Central | 162 | Southride Hills | Bridgewater | 680 |
| Central | 255 | Country Wood | Bridgewater | 2,788 |
| Central | 1041 | Watchung Development Corp | Green Brook | 5,407 |
| Central | 1103 | Woodbridge Centre Plaza | Woodbridge | 3,337 |
| Southern | 26 | Rittenhouse Park | Willingboro | 7,532 |
| Southern | 87 | Park Place | Cinnaminson | 4,361 |
| Southern | 243 | Hunters Crossing | Mout Laurel | 2,904 |
| Southern | 249 | Bee Farm | Gloucester | 3,387 |
| Southern | 311 | Acorn Hill | Voorhees | 1,829 |
| Southern | 1123 | The Village | Lawrence | 2,727 |
| Southern | 1128 | Montgomery Hills | Montgomery | 20,954 |
| Metro | 112 | Green mountain Estates | Wayne | 17,895 |
| Metro | 422 | The Eagle Rock | Roseland | 11,086 |
| Central | 27 | Gramercy Park | Piscataway | 4,931 |
| Central | 164 | College Park Estates | Edison | 3,591 |
| Central | 179 | Easton North & Forrestgate & Quailcrest | Franklin | 4,945 |
| Central | 278 | Oaks at North Brunswick | North Brunswick | 4,775 |
| Central | 351 | Tingley Square | Edison | 5,789 |
| Central | 397 | Society Hill | Franklin | 29,099 |
| Southern | 7 | Cambridge Park | Evesham | 37,291 |
| Southern | 52 | Leisuretowne | Southampton | 54,015 |
| Southern | 93 | Sycamore Village | Voorhees | 2,473 |
| Southern | 123 | Dorado Holding Company | Lumberton | 805 |
| Southern | 128 | Inverness Apartments | Deptford | 3,096 |
| Southern | 319 | Timbercrest | Mount Laurel | 8,380 |
| Southern | 1039 | High Ridge Homes | South Brunswick | 10,194 |
| Southern | 1065 | Golden Crest Estates | Hamilton | 11,074 |
| Southern | 1097 | Rivers Edge Apts. | Ewing | 2,084 |
| Southern | 1103 | Forrestal | Plainsboro | 22,802 |
| Metro | 84 | Birchwood park Homes | Fairfield | 2,659 |
| Metro | 171 | Van Dyke Wallington | Wallington | 4,182 |
| Metro | 87 | Lindsley Heights | North Caldwell | 3,703 |
| Metro | 70 | Old short Hills North | Livingston | 5,498 |
| Metro | 216 | Oak Hill Estates | Wayne | 7,914 |

| | | | | |
|---|---|---|---|---|
| Metro | 82 | Eagle Ridge Club | West Orange | 49,074 |
| Central | 36 | Civic Center Apartments | East Brunswick | 3,977 |
| Central | 44 | Colonial Oaks | East Brunswick | 7,031 |
| Central | 80 | Homestead Estates | Hillsborough | 4,802 |
| Central | 89 | Farrington Lake Homes | North Brunswick | 2,525 |
| Central | 253 | Blackford Oaks | Piscataway | 1,532 |
| Central | 261 | Peppermint Hill | North Brunswick | 393 |
| Central | 282 | Huntington Park | Hillsborough | 4,539 |
| Central | 290 | Birchview Gardens | Franklin | 711 |
| Central | 301 | Timberline at Edison | Edison | 1,376 |
| Central | 303 | Livingston Acres | Edison | 1,521 |
| Central | 350 | Birch Run | Piscataway | 1,544 |
| Central | 376 | Durham Woods | Edison | 5,986 |
| Central | 678 | Starpoint | Piscataway | 2,305 |
| Central | 796 | Harbortown | Perth Amboy | 3,438 |
| Southern | 70 | Heritage Grove at Echelon Village | Voorhees | 45,054 |
| Southern | 111 | Fox Meadow | Maple Shade | 7,543 |
| Southern | 130 | Uxbridge | Cherry Hill | 1,550 |
| Southern | 151 | Village of Stony Run | Maple Shade | 2,360 |
| Southern | 158 | exton Run Apartments | Maple Shade | 2,002 |
| Southern | 180 | Stoneybrook Apartments | Deptford | 2,008 |
| Southern | 1063 | Fox Run | Plainsboro | 6,218 |
| Southern | 1314 | Princeton Gate | South Brunswick | 22,838 |

**Schedule EFG-IAP-7 Lashed Cable Project**

| Circuit | OH Mileage |
|---|---|
| OAK 4008 | 2.568 |
| ORA 4001 | 3.295 |
| NRP 4010 | 2.289 |
| MCL 4007 | 2.798 |
| RSL 4007 | 3.089 |

**Schedule EFG-IAP-8 Pole Upgrades**

| Division | Municipality | Address | Class | Height | Pole Number |
|---|---|---|---|---|---|
| Central | East Brunswick Twp | 149 MILLTOWN RD | 4 | 35.00 | 63893 |
| Central | East Brunswick Twp | 19 DANIEL PL | 4 | 40.00 | 63604 |
| Central | East Brunswick Twp | 9 DANIEL PL | 4 | 35.00 | 63606 |
| Central | East Brunswick Twp | 3 DANIEL PL | 4 | 35.00 | 63608 |
| Central | East Brunswick Twp | 6 PINE RIDGE DR | 4 | 35.00 | 63610 |
| Central | East Brunswick Twp | 12 PINE RIDGE DR | 4 | 35.00 | 64159 |
| Central | East Brunswick Twp | 7 SERVISS AVE | 4 | 35.00 | 61980 |
| Central | East Brunswick Twp | 224 STATE HIGHWAY 18 | 4 | 35.00 | 63861 |
| Central | East Brunswick Twp | 292 STATE ROUTE 18 | 4 | 35.00 | 3378 |
| Central | East Brunswick Twp | 1 S WOODLAND AVE | 4 | 35.00 | 65674 |
| Central | East Brunswick Twp | 202 STATE HIGHWAY 18 | 4 | 40.00 | 61203 |
| Central | East Brunswick Twp | 192 STATE HIGHWAY 18 | 4 | 35.00 | 3175 |
| Central | East Brunswick Twp | 21 MCGUIRE ST | 4 | 35.00 | 65614 |
| Central | East Brunswick Twp | 99 MCGUIRE ST | 4 | 40.00 | 65617 |
| Central | East Brunswick Twp | 74 EDGEBORO RD | 4 | 30.00 | 64921 |
| Central | East Brunswick Twp | 69 EDGEBORO RD | 4 | 40.00 | 64918 |
| Central | East Brunswick Twp | 67 EDGEBORO RD | 4 | 40.00 | 64917 |
| Central | East Brunswick Twp | 51 WESTONS MILL RD | 4 | 40.00 | 60152 |
| Central | East Brunswick Twp | 61 EDGEBORO RD | 4 | 40.00 | 64914 |
| Central | East Brunswick Twp | 53 EDGEBORO RD | 4 | 40.00 | 64911 |
| Central | East Brunswick Twp | 40 EDGEBORO RD | 4 | 40.00 | 63106 |
| Central | East Brunswick Twp | 303 STATE ROUTE 18 | 4 | 40.00 | 63408 |
| Central | East Brunswick Twp | 12 CONNERTY CT | 4 | 40.00 | 65804 |
| Central | East Brunswick Twp | 42 MITCHELL AVE | 4 | 40.00 | 62442 |
| Central | East Brunswick Twp | 13 LAWRENCentral BROOK | 4 | 35.00 | 63383 |
| Central | East Brunswick Twp | 40 NORTH DR | 4 | 35.00 | 60924 |
| Central | East Brunswick Twp | 2 LAKE AVE | 4 | 40.00 | 65089 |
| Central | East Brunswick Twp | 1 LAKE AVE | 4 | 35.00 | 6934 |
| Central | East Brunswick Twp | 9 SOUTH DR | 4 | 35.00 | 60901 |
| Central | East Brunswick Twp | 95 LEA PL | 4 | 35.00 | 60900 |
| Central | East Brunswick Twp | 7 GAGE RD | 4 | 40.00 | 62859 |
| Central | East Brunswick Twp | 5 KIRKLIN PL | 4 | 35.00 | 62897 |
| Central | East Brunswick Twp | 229 STATE HIGHWAY 18 | 4 | 35.00 | 65612 |
| Central | East Brunswick Twp | 235 STATE HIGHWAY 18 | 4 | 40.00 | 60200 |
| Central | East Brunswick Twp | 24 AINSLIE CT | 4 | 35.00 | 62909 |
| Central | East Brunswick Twp | 4 AINSLIE CT | 4 | 40.00 | 62907 |
| Central | East Brunswick Twp | 47 GAGE RD | 4 | 40.00 | 62873 |
| Central | East Brunswick Twp | 10 WESTWOOD RD | 4 | 40.00 | 63011 |
| Central | East Brunswick Twp | 17 WESTWOOD RD | 4 | 40.00 | 63009 |
| Central | East Brunswick Twp | 33 WHITEHALL RD | 4 | 40.00 | 63002 |
| Central | East Brunswick Twp | 39 WHITEHALL RD | 4 | 40.00 | 62999 |
| Central | East Brunswick Twp | 31 MILLTOWN RD | 4 | 35.00 | 3664 |
| Central | East Brunswick Twp | 40 NARICON PL | 4 | 35.00 | 62192 |

| | | | | | |
|---|---|---|---|---|---|
| Central | East Brunswick Twp | 65 WESTONS MILL RD | 4 | 40.00 | 60157 |
| Central | East Brunswick Twp | 67 WESTONS MILL RD | 4 | 40.00 | 60158 |
| Central | East Brunswick Twp | 69 WESTONS MILL RD | 4 | 40.00 | 60159 |
| Central | East Brunswick Twp | 1 MYRON PL | 4 | 40.00 | 60931 |
| Central | East Brunswick Twp | 66 LAUREL LN | 4 | 35.00 | 62847 |
| Central | East Brunswick Twp | 63 PATTON DR | 4 | 35.00 | 61853 |
| Central | East Brunswick Twp | 55 SCHOOLHOUSE LN | 4 | 35.00 | 61168 |
| Central | East Brunswick Twp | 21 KENNEDY BLVD | 4 | 35.00 | 3895 |
| Central | East Brunswick Twp | 32 KENNEDY BLVD | 4 | 40.00 | 64998 |
| Central | East Brunswick Twp | 83 KENNEDY BLVD | 4 | 40.00 | 66207 |
| Central | East Brunswick Twp | 26 AINSWORTH AVE | 4 | 40.00 | 65029 |
| Central | East Brunswick Twp | 20 AINSWORTH AVE | 4 | 40.00 | 65064 |
| Central | East Brunswick Twp | 6 GATES AVE | 4 | 35.00 | 62935 |
| Central | East Brunswick Twp | 53 SCHOOLHOUSE LN | 4 | 35.00 | 61390 |
| Central | East Brunswick Twp | 14 N WOODLAND AVE | 4 | 40.00 | 62117 |
| Central | East Brunswick Twp | 16 N WOODLAND AVE | 4 | 35.00 | 61455 |
| Central | East Brunswick Twp | 28 N WOODLAND AVE | 4 | 35.00 | 61458 |
| Central | East Brunswick Twp | 32 N WOODLAND AVE | 4 | 35.00 | 61459 |
| Central | East Brunswick Twp | 53 S WOODLAND AVE | 4 | 35.00 | 62127 |
| Central | East Brunswick Twp | 38 HARVEY CIR | 4 | 35.00 | 3714 |
| Central | East Brunswick Twp | 32 HARVEY CIR | 4 | 35.00 | 3717 |
| Central | East Brunswick Twp | 9 HALICK CT | 4 | 40.00 | 63006 |
| Central | East Brunswick Twp | 47 WHITEHALL RD | 4 | 40.00 | 62996 |
| Central | East Brunswick Twp | 49 WHITEHALL RD | 4 | 40.00 | 62995 |
| Central | East Brunswick Twp | 37 AGATE RD | 4 | 40.00 | 62980 |
| Central | East Brunswick Twp | 26 AGATE RD | 4 | 40.00 | 62983 |
| Central | East Brunswick Twp | 126 AINSWORTH AVE | 4 | 35.00 | 64480 |
| Central | East Brunswick Twp | 128 AINSWORTH AVE | 4 | 35.00 | 64479 |
| Central | East Brunswick Twp | 56 PARKER ST | 4 | 35.00 | 60793 |
| Central | East Brunswick Twp | 4 AGATE RD | 4 | 40.00 | 62991 |
| Central | East Brunswick Twp | 28 WHITEHALL RD | 4 | 40.00 | 63004 |
| Central | East Brunswick Twp | 96 AINSWORTH AVE | 4 | 35.00 | 64758 |
| Central | East Brunswick Twp | 409 OLD BRIDGE TPKE | 4 | 40.00 | 62633 |
| Central | East Brunswick Twp | 122 AINSWORTH AVE | 4 | 40.00 | 64655 |
| Central | East Brunswick Twp | 11 ALDRICH ST | 4 | 35.00 | 62655 |
| Central | East Brunswick Twp | 92 MANTON AVE | 4 | 35.00 | 63943 |
| Central | East Brunswick Twp | 370 STATE HIGHWAY 18 | 4 | 35.00 | 63870 |
| Central | East Brunswick Twp | 449 RYDERS LN | 4 | 30.00 | 65696 |
| Central | East Brunswick Twp | 19 FETYKO AVE | 4 | 35.00 | 64109 |
| Central | East Brunswick Twp | 26 ALLWOOD RD | 4 | 40.00 | 63166 |
| Central | East Brunswick Twp | 30 ALLWOOD RD | 4 | 40.00 | 63167 |
| Central | East Brunswick Twp | 6 BETH CT | 4 | 35.00 | 64243 |
| Central | East Brunswick Twp | 4 BETH CT | 4 | 35.00 | 64242 |
| Central | East Brunswick Twp | 3 BERNARD RD | 4 | 40.00 | 63022 |
| Central | East Brunswick Twp | 11 BERNARD RD | 4 | 40.00 | 63024 |
| Central | East Brunswick Twp | 15 BERNARD RD | 4 | 40.00 | 63025 |
| Central | East Brunswick Twp | 33 BERNARD RD | 4 | 40.00 | 63029 |

| | | | | | |
|---|---|---|---|---|---|
| Central | East Brunswick Twp | 73 BERNARD RD | 4 | 40.00 | 63030 |
| Central | East Brunswick Twp | 22 WHITEHALL RD | 4 | 40.00 | 63015 |
| Central | East Brunswick Twp | 102 TAYLOR AVE | 4 | 40.00 | 64046 |
| Central | East Brunswick Twp | 3 DELLWOOD CT | 4 | 35.00 | 64506 |
| Central | East Brunswick Twp | 268 TAYLOR AVE | 4 | 35.00 | 64074 |
| Central | East Brunswick Twp | 46 SULLIVAN WAY | 4 | 40.00 | 63035 |
| Central | East Brunswick Twp | 98 BARNS CT | 4 | 35.00 | 64435 |
| Central | East Brunswick Twp | 17 SHERRY RD | 4 | 35.00 | 63690 |
| Central | East Brunswick Twp | 6 HAMLIN RD | 4 | 40.00 | 63149 |
| Central | East Brunswick Twp | 8 HAMLIN RD | 4 | 40.00 | 63148 |
| Central | East Brunswick Twp | 12 HAMLIN RD | 4 | 40.00 | 63147 |
| Central | East Brunswick Twp | 21 SHERRY RD | 4 | 35.00 | 63689 |
| Central | East Brunswick Twp | 4 BELL CT | 4 | 40.00 | 62958 |
| Central | East Brunswick Twp | 29 GULF RD | 4 | 40.00 | 63150 |
| Central | East Brunswick Twp | 18 GULF RD | 4 | 40.00 | 63153 |
| Central | East Brunswick Twp | 20 GULF RD | 4 | 40.00 | 63152 |
| Central | East Brunswick Twp | 6 GULF RD | 4 | 40.00 | 63156 |
| Central | East Brunswick Twp | 5 BRUNING RD | 4 | 40.00 | 63136 |
| Central | East Brunswick Twp | 25 BUSH PKWY | 4 | 35.00 | 62976 |
| Central | East Brunswick Twp | 16 BRUNING RD | 4 | 40.00 | 63140 |
| Central | East Brunswick Twp | 16 NORTON RD | 4 | 35.00 | 5654 |
| Central | East Brunswick Twp | 6 JEAN RD | 4 | 35.00 | 64221 |
| Central | East Brunswick Twp | 57 STRATFORD RD | 4 | 40.00 | 62369 |
| Central | East Brunswick Twp | 20 PERRY RD | 4 | 40.00 | 63133 |
| Central | East Brunswick Twp | 12 PERRY RD | 4 | 40.00 | 63131 |
| Central | East Brunswick Twp | 8 PERRY RD | 4 | 40.00 | 63130 |
| Central | East Brunswick Twp | 1 PERRY RD | 4 | 40.00 | 63124 |
| Central | East Brunswick Twp | 96 ALLWOOD RD | 4 | 40.00 | 63127 |
| Central | East Brunswick Twp | 41 W AMHERST ST | 4 | 35.00 | 61511 |
| Central | East Brunswick Twp | 38 UNIVERSITY RD | 4 | 40.00 | 63923 |
| Central | East Brunswick Twp | 79 FETYKO AVE | 4 | 35.00 | 61448 |
| Central | East Brunswick Twp | 10 THRUSH DR | 4 | 35.00 | 64452 |
| Central | East Brunswick Twp | 28 UNIVERSITY RD | 4 | 35.00 | 64038 |
| Central | East Brunswick Twp | 3 THRUSH DR | 4 | 35.00 | 63084 |
| Central | East Brunswick Twp | 39 PROSPECT ST | 4 | 35.00 | 65008 |
| Central | East Brunswick Twp | 2 PARSONS RD | 4 | 35.00 | 63935 |
| Central | East Brunswick Twp | 4 VAUXHALL RD | 4 | 35.00 | 63928 |
| Central | East Brunswick Twp | 14 VAUXHALL RD | 4 | 35.00 | 63932 |
| Central | East Brunswick Twp | 17 VAUXHALL RD | 4 | 35.00 | 63933 |
| Central | East Brunswick Twp | 19 VAUXHALL RD | 4 | 35.00 | 63934 |
| Central | East Brunswick Twp | 66 DUTCH RD | 4 | 40.00 | 63257 |
| Central | East Brunswick Twp | 62 DUTCH RD | 4 | 40.00 | 63259 |
| Central | East Brunswick Twp | 48 DUTCH RD | 4 | 40.00 | 63265 |
| Central | East Brunswick Twp | 44 DUTCH RD | 4 | 40.00 | 63266 |
| Central | East Brunswick Twp | 34 WELLINGTON RD | 4 | 35.00 | 63914 |
| Central | East Brunswick Twp | 37 TOMPKINS RD | 4 | 35.00 | 63911 |
| Central | East Brunswick Twp | 49 WELLINGTON RD | 4 | 35.00 | 63920 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 48 PUTNAM RD | 4 | 40.00 | 64608 |
| Central | East Brunswick Twp | 3 YALE CT | 4 | 40.00 | 63993 |
| Central | East Brunswick Twp | 12 ROWAN CT | 4 | 35.00 | 64217 |
| Central | East Brunswick Twp | 10 ROWAN CT | 4 | 35.00 | 64216 |
| Central | East Brunswick Twp | 66 1ST ST | 4 | 35.00 | 64105 |
| Central | East Brunswick Twp | 10 ELKINS RD | 4 | 40.00 | 65070 |
| Central | East Brunswick Twp | 5 COLONIAL DR | 4 | 35.00 | 64016 |
| Central | East Brunswick Twp | 3 COLONIAL DR | 4 | 35.00 | 64015 |
| Central | East Brunswick Twp | 11 ELKINS RD | 4 | 40.00 | 65071 |
| Central | East Brunswick Twp | 68 BRISTOL CT | 4 | 35.00 | 64901 |
| Central | East Brunswick Twp | 12 NEW DOVER RD | 4 | 35.00 | 64897 |
| Central | East Brunswick Twp | 325 MILLTOWN RD | 4 | 35.00 | 64331 |
| Central | East Brunswick Twp | 3 NEW DOVER RD | 4 | 35.00 | 64793 |
| Central | East Brunswick Twp | 11 COLONIAL DR | 4 | 35.00 | 64794 |
| Central | East Brunswick Twp | 13 COLONIAL DR | 4 | 35.00 | 64795 |
| Central | East Brunswick Twp | 19 COLONIAL DR | 4 | 35.00 | 64797 |
| Central | East Brunswick Twp | 27 COLONIAL DR | 4 | 35.00 | 64799 |
| Central | East Brunswick Twp | 29 COLONIAL DR | 4 | 40.00 | 64800 |
| Central | East Brunswick Twp | 33 COLONIAL DR | 4 | 35.00 | 64801 |
| Central | East Brunswick Twp | 50 LYNBROOK PL | 4 | 40.00 | 61936 |
| Central | East Brunswick Twp | 20 FAIRVIEW AVE | 4 | 35.00 | 61939 |
| Central | East Brunswick Twp | 98 1ST ST | 4 | 35.00 | 65405 |
| Central | East Brunswick Twp | 13 KIMBERLY RD | 4 | 40.00 | 66011 |
| Central | East Brunswick Twp | 1146 STATE HIGHWAY 18 | 4 | 35.00 | 64146 |
| Central | East Brunswick Twp | 1132 STATE HIGHWAY 18 | 4 | 35.00 | 64153 |
| Central | East Brunswick Twp | 1086 STATE ROUTE 18 | 4 | 35.00 | 64154 |
| Central | East Brunswick Twp | 33 COTTERS LN | 4 | 40.00 | 5475 |
| Central | East Brunswick Twp | 1 ROLLING RD | 4 | 35.00 | 63489 |
| Central | East Brunswick Twp | 301 RUES LN | 4 | 35.00 | 61106 |
| Central | East Brunswick Twp | 305 RUES LN | 4 | 40.00 | 61104 |
| Central | East Brunswick Twp | 393 STATE HIGHWAY 18 | 4 | 35.00 | 64230 |
| Central | East Brunswick Twp | 411 STATE ROUTE 18 | 4 | 40.00 | 60517 |
| Central | East Brunswick Twp | 984 OLD BRIDGE TPKE | 4 | 30.00 | 61772 |
| Central | East Brunswick Twp | 25 COTTERS LN | 4 | 40.00 | 65285 |
| Central | East Brunswick Twp | 5 4TH ST | 4 | 35.00 | 64121 |
| Central | East Brunswick Twp | 29 COTTERS LN | 4 | 35.00 | 65690 |
| Central | East Brunswick Twp | 78 COTTERS LN | 4 | 35.00 | 6506 |
| Central | East Brunswick Twp | 115 OLD BRIDGE TPKE | 4 | 40.00 | 60290 |
| Central | East Brunswick Twp | 129 JOSEPH ST | 4 | 35.00 | 64544 |
| Central | East Brunswick Twp | 121 JOSEPH ST | 4 | 35.00 | 64547 |
| Central | East Brunswick Twp | 49 6TH ST | 4 | 40.00 | 65174 |
| Central | East Brunswick Twp | 34 HARVEY CIR | 4 | 35.00 | 3716 |
| Central | East Brunswick Twp | 1 5TH ST | 4 | 35.00 | 64104 |
| Central | Elizabeth City | 1013 CROSS AVE | 4 | 40.00 | 63064 |
| Central | Elizabeth City | 1304 FREMONT PL | 4 | 35.00 | 64910 |
| Central | Elizabeth City | 1438 LEXINGTON PL | 4 | 35.00 | 63499 |
| Central | Elizabeth City | 1019 N BROAD ST | 4 | 45.00 | 65778 |

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|---|---|---|---|---|---|
| Central | Elizabeth City | 1446 CONCORD PL | 4 | 40.00 | 63292 |
| Central | Elizabeth City | 1375 ALINA ST | 4 | 40.00 | 63086 |
| Central | Elizabeth City | 540 WESTFIELD AVE | 4 | 40.00 | 66260 |
| Central | Elizabeth City | 822 EMERSON AVE | 4 | 35.00 | 63708 |
| Central | Elizabeth City | 832 EMERSON AVE | 4 | 35.00 | 63707 |
| Central | Elizabeth City | 852 EMERSON AVE | 4 | 35.00 | 63706 |
| Central | Elizabeth City | 479 WINTHROP PL | 4 | 40.00 | 64727 |
| Central | Elizabeth City | 743 WESTFIELD AVE | 4 | 40.00 | 6100 |
| Central | Elizabeth City | 886 FLORAL AVE | 4 | 35.00 | 63369 |
| Central | Elizabeth City | 754 WESTFIELD AVE | 4 | 40.00 | 60586 |
| Central | Elizabeth City | 408 W GRAND ST | 4 | 35.00 | 67887 |
| Central | Elizabeth City | 100 DEHART PL | 4 | 40.00 | 62687 |
| Central | East Brunswick Twp | 6 ELM ST | 4 | 35.00 | 61488 |
| Central | East Brunswick Twp | 98 PARK PL | 4 | 35.00 | 3670 |
| Central | East Brunswick Twp | 25 ELM ST | 4 | 35.00 | 3656 |
| Central | East Brunswick Twp | 498 STATE HIGHWAY 18 | 4 | 40.00 | 3593 |
| Central | Elizabeth City | 570 LINDEN AVE | 4 | 40.00 | 60482 |
| Central | East Brunswick Twp | 98 PARK PL | 4 | 35.00 | 3666 |
| Central | Elizabeth City | 200 MONMOUTH RD | 4 | 40.00 | 62926 |
| Central | East Brunswick Twp | 32 MILLTOWN RD | 4 | 40.00 | 60429 |
| Central | East Brunswick Twp | 26 MILLTOWN RD | 4 | 35.00 | 60430 |
| Central | Elizabeth City | 809 LIVINGSTON RD | 4 | 40.00 | 62609 |
| Central | East Brunswick Twp | 500 STATE ROUTE 18 | 4 | 35.00 | 3661 |
| Central | Elizabeth City | 547 MURRAY ST | 4 | 40.00 | 62387 |
| Central | East Brunswick Twp | 548 STATE ROUTE 18 | 4 | 35.00 | 3689 |
| Central | East Brunswick Twp | 21 WALKER ST | 4 | 35.00 | 65573 |
| Central | East Brunswick Twp | 17 WALKER ST | 4 | 35.00 | 65572 |
| Central | East Brunswick Twp | 7 WALKER ST | 4 | 40.00 | 61780 |
| Central | Elizabeth City | 920 W GRAND ST | 4 | 40.00 | 63892 |
| Central | East Brunswick Twp | 945 OLD BRIDGE TPKE | 4 | 35.00 | 62354 |
| Central | East Brunswick Twp | 160 PRIGMORE ST | 4 | 35.00 | 60714 |
| Central | East Brunswick Twp | 176 PRIGMORE ST | 4 | 35.00 | 61997 |
| Central | Elizabeth City | 36 DEHART PL | 4 | 40.00 | 68338 |
| Central | East Brunswick Twp | 616 STATE ROUTE 18 | 4 | 35.00 | 60531 |
| Central | Elizabeth City | 968 GARDEN ST | 4 | 35.00 | 7554 |
| Central | East Brunswick Twp | 199 JOSEPH ST | 4 | 35.00 | 63422 |
| Central | East Brunswick Twp | 15 FOUNTAIN ST | 4 | 35.00 | 62002 |
| Central | East Brunswick Twp | 187 JOSEPH ST | 4 | 35.00 | 61875 |
| Central | East Brunswick Twp | 27 MARIETTA ST | 4 | 35.00 | 60727 |
| Central | East Brunswick Twp | 155 JOSEPH ST | 4 | 35.00 | 62005 |
| Central | Elizabeth City | 434 NEW YORK AVE | 4 | 35.00 | 9743 |
| Central | Elizabeth City | 148 BELLEVUE ST | 4 | 40.00 | 63305 |
| Central | East Brunswick Twp | 162 WILLOW ST | 4 | 35.00 | 61485 |
| Central | East Brunswick Twp | 168 WILLOW ST | 4 | 35.00 | 61484 |
| Central | Elizabeth City | 156 BURNETT ST | 4 | 35.00 | 61995 |
| Central | Elizabeth City | 142 BURNETT ST | 4 | 35.00 | 64267 |
| Central | Elizabeth City | 114 WASHINGTON AVE | 4 | 40.00 | 60755 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 81 VICTORY PL | 4 | 35.00 | 62969 |
| Central | East Brunswick Twp | 69 VICTORY PL | 4 | 40.00 | 62970 |
| Central | East Brunswick Twp | 1 FOUNTAIN ST | 4 | 40.00 | 60112 |
| Central | Elizabeth City | 128 ELY ST | 4 | 40.00 | 62625 |
| Central | Elizabeth City | 718 LINDEN AVE | 4 | 40.00 | 60486 |
| Central | Elizabeth City | 92 WATSON AVE | 4 | 40.00 | 69453 |
| Central | East Brunswick Twp | 635 STATE ROUTE 18 | 4 | 40.00 | 60535 |
| Central | East Brunswick Twp | 16 MEMORIAL DR | 4 | 35.00 | 61314 |
| Central | East Brunswick Twp | 759 STATE ROUTE 18 | 4 | 40.00 | 60694 |
| Central | Elizabeth City | 706 PEARL ST | 4 | 40.00 | 63100 |
| Central | East Brunswick Twp | 42 DEERFIELD RD | 4 | 40.00 | 62319 |
| Central | East Brunswick Twp | 88 HARWIN DR | 4 | 40.00 | 62389 |
| Central | East Brunswick Twp | 6 HARWIN DR | 4 | 35.00 | 61567 |
| Central | Elizabeth City | 24 WATSON AVE | 4 | 35.00 | 64096 |
| Central | Elizabeth City | 6 BELLEVUE ST | 4 | 35.00 | 64324 |
| Central | Elizabeth City | 867 VINE ST | 4 | 40.00 | 64726 |
| Central | East Brunswick Twp | 12 RICHARD RD | 4 | 35.00 | 62302 |
| Central | Elizabeth City | 226 PRINCentralTON RD | 4 | 35.00 | 63277 |
| Central | Elizabeth City | 387 S BROAD ST | 4 | 40.00 | 66099 |
| Central | East Brunswick Twp | 26 NELSON CIR | 4 | 35.00 | 61697 |
| Central | East Brunswick Twp | 16 NELSON CIR | 4 | 35.00 | 61695 |
| Central | East Brunswick Twp | 4 NELSON CIR | 4 | 40.00 | 61691 |
| Central | Elizabeth City | 840 PARK AVE | 4 | 35.00 | 60635 |
| Central | East Brunswick Twp | 90 NELSON CIR | 4 | 35.00 | 61700 |
| Central | East Brunswick Twp | 62 NELSON CIR | 4 | 35.00 | 61702 |
| Central | East Brunswick Twp | 38 NELSON CIR | 4 | 35.00 | 61704 |
| Central | East Brunswick Twp | 15 FAIRFIELD RD | 4 | 35.00 | 62277 |
| Central | East Brunswick Twp | 32 NELSON CIR | 4 | 35.00 | 61705 |
| Central | East Brunswick Twp | 30 NELSON CIR | 4 | 40.00 | 61699 |
| Central | Elizabeth City | 757 VINE ST | 4 | 40.00 | 62794 |
| Central | East Brunswick Twp | 2 DRESDEN RD | 4 | 40.00 | 62293 |
| Central | East Brunswick Twp | 11 COLEMAN RD | 4 | 40.00 | 62294 |
| Central | East Brunswick Twp | 13 COLEMAN PL | 4 | 35.00 | 62296 |
| Central | East Brunswick Twp | 67 COLEMAN PL | 4 | 35.00 | 62297 |
| Central | Elizabeth City | 883 LIVINGSTON RD | 4 | 40.00 | 62729 |
| Central | Elizabeth City | 133 HILLSIDE RD | 4 | 40.00 | 62919 |
| Central | Elizabeth City | 111 HILLSIDE RD | 4 | 40.00 | 62921 |
| Central | East Brunswick Twp | 3 JOANNA CT | 4 | 40.00 | 65814 |
| Central | East Brunswick Twp | 1081 OLD BRIDGE TPKE | 4 | 40.00 | 60305 |
| Central | East Brunswick Twp | 14 KENDALL RD | 4 | 40.00 | 61754 |
| Central | Elizabeth City | 942 PARK AVE | 4 | 35.00 | 63840 |
| Central | East Brunswick Twp | 5 JOANNA CT | 4 | 35.00 | 5443 |
| Central | Elizabeth City | 4 NEWCOMB PL | 4 | 40.00 | 68024 |
| Central | Elizabeth City | 869 GROVE ST | 4 | 40.00 | 65628 |
| Central | Elizabeth City | 116 GLENWOOD RD | 4 | 35.00 | 64582 |
| Central | Elizabeth City | 168 GLENWOOD RD | 4 | 40.00 | 62213 |
| Central | Elizabeth City | 156 GLENWOOD RD | 4 | 40.00 | 62212 |

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|---|---|---|---|---|---|
| Central | Elizabeth City | 146 GLENWOOD RD | 4 | 35.00 | 62211 |
| Central | Elizabeth City | 197 HALSTED RD | 4 | 35.00 | 63600 |
| Central | Elizabeth City | 226 GLENWOOD RD | 4 | 40.00 | 62219 |
| Central | Elizabeth City | 208 GLENWOOD RD | 4 | 40.00 | 62217 |
| Central | East Brunswick Twp | 22 STUART DR | 4 | 35.00 | 61728 |
| Central | East Brunswick Twp | 8 GROTT LN | 4 | 35.00 | 61719 |
| Central | East Brunswick Twp | 39 GROTT LN | 4 | 35.00 | 61733 |
| Central | East Brunswick Twp | 99 SHERIDAN AVE | 4 | 35.00 | 64643 |
| Central | East Brunswick Twp | 14 TERRY LN | 4 | 35.00 | 62162 |
| Central | Elizabeth City | 411 FAY AVE | 4 | 40.00 | 64325 |
| Central | East Brunswick Twp | 6 TERRY LN | 4 | 35.00 | 62158 |
| Central | East Brunswick Twp | 14 SHERIDAN AVE | 4 | 35.00 | 62134 |
| Central | Elizabeth City | 934 EDGEWOOD RD | 4 | 40.00 | 63606 |
| Central | East Brunswick Twp | 10 SHERIDAN AVE | 4 | 40.00 | 62133 |
| Central | East Brunswick Twp | 6 STUART DR | 4 | 35.00 | 61732 |
| Central | Elizabeth City | 519 GRIER AVE | 4 | 40.00 | 60781 |
| Central | East Brunswick Twp | 81 RACentral TRACK RD | 4 | 40.00 | 62147 |
| Central | East Brunswick Twp | 77 RACentral TRACK RD | 4 | 35.00 | 62148 |
| Central | Elizabeth City | 948 BYRON AVE | 4 | 35.00 | 63387 |
| Central | East Brunswick Twp | 11 ELAINE RD | 4 | 35.00 | 62153 |
| Central | Elizabeth City | 1091 DEWEY PL | 4 | 40.00 | 60468 |
| Central | East Brunswick Twp | 7 VIOLET CT | 4 | 35.00 | 62167 |
| Central | East Brunswick Twp | 27 ELAINE RD | 4 | 40.00 | 62155 |
| Central | Elizabeth City | 2 CentralDAR AVE | 4 | 35.00 | 65578 |
| Central | East Brunswick Twp | 98 ELAINE RD | 4 | 40.00 | 66506 |
| Central | East Brunswick Twp | 367 CRANBURY RD | 4 | 35.00 | 64119 |
| Central | Elizabeth City | 1038 EDGEWOOD RD | 4 | 40.00 | 63983 |
| Central | East Brunswick Twp | 4 MELVIN AVE | 4 | 30.00 | 61747 |
| Central | East Brunswick Twp | 98 VALE CT | 4 | 35.00 | 61798 |
| Central | East Brunswick Twp | 48 HIGH POINT RD | 4 | 40.00 | 61537 |
| Central | East Brunswick Twp | 42 VALE CT | 4 | 35.00 | 61797 |
| Central | Elizabeth City | 1005 COOLIDGE RD | 4 | 40.00 | 63825 |
| Central | East Brunswick Twp | 9 VALE CT | 4 | 40.00 | 61792 |
| Central | Elizabeth City | 1023 S ELMORA AVE | 4 | 35.00 | 6783 |
| Central | East Brunswick Twp | 18 MADELINE AVE | 4 | 40.00 | 60369 |
| Central | East Brunswick Twp | 4 TOROR RD | 4 | 35.00 | 64726 |
| Central | Elizabeth City | 1122 S ELMORA AVE | 4 | 40.00 | 61674 |
| Central | Elizabeth City | 1133 APPLEGATE AVE | 4 | 35.00 | 63576 |
| Central | Elizabeth City | 1050 BYRON AVE | 4 | 35.00 | 63624 |
| Central | Elizabeth City | 1030 SEIB AVE | 4 | 35.00 | 64878 |
| Central | East Brunswick Twp | 929 OLD BRIDGE TPKE | 4 | 35.00 | 60331 |
| Central | East Brunswick Twp | 6 MADELINE AVE | 4 | 40.00 | 61529 |
| Central | Elizabeth City | 794 FAY AVE | 4 | 35.00 | 65663 |
| Central | Elizabeth City | 1114 HARDING RD | 4 | 40.00 | 63818 |
| Central | East Brunswick Twp | 44 LOIS AVE | 4 | 35.00 | 62488 |
| Central | Elizabeth City | 1095 COOLIDGE RD | 4 | 40.00 | 63830 |
| Central | East Brunswick Twp | 459 CRANBURY RD | 4 | 40.00 | 64773 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 441 CRANBURY RD | 4 | 40.00 | 61300 |
| Central | East Brunswick Twp | 9 CLAYTON CT | 4 | 35.00 | 62482 |
| Central | East Brunswick Twp | 72 LOIS AVE | 4 | 40.00 | 62466 |
| Central | Elizabeth City | 1127 GALLOPING HILL RD | 4 | 40.00 | 65244 |
| Central | Elizabeth City | 121 BROWNING AVE | 4 | 40.00 | 65510 |
| Central | East Brunswick Twp | 2 GREENBRAE CT | 4 | 35.00 | 63491 |
| Central | East Brunswick Twp | 299 RUES LN | 4 | 35.00 | 61107 |
| Central | East Brunswick Twp | 299 RUES LN | 4 | 35.00 | 61108 |
| Central | East Brunswick Twp | 293 RUES LN | 4 | 35.00 | 61111 |
| Central | East Brunswick Twp | 27 E WAVERLY DR | 4 | 35.00 | 63711 |
| Central | East Brunswick Twp | 279 RUES LN | 4 | 35.00 | 61116 |
| Central | East Brunswick Twp | 6 MERCentralR RD | 4 | 40.00 | 62956 |
| Central | East Brunswick Twp | 261 RUES LN | 4 | 40.00 | 62951 |
| Central | East Brunswick Twp | 253 RUES LN | 4 | 35.00 | 61437 |
| Central | South Brunswick Twp | 3526 STATE ROUTE 27 | 4 | 40.00 | 66075 |
| Central | East Brunswick Twp | 7 WATCHUNG RD | 4 | 35.00 | 63493 |
| Central | East Brunswick Twp | 7 FLAGLER ST | 4 | 40.00 | 61648 |
| Central | East Brunswick Twp | 40 FARMS ROAD CIR | 4 | 35.00 | 65510 |
| Central | East Brunswick Twp | 27 GREEN HILLS RD | 4 | 35.00 | 64847 |
| Central | East Brunswick Twp | 7 ROLLING RD | 4 | 35.00 | 63497 |
| Central | East Brunswick Twp | 3 ROLLING RD | 4 | 35.00 | 63495 |
| Central | East Brunswick Twp | 2 PEGGY RD | 4 | 40.00 | 63300 |
| Central | East Brunswick Twp | 7 GREEN HILLS RD | 4 | 35.00 | 64838 |
| Central | East Brunswick Twp | 21 FLAGIER ST | 4 | 35.00 | 63297 |
| Central | East Brunswick Twp | 15 ROLLING RD | 4 | 35.00 | 63630 |
| Central | East Brunswick Twp | 29 HELENA ST | 4 | 40.00 | 62257 |
| Central | East Brunswick Twp | 33 HELENA ST | 4 | 35.00 | 65169 |
| Central | East Brunswick Twp | 125 DUNHAMS CORNER R | 4 | 35.00 | 65434 |
| Central | East Brunswick Twp | 7 BOWNE ST | 4 | 35.00 | 62664 |
| Central | East Brunswick Twp | 3 LISA CT | 4 | 35.00 | 64650 |
| Central | East Brunswick Twp | 85 JENSEN ST | 4 | 40.00 | 63327 |
| Central | East Brunswick Twp | 81 JENSEN ST | 4 | 35.00 | 63329 |
| Central | East Brunswick Twp | 99 ROLLING RD | 4 | 35.00 | 63708 |
| Central | East Brunswick Twp | 6 DEXTER RD | 4 | 35.00 | 64869 |
| Central | East Brunswick Twp | 6 DEXTER RD | 4 | 35.00 | 64870 |
| Central | East Brunswick Twp | 18 HUDSON RD | 4 | 35.00 | 63702 |
| Central | East Brunswick Twp | 2 SANDRA RD | 4 | 35.00 | 64883 |
| Central | East Brunswick Twp | 98 PALMER CT | 4 | 35.00 | 64856 |
| Central | East Brunswick Twp | 48 PALMER CT | 4 | 35.00 | 64855 |
| Central | East Brunswick Twp | 15 SANDRA RD | 4 | 40.00 | 64854 |
| Central | East Brunswick Twp | 15 HUNTINGTON RD | 4 | 40.00 | 63571 |
| Central | East Brunswick Twp | 3 DOUGLAS RD | 4 | 35.00 | 61910 |
| Central | East Brunswick Twp | 59 JENSEN ST | 4 | 40.00 | 63418 |
| Central | East Brunswick Twp | 55 JENSEN ST | 4 | 40.00 | 63419 |
| Central | East Brunswick Twp | 7 SNOWDEN RD | 4 | 35.00 | 63562 |
| Central | East Brunswick Twp | 47 JENSEN ST | 4 | 35.00 | 63617 |
| Central | East Brunswick Twp | 9 SNOWDEN RD | 4 | 35.00 | 63563 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 49 JENSEN ST | 4 | 35.00 | 63614 |
| Central | East Brunswick Twp | 16 CANNON RD | 4 | 40.00 | 61526 |
| Central | East Brunswick Twp | 36 JENSEN ST | 4 | 35.00 | 64491 |
| Central | East Brunswick Twp | 5 BURNHAM RD | 4 | 40.00 | 61545 |
| Central | East Brunswick Twp | 7 BURNHAM RD | 4 | 40.00 | 61544 |
| Central | East Brunswick Twp | 8 BARRIE RD | 4 | 35.00 | 63574 |
| Central | East Brunswick Twp | 34 JENSEN ST | 4 | 35.00 | 64492 |
| Central | East Brunswick Twp | 15 WOLFF AVE | 4 | 40.00 | 61800 |
| Central | East Brunswick Twp | 34 JENSEN ST | 4 | 35.00 | 64493 |
| Central | East Brunswick Twp | 32 JENSEN ST | 4 | 35.00 | 64494 |
| Central | East Brunswick Twp | 85 SAFRAN AVE | 4 | 35.00 | 61806 |
| Central | East Brunswick Twp | 98 CANTERBURY RD | 4 | 40.00 | 62782 |
| Central | East Brunswick Twp | 6 DIANA CT | 4 | 35.00 | 64735 |
| Central | East Brunswick Twp | 4 DIANA CT | 4 | 35.00 | 64734 |
| Central | East Brunswick Twp | 2 DIANA CT | 4 | 40.00 | 62197 |
| Central | East Brunswick Twp | 21 NORTHFIELD AVE | 4 | 40.00 | 62137 |
| Central | Elizabeth City | 727 GRIER AVE | 4 | 40.00 | 60786 |
| Central | Elizabeth City | 821 MYRTLE ST | 4 | 40.00 | 63475 |
| Central | Elizabeth City | 803 MYRTLE ST | 4 | 40.00 | 66046 |
| Central | East Brunswick Twp | 7 RANGER RD | 4 | 35.00 | 62687 |
| Central | Elizabeth City | 439 NEW YORK AVE | 4 | 35.00 | 66833 |
| Central | Elizabeth City | 152 RACentral ST | 4 | 40.00 | 64384 |
| Central | East Brunswick Twp | 92 CANTERBURY RD | 4 | 40.00 | 62781 |
| Central | East Brunswick Twp | 99 HILLSDALE RD | 4 | 35.00 | 63623 |
| Central | East Brunswick Twp | 98 HILLSDALE RD | 4 | 30.00 | 64529 |
| Central | East Brunswick Twp | 13 BIRCH HILL RD | 4 | 35.00 | 64531 |
| Central | East Brunswick Twp | 93 ALPINE CT | 4 | 35.00 | 64536 |
| Central | Elizabeth City | 977 MCLAIN ST | 4 | 35.00 | 64271 |
| Central | East Brunswick Twp | 1 ALPINE CT | 4 | 35.00 | 64148 |
| Central | Elizabeth City | 930 MCLAIN ST | 4 | 35.00 | 62448 |
| Central | East Brunswick Twp | 97 RIDGE CT | 4 | 35.00 | 62729 |
| Central | Elizabeth City | 336 WASHINGTON AVE | 4 | 35.00 | 67017 |
| Central | East Brunswick Twp | 46 RIDGE CT | 4 | 35.00 | 62728 |
| Central | East Brunswick Twp | 8 RIDGE CT | 4 | 35.00 | 62727 |
| Central | East Brunswick Twp | 4 CLOVIS RD | 4 | 35.00 | 62600 |
| Central | East Brunswick Twp | 6 RIDGE CT | 4 | 35.00 | 62726 |
| Central | East Brunswick Twp | 4 RIDGE CT | 4 | 40.00 | 62691 |
| Central | East Brunswick Twp | 59 CentralNTER LN | 4 | 35.00 | 62724 |
| Central | East Brunswick Twp | 41 CANTERBURY RD | 4 | 35.00 | 62592 |
| Central | Elizabeth City | 386 ROSEHILL PL | 4 | 55.00 | 66579 |
| Central | East Brunswick Twp | 162 SUMMERHILL RD | 4 | 30.00 | 65271 |
| Central | East Brunswick Twp | 244 RUES LN | 4 | 40.00 | 61433 |
| Central | East Brunswick Twp | 45 FARMS ROAD CIR | 4 | 40.00 | 62573 |
| Central | East Brunswick Twp | 226 RUES LN | 4 | 40.00 | 61429 |
| Central | Elizabeth City | 497 LIDGERWOOD AVE | 4 | 40.00 | BT4304 |
| Central | East Brunswick Twp | 61 FARMS ROAD CIR | 4 | 35.00 | 62692 |
| Central | East Brunswick Twp | 200 RUES LN | 4 | 40.00 | 62595 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 71 FARMS ROAD CIR | 4 | 35.00 | 62741 |
| Central | Elizabeth City | 365 NEW YORK AVE | 4 | 35.00 | 66918 |
| Central | East Brunswick Twp | 7 MANSFIELD AVE | 4 | 35.00 | 61831 |
| Central | East Brunswick Twp | 9 MANSFIELD AVE | 4 | 35.00 | 61832 |
| Central | East Brunswick Twp | 78 FARMS ROAD CIR | 4 | 35.00 | 62733 |
| Central | East Brunswick Twp | 143 CHURCH LN | 4 | 35.00 | 63840 |
| Central | East Brunswick Twp | 154 RUES LN | 4 | 45.00 | 61416 |
| Central | East Brunswick Twp | 31 MANSFIELD AVE | 4 | 35.00 | 61837 |
| Central | East Brunswick Twp | 85 FARMS ROAD CIR | 4 | 40.00 | 62723 |
| Central | East Brunswick Twp | 87 FARMS ROAD CIR | 4 | 35.00 | 62722 |
| Central | East Brunswick Twp | 29 MERRILL AVE | 4 | 35.00 | 62208 |
| Central | Elizabeth City | 816 SUMMER ST | 4 | 40.00 | 62991 |
| Central | East Brunswick Twp | 19 VALLEY VIEW RD | 4 | 35.00 | 62215 |
| Central | Elizabeth City | 924 S ELMORA AVE | 4 | 35.00 | 64581 |
| Central | East Brunswick Twp | 27 SALEM RD | 4 | 35.00 | 63959 |
| Central | East Brunswick Twp | 23 SALEM RD | 4 | 35.00 | 63961 |
| Central | East Brunswick Twp | 9 SALEM RD | 4 | 35.00 | 63965 |
| Central | East Brunswick Twp | 1 STERLING CT | 4 | 35.00 | 63966 |
| Central | East Brunswick Twp | 615 CRANBURY RD | 4 | 35.00 | 62043 |
| Central | East Brunswick Twp | 297 SUMMERHILL RD | 4 | 35.00 | 61962 |
| Central | Elizabeth City | 561 S BROAD ST | 4 | 35.00 | 66507 |
| Central | East Brunswick Twp | 27 FRESH PONDS RD | 4 | 35.00 | 60542 |
| Central | Elizabeth City | 752 SUMMER ST | 4 | 40.00 | 62987 |
| Central | Elizabeth City | 737 BAYWAY AVE | 4 | 55.00 | 2334 |
| Central | Elizabeth City | 739 MYRTLE ST | 4 | 35.00 | 65301 |
| Central | Elizabeth City | 753 MORSE MILL RD | 4 | 35.00 | 65302 |
| Central | East Brunswick Twp | 43 WHITE OAK RD | 4 | 35.00 | 63206 |
| Central | East Brunswick Twp | 91 GLENSIDE CT | 4 | 35.00 | 63205 |
| Central | East Brunswick Twp | 15 OVERHILL RD | 4 | 35.00 | 63209 |
| Central | East Brunswick Twp | 44 FRESH PONDS RD | 4 | 35.00 | 64237 |
| Central | Elizabeth City | 757 S BROAD ST | 4 | 40.00 | 64182 |
| Central | East Brunswick Twp | 3 OVERHILL RD | 4 | 35.00 | 65457 |
| Central | Elizabeth City | 737 OGDEN ST | 4 | 40.00 | 63482 |
| Central | Elizabeth City | 668 MYRTLE ST | 4 | 40.00 | 63479 |
| Central | Elizabeth City | 724 OGDEN ST | 4 | 40.00 | 63484 |
| Central | Elizabeth City | 710 OGDEN ST | 4 | 40.00 | 67222 |
| Central | East Brunswick Twp | 131 FRESH PONDS RD | 4 | 35.00 | 60951 |
| Central | East Brunswick Twp | 209 SUMMERHILL RD | 4 | 45.00 | 61097 |
| Central | East Brunswick Twp | 99 FRESH PONDS RD | 4 | 35.00 | 64552 |
| Central | East Brunswick Twp | 137 HARDENBURG LN | 4 | 35.00 | 65684 |
| Central | Elizabeth City | 532 BAYWAY AVE | 4 | 35.00 | 66924 |
| Central | Elizabeth City | 769 COLE AVE | 4 | 40.00 | 64796D |
| Central | East Brunswick Twp | 515 RIVA AVE | 4 | 40.00 | 60013 |
| Central | East Brunswick Twp | 363 DUNHAMS CORNER R | 4 | 40.00 | 65529 |
| Central | Elizabeth City | 447 RICHMOND ST | 4 | 40.00 | 65195 |
| Central | East Brunswick Twp | 9 HENRY ST | 4 | 40.00 | 61468 |
| Central | Elizabeth City | 505 S FRONT ST | 4 | 35.00 | 7609 |

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|---|---|---|---|---|---|
| Central | East Brunswick Twp | 613 RYDERS LN | 4 | 40.00 | 64815 |
| Central | Elizabeth City | 364 S FRONT ST | 4 | 40.00 | 262 |
| Central | East Brunswick Twp | 5 HILLCREST AVE | 4 | 30.00 | 64673 |
| Central | East Brunswick Twp | 9 ALBRECHT LN | 4 | 35.00 | 61047 |
| Central | East Brunswick Twp | 93 HARDENBURG LN | 4 | 35.00 | 60968 |
| Central | East Brunswick Twp | 543 RIVA AVE | 4 | 40.00 | 60018 |
| Central | East Brunswick Twp | 552 RIVA AVE | 4 | 40.00 | 60023 |
| Central | Elizabeth City | 314 3RD AVE | 4 | 35.00 | 7331 |
| Central | East Brunswick Twp | 38 PAUL ST | 4 | 30.00 | 65984 |
| Central | Elizabeth City | 212 MERRITT AVE | 4 | 40.00 | 10642 |
| Central | East Brunswick Twp | 416 DUNHAMS CORNER R | 4 | 35.00 | 60490 |
| Central | East Brunswick Twp | 129 DUTCH RD | 4 | 40.00 | 60764 |
| Central | East Brunswick Twp | 119 DUTCH RD | 4 | 35.00 | 60759 |
| Central | East Brunswick Twp | 191 FRESH PONDS RD | 4 | 35.00 | 63530 |
| Central | East Brunswick Twp | 189 FRESH PONDS RD | 4 | 35.00 | 63531 |
| Central | East Brunswick Twp | 104 DUTCH RD | 4 | 40.00 | 66242 |
| Central | East Brunswick Twp | 346 DUNHAMS CORNER R | 4 | 35.00 | 65490 |
| Central | East Brunswick Twp | 81 FERN RD | 4 | 40.00 | 62052 |
| Central | East Brunswick Twp | 344 DUNHAMS CORNER R | 4 | 40.00 | 65489 |
| Central | East Brunswick Twp | 30 TALL OAKS DR | 4 | 35.00 | 63514 |
| Central | East Brunswick Twp | 282 DUNHAMS CORNER R | 4 | 35.00 | 65254 |
| Central | Elizabeth City | 44 BUTLER ST | 4 | 40.00 | 62882 |
| Central | East Brunswick Twp | 6 SUSSEX RD | 4 | 35.00 | 63504 |
| Central | East Brunswick Twp | 51 BEEKMAN RD | 4 | 35.00 | 62383 |
| Central | East Brunswick Twp | 2 SUSSEX RD | 4 | 40.00 | 527 |
| Central | East Brunswick Twp | 37 TALL OAKS DR | 4 | 35.00 | 63899 |
| Central | East Brunswick Twp | 173 FERN RD | 4 | 35.00 | 63076 |
| Central | East Brunswick Twp | 35 TALL OAKS DR | 4 | 35.00 | 63898 |
| Central | Elizabeth City | 313 FRANKLIN ST | 4 | 40.00 | 64255 |
| Central | East Brunswick Twp | 5 DOGWOOD CT | 4 | 35.00 | 63646 |
| Central | East Brunswick Twp | 3 DOGWOOD CT | 4 | 40.00 | 63517 |
| Central | East Brunswick Twp | 1 DARBY RD | 4 | 35.00 | 63518 |
| Central | East Brunswick Twp | 4 DARBY RD | 4 | 40.00 | 63521 |
| Central | East Brunswick Twp | 151 FERN RD | 4 | 40.00 | 64579 |
| Central | East Brunswick Twp | 282 FRESH PONDS RD | 4 | 35.00 | 62514 |
| Central | East Brunswick Twp | 274 FRESH PONDS RD | 4 | 35.00 | 62512 |
| Central | East Brunswick Twp | 47 TALL OAKS DR | 4 | 40.00 | 63902 |
| Central | East Brunswick Twp | 266 FRESH PONDS RD | 4 | 35.00 | 62511 |
| Central | East Brunswick Twp | 2 WARWICK RD | 4 | 35.00 | 63903 |
| Central | East Brunswick Twp | 99 MATTHEW MNR | 4 | 35.00 | 60937 |
| Central | Elizabeth City | 102 ELIZABETH AVE | 4 | 35.00 | 65615 |
| Central | East Brunswick Twp | 62 YORKTOWN RD | 4 | 35.00 | 64692 |
| Central | East Brunswick Twp | 56 YORKTOWN RD | 4 | 40.00 | 64690 |
| Central | East Brunswick Twp | 40 YORKTOWN RD | 4 | 35.00 | 64683 |
| Central | East Brunswick Twp | 24 BUNKER HL | 4 | 35.00 | 64626 |
| Central | East Brunswick Twp | 22 BUNKER HL | 4 | 35.00 | 64625 |
| Central | East Brunswick Twp | 15 BUNKER HL | 4 | 40.00 | 64622 |

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| Central | East Brunswick Twp | 26 YORKTOWN RD | 4 | 40.00 | 64676 |
| Central | East Brunswick Twp | 21 YORKTOWN RD | 4 | 40.00 | 64577 |
| Central | East Brunswick Twp | 72 BEDFORD CT | 4 | 35.00 | 64575 |
| Central | Elizabeth City | 85 IKEA DR | 4 | 35.00 | 9874 |
| Central | Elizabeth City | 51 ELIZABETH AVE | 4 | 35.00 | 7368 |
| Central | Elizabeth City | 182 PORT AVE | 4 | 40.00 | 62934 |
| Central | Elizabeth City | 185 2ND ST | 4 | 35.00 | 67934 |
| Central | Elizabeth City | 216 BOND ST | 4 | 40.00 | 61764 |
| Central | Elizabeth City | 256 4TH ST | 4 | 40.00 | 65068 |
| Central | Elizabeth City | 1 NORTH AVE E | 4 | 35.00 | 13775 |
| Central | East Brunswick Twp | 17 FARRINGTON AVE | 4 | 40.00 | 61158 |
| Central | East Brunswick Twp | 25 FARRINGTON AVE | 4 | 35.00 | 62712 |
| Central | East Brunswick Twp | 231 RIVA AVE | 4 | 35.00 | 63590 |
| Central | East Brunswick Twp | 231 RIVA AVE | 4 | 40.00 | 63591 |
| Central | East Brunswick Twp | 10 LAKEVIEW AVE | 4 | 35.00 | 60963 |
| Central | East Brunswick Twp | 6 LAKEVIEW AVE | 4 | 35.00 | 60897 |
| Central | East Brunswick Twp | 193 RIVA AVE | 4 | 45.00 | 60238 |
| Central | East Brunswick Twp | 3 STARKIN RD | 4 | 35.00 | 63350 |
| Central | East Brunswick Twp | 69 KAREN DR | 4 | 35.00 | 63464 |
| Central | East Brunswick Twp | 5 STARKIN RD | 4 | 35.00 | 63796 |
| Central | Elizabeth City | 219 BROADWAY | 4 | 35.00 | 8034 |
| Central | East Brunswick Twp | 6 KAREN DR | 4 | 35.00 | 63468 |
| Central | East Brunswick Twp | 4 KAREN DR | 4 | 35.00 | 63467 |
| Central | East Brunswick Twp | 14 STARKIN RD | 4 | 40.00 | 63814 |
| Central | East Brunswick Twp | 45 KAREN DR | 4 | 35.00 | 63466 |
| Central | East Brunswick Twp | 28 INWOOD DR | 4 | 40.00 | 63067 |
| Central | East Brunswick Twp | 21 INWOOD DR | 4 | 35.00 | 63064 |
| Central | East Brunswick Twp | 3 INWOOD DR | 4 | 35.00 | 62849 |
| Central | Elizabeth City | 271 E JERSEY ST | 4 | 35.00 | 11856 |
| Central | East Brunswick Twp | 5 HICKORY RD | 4 | 40.00 | 62415 |
| Central | East Brunswick Twp | 71 MASSING PL | 4 | 40.00 | 60565 |
| Central | East Brunswick Twp | 21 OAKMONT AVE | 4 | 35.00 | 61495 |
| Central | East Brunswick Twp | 21 OAKMONT AVE | 4 | 35.00 | 62352 |
| Central | East Brunswick Twp | 45 LOUISE DR | 4 | 35.00 | 62328 |
| Central | East Brunswick Twp | 49 LOUISE DR | 4 | 35.00 | 62327 |
| Central | East Brunswick Twp | 389 RIVA AVE | 4 | 40.00 | 60276 |
| Central | East Brunswick Twp | 393 RIVA AVE | 4 | 40.00 | 60277 |
| Central | East Brunswick Twp | 408 RIVA AVE | 4 | 35.00 | 1762 |
| Central | East Brunswick Twp | 413 RIVA AVE | 4 | 40.00 | 60339 |
| Central | Elizabeth City | 269 PINE ST | 4 | 40.00 | 62132 |
| Central | Elizabeth City | 98 HOPE LN | 4 | 35.00 | 6287 |
| Central | Elizabeth City | 218 PORT AVE | 4 | 40.00 | 65356 |
| Central | Elizabeth City | 226 PORT AVE | 4 | 45.00 | 65355 |
| Central | East Brunswick Twp | 429 RIVA AVE | 4 | 40.00 | 60345 |
| Central | Elizabeth City | 286 CLARK PL | 4 | 40.00 | 64455 |
| Central | Elizabeth City | 272 CLARK PL | 4 | 35.00 | 64454 |
| Central | Elizabeth City | 188 CLARK PL | 4 | 40.00 | 7884 |

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|---|---|---|---|---|---|
| Central | Elizabeth City | 258 1ST ST | 4 | 35.00 | 66249 |
| Central | Elizabeth City | 147 S PARK ST | 4 | 35.00 | 62311 |
| Central | Elizabeth City | 119 BROADWAY | 4 | 35.00 | 68457 |
| Central | East Brunswick Twp | 3 MARIE TER | 4 | 40.00 | 62814 |
| Central | Elizabeth City | 122 LIVINGSTON ST | 4 | 40.00 | 61087 |
| Central | Elizabeth City | 28 SLATER DR | 4 | 35.00 | 11512 |
| Central | Elizabeth City | 228 INSLEE PL | 4 | 35.00 | 63116 |
| Central | Elizabeth City | 147 RIPLEY PL | 4 | 35.00 | 11624 |
| Central | Elizabeth City | 388 3RD ST | 4 | 35.00 | 66940 |
| Central | Elizabeth City | 254 MONSIGNOR KEMEZIS | 4 | 35.00 | 10132 |
| Central | Elizabeth City | 365 2ND ST | 4 | 30.00 | 67928 |
| Central | Elizabeth City | 329 2ND ST | 4 | 40.00 | 65480 |
| Central | Elizabeth City | 222 FRONT ST | 4 | 35.00 | 11182 |
| Central | South Brunswick Twp | 2181 US HIGHWAY 130 | 4 | 35.00 | 62027 |
| Central | South Brunswick Twp | 2183 US HIGHWAY 130 | 4 | 35.00 | 62026 |
| Central | South Brunswick Twp | 2189 US HIGHWAY 130 | 4 | 35.00 | 62024 |
| Central | South Brunswick Twp | 2279 US HIGHWAY 130 | 4 | 40.00 | 60998 |
| Central | South Brunswick Twp | 3970 US HIGHWAY 1 | 4 | 40.00 | 60411 |
| Central | South Brunswick Twp | 4046 US HIGHWAY 1 | 4 | 40.00 | 60450 |
| Central | South Brunswick Twp | 66 TEXAS AVE | 4 | 35.00 | 63060 |
| Central | South Brunswick Twp | 51 TEXAS AVE | 4 | 35.00 | 4185 |
| Central | South Brunswick Twp | 74 TEXAS AVE | 4 | 40.00 | 62434 |
| Central | South Brunswick Twp | 31 KOHL ST | 4 | 35.00 | 62431 |
| Central | South Brunswick Twp | 86 MAINE ST | 4 | 35.00 | 62429 |
| Central | South Brunswick Twp | 93 MAINE ST | 4 | 35.00 | 62428 |
| Central | South Brunswick Twp | 5 CHERRY ST | 4 | 35.00 | 67163 |
| Central | South Brunswick Twp | 14 CRANSTON RD | 4 | 35.00 | 62955 |
| Central | South Brunswick Twp | 29 CRANSTON RD | 4 | 30.00 | 62975 |
| Central | South Brunswick Twp | 30 TYNDALL RD | 4 | 35.00 | 62927 |
| Central | South Brunswick Twp | 27 DAWSON RD | 4 | 35.00 | 63113 |
| Central | South Brunswick Twp | 30 ROBIN RD | 4 | 35.00 | 4141 |
| Central | South Brunswick Twp | 30 STARLING RD | 4 | 40.00 | 63201 |
| Central | South Brunswick Twp | 6 RALEIGH RD | 4 | 40.00 | 63199 |
| Central | South Brunswick Twp | 12 RALEIGH RD | 4 | 40.00 | 63197 |
| Central | South Brunswick Twp | 18 RALEIGH RD | 4 | 40.00 | 63195 |
| Central | South Brunswick Twp | 22 RALEIGH RD | 4 | 40.00 | 63194 |
| Central | South Brunswick Twp | 679 GEORGES RD | 4 | 35.00 | 66486 |
| Central | South Brunswick Twp | 35 RALEIGH RD | 4 | 40.00 | 63191 |
| Central | South Brunswick Twp | 39 RALEIGH RD | 4 | 40.00 | 63190 |
| Central | South Brunswick Twp | 43 RALEIGH RD | 4 | 40.00 | 63189 |
| Central | South Brunswick Twp | 631 GEORGES RD | 4 | 35.00 | 8070 |
| Central | South Brunswick Twp | 571 GEORGES RD | 4 | 35.00 | 64049 |
| Central | South Brunswick Twp | 275 NEW RD | 4 | 35.00 | 64145 |
| Central | South Brunswick Twp | 251 NEW RD | 4 | 35.00 | 63946 |
| Central | South Brunswick Twp | 14 NEW RD | 4 | 35.00 | 984 |
| Central | South Brunswick Twp | 12 NEW RD | 4 | 35.00 | 986 |
| Central | South Brunswick Twp | 3 CALVIN RD | 4 | 40.00 | 63223 |

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|---|---|---|---|---|---|
| Central | South Brunswick Twp | 6 HASTINGS RD | 4 | 40.00 | 63219 |
| Central | South Brunswick Twp | 1 RALEIGH RD | 4 | 40.00 | 63218 |
| Central | South Brunswick Twp | 83 CALVIN RD | 4 | 40.00 | 63214 |
| Central | South Brunswick Twp | 26 HASTINGS RD | 4 | 35.00 | 61191 |
| Central | South Brunswick Twp | 35 HASTINGS RD | 4 | 40.00 | 63211 |
| Central | South Brunswick Twp | 4 NEW RD | 4 | 35.00 | 63777 |
| Central | South Brunswick Twp | 39 HASTINGS RD | 4 | 40.00 | 63209 |
| Central | South Brunswick Twp | 88 ALLSTON RD | 4 | 40.00 | 63064 |
| Central | South Brunswick Twp | 3506 STATE HIGHWAY 27 | 4 | 40.00 | 63853 |
| Central | South Brunswick Twp | 3490 STATE HIGHWAY 27 | 4 | 40.00 | 66750 |
| Central | South Brunswick Twp | 4 HASTINGS RD | 4 | 40.00 | 63221 |
| Central | South Brunswick Twp | 47 PARSONS RD | 4 | 35.00 | 63729 |
| Central | South Brunswick Twp | 3370 LINCOLN HWY | 4 | 35.00 | 4228 |
| Central | South Brunswick Twp | 16 SAND HILLS RD | 4 | 40.00 | 63413 |
| Central | South Brunswick Twp | 3 WOODROW RD | 4 | 40.00 | 62589 |
| Central | South Brunswick Twp | 2 WOODROW RD | 4 | 40.00 | 62566 |
| Central | South Brunswick Twp | 21 RUMSON RD | 4 | 35.00 | 62869 |
| Central | South Brunswick Twp | 29 SPRINGDALE RD | 4 | 35.00 | 62504 |
| Central | South Brunswick Twp | 31 STOCKTON RD | 4 | 40.00 | 62761 |
| Central | South Brunswick Twp | 134 KENDALL RD | 4 | 40.00 | 62633 |
| Central | South Brunswick Twp | 37 LANGLEY RD | 4 | 35.00 | 63367 |
| Central | South Brunswick Twp | 12 STEVENS RD | 4 | 35.00 | 63757 |
| Central | South Brunswick Twp | 18 STEVENS RD | 4 | 35.00 | 63759 |
| Central | South Brunswick Twp | 20 STEVENS RD | 4 | 40.00 | 63761 |
| Central | South Brunswick Twp | 26 CHIPPER DR | 4 | 35.00 | 4220 |
| Central | South Brunswick Twp | 3 VINEYARD LN | 4 | 35.00 | 63991 |
| Central | South Brunswick Twp | 97 OAKDALE VLG | 4 | 35.00 | 62377 |
| Central | South Brunswick Twp | 12 DARROW CT | 4 | 35.00 | 63329 |
| Central | South Brunswick Twp | 8 DARROW CT | 4 | 35.00 | 63327 |
| Central | South Brunswick Twp | 68 OAKEY DR | 4 | 35.00 | 68470 |
| Central | South Brunswick Twp | 52 OAKEY DR | 4 | 35.00 | 68466 |
| Central | South Brunswick Twp | 265 FRESH PONDS RD | 4 | 35.00 | 8078 |
| Central | South Brunswick Twp | 271 DEANS RHODE HALL R | 4 | 35.00 | 62013 |
| Central | South Brunswick Twp | 97 FRESH PONDS RD | 4 | 35.00 | 67400 |
| Central | South Brunswick Twp | 197 NORTHVIEW DR | 4 | 35.00 | 63988 |
| Central | South Brunswick Twp | 46 REGAL DR | 4 | 40.00 | 5636 |
| Central | South Brunswick Twp | 178 MAJOR RD | 4 | 35.00 | 66831 |
| Central | South Brunswick Twp | 79 LILAC CT | 4 | 35.00 | 3092 |
| Central | South Brunswick Twp | 73 MAJOR RD | 4 | 35.00 | 68417 |
| Central | South Brunswick Twp | 31 MAJOR RD | 4 | 35.00 | 8121 |
| Central | South Brunswick Twp | 561 RIDGE RD | 4 | 35.00 | 5881 |
| Central | South Brunswick Twp | 327 RIDGE RD | 4 | 35.00 | 2344 |
| Central | Millstone Boro | 90 AMWELL RD | 4 | 40.00 | 100 |
| Central | Millstone Boro | 130 AMWELL RD | 4 | 40.00 | 76 |
| Central | Millstone Boro | 57 AMWELL RD | 4 | 35.00 | 96D |
| Central | Millstone Boro | 138 AMWELL RD | 4 | 40.00 | 77 |
| Central | Millstone Boro | 1512 MILLSTONE RIVER RI | 4 | 40.00 | 60 |

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|---|---|---|---|---|---|
| Central | Millstone Boro | 1504 MILLSTONE RIVER RI | 4 | 35.00 | 121 |
| Central | Millstone Boro | 1496 MILLSTONE RIVER RI | 4 | 40.00 | 52 |
| Central | Millstone Boro | 299 ANN ST | 4 | 40.00 | 157 |
| Central | Millstone Boro | 233 ANN ST | 4 | 35.00 | 98 |
| Central | Millstone Boro | 25 WEST ST | 4 | 35.00 | 35 |
| Central | Millstone Boro | 1350 MAIN ST | 4 | 40.00 | 6D |
| Central | Millstone Boro | 5 MAPLE TER | 4 | 35.00 | 101 |
| Central | Manville Boro | 57 VALERIE DR | 4 | 40.00 | 61416 |
| Central | Manville Boro | 242 E CAMPLAIN RD | 4 | 35.00 | 61495 |
| Central | Manville Boro | 292 S 12TH AVE | 4 | 35.00 | 61592 |
| Central | Manville Boro | 1627 COLORADO AVE | 4 | 35.00 | 61674 |
| Central | Manville Boro | 161 S 19TH AVE | 4 | 35.00 | 60817 |
| Central | Manville Boro | 191 S 19TH AVE | 4 | 35.00 | 60816 |
| Central | Manville Boro | 297 S 19TH AVE | 4 | 40.00 | 60652 |
| Central | Manville Boro | 105 S 21ST AVE | 4 | 35.00 | 61177 |
| Central | Manville Boro | 2044 W CAMPLAIN RD | 4 | 40.00 | 60501 |
| Central | Manville Boro | 2116 W CAMPLAIN RD | 4 | 40.00 | 60504 |
| Central | Manville Boro | 35 S 4TH AVE | 4 | 35.00 | 61327 |
| Central | Manville Boro | 113 S 8TH AVE | 4 | 35.00 | 60308 |
| Central | Manville Boro | 91 S 8TH AVE | 4 | 35.00 | 60309 |
| Central | Manville Boro | 147 S 11TH AVE | 4 | 35.00 | 60566 |
| Central | Manville Boro | 101 S 12TH AVE | 4 | 40.00 | 60941 |
| Central | Manville Boro | 113 S 12TH AVE | 4 | 35.00 | 60940 |
| Central | Manville Boro | 93 N 5TH AVE | 4 | 40.00 | 61064 |
| Central | Manville Boro | 39 N 6TH AVE | 4 | 35.00 | 61071 |
| Central | Manville Boro | 18 N 8TH AVE | 4 | 40.00 | 60954 |
| Central | Manville Boro | 68 N 8TH AVE | 4 | 35.00 | 60630 |
| Central | Manville Boro | 42 N 9TH AVE | 4 | 35.00 | 60471 |
| Central | Manville Boro | 72 N 10TH AVE | 4 | 35.00 | 61369 |
| Central | Manville Boro | 1038 NORTH ST | 4 | 35.00 | 1485 |
| Central | Manville Boro | 40 N 12TH AVE | 4 | 40.00 | 61280 |
| Central | Manville Boro | 78 N 8TH AVE | 4 | 40.00 | 60356 |
| Central | Manville Boro | 712 BROOKS BLVD | 4 | 35.00 | 60152 |
| Central | Manville Boro | 658 BROOKS BLVD | 4 | 40.00 | 60151 |
| Central | Manville Boro | 218 N 2ND AVE | 4 | 40.00 | 60132 |
| Central | Manville Boro | 208 KNOPF ST | 4 | 40.00 | 60410 |
| Central | Manville Boro | 266 N 3RD AVE | 4 | 35.00 | 60428 |
| Central | Manville Boro | 276 N 4TH AVE | 4 | 40.00 | 60430 |
| Central | Manville Boro | 292 N 4TH AVE | 4 | 40.00 | 60429 |
| Central | Manville Boro | 358 N 4TH AVE | 4 | 40.00 | 60099 |
| Central | Manville Boro | 300 DUKES PKWY | 4 | 40.00 | 60013 |
| Central | Manville Boro | 424 KNOPF ST | 4 | 40.00 | 60100 |
| Central | Manville Boro | 272 N 5TH AVE | 4 | 40.00 | 60432 |
| Central | Manville Boro | 256 N 5TH AVE | 4 | 35.00 | 60433 |
| Central | Manville Boro | 97 N 6TH AVE | 4 | 30.00 | 60756 |
| Central | Manville Boro | 286 N 6TH AVE | 4 | 35.00 | 60434 |
| Central | Manville Boro | 700 DUKES PKWY | 4 | 40.00 | 60021 |

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|---|---|---|---|---|---|
| Central | Manville Boro | 337 N 7TH AVE | 4 | 35.00 | 60725 |
| Central | Manville Boro | 629 KNOPF ST | 4 | 40.00 | 60415 |
| Central | Manville Boro | 88 N 8TH AVE | 4 | 35.00 | 60573 |
| Central | Manville Boro | 102 N 8TH AVE | 4 | 35.00 | 60574 |
| Central | Manville Boro | 138 N 8TH AVE | 4 | 35.00 | 60805 |
| Central | Manville Boro | 152 N 8TH AVE | 4 | 35.00 | 61001 |
| Central | Manville Boro | 216 N 8TH AVE | 4 | 35.00 | 60809 |
| Central | Manville Boro | 829 KNOPF ST | 4 | 40.00 | 60418 |
| Central | Manville Boro | 376 N 8TH AVE | 4 | 35.00 | 60352 |
| Central | Manville Boro | 870 DUKES PKWY | 4 | 40.00 | 60024 |
| Central | Manville Boro | 306 N 9TH AVE | 4 | 35.00 | 60455 |
| Central | Manville Boro | 933 KNOPF ST | 4 | 40.00 | 60420 |
| Central | Manville Boro | 889 KNOPF ST | 4 | 40.00 | 60419 |
| Central | Manville Boro | 162 N 9TH AVE | 4 | 35.00 | 60514 |
| Central | Manville Boro | 134 N 10TH AVE | 4 | 35.00 | 61330 |
| Central | Manville Boro | 156 N 10TH AVE | 4 | 35.00 | 61277 |
| Central | Manville Boro | 182 N 10TH AVE | 4 | 35.00 | 60621 |
| Central | Manville Boro | 202 N 10TH AVE | 4 | 40.00 | 60620 |
| Central | Manville Boro | 266 N 10TH AVE | 4 | 40.00 | 60371 |
| Central | Manville Boro | 1142 GREEN ST | 4 | 35.00 | 61300 |
| Central | Manville Boro | 372 N 10TH AVE | 4 | 35.00 | 61275 |
| Central | Manville Boro | 1015 JUNE PL | 4 | 35.00 | 60732 |
| Central | Manville Boro | 1013 KNOPF ST | 4 | 35.00 | 60369 |
| Central | Manville Boro | 1111 KNOPF ST | 4 | 35.00 | 60421 |
| Central | Manville Boro | 1126 SAINT JOHN ST | 4 | 35.00 | 61324 |
| Central | Manville Boro | 1119 SAINT JOHN ST | 4 | 30.00 | 61739 |
| Central | Manville Boro | 311 SAINT MARKS PL | 4 | 35.00 | 61060 |
| Central | Manville Boro | 1153 KNOPF ST | 4 | 40.00 | 60424 |
| Central | Manville Boro | 1107 SAINT JOHN ST | 4 | 35.00 | 61062 |
| Central | Manville Boro | 397 CLINTON AVE | 4 | 35.00 | 60369D |
| Central | Manville Boro | 1061 GRESS ST | 4 | 40.00 | 60237 |
| Central | Manville Boro | 1064 DUKES PKWY | 4 | 40.00 | 60031 |
| Central | Manville Boro | 1307 GRESS ST | 4 | 35.00 | 60448 |
| Central | Manville Boro | 1262 SAINT JOHN ST | 4 | 35.00 | 61322 |
| Central | Manville Boro | 1264 BLEECHER ST | 4 | 35.00 | 60639 |
| Central | Manville Boro | 26 N 14TH AVE | 4 | 35.00 | 61034 |
| Central | Manville Boro | 77 N 15TH AVE | 4 | 35.00 | 60764 |
| Central | Manville Boro | 1502 NORTH ST | 4 | 40.00 | 1113 |
| Central | Manville Boro | 65 N 16TH AVE | 4 | 35.00 | 60672 |
| Central | Manville Boro | 67 N 17TH AVE | 4 | 35.00 | 60824 |
| Central | Manville Boro | 36 N 20TH AVE | 4 | 35.00 | 61434 |
| Central | Manville Boro | 84 N 20TH AVE | 4 | 35.00 | 60949 |
| Central | South Brunswick Twp | 100 RIVA AVE | 4 | 35.00 | 60015 |
| Central | South Brunswick Twp | 90 RIVA AVE | 4 | 35.00 | 60019 |
| Central | South Brunswick Twp | 97 RIVA AVE | 4 | 35.00 | 2390 |
| Central | South Brunswick Twp | 95 RIVA AVE | 4 | 35.00 | 66379 |
| Central | South Brunswick Twp | 987 GEORGES RD | 4 | 40.00 | 61627 |

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| Central | South Brunswick Twp | 981 GEORGES RD | 4 | 40.00 | 61629 |
| Central | South Brunswick Twp | 943 GEORGES RD | 4 | 40.00 | 61636 |
| Central | South Brunswick Twp | 223 DEANS LN | 4 | 35.00 | 66608 |
| Central | South Brunswick Twp | 108 DAVIDSON MILL RD | 4 | 35.00 | 60063 |
| Central | South Brunswick Twp | 15 OLD DAVIDSON MILL RI | 4 | 35.00 | 60774 |
| Central | South Brunswick Twp | 423 DUNHAMS CORNER R | 4 | 35.00 | 62283 |
| Central | South Brunswick Twp | 423 DUNHAMS CORNER R | 4 | 35.00 | 62282 |
| Central | South Brunswick Twp | RHODE HALL RD | 4 | 35.00 | 128 |
| Central | South Brunswick Twp | 413 DUNHAMS CORNER R | 4 | 40.00 | 126 |
| Central | South Brunswick Twp | 263 DAVIDSONS MILL RD | 4 | 35.00 | 67359 |
| Central | South Brunswick Twp | 308 DAVIDSONS MILL RD | 4 | 35.00 | 5803 |
| Central | New Brunswick City | 64 COLLEGE AVE | 4 | 40.00 | 2758 |
| Central | New Brunswick City | 19 SENIOR ST | 4 | 40.00 | 60566 |
| Central | New Brunswick City | 48 RICHARDSON ST | 4 | 35.00 | 61829 |
| Central | New Brunswick City | 62 RICHARDSON ST | 4 | 35.00 | 61827 |
| Central | New Brunswick City | 47 HUNTINGTON ST | 4 | 35.00 | 61029 |
| Central | New Brunswick City | 623 GEORGE ST | 4 | 40.00 | 63173 |
| Central | New Brunswick City | 629 GEORGE ST | 4 | 40.00 | 63177 |
| Central | New Brunswick City | 95 SENIOR ST | 4 | 35.00 | 60558 |
| Central | New Brunswick City | 114 HUNTINGTON ST | 4 | 45.00 | 63095 |
| Central | New Brunswick City | 90 JEFFERSON AVE | 4 | 40.00 | 63539 |
| Central | New Brunswick City | 54 LANDING LN | 4 | 40.00 | 62873 |
| Central | Garwood Boro | 556 SOUTH AVE | 4 | 35.00 | 737 |
| Central | New Brunswick City | 26 ROBINSON ST | 4 | 40.00 | 62130 |
| Central | New Brunswick City | 12 ROBINSON ST | 4 | 45.00 | 62129 |
| Central | New Brunswick City | 37 DUKE ST | 4 | 35.00 | 61783 |
| Central | New Brunswick City | 47 DUKE ST | 4 | 35.00 | 61784 |
| Central | New Brunswick City | 73 DUKE ST | 4 | 35.00 | 62144 |
| Central | Garwood Boro | 174 HICKORY AVE | 4 | 40.00 | 60464 |
| Central | New Brunswick City | 263 HAMILTON ST | 4 | 40.00 | 60748 |
| Central | New Brunswick City | 26 WYCKOFF ST | 4 | 35.00 | 62147 |
| Central | New Brunswick City | 6 RESERVOIR AVE | 4 | 40.00 | 62081 |
| Central | New Brunswick City | 45 OAK ST | 4 | 35.00 | 61300 |
| Central | New Brunswick City | 261 SEAMAN ST | 4 | 40.00 | 60373 |
| Central | New Brunswick City | 280 COMSTOCK ST | 4 | 40.00 | 61532 |
| Central | New Brunswick City | 6 NEILSON ST | 4 | 40.00 | 64058 |
| Central | New Brunswick City | 71 TOWNSEND ST | 4 | 35.00 | 62054 |
| Central | New Brunswick City | 83 TOWNSEND ST | 4 | 35.00 | 62052 |
| Central | New Brunswick City | 25 HANDY ST | 4 | 40.00 | 60395 |
| Central | New Brunswick City | 111 HANDY ST | 4 | 40.00 | 61316 |
| Central | New Brunswick City | 133 THROOP AVE | 4 | 35.00 | 63839 |
| Central | New Brunswick City | 66 SIMPLEX AVE | 4 | 35.00 | 62121 |
| Central | New Brunswick City | 177 HALE ST | 4 | 35.00 | 62826 |
| Metropolitan | East Orange City | 93 CARNEGIE AVE | 4 | 35.00 | 61144 |
| Metropolitan | East Orange City | 104 S ORATON PKWY | 4 | 35.00 | 60308 |
| Metropolitan | East Orange City | 50 S BURNETT ST | 4 | 35.00 | 60392 |
| Metropolitan | East Orange City | 152 BEECH ST | 4 | 35.00 | 61098 |

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| Metropolitan | East Orange City | 163 HALSTED ST | 4 | 35.00 | 61129 |
| Metropolitan | East Orange City | 145 EVERGREEN PL | 4 | 35.00 | 60657 |
| Metropolitan | East Orange City | 79 HAMPTON TER | 4 | 40.00 | 60101 |
| Metropolitan | Maplewood Twp | 600 VALLEY ST | 4 | 35.00 | 62711 |
| Metropolitan | Maplewood Twp | 594 VALLEY ST | 4 | 35.00 | 2399 |
| Metropolitan | Maplewood Twp | 627 VALLEY ST | 4 | 40.00 | 62915 |
| Metropolitan | Maplewood Twp | 733 VALLEY ST | 4 | 40.00 | 62442 |
| Metropolitan | Maplewood Twp | 6 MELMAN TER | 4 | 35.00 | 62412 |
| Metropolitan | Maplewood Twp | 7 RYNDA RD | 4 | 40.00 | 62013 |
| Metropolitan | Maplewood Twp | 37 RYNDA RD | 4 | 35.00 | 62017 |
| Metropolitan | Maplewood Twp | 15 NORTHVIEW TER | 4 | 35.00 | 62418 |
| Metropolitan | Maplewood Twp | 2098 MILLBURN AVE | 4 | 45.00 | 60834 |
| Metropolitan | Maplewood Twp | 2072 MILLBURN AVE | 4 | 35.00 | 62950 |
| Metropolitan | Maplewood Twp | 15 MANLEY TER | 4 | 35.00 | 61629 |
| Metropolitan | Maplewood Twp | 21 BROADVIEW AVE | 4 | 40.00 | 61620 |
| Metropolitan | Maplewood Twp | 7 BOWDOIN ST | 4 | 40.00 | 61025 |
| Metropolitan | Maplewood Twp | 57 TUSCAN RD | 4 | 35.00 | 60662 |
| Metropolitan | Maplewood Twp | 2 YALE ST | 4 | 35.00 | 60643 |
| Metropolitan | Maplewood Twp | 717 VALLEY ST | 4 | 40.00 | 62638D |
| Metropolitan | Maplewood Twp | 705 VALLEY ST | 4 | 40.00 | 62636 |
| Metropolitan | Maplewood Twp | 24 OBERLIN ST | 4 | 35.00 | 60580 |
| Metropolitan | Maplewood Twp | 33 PIERSON RD S | 4 | 35.00 | 61539 |
| Metropolitan | Maplewood Twp | 57 PIERSON RD S | 4 | 35.00 | 61546 |
| Metropolitan | Maplewood Twp | 9 RUTGERS ST | 4 | 35.00 | 61496 |
| Metropolitan | Maplewood Twp | 93 OSBORNE TER | 4 | 35.00 | 60240 |
| Metropolitan | East Orange City | 671 CentralNTRAL AVE | 4 | 30.00 | 61850 |
| Metropolitan | Elizabeth City | 1153 POLARIS ST | 4 | 40.00 | 68923 |
| Metropolitan | Elizabeth City | 1022 POLARIS ST | 4 | 40.00 | 68909 |
| Metropolitan | Maplewood Twp | 1931 SPRINGFIELD AVE | 4 | 40.00 | 60854 |
| Metropolitan | Maplewood Twp | 34 LAUREL AVE | 4 | 35.00 | 62162 |
| Metropolitan | Elizabeth City | 2367 MCLESTER ST | 4 | 35.00 | 12789 |
| Metropolitan | Maplewood Twp | 27 FLORIDA ST | 4 | 35.00 | 60615 |
| Metropolitan | Maplewood Twp | 17 REVERE AVE | 4 | 35.00 | 61877 |
| Metropolitan | Maplewood Twp | 1859 SPRINGFIELD AVE | 4 | 40.00 | 60862 |
| Metropolitan | Maplewood Twp | 1835 SPRINGFIELD AVE | 4 | 40.00 | 60865 |
| Metropolitan | Maplewood Twp | 1779 SPRINGFIELD AVE | 4 | 35.00 | 60870 |
| Metropolitan | Maplewood Twp | 1759 SPRINGFIELD AVE | 4 | 40.00 | 60873 |
| Metropolitan | Maplewood Twp | 1743 SPRINGFIELD AVE | 4 | 40.00 | 60874 |
| Metropolitan | Maplewood Twp | 1705 SPRINGFIELD AVE | 4 | 40.00 | 60878 |
| Metropolitan | Maplewood Twp | 1655 SPRINGFIELD AVE | 4 | 40.00 | 60883 |
| Metropolitan | Maplewood Twp | 50 OBERLIN ST | 4 | 35.00 | 60644 |
| Metropolitan | Maplewood Twp | 40 OBERLIN ST | 4 | 40.00 | 60576 |
| Metropolitan | Maplewood Twp | 98 HARVARD AVE | 4 | 35.00 | 61718 |
| Metropolitan | Maplewood Twp | 90 HARVARD AVE | 4 | 35.00 | 61716 |
| Metropolitan | Maplewood Twp | 58 OBERLIN ST | 4 | 35.00 | 62434 |
| Metropolitan | Maplewood Twp | 62 YALE ST | 4 | 35.00 | 62703 |
| Metropolitan | Maplewood Twp | 724 PROSPECT ST | 4 | 40.00 | 60325 |

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| Metropolitan | Maplewood Twp | 13 MARION PL | 4 | 35.00 | 61727 |
| Metropolitan | Maplewood Twp | 83 PARK AVE | 4 | 35.00 | 60246 |
| Metropolitan | Maplewood Twp | 129 INDIANA ST | 4 | 35.00 | 62342 |
| Metropolitan | Maplewood Twp | 79 PIERSON RD S | 4 | 40.00 | 61549 |
| Metropolitan | Maplewood Twp | 97 PIERSON RD S | 4 | 35.00 | 61551 |
| Metropolitan | Maplewood Twp | 1613 SPRINGFIELD AVE | 4 | 40.00 | 60888 |
| Metropolitan | Maplewood Twp | 2 VERMONT ST | 4 | 40.00 | 60682 |
| Metropolitan | Maplewood Twp | 9 AMHERST CT | 4 | 40.00 | 61685 |
| Metropolitan | Maplewood Twp | 19 AMHERST CT | 4 | 35.00 | 62698 |
| Metropolitan | Maplewood Twp | 13 WELLESLEY RD | 4 | 35.00 | 61488 |
| Metropolitan | Maplewood Twp | 279 HILTON AVE | 4 | 35.00 | 62172 |
| Metropolitan | Maplewood Twp | 261 HILTON AVE | 4 | 35.00 | 62173 |
| Metropolitan | Maplewood Twp | 206 FRANKLIN AVE | 4 | 35.00 | 61735 |
| Metropolitan | Maplewood Twp | 190 HILTON AVE | 4 | 40.00 | 61230 |
| Metropolitan | Maplewood Twp | 640 PROSPECT ST | 4 | 40.00 | 60540 |
| Metropolitan | Maplewood Twp | 3 PARK AVE | 4 | 35.00 | 60232 |
| Metropolitan | Maplewood Twp | 2 SOMMER AVE | 4 | 40.00 | 60250 |
| Metropolitan | Maplewood Twp | 8 SOMMER AVE | 4 | 40.00 | 60251 |
| Metropolitan | Maplewood Twp | 14 SOMMER AVE | 4 | 40.00 | 60252 |
| Metropolitan | Maplewood Twp | 23 HUBERT PL | 4 | 35.00 | 60254 |
| Metropolitan | Maplewood Twp | 28 SOMMER AVE | 4 | 40.00 | 60255 |
| Metropolitan | Maplewood Twp | 34 SOMMER AVE | 4 | 40.00 | 60257 |
| Metropolitan | Maplewood Twp | 43 COURTER AVE | 4 | 35.00 | 1513 |
| Metropolitan | Maplewood Twp | 67 COURTER AVE | 4 | 40.00 | 1434 |
| Metropolitan | Maplewood Twp | 192 FRANKLIN AVE | 4 | 40.00 | 61737 |
| Metropolitan | Maplewood Twp | 206 OAKLAND RD | 4 | 35.00 | 1459 |
| Metropolitan | Maplewood Twp | 8 GIRARD PL | 4 | 40.00 | 60260 |
| Metropolitan | Maplewood Twp | 140 FRANKLIN AVE | 4 | 35.00 | 60023 |
| Metropolitan | Maplewood Twp | 23 WELLESLEY ST | 4 | 40.00 | 62767 |
| Metropolitan | Maplewood Twp | 2 HARVARD AVE | 4 | 35.00 | 62303 |
| Metropolitan | Maplewood Twp | 22 HARVARD AVE | 4 | 35.00 | 61567 |
| Metropolitan | Maplewood Twp | 12 FRANKLIN AVE | 4 | 35.00 | 61866 |
| Metropolitan | Maplewood Twp | 668 PROSPECT ST | 4 | 40.00 | 60535 |
| Metropolitan | Maplewood Twp | 672 PROSPECT ST | 4 | 40.00 | 60534 |
| Metropolitan | Maplewood Twp | 700 PROSPECT ST | 4 | 40.00 | 60329 |
| Metropolitan | Maplewood Twp | 72 PLYMOUTH AVE | 4 | 35.00 | 1472 |
| Metropolitan | Maplewood Twp | 481 VALLEY ST | 4 | 40.00 | 62566 |
| Metropolitan | Maplewood Twp | 55 FOREST RD | 4 | 40.00 | 62835 |
| Metropolitan | Maplewood Twp | 41 FOREST RD | 4 | 40.00 | 62836 |
| Metropolitan | Maplewood Twp | 16 FOREST RD | 4 | 40.00 | 62837 |
| Metropolitan | Maplewood Twp | 16 W PARKER AVE | 4 | 40.00 | 1384 |
| Metropolitan | Maplewood Twp | 14 DUNNELL RD | 4 | 35.00 | 60915 |
| Metropolitan | Maplewood Twp | 13 CONCORD AVE | 4 | 35.00 | 62261 |
| Metropolitan | Maplewood Twp | 25 CONCORD AVE | 4 | 35.00 | 62260 |
| Metropolitan | Maplewood Twp | 159 LEXINGTON AVE | 4 | 35.00 | 61884 |
| Metropolitan | Maplewood Twp | 33 JEFFERSON AVE | 4 | 35.00 | 60762 |
| Metropolitan | Maplewood Twp | 56 BURNETT TER | 4 | 40.00 | 1907 |

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|---|---|---|---|---|---|
| Metropolitan | Maplewood Twp | 8 BURNETT TER | 4 | 40.00 | 60691 |
| Metropolitan | Maplewood Twp | 32 BURNETT TER | 4 | 35.00 | 63119 |
| Metropolitan | Maplewood Twp | 489 VALLEY ST | 4 | 40.00 | 62639 |
| Metropolitan | Maplewood Twp | 32 MAPLEWOOD AVE | 4 | 35.00 | 2158 |
| Metropolitan | Maplewood Twp | 7 PLYMOUTH AVE | 4 | 35.00 | 61107 |
| Metropolitan | Maplewood Twp | 86 PARK RD | 4 | 40.00 | 60940 |
| Metropolitan | Maplewood Twp | 52 PRINCentralTON ST | 4 | 40.00 | 62146 |
| Metropolitan | Maplewood Twp | 115 LEXINGTON AVE | 4 | 35.00 | 62140 |
| Metropolitan | Maplewood Twp | 45 WELLESLEY ST | 4 | 40.00 | 62143 |
| Metropolitan | Maplewood Twp | 78 MOUNTAIN VIEW TER | 4 | 40.00 | 60291 |
| Metropolitan | Maplewood Twp | 40 OAKVIEW AVE | 4 | 40.00 | 60290 |
| Metropolitan | Maplewood Twp | 32 OAKVIEW AVE | 4 | 40.00 | 60288 |
| Metropolitan | Maplewood Twp | 26 OAKVIEW AVE | 4 | 35.00 | 60287 |
| Metropolitan | Maplewood Twp | 22 OAKVIEW AVE | 4 | 40.00 | 60286 |
| Metropolitan | Maplewood Twp | 16 OAKVIEW AVE | 4 | 35.00 | 60285 |
| Metropolitan | Maplewood Twp | 28 HEADLEY PL | 4 | 35.00 | 62387 |
| Metropolitan | Maplewood Twp | 13 SAINT LAWRENCentral A | 4 | 35.00 | 61110 |
| Metropolitan | Maplewood Twp | 24 DE HART RD | 4 | 40.00 | 61830 |
| Metropolitan | Maplewood Twp | 454 RIDGEWOOD RD | 4 | 40.00 | 60390 |
| Metropolitan | Maplewood Twp | 75 ARCULARIUS TER | 4 | 35.00 | 60389 |
| Metropolitan | Maplewood Twp | 21 ARCULARIUS TER | 4 | 35.00 | 61353 |
| Metropolitan | Maplewood Twp | 22 PARK RD | 4 | 40.00 | 60299 |
| Metropolitan | Maplewood Twp | 14 PARK RD | 4 | 35.00 | 60297 |
| Metropolitan | Maplewood Twp | 112 DUNNELL RD | 4 | 40.00 | 62514 |
| Metropolitan | Maplewood Twp | 45 KENDAL AVE | 4 | 35.00 | 61199 |
| Metropolitan | Maplewood Twp | 122 DUNNELL RD | 4 | 40.00 | 62516 |
| Metropolitan | Maplewood Twp | 59 MAPLEWOOD AVE | 4 | 40.00 | 62150 |
| Metropolitan | Maplewood Twp | 67 MAPLEWOOD AVE | 4 | 40.00 | 61035 |
| Metropolitan | Maplewood Twp | 91 MAPLEWOOD AVE | 4 | 40.00 | 60445 |
| Metropolitan | Maplewood Twp | 107 MAPLEWOOD AVE | 4 | 40.00 | 60441 |
| Metropolitan | Maplewood Twp | 113 MAPLEWOOD AVE | 4 | 40.00 | 60440 |
| Metropolitan | Maplewood Twp | 207 DUNNELL RD | 4 | 35.00 | 62065 |
| Metropolitan | Maplewood Twp | 120 MAPLEWOOD AVE | 4 | 40.00 | 60438 |
| Metropolitan | Maplewood Twp | 37 WOODLAND RD | 4 | 40.00 | 60415 |
| Metropolitan | Maplewood Twp | 87 WOODLAND RD | 4 | 35.00 | 2834 |
| Metropolitan | Maplewood Twp | 2 ROOSEVELT RD | 4 | 40.00 | 60366 |
| Metropolitan | Maplewood Twp | 565 RIDGEWOOD RD | 4 | 40.00 | 60364 |
| Metropolitan | Maplewood Twp | 5 BEACH PL | 4 | 35.00 | 60210 |
| Metropolitan | Maplewood Twp | 22 HICKORY DR | 4 | 35.00 | 60134 |
| Metropolitan | Maplewood Twp | 42 HICKORY DR | 4 | 35.00 | 60130 |
| Metropolitan | Maplewood Twp | 48 HICKORY DR | 4 | 40.00 | 60128 |
| Metropolitan | Maplewood Twp | 85 KENDAL AVE | 4 | 35.00 | 61208 |
| Metropolitan | Maplewood Twp | 79 KENDAL AVE | 4 | 35.00 | 61207 |
| Metropolitan | Maplewood Twp | 19 GARTHWAITE TER | 4 | 35.00 | 61720 |
| Metropolitan | Maplewood Twp | 26 HOFFMAN ST | 4 | 35.00 | 61363 |
| Metropolitan | Maplewood Twp | 466 RIDGEWOOD RD | 4 | 40.00 | 60387 |
| Metropolitan | Maplewood Twp | 9 COLLINWOOD RD | 4 | 40.00 | 61274 |

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| Metropolitan | Maplewood Twp | 19 BROOKSIDE RD | 4 | 35.00 | 62252 |
| Metropolitan | Maplewood Twp | 514 RIDGEWOOD RD | 4 | 35.00 | 60375 |
| Metropolitan | Maplewood Twp | 39 CURTIS PL | 4 | 40.00 | 60108 |
| Metropolitan | Maplewood Twp | 14 MARYLAND RD | 4 | 35.00 | 62049 |
| Metropolitan | Maplewood Twp | 53 CURTIS PL | 4 | 35.00 | 60104 |
| Metropolitan | Maplewood Twp | 61 BROOKSIDE RD | 4 | 35.00 | 2358 |
| Metropolitan | Maplewood Twp | 283 WYOMING AVE | 4 | 40.00 | 62329 |
| Metropolitan | Maplewood Twp | 295 WYOMING AVE | 4 | 30.00 | 62778 |
| Metropolitan | Maplewood Twp | 64 BROOKSIDE RD | 4 | 35.00 | 61563 |
| Metropolitan | Maplewood Twp | 25 DURAND RD | 4 | 40.00 | 60182 |
| Metropolitan | Maplewood Twp | 33 DURAND RD | 4 | 40.00 | 60181 |
| Metropolitan | Maplewood Twp | 49 DURAND RD | 4 | 35.00 | 62892 |
| Metropolitan | Maplewood Twp | 32 MOUNTAIN AVE | 4 | 40.00 | 60052 |
| Metropolitan | Maplewood Twp | 13 RIDGEWOOD TER | 4 | 35.00 | 60090 |
| Metropolitan | Maplewood Twp | 3 RIDGEWOOD TER | 4 | 35.00 | 60092 |
| Metropolitan | Maplewood Twp | 42 LENOX PL | 4 | 35.00 | 60098 |
| Metropolitan | Maplewood Twp | 68 LENOX PL | 4 | 35.00 | 60096 |
| Metropolitan | Maplewood Twp | 192 MAPLEWOOD AVE | 4 | 40.00 | 3433 |
| Metropolitan | Maplewood Twp | 9 MOUNTAIN AVE | 4 | 35.00 | 60059 |
| Metropolitan | Maplewood Twp | 9 BURNETT ST | 4 | 35.00 | 60492 |
| Metropolitan | East Orange City | 39 TELFORD ST | 4 | 35.00 | 60696 |
| Metropolitan | Maplewood Twp | 638 RIDGEWOOD RD | 4 | 40.00 | 60345 |
| Metropolitan | Maplewood Twp | 9 CARLTON CT | 4 | 35.00 | 2561 |
| Metropolitan | Maplewood Twp | 9 BERKELEY RD | 4 | 35.00 | 62364 |
| Metropolitan | Maplewood Twp | 35 WASHINGTON PARK | 4 | 40.00 | 60988 |
| Metropolitan | Maplewood Twp | 33 BURNETT ST | 4 | 40.00 | 60486 |
| Metropolitan | Maplewood Twp | 35 WASHINGTON PARK | 4 | 35.00 | 60987 |
| Metropolitan | Maplewood Twp | 5 NEW ENGLAND RD | 4 | 35.00 | 60979 |
| Metropolitan | Maplewood Twp | 3 NEW ENGLAND RD | 4 | 40.00 | 61393 |
| Metropolitan | Maplewood Twp | 7 NEW ENGLAND RD | 4 | 40.00 | 61392 |
| Metropolitan | Maplewood Twp | 28 SALTER PL | 4 | 35.00 | 60469 |
| Metropolitan | Maplewood Twp | 23 NEW ENGLAND RD | 4 | 35.00 | 61388 |
| Metropolitan | Maplewood Twp | 25 NEW ENGLAND RD | 4 | 35.00 | 61387 |
| Metropolitan | Maplewood Twp | 16 OWEN DR | 4 | 35.00 | 60970 |
| Metropolitan | Maplewood Twp | 58 SALTER PL | 4 | 35.00 | 60462 |
| Metropolitan | Maplewood Twp | 91 PIERSON RD | 4 | 35.00 | 60215 |
| Metropolitan | Maplewood Twp | 61 PIERSON RD | 4 | 35.00 | 60218 |
| Metropolitan | Maplewood Twp | 12 CentralDAR LN | 4 | 40.00 | 62291 |
| Metropolitan | Maplewood Twp | 8 WOODHILL DR | 4 | 40.00 | 62373 |
| Metropolitan | Maplewood Twp | 7 COLONIAL TER | 4 | 40.00 | 61381 |
| Metropolitan | Maplewood Twp | 15 COLONIAL TER | 4 | 35.00 | 61379 |
| Metropolitan | Maplewood Twp | 12 EVERGREEN PL | 4 | 35.00 | 61374 |
| Metropolitan | Maplewood Twp | 6 TOWER DR | 4 | 40.00 | 62019 |
| Metropolitan | Maplewood Twp | 12 TOWER DR | 4 | 40.00 | 62390 |
| Metropolitan | Maplewood Twp | 34 CRESTWOOD DR | 4 | 35.00 | 62427 |
| Metropolitan | Maplewood Twp | 14 CRESTWOOD DR | 4 | 35.00 | 61944 |
| Metropolitan | Maplewood Twp | 3 CRESTWOOD DR | 4 | 40.00 | 61951 |

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| Metropolitan | Irvington Town | 544 STUYVESANT AVE | 4 | 40.00 | 60382 |
| Metropolitan | Irvington Town | 22 NEWTON PL | 4 | 35.00 | 62811 |
| Metropolitan | Maplewood Twp | 23 COLLINWOOD RD | 4 | 40.00 | 61271 |
| Metropolitan | Maplewood Twp | 29 COLLINWOOD RD | 4 | 40.00 | 61269 |
| Metropolitan | Maplewood Twp | 59 COLLINWOOD RD | 4 | 35.00 | 61696 |
| Metropolitan | Maplewood Twp | 97 COLLINWOOD RD | 4 | 35.00 | 61731 |
| Metropolitan | Maplewood Twp | 217 WYOMING AVE | 4 | 40.00 | 60196 |
| Metropolitan | Maplewood Twp | 13 CLAREMONT DR | 4 | 35.00 | 62382 |
| Metropolitan | Maplewood Twp | 28 CLAREMONT AVE | 4 | 40.00 | 60190 |
| Metropolitan | Maplewood Twp | 5 HEMLOCK CT | 4 | 35.00 | 62518 |
| Metropolitan | Maplewood Twp | 14 CLAREMONT AVE | 4 | 35.00 | 60193 |
| Metropolitan | Maplewood Twp | 8 CLAREMONT AVE | 4 | 40.00 | 60194 |
| Metropolitan | Maplewood Twp | 7 EUCLID AVE | 4 | 40.00 | 60411 |
| Metropolitan | Maplewood Twp | 27 EUCLID AVE | 4 | 40.00 | 60407 |
| Metropolitan | Maplewood Twp | 102 DURAND RD | 4 | 40.00 | 60166 |
| Metropolitan | Maplewood Twp | 98 DURAND RD | 4 | 35.00 | 60167 |
| Metropolitan | Irvington Town | 622 STUYVESANT AVE | 4 | 45.00 | 60373 |
| Metropolitan | Maplewood Twp | 44 WEST LN | 4 | 35.00 | 61920 |
| Metropolitan | Irvington Town | 590 STUYVESANT AVE | 4 | 45.00 | 60377 |
| Metropolitan | Maplewood Twp | 8 MORSE DR | 4 | 40.00 | 61693 |
| Metropolitan | East Orange City | 192 SANFORD ST | 4 | 35.00 | 60861 |
| Metropolitan | East Orange City | 356 RHODE ISLAND AVE | 4 | 35.00 | 61403 |
| Metropolitan | Irvington Town | 65 GRANT PL | 4 | 35.00 | 61693 |
| Metropolitan | Irvington Town | 35 LAUREL AVE | 4 | 40.00 | 60850 |
| Metropolitan | Maplewood Twp | 54 WARNER RD | 4 | 35.00 | 62738 |
| Metropolitan | Maplewood Twp | 9 WARNER RD | 4 | 40.00 | 62111 |
| Metropolitan | Maplewood Twp | 7 FAIRVIEW TER | 4 | 40.00 | 61992 |
| Metropolitan | Maplewood Twp | 19 FAIRVIEW TER | 4 | 40.00 | 62073 |
| Metropolitan | Maplewood Twp | 25 FAIRVIEW TER | 4 | 35.00 | 61931 |
| Metropolitan | Maplewood Twp | 27 FAIRVIEW TER | 4 | 40.00 | 61932 |
| Metropolitan | Maplewood Twp | 39 FAIRVIEW TER | 4 | 40.00 | 62450 |
| Metropolitan | Irvington Town | 57 SHERMAN PL | 4 | 35.00 | 61343 |
| Metropolitan | Irvington Town | 56 ELMWOOD AVE | 4 | 40.00 | 61068 |
| Metropolitan | Maplewood Twp | 11 ROOSEVELT RD | 4 | 35.00 | 60159 |
| Metropolitan | Maplewood Twp | 7 ROOSEVELT RD | 4 | 40.00 | 60160 |
| Metropolitan | Maplewood Twp | 5 ROOSEVELT RD | 4 | 40.00 | 60161 |
| Metropolitan | Irvington Town | 1372 CLINTON AVE | 4 | 35.00 | 62687 |
| Metropolitan | East Orange City | 354 ELMWOOD AVE | 4 | 35.00 | 60092 |
| Metropolitan | East Orange City | 68 WAYNE AVE | 4 | 35.00 | 60448 |
| Metropolitan | Maplewood Twp | 220 TUSCAN RD | 4 | 40.00 | 62568 |
| Metropolitan | Irvington Town | 48 ELMWOOD TER | 4 | 40.00 | 61050 |
| Metropolitan | Maplewood Twp | 37 BURNETT AVE | 4 | 40.00 | 60640 |
| Metropolitan | Maplewood Twp | 43 BURNETT AVE | 4 | 40.00 | 60639 |
| Metropolitan | Maplewood Twp | 63 BURNETT AVE | 4 | 40.00 | 60637 |
| Metropolitan | Maplewood Twp | 93 LOMBARDY PL | 4 | 40.00 | 62214 |
| Metropolitan | Maplewood Twp | 79 LOMBARDY PL | 4 | 40.00 | 62215 |
| Metropolitan | Maplewood Twp | 169 BURNETT AVE | 4 | 40.00 | 60626 |

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| Metropolitan | East Orange City | 25 ELLIOT PL | 4 | 35.00 | 60595 |
| Metropolitan | Maplewood Twp | 236 BURNETT AVE | 4 | 40.00 | 62814 |
| Metropolitan | Maplewood Twp | 175 RUTGERS ST | 4 | 35.00 | 61080 |
| Metropolitan | East Orange City | 218 DODD ST | 4 | 40.00 | 61498 |
| Metropolitan | Irvington Town | 186 HEADLEY TER | 4 | 35.00 | 61801 |
| Metropolitan | Maplewood Twp | 203 RUTGERS ST | 4 | 40.00 | 62354 |
| Metropolitan | East Orange City | 131 BRIGHTON AVE | 4 | 35.00 | 61172 |
| Metropolitan | Irvington Town | 881 SANFORD AVE | 4 | 40.00 | 60155 |
| Metropolitan | Irvington Town | 51 NEWTON PL | 4 | 40.00 | 61594 |
| Metropolitan | Irvington Town | 21 NEWTON PL | 4 | 35.00 | 61592 |
| Metropolitan | Irvington Town | 148 HILLSIDE TER | 4 | 40.00 | 60862 |
| Metropolitan | Irvington Town | 80 HILLSIDE TER | 4 | 35.00 | 61668 |
| Metropolitan | Irvington Town | 442 CHAPMAN ST | 4 | 35.00 | 61991 |
| Metropolitan | Irvington Town | 452 CHAPMAN ST | 4 | 35.00 | 61990 |
| Metropolitan | East Orange City | 46 E PARK ST | 4 | 35.00 | 60459 |
| Metropolitan | East Orange City | 29 BURCHARD AVE | 4 | 35.00 | 61582 |
| Metropolitan | East Orange City | 74 LAKE ST | 4 | 40.00 | 61203 |
| Metropolitan | East Orange City | ERIE RIGHT OF WAY | 4 | 50.00 | 1456 |
| Metropolitan | Irvington Town | 37 HEADLEY TER | 4 | 35.00 | 60285 |
| Metropolitan | Irvington Town | 43 HEADLEY TER | 4 | 35.00 | 60286 |
| Metropolitan | Irvington Town | 173 ELMWOOD AVE | 4 | 40.00 | 60288 |
| Metropolitan | Irvington Town | 66 TIFFANY PL | 4 | 35.00 | 60870 |
| Metropolitan | Irvington Town | 99 HEADLEY TER | 4 | 40.00 | 60869 |
| Metropolitan | East Orange City | 610 SPRINGDALE AVE | 4 | 35.00 | 60118 |
| Metropolitan | Irvington Town | 202 LAUREL AVE | 4 | 35.00 | 61789 |
| Metropolitan | Irvington Town | 78 FRANKLIN TER | 4 | 35.00 | 62461 |
| Metropolitan | Irvington Town | 54 FRANKLIN TER | 4 | 40.00 | 62464 |
| Metropolitan | Irvington Town | 207 ELMWOOD AVE | 4 | 40.00 | 62602 |
| Metropolitan | Irvington Town | 211 ELMWOOD AVE | 4 | 45.00 | 60174 |
| Metropolitan | Irvington Town | 68 BECKER TER | 4 | 40.00 | 60267 |
| Metropolitan | Irvington Town | 42 BECKER TER | 4 | 40.00 | 60265 |
| Metropolitan | Irvington Town | 32 BECKER TER | 4 | 35.00 | 60264 |
| Metropolitan | Irvington Town | 18 BECKER TER | 4 | 40.00 | 60263 |
| Metropolitan | East Orange City | 98 NORMAN PL | 4 | 40.00 | 2045D |
| Metropolitan | East Orange City | 73 CRESCentralNT RD | 4 | 55.00 | 1431D |
| Metropolitan | East Orange City | 71 CRESCentralNT RD | 4 | 35.00 | 1985D |
| Metropolitan | Maplewood Twp | 59 LEE CT | 4 | 40.00 | 62828 |
| Metropolitan | Maplewood Twp | 33 JACOBY ST | 4 | 40.00 | 61188 |
| Metropolitan | East Orange City | 38 RENSHAW AVE | 4 | 35.00 | 61810 |
| Metropolitan | East Orange City | 50 CHAUNCentralY AVE | 4 | 35.00 | 60993 |
| Metropolitan | Maplewood Twp | 99 HENRY PL | 4 | 35.00 | 62522 |
| Metropolitan | Maplewood Twp | 17 HARDING ST | 4 | 35.00 | 61425 |
| Metropolitan | Maplewood Twp | 15 HUGHES ST | 4 | 35.00 | 61430 |
| Metropolitan | Maplewood Twp | 123 JACOBY ST | 4 | 40.00 | 61420 |
| Metropolitan | Maplewood Twp | 8 GIFFORD CT | 4 | 40.00 | 62819 |
| Metropolitan | Maplewood Twp | 6 GIFFORD CT | 4 | 40.00 | 62818 |
| Metropolitan | East Orange City | 181 HOFFMAN BLVD | 4 | 35.00 | 61025 |

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|---|---|---|---|---|---|
| Metropolitan | Maplewood Twp | 39 TROY CT | 4 | 35.00 | 62870 |
| Metropolitan | East Orange City | 197 HOFFMAN BLVD | 4 | 35.00 | 61023 |
| Metropolitan | East Orange City | 223 HOFFMAN BLVD | 4 | 35.00 | 61019 |
| Metropolitan | East Orange City | 231 HOFFMAN BLVD | 4 | 40.00 | 61031 |
| Metropolitan | East Orange City | 245 HOFFMAN BLVD | 4 | 35.00 | 61334 |
| Metropolitan | East Orange City | 611 N GROVE ST | 4 | 35.00 | 60224 |
| Metropolitan | Maplewood Twp | 29 PORTER RD | 4 | 35.00 | 61631 |
| Metropolitan | Maplewood Twp | 39 MENZEL AVE | 4 | 35.00 | 61346 |
| Metropolitan | Irvington Town | 57 LINCOLN PL | 4 | 40.00 | 60182 |
| Metropolitan | Irvington Town | 65 LINCOLN PL | 4 | 40.00 | 60183 |
| Metropolitan | Maplewood Twp | 26 SCHAEFFER RD | 4 | 35.00 | 61330 |
| Metropolitan | Maplewood Twp | 195 JACOBY ST | 4 | 35.00 | 61790 |
| Metropolitan | East Orange City | 469 PARK AVE | 4 | 35.00 | 60973 |
| Metropolitan | East Orange City | 87 HOFFMAN BLVD | 4 | 35.00 | 61530 |
| Metropolitan | East Orange City | 449 PARK AVE | 4 | 35.00 | 60975 |
| Metropolitan | East Orange City | 443 PARK AVE | 4 | 35.00 | 60976 |
| Metropolitan | Maplewood Twp | 165 JACOBY ST | 4 | 35.00 | 61415 |
| Metropolitan | Irvington Town | 57 MAPLE AVE | 4 | 35.00 | 94 |
| Metropolitan | Irvington Town | 29 MAPLE AVE | 4 | 35.00 | 98 |
| Metropolitan | Irvington Town | 15 MAPLE AVE | 4 | 35.00 | 100 |
| Metropolitan | Irvington Town | 7 MAPLE AVE | 4 | 35.00 | 2459 |
| Metropolitan | Irvington Town | 37 PARK PL | 4 | 40.00 | 61264 |
| Metropolitan | East Orange City | 71 LESLIE ST | 4 | 35.00 | 60244 |
| Metropolitan | East Orange City | 76 DIVISION ST | 4 | 40.00 | 61345 |
| Metropolitan | Maplewood Twp | 1 FIELD RD | 4 | 40.00 | 62550 |
| Metropolitan | Irvington Town | 72 HARRISON PL | 4 | 40.00 | 61311 |
| Metropolitan | Irvington Town | 42 HARRISON PL | 4 | 40.00 | 60036 |
| Metropolitan | Irvington Town | 83 HARRISON PL | 4 | 35.00 | 4775 |
| Metropolitan | Irvington Town | 82 HARRISON PL | 4 | 40.00 | 61143 |
| Metropolitan | Irvington Town | 208 MUNN AVE | 4 | 35.00 | 61998 |
| Metropolitan | Irvington Town | 145 LINCOLN PL | 4 | 40.00 | 60412 |
| Metropolitan | Irvington Town | 190 MUNN AVE | 4 | 35.00 | 62281 |
| Metropolitan | Irvington Town | 28 UNION AVE | 4 | 35.00 | 63607 |
| Metropolitan | Irvington Town | 76 W TREMONT TER | 4 | 35.00 | 63027 |
| Metropolitan | Irvington Town | 88 W TREMONT TER | 4 | 35.00 | 62746 |
| Metropolitan | Irvington Town | 259 MYRTLE AVE | 4 | 40.00 | 60605 |
| Metropolitan | Irvington Town | 258 W 19TH AVE | 4 | 35.00 | 62530 |
| Metropolitan | Irvington Town | 35 UNIVERSITY PL | 4 | 40.00 | 61927 |
| Metropolitan | Irvington Town | 292 MYRTLE AVE | 4 | 35.00 | 62401 |
| Metropolitan | Irvington Town | 118 ELLIS AVE | 4 | 40.00 | 60694 |
| Metropolitan | Irvington Town | 112 ELLIS AVE | 4 | 40.00 | 60693 |
| Metropolitan | Irvington Town | 392 COLUMBIA AVE | 4 | 40.00 | 62984 |
| Metropolitan | Irvington Town | 22 UNIVERSITY PL | 4 | 35.00 | 61969 |
| Metropolitan | Irvington Town | 237 PARK PL | 4 | 40.00 | 61544 |
| Metropolitan | Irvington Town | 213 PARK PL | 4 | 40.00 | 60389 |
| Metropolitan | Irvington Town | 3 PROSPECT AVE | 4 | 35.00 | 60002 |
| Metropolitan | Irvington Town | 6 ELM PL | 4 | 40.00 | 62372 |

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|---|---|---|---|---|---|
| Metropolitan | Irvington Town | 77 HOPKINS PL | 4 | 35.00 | 63530 |
| Metropolitan | Irvington Town | 46 DELMAR PL | 4 | 40.00 | 62767 |
| Metropolitan | Irvington Town | 359 MYRTLE AVE | 4 | 40.00 | 60615 |
| Metropolitan | Irvington Town | 250 MYRTLE AVE | 4 | 40.00 | 60603 |
| Metropolitan | Irvington Town | 217 LINCOLN PL | 4 | 35.00 | 61281 |
| Metropolitan | Irvington Town | 129 UNION AVE | 4 | 35.00 | 63032 |
| Metropolitan | Irvington Town | 219 MYRTLE AVE | 4 | 40.00 | 60599 |
| Metropolitan | Irvington Town | 199 MYRTLE AVE | 4 | 40.00 | 60597 |
| Metropolitan | Irvington Town | 441 21ST ST | 4 | 40.00 | 61105 |
| Metropolitan | Irvington Town | 78 WOODLAWN PL | 4 | 35.00 | 62438 |
| Metropolitan | Irvington Town | 413 21ST ST | 4 | 35.00 | 61109 |
| Metropolitan | Irvington Town | 59 MAPLE PL | 4 | 35.00 | 62498 |
| Metropolitan | Irvington Town | 26 W STRATFORD PL | 4 | 35.00 | 61093 |
| Metropolitan | Irvington Town | 179 MYRTLE AVE | 4 | 40.00 | 60595 |
| Metropolitan | Irvington Town | 182 LINDEN AVE | 4 | 40.00 | 60581 |
| Metropolitan | Irvington Town | 147 MONTGOMERY AVE | 4 | 40.00 | 61547 |
| Metropolitan | Irvington Town | 402 MYRTLE AVE | 4 | 40.00 | 61954 |
| Metropolitan | Irvington Town | 119 PARK PL | 4 | 35.00 | 60396 |
| Metropolitan | Irvington Town | 201 COLUMBIA AVE | 4 | 35.00 | 61600 |
| Metropolitan | Irvington Town | 183 COLUMBIA AVE | 4 | 35.00 | 61602 |
| Metropolitan | Irvington Town | 53 BROOKSIDE AVE | 4 | 35.00 | 63246 |
| Metropolitan | Irvington Town | 150 NESBIT TER | 4 | 35.00 | 60213 |
| Metropolitan | Irvington Town | 29 SMITH ST | 4 | 35.00 | 63269 |
| Metropolitan | Irvington Town | 50 SMITH ST | 4 | 40.00 | 60526 |
| Metropolitan | Irvington Town | 107 DURAND PL | 4 | 35.00 | 62040 |
| Metropolitan | Irvington Town | 49 WAGNER PL | 4 | 35.00 | 62837 |
| Metropolitan | Irvington Town | 415 NYE AVE | 4 | 40.00 | 63517 |
| Metropolitan | Irvington Town | 116 MYRTLE AVE | 4 | 45.00 | 61045 |
| Metropolitan | Irvington Town | 106 MAPLE AVE | 4 | 40.00 | 61183 |
| Metropolitan | Irvington Town | 135 MADISON AVE | 4 | 40.00 | 60635 |
| Metropolitan | Irvington Town | 124 MAPLE AVE | 4 | 35.00 | 61185 |
| Metropolitan | Irvington Town | 37 GRACentral ST | 4 | 35.00 | 60236 |
| Metropolitan | Irvington Town | 1209 CLINTON AVE | 4 | 40.00 | 60789 |
| Metropolitan | Irvington Town | 77 BRUEN AVE | 4 | 40.00 | 2919 |
| Metropolitan | Irvington Town | 83 RUTH ST | 4 | 35.00 | 62241 |
| Metropolitan | Irvington Town | 53 RUTH ST | 4 | 35.00 | 62240 |
| Metropolitan | Irvington Town | 63 BRUEN AVE | 4 | 35.00 | 2917 |
| Metropolitan | Irvington Town | 27 RUTH ST | 4 | 35.00 | 62239 |
| Metropolitan | Irvington Town | 105 LINDEN AVE | 4 | 40.00 | 61011 |
| Metropolitan | Irvington Town | 30 WILSON PL | 4 | 35.00 | 60007 |
| Metropolitan | Irvington Town | 72 STANLEY ST | 4 | 35.00 | 62432 |
| Metropolitan | Irvington Town | 83 IRVINGTON PL | 4 | 35.00 | 62996 |
| Metropolitan | East Orange City | 28 WOODLAND AVE | 4 | 35.00 | 61287 |
| Metropolitan | Irvington Town | 17 ORANGE PL | 4 | 35.00 | 62985 |
| Metropolitan | Irvington Town | 18 DURAND PL | 4 | 40.00 | 61604 |
| Metropolitan | Irvington Town | 67 LINDEN AVE | 4 | 40.00 | 61008 |
| Metropolitan | Irvington Town | 30 DURAND PL | 4 | 40.00 | 61605 |

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| Metropolitan | Irvington Town | 33 HOWARD ST | 4 | 40.00 | 61237 |
| Metropolitan | Irvington Town | 27 HOWARD ST | 4 | 35.00 | 61238 |
| Metropolitan | Irvington Town | 44 DURAND PL | 4 | 40.00 | 61606 |
| Metropolitan | Irvington Town | 28 WAGNER PL | 4 | 35.00 | 61719 |
| Metropolitan | Irvington Town | 23 LINDEN AVE | 4 | 35.00 | 62354 |
| Metropolitan | Irvington Town | 442 NYE AVE | 4 | 40.00 | 62817 |
| Metropolitan | East Orange City | 136 S GROVE ST | 4 | 35.00 | 60318 |
| Metropolitan | Irvington Town | 163 MAPLE AVE | 4 | 40.00 | 61190 |
| Metropolitan | Irvington Town | 104 WILSON PL | 4 | 40.00 | 61791 |
| Metropolitan | Irvington Town | 70 DURAND PL | 4 | 35.00 | 61610 |
| Metropolitan | Irvington Town | 52 DURAND PL | 4 | 40.00 | 61607 |
| Metropolitan | Irvington Town | 29 MAY ST | 4 | 35.00 | 1858 |
| Metropolitan | Irvington Town | 160 CUMMINGS ST | 4 | 40.00 | 60888 |
| Metropolitan | East Orange City | 172 RUTLEDGE AVE | 4 | 35.00 | 60216 |
| Metropolitan | Irvington Town | 198 CUMMINGS ST | 4 | 40.00 | 60632 |
| Metropolitan | Irvington Town | 49 MAY ST | 4 | 40.00 | 61487 |
| Metropolitan | Irvington Town | 109 GRACentral ST | 4 | 40.00 | 61488 |
| Metropolitan | Irvington Town | 370 VERMONT AVE | 4 | 35.00 | 62823 |
| Metropolitan | East Orange City | 55 N 23RD ST | 4 | 35.00 | 60738 |
| Metropolitan | Irvington Town | 9 39TH ST | 4 | 40.00 | 61704 |
| Metropolitan | Irvington Town | 94 PROSPECT AVE | 4 | 40.00 | 62763 |
| Metropolitan | Irvington Town | 47 39TH ST | 4 | 40.00 | 61701 |
| Metropolitan | East Orange City | 2 4TH AVE | 4 | 45.00 | 60428 |
| Metropolitan | East Orange City | 73 DIVISION PL | 4 | 35.00 | 60396 |
| Metropolitan | East Orange City | 89 AMPERE PKWY | 4 | 35.00 | 60251 |
| Metropolitan | Irvington Town | 15 BAMFORD PL | 4 | 35.00 | 61174 |
| Metropolitan | East Orange City | 113 AMPERE PKWY | 4 | 40.00 | 60254 |
| Metropolitan | Irvington Town | 55 BAMFORD PL | 4 | 35.00 | 62418 |
| Metropolitan | East Orange City | 119 AMPERE PKWY | 4 | 35.00 | 60255 |
| Metropolitan | East Orange City | 13 1ST AVE | 4 | 35.00 | 60256 |
| Metropolitan | East Orange City | 85 RUTLEDGE AVE | 4 | 35.00 | 60249 |
| Metropolitan | Irvington Town | 72 ADAMS ST | 4 | 40.00 | 61404 |
| Metropolitan | Irvington Town | 50 OAKLAND ST | 4 | 40.00 | 61403 |
| Metropolitan | East Orange City | 69 WOODLAND AVE | 4 | 35.00 | 1024 |
| Metropolitan | East Orange City | 183 N MAPLE AVE | 4 | 35.00 | 60196 |
| Metropolitan | East Orange City | 49 WOODLAND AVE | 4 | 35.00 | 61178 |
| Metropolitan | Irvington Town | 4 W ALLEN ST | 4 | 35.00 | 61686 |
| Metropolitan | Irvington Town | 239 MADISON AVE | 4 | 40.00 | 61371 |
| Metropolitan | Irvington Town | 249 MADISON AVE | 4 | 40.00 | 61370 |
| Metropolitan | Irvington Town | 103 LENOX AVE | 4 | 35.00 | 3199 |
| Metropolitan | Irvington Town | 14 LIBERTY ST | 4 | 35.00 | 62364 |
| Metropolitan | East Orange City | 18 RUTLEDGE AVE | 4 | 35.00 | 60283 |
| Metropolitan | East Orange City | 41 ELLINGTON ST | 4 | 35.00 | 60270 |
| Metropolitan | East Orange City | 11 ELLINGTON ST | 4 | 35.00 | 61344 |
| Metropolitan | Irvington Town | 56 GIFFORD PL | 4 | 40.00 | 63144 |
| Metropolitan | East Orange City | 42 N 16TH ST | 4 | 35.00 | 60445 |
| Metropolitan | East Orange City | 24 N 16TH ST | 4 | 35.00 | 61073 |

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|---|---|---|---|---|---|
| Metropolitan | East Orange City | 32 N 16TH ST | 4 | 35.00 | 61074 |
| Metropolitan | East Orange City | 21 MELMORE GDNS | 4 | 35.00 | 61804 |
| Metropolitan | East Orange City | 74 STATE ST | 4 | 35.00 | 60699 |
| Metropolitan | East Orange City | 70 MADISON AVE | 4 | 40.00 | 60955 |
| Metropolitan | East Orange City | 134 ROOSEVELT AVE | 4 | 35.00 | 60551 |
| Metropolitan | East Orange City | 90 LAFAYETTE AVE | 4 | 40.00 | 60546 |
| Metropolitan | East Orange City | 113 ROOSEVELT AVE | 4 | 35.00 | 61190 |
| Metropolitan | East Orange City | 36 GRANT AVE | 4 | 35.00 | 60653 |
| Metropolitan | East Orange City | 324 RUTLEDGE AVE | 4 | 40.00 | 60173 |
| Metropolitan | East Orange City | 28 GRAND AVE | 4 | 35.00 | 60789 |
| Metropolitan | East Orange City | E OF GRAND AVE | 4 | 35.00 | 60831 |
| Metropolitan | Irvington Town | 41 40TH ST | 4 | 40.00 | 60277 |
| Metropolitan | Irvington Town | 45 40TH ST | 4 | 35.00 | 60276 |
| Metropolitan | East Orange City | 264 SHEPARD AVE | 4 | 35.00 | 61050 |
| Metropolitan | Irvington Town | 587 S 21ST ST | 4 | 40.00 | 63301 |
| Metropolitan | Irvington Town | 94 BALL ST | 4 | 40.00 | 61147 |
| Metropolitan | East Orange City | 247 SHEPARD AVE | 4 | 35.00 | 61113 |
| Metropolitan | Irvington Town | 279 ISABELLA AVE | 4 | 40.00 | 61981 |
| Metropolitan | East Orange City | 218 EPPIRT ST | 4 | 35.00 | 61562 |
| Metropolitan | Irvington Town | 297 ISABELLA AVE | 4 | 35.00 | 61866 |
| Metropolitan | Irvington Town | 319 ISABELLA AVE | 4 | 35.00 | 61863 |
| Metropolitan | Irvington Town | 62 FULLER PL | 4 | 40.00 | 61859 |
| Metropolitan | Irvington Town | 37 43RD ST | 4 | 35.00 | 60257 |
| Metropolitan | Irvington Town | 399 ISABELLA AVE | 4 | 35.00 | 62841 |
| Metropolitan | Irvington Town | 282 VERMONT AVE | 4 | 35.00 | 61810 |
| Metropolitan | Irvington Town | 124 DELMAR PL | 4 | 40.00 | 62933 |
| Metropolitan | Irvington Town | 274 VERMONT AVE | 4 | 40.00 | 61809 |
| Metropolitan | Irvington Town | 266 VERMONT AVE | 4 | 35.00 | 61808 |
| Metropolitan | Irvington Town | 256 VERMONT AVE | 4 | 40.00 | 61807 |
| Metropolitan | Irvington Town | 90 UNIVERSITY PL | 4 | 40.00 | 61915 |
| Metropolitan | Irvington Town | 84 MELROSE AVE | 4 | 40.00 | 61773 |
| Metropolitan | Irvington Town | 6 FERN AVE | 4 | 35.00 | 63104 |
| Metropolitan | Irvington Town | 28 FERN AVE | 4 | 35.00 | 62477 |
| Metropolitan | Irvington Town | 36 FERN AVE | 4 | 35.00 | 62476 |
| Metropolitan | Irvington Town | 44 FERN AVE | 4 | 40.00 | 62475 |
| Metropolitan | Irvington Town | 97 WALTER PL | 4 | 40.00 | 61919 |
| Metropolitan | Irvington Town | 97 MELROSE AVE | 4 | 40.00 | 61911 |
| Metropolitan | Irvington Town | 238 40TH ST | 4 | 40.00 | 61427 |
| Metropolitan | Irvington Town | 2 HERPERS ST | 4 | 35.00 | 63417 |
| Metropolitan | Irvington Town | 71 WESTERN PKWY | 4 | 40.00 | 63370 |
| Metropolitan | Irvington Town | 91 WESTERN PKWY | 4 | 35.00 | 62617 |
| Metropolitan | Irvington Town | 135 WESTERN PKWY | 4 | 40.00 | 62331 |
| Metropolitan | Irvington Town | 12 W AVON AVE | 4 | 35.00 | 60059 |
| Metropolitan | Irvington Town | 557 LYONS AVE | 4 | 40.00 | 60491 |
| Metropolitan | East Orange City | 454 HALSTED ST | 4 | 35.00 | 60893 |
| Metropolitan | Irvington Town | 195 BROOKSIDE AVE | 4 | 40.00 | 62724 |
| Metropolitan | Irvington Town | 18 CORDIER ST | 4 | 35.00 | 3144 |

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|---|---|---|---|---|---|
| Metropolitan | Irvington Town | 1839 N WALKER AVE | 4 | 40.00 | 3127 |
| Metropolitan | Irvington Town | 43 20TH AVE | 4 | 40.00 | 60706 |
| Metropolitan | Irvington Town | 59 ROSEHILL PL | 4 | 40.00 | 60463 |
| Metropolitan | Irvington Town | 232 ELLIS AVE | 4 | 40.00 | 61583 |
| Metropolitan | Irvington Town | 242 ELLIS AVE | 4 | 40.00 | 61582 |
| Metropolitan | Irvington Town | 290 ELLIS AVE | 4 | 35.00 | 61577 |
| Metropolitan | Irvington Town | 346 ELLIS AVE | 4 | 40.00 | 61803 |
| Metropolitan | Irvington Town | 45 BERKSHIRE PL | 4 | 35.00 | 62133 |
| Metropolitan | Irvington Town | 29 BERKSHIRE PL | 4 | 35.00 | 62305 |
| Metropolitan | Irvington Town | 25 N MAPLE AVE | 4 | 35.00 | 62969 |
| Metropolitan | Irvington Town | 337 COIT ST | 4 | 35.00 | 62271 |
| Metropolitan | Irvington Town | 49 MELVILLE PL | 4 | 40.00 | 62290 |
| Metropolitan | Irvington Town | 26 BERKELEY TER | 4 | 40.00 | 61317 |
| Metropolitan | Irvington Town | 30 HARDING TER | 4 | 35.00 | 61456 |
| Metropolitan | Irvington Town | 50 HARDING TER | 4 | 40.00 | 61457 |
| Metropolitan | Essex Fells Twp | 14 EAGLE ROCK AVE | 4 | 35.00 | 60664 |
| Metropolitan | Irvington Town | 23 MOUNT VERNON AVE | 4 | 40.00 | 61964 |
| Metropolitan | Irvington Town | 17 MOUNT VERNON AVE | 4 | 35.00 | 61963 |
| Metropolitan | Irvington Town | 35 BRIGHTON TER | 4 | 40.00 | 60752 |
| Metropolitan | Irvington Town | 146 40TH ST | 4 | 40.00 | 61437 |
| Metropolitan | Irvington Town | 85 OLYMPIC TER | 4 | 40.00 | 60319 |
| Metropolitan | Irvington Town | 42 ARGYLE TER | 4 | 35.00 | 63190 |
| Metropolitan | Irvington Town | 64 ARGYLE TER | 4 | 35.00 | 63192 |
| Metropolitan | Irvington Town | 86 ARGYLE TER | 4 | 35.00 | 63194 |
| Metropolitan | Irvington Town | 136 40TH ST | 4 | 40.00 | 61438 |
| Metropolitan | Irvington Town | 881 STUYVESANT AVE | 4 | 40.00 | 63341 |
| Metropolitan | Irvington Town | 27 LESLIE PL | 4 | 40.00 | 61665 |
| Metropolitan | Irvington Town | 88 CHESTER AVE | 4 | 40.00 | 60454 |
| Metropolitan | Irvington Town | 203 19TH AVE | 4 | 40.00 | 62405 |
| Metropolitan | Irvington Town | 20 KROTIK PL | 4 | 35.00 | 2257 |
| Metropolitan | Irvington Town | 291 EASTERN PKWY | 4 | 35.00 | 3357 |
| Metropolitan | Irvington Town | 82 CAMPFIELD ST | 4 | 35.00 | 61503 |
| Metropolitan | Irvington Town | 874 CHANCentralLLOR AVE | 4 | 35.00 | 61228 |
| Metropolitan | Irvington Town | 248 EASTERN PKWY | 4 | 35.00 | 3402 |
| Metropolitan | Irvington Town | 136 BERKSHIRE PL | 4 | 35.00 | 61509 |
| Metropolitan | Irvington Town | 904 CHANCentralLLOR AVE | 4 | 40.00 | 60221 |
| Metropolitan | Irvington Town | 85 BRECKENRIDGE TER | 4 | 40.00 | 61761 |
| Metropolitan | Irvington Town | 65 TICHENOR TER | 4 | 35.00 | 61057 |
| Metropolitan | Irvington Town | 77 TICHENOR TER | 4 | 35.00 | 61058 |
| Metropolitan | Irvington Town | 742 18TH AVE | 4 | 35.00 | 62016 |
| Metropolitan | East Orange City | 68 ARSDALE TER | 4 | 35.00 | 60387 |
| Metropolitan | Irvington Town | 317 UNION AVE | 4 | 40.00 | 60430 |
| Metropolitan | Irvington Town | 394 21ST ST | 4 | 40.00 | 60722 |
| Metropolitan | Irvington Town | 3 BRECKENRIDGE TER | 4 | 40.00 | 60666 |
| Metropolitan | Irvington Town | 27 CORNELL ST | 4 | 35.00 | 61758 |
| Metropolitan | Irvington Town | 29 MONTROSE TER | 4 | 40.00 | 61727 |
| Metropolitan | Irvington Town | 15 TICHENOR TER | 4 | 40.00 | 61053 |

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|---|---|---|---|---|---|
| Metropolitan | Irvington Town | 83 MONTROSE TER | 4 | 40.00 | 61731 |
| Metropolitan | East Orange City | 30 HILLCREST TER | 4 | 35.00 | 60371 |
| Metropolitan | East Orange City | 843 S ORANGE AVE | 4 | 35.00 | 61647 |
| Metropolitan | Irvington Town | 284 NESBIT TER | 4 | 40.00 | 61298 |
| Metropolitan | Irvington Town | 300 NESBIT TER | 4 | 40.00 | 62109 |
| Metropolitan | East Orange City | 76 FAIRMOUNT TER | 4 | 40.00 | 60363 |
| Metropolitan | Irvington Town | 380 PARK PL | 4 | 40.00 | 61494 |
| Metropolitan | East Orange City | 45 MOUNTAINVIEW AVE | 4 | 35.00 | 60360 |
| Metropolitan | Irvington Town | 126 22ND ST | 4 | 40.00 | 61833 |
| Metropolitan | Irvington Town | 165 PAINE AVE | 4 | 35.00 | 62639 |
| Metropolitan | East Orange City | 349 SHEPARD AVE | 4 | 35.00 | 60342 |
| Metropolitan | Irvington Town | 51 SHERIDAN ST | 4 | 35.00 | 61469 |
| Metropolitan | East Orange City | 14 SUNNYSIDE TER | 4 | 35.00 | 60345 |
| Metropolitan | Irvington Town | SS 17TH AVE | 4 | 35.00 | 61137 |
| Metropolitan | East Orange City | 90 SUNNYSIDE TER | 4 | 40.00 | 60353 |
| Metropolitan | Irvington Town | 35 HARDGROVE TER | 4 | 35.00 | 62703 |
| Metropolitan | Irvington Town | 180 EASTERN PKWY | 4 | 35.00 | 63490 |
| Metropolitan | Irvington Town | 18 HARDGROVE TER | 4 | 35.00 | 62976 |
| Metropolitan | Irvington Town | 66 ARVERNE TER | 4 | 40.00 | 61386 |
| Metropolitan | Irvington Town | 23 HARPER AVE | 4 | 40.00 | 63101 |
| Metropolitan | East Orange City | 97 MOUNTAINVIEW AVE | 4 | 35.00 | 60336 |
| Metropolitan | Irvington Town | 3 PHILIP PL | 4 | 35.00 | 61896 |
| Metropolitan | Irvington Town | 410 16TH AVE | 4 | 40.00 | 63130 |
| Metropolitan | Irvington Town | 8 ROBERT PL | 4 | 35.00 | 62313 |
| Metropolitan | East Orange City | 131 BROOKWOOD ST | 4 | 35.00 | 1647 |
| Metropolitan | Irvington Town | 145 21ST ST | 4 | 35.00 | 61180 |
| Metropolitan | East Orange City | 185 BROOKWOOD ST | 4 | 35.00 | 60713 |
| Metropolitan | Irvington Town | 6 SMALLEY TER | 4 | 35.00 | 61514 |
| Metropolitan | Irvington Town | 37 LINDSLEY AVE | 4 | 35.00 | 62097 |
| Metropolitan | Irvington Town | 25 DUPONT PL | 4 | 35.00 | 62854 |
| Metropolitan | Irvington Town | 40 HOFFMAN PL | 4 | 35.00 | 62492 |
| Metropolitan | Irvington Town | 42 UNION PL | 4 | 30.00 | 62090 |
| Metropolitan | Irvington Town | 20 WEBSTER ST | 4 | 40.00 | 62735 |
| Metropolitan | Irvington Town | 42 WEBSTER ST | 4 | 35.00 | 62737 |
| Metropolitan | Essex Fells Twp | 358 FELLS RD | 4 | 40.00 | 60500 |
| Metropolitan | Irvington Town | 2 LAVENTHAL AVE | 4 | 30.00 | 62936 |
| Metropolitan | Irvington Town | 459 GROVE ST | 4 | 40.00 | 63360 |
| Metropolitan | Irvington Town | 24 LAVENTHAL AVE | 4 | 35.00 | 61780 |
| Metropolitan | Irvington Town | 24 STEWART AVE | 4 | 35.00 | 62705 |
| Metropolitan | Irvington Town | 371 NESBIT TER | 4 | 35.00 | 62901 |
| Metropolitan | Irvington Town | 58 OAK AVE | 4 | 40.00 | 62576 |
| Metropolitan | Essex Fells Twp | 258 FELLS RD | 4 | 35.00 | 60787 |
| Metropolitan | Irvington Town | 62 MILL RD | 4 | 35.00 | 63282 |
| Metropolitan | Irvington Town | 19 SAGER PL | 4 | 40.00 | 62490 |
| Metropolitan | Irvington Town | 63 SAGER PL | 4 | 35.00 | 62615 |
| Metropolitan | Irvington Town | 445 GROVE ST | 4 | 40.00 | 60247 |
| Metropolitan | Essex Fells Twp | 51 GORDON RD | 4 | 35.00 | 60324 |

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| Metropolitan | Irvington Town | 550 MILL RD | 4 | 40.00 | 63518 |
| Metropolitan | Essex Fells Twp | 39 GORDON RD | 4 | 40.00 | 60322 |
| Metropolitan | Essex Fells Twp | 205 OLD CHESTER RD | 4 | 35.00 | 60553 |
| Metropolitan | Essex Fells Twp | 255 ROSELAND AVE | 4 | 35.00 | 60149 |
| Metropolitan | Essex Fells Twp | 1 OLD EAGLE ROCK AVE | 4 | 35.00 | 60443 |
| Metropolitan | Fairfield Twp Ess | 26 DANIEL RD | 4 | 40.00 | 62433 |
| Metropolitan | Essex Fells Twp | 181 FELLS RD | 4 | 35.00 | 60534 |
| Metropolitan | Essex Fells Twp | 173 FELLS RD | 4 | 35.00 | 60532 |
| Metropolitan | Essex Fells Twp | W OAK LANE | 4 | 35.00 | 60808 |
| Metropolitan | Essex Fells Twp | 284 RUNNYMEDE RD | 4 | 35.00 | 830 |
| Metropolitan | Essex Fells Twp | 9 BARBERRY WAY | 4 | 40.00 | 60678 |
| Metropolitan | Fairfield Twp Ess | 415 HORSENECK RD | 4 | 35.00 | 60959 |
| Metropolitan | Fairfield Twp Ess | 28 PIER LN W | 4 | 40.00 | 61883 |
| Metropolitan | Fairfield Twp Ess | 53 PIER LN W | 4 | 40.00 | 60836 |
| Metropolitan | Essex Fells Twp | 135 FOREST WAY | 4 | 40.00 | 60224 |
| Metropolitan | Fairfield Twp Ess | 469 HORSENECK RD | 4 | 35.00 | 553 |
| Metropolitan | Fairfield Twp Ess | 19 CLINTON ST | 4 | 35.00 | 60924 |
| Metropolitan | Fairfield Twp Ess | 99 BUTZ AVE | 4 | 35.00 | 60926 |
| Metropolitan | Fairfield Twp Ess | 1 ORLANDO DR | 4 | 40.00 | 60266 |
| Metropolitan | Fairfield Twp Ess | 32 PIER LN | 4 | 35.00 | 62017 |
| Metropolitan | Essex Fells Twp | 229 RUNNYMEDE RD | 4 | 35.00 | 883 |
| Metropolitan | Essex Fells Twp | 185 FOREST WAY | 4 | 35.00 | 60153 |
| Metropolitan | Essex Fells Twp | 219 ROSELAND AVE | 4 | 40.00 | 60125 |
| Metropolitan | Fairfield Twp Ess | 190 PASSAIC AVE | 4 | 45.00 | 60488 |
| Metropolitan | Fairfield Twp Ess | 22 US HIGHWAY 46 | 4 | 40.00 | 60376 |
| Metropolitan | Essex Fells Twp | 28 PARK LN | 4 | 40.00 | 60521 |
| Metropolitan | Essex Fells Twp | 158 OVAL RD | 4 | 35.00 | 60766 |
| Metropolitan | Essex Fells Twp | 47 HOLTON LN | 4 | 35.00 | 60763 |
| Metropolitan | Essex Fells Twp | 5 BUTTONWOOD RD | 4 | 30.00 | 60759 |
| Metropolitan | Essex Fells Twp | 33 OAK LN | 4 | 40.00 | 60009 |
| Metropolitan | Essex Fells Twp | 42 OAK LN | 4 | 35.00 | 274 |
| Metropolitan | Essex Fells Twp | 25 OAK LN | 4 | 35.00 | 60706 |
| Metropolitan | Essex Fells Twp | 55 HOLTON LN | 4 | 35.00 | 60764 |
| Metropolitan | Fairfield Twp Ess | 31 GREENBROOK RD | 4 | 40.00 | 60480 |
| Metropolitan | Essex Fells Twp | 249 ROSELAND AVE | 4 | 45.00 | 60147 |
| Metropolitan | Essex Fells Twp | 251 ROSELAND AVE | 4 | 40.00 | 60146 |
| Metropolitan | Essex Fells Twp | 85 OAK LN | 4 | 35.00 | 60412 |
| Metropolitan | Essex Fells Twp | 73 AVON DR | 4 | 40.00 | 60723 |
| Metropolitan | Fairfield Twp Ess | 53 VALENTINO RD | 4 | 40.00 | 60541 |
| Metropolitan | Fairfield Twp Ess | 26 PLYMOUTH ST | 4 | 40.00 | 60062 |
| Metropolitan | Fairfield Twp Ess | 47 PLYMOUTH ST | 4 | 35.00 | 61001 |
| Metropolitan | Fairfield Twp Ess | 252 PASSAIC AVE | 4 | 40.00 | 62420 |
| Metropolitan | Fairfield Twp Ess | 114 US HIGHWAY 46 | 4 | 40.00 | 1028 |
| Metropolitan | Fairfield Twp Ess | 117 CLINTON RD | 4 | 40.00 | 62714 |
| Metropolitan | Essex Fells Twp | 33 AVON DR | 4 | 40.00 | 60717 |
| Metropolitan | Fairfield Twp Ess | 91 CLINTON RD | 4 | 40.00 | 63557 |
| Metropolitan | Essex Fells Twp | 57 AVON DR | 4 | 35.00 | 60720 |

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| Metropolitan | Fairfield Twp Ess | 6 RAY PL | 4 | 40.00 | 61028 |
| Metropolitan | Fairfield Twp Ess | 11 RAY PL | 4 | 40.00 | 61171 |
| Metropolitan | Fairfield Twp Ess | 15 RAY PL | 4 | 35.00 | 61693 |
| Metropolitan | Fairfield Twp Ess | PP S MILL ST | 4 | 40.00 | 60970 |
| Metropolitan | Fairfield Twp Ess | 43 CLINTON RD | 4 | 40.00 | 63201 |
| Metropolitan | Fairfield Twp Ess | 19 MILL ST | 4 | 40.00 | 61803 |
| Metropolitan | Haledon Boro | 361 MORISSE AVE | 4 | 35.00 | 61068 |
| Metropolitan | Fairfield Twp Ess | 45 SUNSET RD | 4 | 40.00 | 61014 |
| Metropolitan | Fairfield Twp Ess | 39 SUNSET RD | 4 | 40.00 | 61015 |
| Metropolitan | Fairfield Twp Ess | 41 FLEETWOOD AVE | 4 | 40.00 | 60976 |
| Metropolitan | Fairfield Twp Ess | 33 FLEETWOOD AVE | 4 | 35.00 | 60975 |
| Metropolitan | Fairfield Twp Ess | 26 OAKLAND TER | 4 | 35.00 | 60887 |
| Metropolitan | Fairfield Twp Ess | 22 OAKLAND TER | 4 | 40.00 | 60886 |
| Metropolitan | Haledon Boro | 203 POMPTON RD | 4 | 35.00 | 6130 |
| Metropolitan | Haledon Boro | 48 LENHARD DR | 4 | 40.00 | 60109 |
| Metropolitan | Haledon Boro | 94 FORD RD | 4 | 35.00 | 60810 |
| Metropolitan | Fairfield Twp Ess | 567 US HIGHWAY 46 | 4 | 40.00 | 60513 |
| Metropolitan | Haledon Boro | 38 CIRCLE AVE | 4 | 30.00 | 60919 |
| Metropolitan | Haledon Boro | 66 LUPTON LN | 4 | 35.00 | 6090 |
| Metropolitan | Fairfield Twp Ess | 1275 BLOOMFIELD AVE | 4 | 35.00 | 61970 |
| Metropolitan | Essex Fells Twp | 80 WOOTTON RD | 4 | 35.00 | 60395 |
| Metropolitan | Essex Fells Twp | 22 WOOTTON RD | 4 | 35.00 | 60044 |
| Metropolitan | Fairfield Twp Ess | 589 US HIGHWAY 46 | 4 | 35.00 | 60743 |
| Metropolitan | Essex Fells Twp | 23 MAPLE LN | 4 | 35.00 | 60749 |
| Metropolitan | Essex Fells Twp | 30 MAPLE LN | 4 | 35.00 | 60750 |
| Metropolitan | Essex Fells Twp | 99 MAPLE LN | 4 | 35.00 | 60755 |
| Metropolitan | Essex Fells Twp | 38 HATHAWAY LN | 4 | 40.00 | 60409 |
| Metropolitan | Essex Fells Twp | 27 HATHAWAY LN | 4 | 35.00 | 60466 |
| Metropolitan | Essex Fells Twp | 197 RENSSELAER RD | 4 | 35.00 | 60137 |
| Metropolitan | Essex Fells Twp | 193 RENSSELAER RD | 4 | 35.00 | 60136 |
| Metropolitan | Fairfield Twp Ess | 503 US HIGHWAY 46 | 4 | 40.00 | 63212 |
| Metropolitan | Essex Fells Twp | 8 WELSH RD | 4 | 35.00 | 60140 |
| Metropolitan | Essex Fells Twp | 26 WELSH RD | 4 | 35.00 | 60144 |
| Metropolitan | Essex Fells Twp | 30 WELSH RD | 4 | 35.00 | 60300 |
| Metropolitan | Essex Fells Twp | 42 WELSH RD | 4 | 35.00 | 60302 |
| Metropolitan | Essex Fells Twp | 146 HAWTHORNE RD | 4 | 35.00 | 60877 |
| Metropolitan | Fairfield Twp Ess | 14 COMMERCentral RD | 4 | 40.00 | 62309 |
| Metropolitan | Essex Fells Twp | 104 RENSSELAER RD | 4 | 35.00 | 60080 |
| Metropolitan | Essex Fells Twp | 317 ROSELAND AVE | 4 | 35.00 | 60880 |
| Metropolitan | Fairfield Twp Ess | 6 PARK AVE | 4 | 35.00 | 62095 |
| Metropolitan | Essex Fells Twp | 185 RENSSELAER RD | 4 | 35.00 | 60134 |
| Metropolitan | Fairfield Twp Ess | 401 HORSENECK RD | 4 | 40.00 | 62717 |
| Metropolitan | Essex Fells Twp | 96 RENSSELAER RD | 4 | 35.00 | 60082 |
| Metropolitan | Fairfield Twp Ess | 117 US HIGHWAY 46 | 4 | 40.00 | 61825 |
| Metropolitan | Essex Fells Twp | 333 ROSELAND AVE | 4 | 35.00 | 60354 |
| Metropolitan | Fairfield Twp Ess | 21 DANIEL RD | 4 | 40.00 | 62362 |
| Metropolitan | Fairfield Twp Ess | 298 ELDRIDGE RD | 4 | 40.00 | 62360 |

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| Metropolitan | Haledon Boro | 70 VEREIN ST | 4 | 35.00 | 60632 |
| Metropolitan | Essex Fells Twp | 87 HAWTHORNE RD | 4 | 35.00 | 60064 |
| Metropolitan | Essex Fells Twp | 81 HAWTHORNE RD | 4 | 35.00 | 60065 |
| Metropolitan | Essex Fells Twp | 22 INWOOD RD | 4 | 35.00 | 60436 |
| Metropolitan | Fairfield Twp Ess | 8 DANIEL RD | 4 | 40.00 | 62356 |
| Metropolitan | Essex Fells Twp | 67 HAWTHORNE RD | 4 | 35.00 | 60067 |
| Metropolitan | Essex Fells Twp | 34 INWOOD RD | 4 | 35.00 | 60434 |
| Metropolitan | Fairfield Twp Ess | 458 FAIRFIELD RD | 4 | 55.00 | 61173 |
| Metropolitan | Essex Fells Twp | 39 INWOOD RD | 4 | 40.00 | 60625 |
| Metropolitan | Essex Fells Twp | 49 HAWTHORNE RD | 4 | 35.00 | 60070 |
| Metropolitan | Haledon Boro | 406 CentralNTRAL AVE | 4 | 35.00 | 60314 |
| Metropolitan | Fairfield Twp Ess | 7 FAIRFIELD CT | 4 | 35.00 | 60441 |
| Metropolitan | Essex Fells Twp | 152 RENSSELAER RD | 4 | 40.00 | 60421 |
| Metropolitan | Fairfield Twp Ess | 81 BEVERLY RD | 4 | 40.00 | 60874 |
| Metropolitan | Fairfield Twp Ess | 86 BEVERLY RD | 4 | 40.00 | 60875 |
| Metropolitan | Essex Fells Twp | 38 BEECHTREE LN | 4 | 35.00 | 60426 |
| Metropolitan | Fairfield Twp Ess | 122 BEVERLY RD | 4 | 40.00 | 60883 |
| Metropolitan | Fairfield Twp Ess | 10 MAYHEW DR | 4 | 35.00 | 61772 |
| Metropolitan | Fairfield Twp Ess | 146 LEHIGH DR | 4 | 35.00 | 61347 |
| Metropolitan | Essex Fells Twp | 98 BEECHTREE LN | 4 | 35.00 | 60432 |
| Metropolitan | Fairfield Twp Ess | 5 FLEETWOOD AVE | 4 | 35.00 | 61309 |
| Metropolitan | Fairfield Twp Ess | 145 BEVERLY RD | 4 | 40.00 | 61779 |
| Metropolitan | Fairfield Twp Ess | 149 BEVERLY RD | 4 | 40.00 | 61344 |
| Metropolitan | Fairfield Twp Ess | 72 DUVAL CT | 4 | 40.00 | 61258 |
| Metropolitan | Fairfield Twp Ess | 161 BEVERLY RD | 4 | 40.00 | 61255 |
| Metropolitan | Essex Fells Twp | 8 OVAL RD | 4 | 35.00 | 60276 |
| Metropolitan | Essex Fells Twp | 12 OVAL RD | 4 | 35.00 | 60277 |
| Metropolitan | Fairfield Twp Ess | 77 CURTISS ST | 4 | 35.00 | 61633 |
| Metropolitan | Fairfield Twp Ess | 233 HORSENECK RD | 4 | 35.00 | 62796 |
| Metropolitan | Fairfield Twp Ess | 217 HORSENECK RD | 4 | 35.00 | 60521 |
| Metropolitan | Fairfield Twp Ess | 279 HORSENECK RD | 4 | 35.00 | 60091 |
| Metropolitan | Fairfield Twp Ess | 271 HORSENECK RD | 4 | 40.00 | 60090 |
| Metropolitan | Fairfield Twp Ess | 701 US HIGHWAY 46 | 4 | 40.00 | 2189 |
| Metropolitan | Fairfield Twp Ess | 96 RIVEREDGE DR | 4 | 40.00 | 2649 |
| Metropolitan | Fairfield Twp Ess | 372 BIG PIECentral RD | 4 | 35.00 | 61063 |
| Metropolitan | Fairfield Twp Ess | 176 FAIRFIELD RD | 4 | 40.00 | 60218 |
| Metropolitan | Fairfield Twp Ess | 133 LITTLE FALLS RD | 4 | 35.00 | 60621 |
| Metropolitan | Fairfield Twp Ess | 9 LITTLE FALLS RD | 4 | 55.00 | 769 |
| Metropolitan | Fairfield Twp Ess | 44 PIER LN | 4 | 40.00 | 60263 |
| Metropolitan | Fairfield Twp Ess | 116 FAIRFIELD RD | 4 | 40.00 | 60205 |
| Metropolitan | Fairfield Twp Ess | 98 TOLL TER | 4 | 35.00 | 60944 |
| Metropolitan | Fairfield Twp Ess | 28 HARDING DR | 4 | 35.00 | 61051 |
| Metropolitan | Fairfield Twp Ess | 86 PIER LN | 4 | 35.00 | 60942 |
| Metropolitan | Fairfield Twp Ess | 64 FAIRFIELD RD | 4 | 40.00 | 60193 |
| Metropolitan | Fairfield Twp Ess | 6 TOLL TER | 4 | 40.00 | 60439 |
| Metropolitan | Fairfield Twp Ess | 198 PIER LN | 4 | 40.00 | 60605 |
| Metropolitan | Fairfield Twp Ess | 167 LITTLE FALLS RD | 4 | 40.00 | 60602 |

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| Metropolitan | Fairfield Twp Ess | 22 FAIRFIELD RD | 4 | 40.00 | 60184 |
| Metropolitan | Fairfield Twp Ess | 14 MONTESANO RD | 4 | 40.00 | 61238 |
| Metropolitan | Fairfield Twp Ess | 5 HENRIETTA DR | 4 | 40.00 | 61182 |
| Metropolitan | Fairfield Twp Ess | 50 MONTESANO RD | 4 | 40.00 | 62287 |
| Metropolitan | Fairfield Twp Ess | 7 BARBARA DR | 4 | 40.00 | 61267 |
| Metropolitan | Fairfield Twp Ess | 320 HOLLYWOOD AVE | 4 | 40.00 | 60393 |
| Metropolitan | Fairfield Twp Ess | 9 BARBARA DR | 4 | 40.00 | 61268 |
| Metropolitan | Fairfield Twp Ess | 11 CARLOS DR | 4 | 35.00 | 60964 |
| Metropolitan | Fairfield Twp Ess | 25 BARBARA DR | 4 | 40.00 | 61275 |
| Metropolitan | Fairfield Twp Ess | 20 LANE RD | 4 | 40.00 | 62240 |
| Metropolitan | Fairfield Twp Ess | 6 BRYN MAWR WAY | 4 | 35.00 | 62994 |
| Metropolitan | Fairfield Twp Ess | 345 BIG PIECentral RD | 4 | 35.00 | 60413 |
| Metropolitan | Fairfield Twp Ess | 328 BIG PIECentral RD | 4 | 35.00 | 60417 |
| Metropolitan | Fairfield Twp Ess | 207 LITTLE FALLS RD | 4 | 40.00 | 61902 |
| Metropolitan | Fairfield Twp Ess | 322 BIG PIECentral RD | 4 | 35.00 | 60859 |
| Metropolitan | Fairfield Twp Ess | 12 MAPLEWOOD AVE | 4 | 35.00 | 62090 |
| Metropolitan | Fairfield Twp Ess | 318 BIG PIECentral RD | 4 | 35.00 | 60860 |
| Metropolitan | Fairfield Twp Ess | 21 COLT ST | 4 | 35.00 | 61153 |
| Metropolitan | Fairfield Twp Ess | 312 BIG PIECentral RD | 4 | 35.00 | 60861 |
| Metropolitan | Fairfield Twp Ess | 13 PHILIP DR | 4 | 35.00 | 61729 |
| Metropolitan | Fairfield Twp Ess | 12 KEVIN TER | 4 | 35.00 | 61747 |
| Metropolitan | Fairfield Twp Ess | 347 OLD COUNTRY RD | 4 | 35.00 | 62987 |
| Metropolitan | Fairfield Twp Ess | 355 OLD COUNTRY RD | 4 | 35.00 | 62983 |
| Metropolitan | Fairfield Twp Ess | 365 BIG PIECentral RD | 4 | 40.00 | 60407 |
| Metropolitan | Fairfield Twp Ess | 367 BIG PIECentral RD | 4 | 40.00 | 60406 |
| Metropolitan | Fairfield Twp Ess | 371 BIG PIECentral RD | 4 | 40.00 | 60405 |
| Metropolitan | Fairfield Twp Ess | 8 COLERIDGE TER | 4 | 35.00 | 62590 |
| Metropolitan | Fairfield Twp Ess | 373 BIG PIECentral RD | 4 | 40.00 | 60404 |
| Metropolitan | Fairfield Twp Ess | 99 SHIRE AVE | 4 | 40.00 | 61593 |
| Metropolitan | Fairfield Twp Ess | 235 HOLLYWOOD AVE | 4 | 40.00 | 60761 |
| Metropolitan | Fairfield Twp Ess | 9 JOCINE DR | 4 | 35.00 | 61254 |
| Metropolitan | Fairfield Twp Ess | 232 LITTLE FALLS RD | 4 | 30.00 | 62092 |
| Metropolitan | Fairfield Twp Ess | 23 SAND RD | 4 | 40.00 | 60673 |
| Metropolitan | Fairfield Twp Ess | 8 BATES DR | 4 | 40.00 | 61247 |
| Metropolitan | Fairfield Twp Ess | 91 DEY AVE | 4 | 35.00 | 61594 |
| Metropolitan | Fairfield Twp Ess | 10 BATES DR | 4 | 40.00 | 61248 |
| Metropolitan | Fairfield Twp Ess | 91 COLT ST | 4 | 35.00 | 61157 |
| Metropolitan | Fairfield Twp Ess | 12 BATES DR | 4 | 40.00 | 61249 |
| Metropolitan | Fairfield Twp Ess | 4 GREEN MEADOWS RD | 4 | 40.00 | 61595 |
| Metropolitan | Fairfield Twp Ess | 26 VAN NESS AVE | 4 | 35.00 | 61894 |
| Metropolitan | Fairfield Twp Ess | 61 SAND RD | 4 | 40.00 | 60682 |
| Metropolitan | Fairfield Twp Ess | 79 SAND RD | 4 | 40.00 | 60686 |
| Metropolitan | Fairfield Twp Ess | 76 VAN NESS AVE | 4 | 35.00 | 61900 |
| Metropolitan | Fairfield Twp Ess | 13 VINE ST | 4 | 40.00 | 61673 |
| Metropolitan | Fairfield Twp Ess | 5 VINE ST | 4 | 40.00 | 61670 |
| Metropolitan | Fairfield Twp Ess | 3 VINE ST | 4 | 40.00 | 61669 |
| Metropolitan | Fairfield Twp Ess | 1 OAK RD | 4 | 40.00 | 62535 |

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| Metropolitan | Fairfield Twp Ess | 68 DELL CT | 4 | 35.00 | 62129 |
| Metropolitan | Fairfield Twp Ess | 20 COMMERCentral RD | 4 | 40.00 | 62310 |
| Metropolitan | Fairfield Twp Ess | 11 ESPOSITO DR | 4 | 35.00 | 62112 |
| Metropolitan | Fairfield Twp Ess | 1245 BLOOMFIELD AVE | 4 | 35.00 | 61967 |
| Metropolitan | Fairfield Twp Ess | 15 ADDISON DR | 4 | 35.00 | 62183 |
| Metropolitan | Fairfield Twp Ess | 7 LAW DR | 4 | 35.00 | 60383 |
| Metropolitan | Fairfield Twp Ess | 10 LAW DR | 4 | 40.00 | 62468 |
| Metropolitan | Fairfield Twp Ess | 7 ADDISON DR | 4 | 35.00 | 62186 |
| Metropolitan | Fairfield Twp Ess | 13 LEBEDA DR | 4 | 40.00 | 61227 |
| Metropolitan | Fairfield Twp Ess | 179 SAND RD | 4 | 35.00 | 61221 |
| Metropolitan | Fairfield Twp Ess | 9 GLENROY RD S | 4 | 40.00 | 61334 |
| Metropolitan | Fairfield Twp Ess | 7 MALCOLM DR | 4 | 40.00 | 61302 |
| Metropolitan | Fairfield Twp Ess | 6 MALCOLM DR | 4 | 40.00 | 61301 |
| Metropolitan | Fairfield Twp Ess | 52 HENNING DR | 4 | 35.00 | 62071 |
| Metropolitan | Fairfield Twp Ess | 1 MALCOLM DR | 4 | 40.00 | 61298 |
| Metropolitan | Fairfield Twp Ess | 9 CLUB RD | 4 | 40.00 | 61287 |
| Metropolitan | Fairfield Twp Ess | 50 HENNING DR | 4 | 35.00 | 62058 |
| Metropolitan | Fairfield Twp Ess | 48 HENNING DR | 4 | 35.00 | 62057 |
| Metropolitan | Fairfield Twp Ess | 41 GLENROY RD S | 4 | 40.00 | 61618 |
| Metropolitan | Fairfield Twp Ess | 10 CARL DR | 4 | 40.00 | 61297 |
| Metropolitan | Fairfield Twp Ess | 30 STEWART PL | 4 | 40.00 | 62313 |
| Metropolitan | Fairfield Twp Ess | 4 ESPOSITO DR | 4 | 35.00 | 62111 |
| Metropolitan | Fairfield Twp Ess | 7 CLUB RD | 4 | 40.00 | 61286 |
| Metropolitan | Fairfield Twp Ess | 139 SAND RD | 4 | 40.00 | 61283 |
| Metropolitan | Fairfield Twp Ess | 145 SAND RD | 4 | 40.00 | 61330 |
| Metropolitan | Fairfield Twp Ess | 21 COMMERCentral RD | 4 | 40.00 | 63018 |
| Metropolitan | Fairfield Twp Ess | 99 MEADOW CT | 4 | 35.00 | 61204 |
| Metropolitan | Fairfield Twp Ess | 99 MEADOW CT | 4 | 35.00 | 61203 |
| Metropolitan | Fairfield Twp Ess | 25 COMMERCentral RD | 4 | 40.00 | 63070 |
| Metropolitan | Fairfield Twp Ess | 25 COMMERCentral RD | 4 | 40.00 | 63072 |
| Metropolitan | Fairfield Twp Ess | 30 HENNING DR | 4 | 35.00 | 62048 |
| Metropolitan | Fairfield Twp Ess | 32 HENNING DR | 4 | 35.00 | 62049 |
| Metropolitan | Fairfield Twp Ess | 34 HENNING DR | 4 | 35.00 | 62050 |
| Metropolitan | Fairfield Twp Ess | 89 SAND RD | 4 | 40.00 | 61033 |
| Metropolitan | Fairfield Twp Ess | 93 SAND RD | 4 | 40.00 | 61034 |
| Metropolitan | Fairfield Twp Ess | 2 STAG TRL | 4 | 40.00 | 62188 |
| Metropolitan | Fairfield Twp Ess | 10 STAG TRL | 4 | 35.00 | 62376 |
| Metropolitan | Fairfield Twp Ess | 14 STAG TRL | 4 | 40.00 | 62377 |
| Metropolitan | Fairfield Twp Ess | 155 LEHIGH DR | 4 | 40.00 | 61138 |
| Metropolitan | Fairfield Twp Ess | 24 STAG TRL | 4 | 35.00 | 63659 |
| Metropolitan | Fairfield Twp Ess | 125 LEHIGH DR | 4 | 40.00 | 63515 |
| Metropolitan | Fairfield Twp Ess | 36 STAG TRL | 4 | 35.00 | 62602 |
| Metropolitan | Fairfield Twp Ess | 95 BROADWAY LN | 4 | 35.00 | 60746 |
| Metropolitan | Fairfield Twp Ess | 92 BROADWAY LN | 4 | 35.00 | 60747 |
| Metropolitan | Fairfield Twp Ess | 85 BROADWAY LN | 4 | 35.00 | 60749 |
| Metropolitan | Fairfield Twp Ess | 11 CAMP LN | 4 | 35.00 | 61083 |
| Metropolitan | Fairfield Twp Ess | 84 BROADWAY LN | 4 | 35.00 | 60750 |

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| Metropolitan | Fairfield Twp Ess | 49 MADISON RD | 4 | 35.00 | 62871 |
| Metropolitan | Fairfield Twp Ess | 16 MADISON RD | 4 | 40.00 | 63117 |
| Metropolitan | Fairfield Twp Ess | 1237 BLOOMFIELD AVE | 4 | 35.00 | 714 |
| Metropolitan | Fairfield Twp Ess | 19 INDUSTRIAL RD | 4 | 40.00 | 62859 |
| Metropolitan | Fairfield Twp Ess | 33 GLENROY RD E | 4 | 40.00 | 62211 |
| Metropolitan | Fairfield Twp Ess | 24 FOX HILL RD | 4 | 35.00 | 61852 |
| Metropolitan | Fairfield Twp Ess | 1 MARGINAL RD | 4 | 40.00 | 62217 |
| Metropolitan | Fairfield Twp Ess | 97 FOX HILL RD | 4 | 35.00 | 61860 |
| Metropolitan | Fairfield Twp Ess | 55 ERIC RD | 4 | 35.00 | 61867 |
| Metropolitan | Fairfield Twp Ess | 12 FOX HILL RD | 4 | 35.00 | 61847 |
| Metropolitan | Fairfield Twp Ess | 13 MATT DR | 4 | 35.00 | 61753 |
| Metropolitan | Fairfield Twp Ess | 15 MATT DR | 4 | 35.00 | 61754 |
| Metropolitan | Fairfield Twp Ess | 48 SYCAMORE PL | 4 | 35.00 | 61374 |
| Metropolitan | Fairfield Twp Ess | 41 MAPLE PL | 4 | 40.00 | 61262 |
| Metropolitan | Fairfield Twp Ess | 3 TOBIA PL | 4 | 40.00 | 61260 |
| Metropolitan | Fairfield Twp Ess | 4 LAUREL PL | 4 | 35.00 | 60853 |
| Metropolitan | Fairfield Twp Ess | 43 LAUREL PL | 4 | 35.00 | 61368 |
| Metropolitan | Fairfield Twp Ess | 1 POPLAR PL | 4 | 35.00 | 61369 |
| Metropolitan | Paterson City | 31 N 6TH ST | 4 | 45.00 | 64406 |
| Metropolitan | Paterson City | 91 BELMONT AVE | 4 | 45.00 | 68223 |
| Metropolitan | Paterson City | 10 N 4TH ST | 4 | 35.00 | 10324 |
| Metropolitan | Paterson City | 332 UNION AVE | 4 | 25.00 | 10911 |
| Metropolitan | Paterson City | 132 SHERIDAN AVE | 4 | 45.00 | 61054 |
| Metropolitan | Paterson City | 111 SHERIDAN AVE | 4 | 50.00 | 61051 |
| Metropolitan | Paterson City | 23 RYLE AVE | 4 | 35.00 | 67655 |
| Metropolitan | Paterson City | 94 CORAL ST | 4 | 40.00 | 63997 |
| Metropolitan | Paterson City | 24 CORAL ST | 4 | 40.00 | 64448 |
| Metropolitan | Paterson City | 67 ALBION AVE | 4 | 45.00 | 63565 |
| Metropolitan | Paterson City | 29 REDWOOD AVE | 4 | 40.00 | 62098 |
| Metropolitan | Paterson City | 87 JASPER ST | 4 | 40.00 | 66861 |
| Metropolitan | Paterson City | 39 KEARNEY ST | 4 | 35.00 | 66152 |
| Metropolitan | Paterson City | 244 MAPLE ST | 4 | 35.00 | 62075 |
| Metropolitan | Paterson City | 444 TOTOWA AVE | 4 | 35.00 | 13459 |
| Metropolitan | Paterson City | 230 TOTOWA AVE | 4 | 45.00 | 64129 |
| Metropolitan | Paterson City | 38 MAPLE ST | 4 | 35.00 | 64708 |
| Metropolitan | Paterson City | 47 PATERSON AVE | 4 | 40.00 | 61067 |
| Metropolitan | Paterson City | 243 TOTOWA AVE | 4 | 40.00 | 64130 |
| Metropolitan | Paterson City | 1 BERKSHIRE AVE | 4 | 35.00 | 68477 |
| Metropolitan | Paterson City | 91 MANCHESTER AVE | 4 | 35.00 | 64661 |
| Metropolitan | Paterson City | 28 JAMES ST | 4 | 40.00 | 64580 |
| Metropolitan | Paterson City | 44 TOTOWA AVE | 4 | 45.00 | 62569 |
| Metropolitan | Paterson City | 271 CROSBY AVE | 4 | 40.00 | 69708 |
| Metropolitan | Paterson City | 351 UNION AVE | 4 | 35.00 | 11547 |
| Metropolitan | Paterson City | 238 MARION ST | 4 | 40.00 | 64635 |
| Metropolitan | Paterson City | 10 GARRISON ST | 4 | 35.00 | 62912 |
| Metropolitan | Paterson City | 300 JEFFERSON ST | 4 | 40.00 | 63548 |
| Metropolitan | Paterson City | 46 CARRELTON DR | 4 | 40.00 | 66987 |

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| Metropolitan | Paterson City | 70 N 4TH ST | 4 | 40.00 | 66357 |
| Metropolitan | Paterson City | 87 TEMPLE ST | 4 | 40.00 | 66606 |
| Metropolitan | Paterson City | 51 ARCH ST | 4 | 50.00 | 66322 |
| Metropolitan | Paterson City | 160 E 5TH ST | 4 | 35.00 | 67436 |
| Metropolitan | Paterson City | 4 BLEEKER ST | 4 | 40.00 | 68638 |
| Metropolitan | Paterson City | 52 6TH AVE | 4 | 40.00 | 62651 |
| Metropolitan | Paterson City | 49 E 5TH ST | 4 | 40.00 | 13297 |
| Metropolitan | Paterson City | 119 BUTLER ST | 4 | 50.00 | 65185 |
| Metropolitan | Paterson City | 83 BUTLER ST | 4 | 40.00 | 63875 |
| Metropolitan | Paterson City | 20 MAY ST | 4 | 40.00 | 67737 |
| Metropolitan | Nutley Town | 68 HILLSIDE AVE | 4 | 35.00 | 63528 |
| Metropolitan | Paterson City | 192 6TH AVE | 4 | 40.00 | 60908 |
| Metropolitan | Paterson City | 255 VAN BLARCOM ST | 4 | 35.00 | 67744 |
| Metropolitan | Paterson City | 52 MAY ST | 4 | 35.00 | 68308 |
| Metropolitan | Paterson City | 176 E 7TH ST | 4 | 40.00 | 10628 |
| Metropolitan | Paterson City | 1 5TH AVE | 4 | 40.00 | 69946 |
| Metropolitan | Paterson City | 122 5TH AVE | 4 | 45.00 | 66904 |
| Metropolitan | Paterson City | 689 RIVER ST | 4 | 35.00 | 9702 |
| Metropolitan | Paterson City | 15 3RD AVE | 4 | 55.00 | 69688 |
| Metropolitan | Paterson City | 43 ALBERT M TYLER PL | 4 | 45.00 | 61141 |
| Metropolitan | Paterson City | 207 E 18TH ST | 4 | 35.00 | 64779 |
| Metropolitan | Paterson City | 216 E 18TH ST | 4 | 35.00 | 68207 |
| Metropolitan | Paterson City | 30 TYLER ST | 4 | 35.00 | 6244 |
| Metropolitan | Paterson City | 39 STRAIGHT ST | 4 | 35.00 | 12748 |
| Metropolitan | Paterson City | 58 LAWRENCentral ST | 4 | 40.00 | 64816 |
| Metropolitan | Paterson City | 177 12TH AVE | 4 | 50.00 | 60331 |
| Metropolitan | Paterson City | 171 12TH AVE | 4 | 55.00 | 60330 |
| Metropolitan | Paterson City | 338 HAMILTON AVE | 4 | 40.00 | 61841 |
| Metropolitan | Paterson City | 137 WARREN ST | 4 | 40.00 | 65146 |
| Metropolitan | Paterson City | 156 LAWRENCentral PL | 4 | 40.00 | 64183 |
| Metropolitan | Paterson City | 427 E 18TH ST | 4 | 40.00 | 67046 |
| Metropolitan | Paterson City | 230 WARREN ST | 4 | 35.00 | 63908 |
| Metropolitan | Paterson City | 198 PUTNAM ST | 4 | 40.00 | 65155 |
| Metropolitan | Paterson City | 347 E 19TH ST | 4 | 40.00 | 62559 |
| Metropolitan | Paterson City | 105 AUBURN ST | 4 | 35.00 | 70757 |
| Metropolitan | Paterson City | 279 COLLEGE BLVD | 4 | 40.00 | 69658 |
| Metropolitan | Paterson City | 43 TYLER ST | 4 | 35.00 | 65115 |
| Metropolitan | Paterson City | 48 GOVERNOR ST | 4 | 50.00 | 60165 |
| Metropolitan | Paterson City | 99 ANN ST | 4 | 40.00 | 66411 |
| Metropolitan | Paterson City | 13 12TH AVE | 4 | 45.00 | 61764 |
| Metropolitan | Paterson City | 9 AUBURN ST | 4 | 45.00 | 60307 |
| Metropolitan | Paterson City | 35 AUBURN ST | 4 | 50.00 | 60351 |
| Metropolitan | Paterson City | 32 GODWIN AVE | 4 | 40.00 | 61763 |
| Metropolitan | Paterson City | 147 STRAIGHT ST | 4 | 65.00 | 64712 |
| Metropolitan | Paterson City | 161 HAMILTON AVE | 4 | 35.00 | 8716 |
| Metropolitan | Paterson City | 280 SUMMER ST | 4 | 40.00 | 69660 |
| Metropolitan | Paterson City | 345 ELLISON ST | 4 | 40.00 | 68750 |

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|---|---|---|---|---|---|
| Metropolitan | Paterson City | 24 PEARL ST | 4 | 40.00 | 61721 |
| Metropolitan | Paterson City | 6 PEARL ST | 4 | 35.00 | 65307 |
| Metropolitan | Paterson City | 10 PENNINGTON AVE | 4 | 40.00 | 62867 |
| Metropolitan | Paterson City | 238 16TH AVE | 4 | 35.00 | 65321 |
| Metropolitan | Paterson City | 188 16TH AVE | 4 | 40.00 | 60514 |
| Metropolitan | Paterson City | 386 GRAHAM AVE | 4 | 45.00 | 60637 |
| Metropolitan | Paterson City | 617 E 18TH ST | 4 | 45.00 | 61322 |
| Metropolitan | Paterson City | 548 E 18TH ST | 4 | 35.00 | 69146 |
| Metropolitan | Paterson City | 489 MCLEAN BLVD | 4 | 35.00 | 67799 |
| Metropolitan | Paterson City | 521 MCLEAN BLVD | 4 | 40.00 | 10529 |
| Metropolitan | Paterson City | 529 MCLEAN BLVD | 4 | 40.00 | 10533 |
| Metropolitan | Paterson City | 16 E 40TH ST | 4 | 40.00 | 11934 |
| Metropolitan | Paterson City | 514 MCLEAN BLVD | 4 | 40.00 | 69038 |
| Metropolitan | Paterson City | 522 MCLEAN BLVD | 4 | 40.00 | 11926 |
| Metropolitan | Paterson City | 124 MCLEAN BLVD | 4 | 40.00 | 70422 |
| Metropolitan | Paterson City | 836 LOU COSTELLO'S PL | 4 | 40.00 | 60982 |
| Metropolitan | Paterson City | 805 E 26TH ST | 4 | 35.00 | 10491 |
| Metropolitan | Paterson City | 904 E 28TH ST | 4 | 40.00 | 63388 |
| Metropolitan | Paterson City | 879 MARKET ST | 4 | 45.00 | 61356 |
| Metropolitan | Paterson City | 61 E 20TH ST | 4 | 45.00 | 63526 |
| Metropolitan | Paterson City | 73 BECKWITH AVE | 4 | 35.00 | 13954 |
| Metropolitan | Paterson City | 73 TRENTON AVE | 4 | 45.00 | 62663 |
| Metropolitan | Paterson City | 34 MARTIN ST | 4 | 40.00 | 65642 |
| Metropolitan | Paterson City | 389 SUMMER ST | 4 | 35.00 | 64331 |
| Metropolitan | Paterson City | 209 CARLISLE AVE | 4 | 40.00 | 64879 |
| Metropolitan | Paterson City | 69 MCBRIDE AVE | 4 | 35.00 | 12411 |
| Metropolitan | Paterson City | 24 MILL ST | 4 | 40.00 | 67664 |
| Metropolitan | Paterson City | 165 MILL ST | 4 | 35.00 | 69079 |
| Palisades | Union City | 305 39TH ST | 4 | 40.00 | 60719 |
| Palisades | Cresskill Boro | MADISON AVE | 4 | 40.00 | 60009 |
| Palisades | Rutherford Boro | 244 MOUNTAIN WAY | 4 | 40.00 | 60092 |
| Palisades | Rutherford Boro | 181 UNION AVE | 4 | 40.00 | 60801 |
| Palisades | Rutherford Boro | 512 STUYVESANT AVE | 4 | 40.00 | 60419 |
| Palisades | Rutherford Boro | 532 RIVERSIDE AVE | 4 | 40.00 | 61748 |
| Palisades | Rutherford Boro | 217 MONTROSS AVE | 4 | 45.00 | 61074 |
| Palisades | Rutherford Boro | 59 E PASSAIC AVE | 4 | 40.00 | 61450 |
| Palisades | Rutherford Boro | 31 ELM ST | 4 | 40.00 | 61291 |
| Palisades | Rutherford Boro | 261 WOOD ST | 4 | 35.00 | 61984 |
| Palisades | Rutherford Boro | 312 RIVERSIDE AVE | 4 | 40.00 | 61853 |
| Palisades | Rutherford Boro | 181 WOODWARD AVE | 4 | 35.00 | 60857 |
| Palisades | Rutherford Boro | 45 KIP AVE | 4 | 35.00 | 62266 |
| Palisades | Rutherford Boro | 174 MAPLE ST | 4 | 35.00 | 61144 |
| Palisades | Rutherford Boro | 353 UNION AVE | 4 | 40.00 | 60775 |
| Palisades | Rutherford Boro | 371 UNION AVE | 4 | 40.00 | 60765 |
| Palisades | Rutherford Boro | 1 WALNUT ST | 4 | 40.00 | 2226 |
| Palisades | Rutherford Boro | 58 RAYMOND AVE | 4 | 40.00 | 61374 |
| Palisades | Rutherford Boro | 15 JACKSON AVE | 4 | 40.00 | 60779 |

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|---|---|---|---|---|---|
| Palisades | Jersey City | 150 SUMMIT AVE | 4 | 35.00 | 15981 |
| Palisades | Jersey City | 34 FLOYD ST | 4 | 40.00 | 69050 |
| Palisades | Fort Lee Boro | 364 WILSON AVE | 4 | 40.00 | 61365 |
| Palisades | Jersey City | 166 BROADWAY | 4 | 35.00 | 70424 |
| Palisades | Jersey City | 146 BROADWAY | 4 | 35.00 | 10639 |
| Palisades | Fort Lee Boro | 1356 SELDEN PL | 4 | 35.00 | 61968 |
| Palisades | Fort Lee Boro | 247 BELLEMEADE AVE | 4 | 40.00 | 60869 |
| Palisades | Fort Lee Boro | 272 FOREST RD | 4 | 35.00 | 62012 |
| Palisades | Fort Lee Boro | W/O RAMP FROM RT 46 | 4 | 40.00 | 63083 |
| Palisades | Fort Lee Boro | 1461 14TH ST | 4 | 40.00 | 62211 |
| Palisades | Fort Lee Boro | 1682 ANDERSON AVE | 4 | 40.00 | 60077 |
| Palisades | Fort Lee Boro | 27 PLATEAU AVE | 4 | 35.00 | 61722 |
| Palisades | Fort Lee Boro | 434 CentralNTER ST | 4 | 35.00 | 61172 |
| Palisades | Jersey City | 753 SUMMIT AVE | 4 | 35.00 | 17929 |
| Palisades | Jersey City | 254 SAINT PAULS AVE | 4 | 45.00 | 67414 |
| Palisades | Jersey City | 9 SKILLMAN AVE | 4 | 40.00 | 65969 |
| Palisades | Jersey City | 104 VAN WINKLE AVE | 4 | 35.00 | 70128 |
| Palisades | Jersey City | 243 10TH ST | 4 | 40.00 | 80013 |
| Palisades | Jersey City | 117 MAGNOLIA AVE | 4 | 35.00 | 17293 |
| Palisades | Jersey City | 54 DIVISION ST | 4 | 35.00 | 12594 |
| Palisades | Jersey City | 398 7TH ST | 4 | 40.00 | 65534 |
| Palisades | Jersey City | 33 TRENTON ST | 4 | 35.00 | 65655 |
| Palisades | Jersey City | 342 6TH ST | 4 | 40.00 | 66427 |
| Palisades | Jersey City | 635 JERSEY AVE | 4 | 40.00 | 70635 |
| Palisades | Jersey City | 231 6TH ST | 4 | 35.00 | 14025 |
| Palisades | Jersey City | 225 PAVONIA AVE | 4 | 40.00 | 69485 |
| Palisades | Jersey City | 36 NEWKIRK ST | 4 | 40.00 | 63353 |
| Palisades | Jersey City | 444 EGE AVE | 4 | 40.00 | 66901 |
| Palisades | Jersey City | 164 BRUNSWICK ST | 4 | 40.00 | 65418 |
| Palisades | Jersey City | 340 5TH ST | 4 | 45.00 | 66722 |
| Palisades | Jersey City | 128 MONTGOMERY ST | 4 | 40.00 | 19952 |
| Palisades | Jersey City | 51 WELSH LN | 4 | 40.00 | 64345 |
| Palisades | Jersey City | 180 HARRISON AVE | 4 | 35.00 | 72423 |
| Palisades | Jersey City | 93 BENTLEY AVE | 4 | 35.00 | 10685 |
| Palisades | Jersey City | 287 MONTGOMERY ST | 4 | 40.00 | 12170 |
| Palisades | Jersey City | 47 BENTLEY AVE | 4 | 35.00 | 10690 |
| Palisades | Jersey City | 141 MERCentralR ST | 4 | 40.00 | 71282 |
| Palisades | Jersey City | 347 MONMOUTH ST | 4 | 40.00 | 70249 |
| Palisades | Jersey City | 149 BELMONT AVE | 4 | 35.00 | 10681 |
| Palisades | Jersey City | 22 STUYVESANT AVE | 4 | 35.00 | 62996 |
| Palisades | Jersey City | 203 GROVE ST | 4 | 40.00 | 65555 |
| Palisades | Jersey City | 40 VAN REYPEN ST | 4 | 35.00 | 70407 |
| Palisades | Jersey City | 58 STUYVESANT AVE | 4 | 40.00 | 67268 |
| Palisades | Jersey City | 16 CORBIN AVE | 4 | 40.00 | 5351 |
| Palisades | Jersey City | 431 DUNCAN AVE | 4 | 40.00 | 66148 |
| Palisades | Jersey City | 897 MONTGOMERY ST | 4 | 40.00 | 69022 |
| Palisades | Jersey City | 803 STATE HIGHWAY 440 | 4 | 35.00 | 21566 |

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|---|---|---|---|---|---|
| Palisades | Jersey City | 1022 LINCOLN HWY | 4 | 35.00 | 21569 |
| Palisades | Jersey City | 966 PAVONIA AVE | 4 | 40.00 | 67278 |
| Palisades | Jersey City | 72 HAWTHORNE AVE | 4 | 40.00 | 64809 |
| Palisades | Jersey City | 322 BROADWAY | 4 | 35.00 | 69250 |
| Palisades | Jersey City | 472 FREEMAN AVE | 4 | 35.00 | 15640 |
| Palisades | Jersey City | 108 LOGAN AVE | 4 | 45.00 | 64845 |
| Palisades | Bayonne City | 258 AVENUE E | 4 | 35.00 | 63009 |
| Palisades | Jersey City | 6 WALLIS AVE | 4 | 50.00 | 64967 |
| Palisades | Jersey City | 31 MARION PL | 4 | 40.00 | 63553 |
| Palisades | Jersey City | 279 BRIGHT ST | 4 | 35.00 | 14819 |
| Palisades | Jersey City | 279 BRIGHT ST | 4 | 35.00 | 17346 |
| Palisades | Jersey City | 276 BRIGHT ST | 4 | 35.00 | 20064 |
| Palisades | Jersey City | 62 JEWETT AVE | 4 | 35.00 | 72371 |
| Palisades | Jersey City | 21 JEWETT AVE | 4 | 35.00 | 15953 |
| Palisades | Jersey City | 27 BALDWIN AVE | 4 | 40.00 | 69826 |
| Palisades | Jersey City | 35 BALDWIN AVE | 4 | 35.00 | 69825 |
| Palisades | Jersey City | 322 DUNCAN AVE | 4 | 35.00 | 69443 |
| Palisades | Jersey City | 232 HARRISON AVE | 4 | 35.00 | 10585 |
| Palisades | Jersey City | 71 ASTOR PL | 4 | 40.00 | 69856 |
| Palisades | Jersey City | 72 FAIRMOUNT AVE | 4 | 35.00 | 6790 |
| Palisades | Jersey City | 63 AMITY ST | 4 | 40.00 | 18760 |
| Palisades | Jersey City | 812 COMMUNIPAW AVE | 4 | 35.00 | 65077 |
| Palisades | Jersey City | 32 BELVIDERE AVE | 4 | 35.00 | 67717 |
| Palisades | Jersey City | 61 DELAWARE AVE | 4 | 40.00 | 63543 |
| Palisades | Jersey City | 28 CONDICT ST | 4 | 40.00 | 61061 |
| Palisades | Jersey City | 20 SIEDLER ST | 4 | 40.00 | 2866 |
| Palisades | Jersey City | 65 CULVER AVE | 4 | 40.00 | 66795 |
| Palisades | Jersey City | 47 COLLEGE ST | 4 | 40.00 | 66600 |
| Palisades | Jersey City | 15 COLLEGE DR | 4 | 40.00 | 66529 |
| Palisades | Jersey City | 498 MALLORY AVE | 4 | 35.00 | 68398 |
| Palisades | Jersey City | 192 DUNCAN AVE | 4 | 35.00 | 18368 |
| Palisades | Jersey City | 37 CULVER AVE | 4 | 40.00 | 67716 |
| Palisades | Jersey City | 89 VAN HORNE ST | 4 | 40.00 | 65573 |
| Palisades | Jersey City | 281 KEARNEY AVE | 4 | 35.00 | 61271 |
| Palisades | Jersey City | 238 CLAREMONT AVE | 4 | 40.00 | 62832 |
| Palisades | Jersey City | 174 AUDUBON AVE | 4 | 40.00 | 66422 |
| Palisades | Jersey City | 85 ORCHARD ST | 4 | 35.00 | 69346 |
| Palisades | Jersey City | 63 NEVIN ST | 4 | 40.00 | 72803 |
| Palisades | Jersey City | 289 LEXINGTON AVE | 4 | 40.00 | 64531 |
| Palisades | Jersey City | 103 HARBOR DR | 4 | 40.00 | 16590 |
| Palisades | Jersey City | 12 SIEDLER ST | 4 | 40.00 | 2865 |
| Palisades | Jersey City | 574 BRAMHALL AVE | 4 | 35.00 | 70020 |
| Palisades | Jersey City | 416 UNION ST | 4 | 40.00 | 62209 |
| Palisades | Jersey City | 342 UNION ST | 4 | 35.00 | 66354 |
| Palisades | Jersey City | 32 WILLIAMS AVE | 4 | 40.00 | 69630 |
| Palisades | Jersey City | 181 MALLORY AVE | 4 | 45.00 | 64646 |
| Palisades | Jersey City | 13 MILLER ST | 4 | 35.00 | 72526 |

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|---|---|---|---|---|---|
| Palisades | Jersey City | 389 VIRGINIA AVE | 4 | 40.00 | 64082 |
| Palisades | Jersey City | 39 BENNETT ST | 4 | 40.00 | 68785 |
| Palisades | Jersey City | 97 VAN CLEEF ST | 4 | 45.00 | 16317 |
| Palisades | Jersey City | 199 GRANT AVE | 4 | 45.00 | 61319 |
| Palisades | Jersey City | 177 ORIENT AVE | 4 | 35.00 | 69464 |
| Palisades | Jersey City | 160 ORIENT AVE | 4 | 40.00 | 64370 |
| Palisades | Jersey City | 99 MORTON PL | 4 | 35.00 | 20990 |
| Palisades | Jersey City | 137 EGE AVE | 4 | 40.00 | 62246 |
| Palisades | Jersey City | 143 EGE AVE | 4 | 40.00 | 62322 |
| Palisades | Jersey City | 153 EGE AVE | 4 | 35.00 | 68529 |
| Palisades | Jersey City | 69 WADE AVE | 4 | 40.00 | 63377 |
| Palisades | Jersey City | 62 EGE AVE | 4 | 35.00 | 69246 |
| Palisades | Jersey City | 18 MARTIN LUTHER KING J | 4 | 35.00 | 11426 |
| Palisades | Jersey City | 295 BERGEN AVE | 4 | 35.00 | 65084 |
| Palisades | Jersey City | 154 ORIENT AVE | 4 | 40.00 | 64371 |
| Palisades | Jersey City | 75 ORIENT AVE | 4 | 40.00 | 69567 |
| Palisades | Jersey City | 189 CLAREMONT AVE | 4 | 40.00 | 70061 |
| Palisades | Jersey City | 701 STATE ROUTE 440 | 4 | 35.00 | 24890 |
| Palisades | Jersey City | 127 GRANT AVE | 4 | 40.00 | 61313 |
| Palisades | Jersey City | 25 MANNING AVE | 4 | 40.00 | 62248 |
| Palisades | Jersey City | 172 MYRTLE AVE | 4 | 40.00 | 70027 |
| Palisades | Jersey City | 113 MYRTLE AVE | 4 | 35.00 | 70034 |
| Palisades | Jersey City | 106 MYRTLE AVE | 4 | 35.00 | 70035 |
| Palisades | Jersey City | 196 WILKINSON AVE | 4 | 35.00 | 69951 |
| Palisades | Jersey City | 301 CLERK ST | 4 | 40.00 | 68081 |
| Palisades | Jersey City | 253 WHITON ST | 4 | 40.00 | 61052 |
| Palisades | Jersey City | 1926 JOHN F KENNEDY BL | 4 | 35.00 | 74277 |
| Palisades | Jersey City | 217 RANDOLPH AVE | 4 | 40.00 | 67679 |
| Palisades | Jersey City | 129 PACIFIC AVE | 4 | 35.00 | 72642 |
| Palisades | Jersey City | 293 STEGMAN PKWY | 4 | 35.00 | 63564 |
| Palisades | Jersey City | 248 VAN NOSTRAND AVE | 4 | 40.00 | 66080 |
| Palisades | Jersey City | 4 HIGHVIEW RD | 4 | 35.00 | 66872 |
| Palisades | Jersey City | 28 HIGHVIEW RD | 4 | 35.00 | 64985 |
| Palisades | Jersey City | 260 DWIGHT ST | 4 | 35.00 | 17139 |
| Palisades | Jersey City | 298 OLD BERGEN RD | 4 | 40.00 | 63103 |
| Palisades | Jersey City | 331 STEVENS AVE | 4 | 35.00 | 10355 |
| Palisades | Jersey City | 333 ARMSTRONG AVE | 4 | 40.00 | 65126 |
| Palisades | Jersey City | 6 E BIDWELL AVE | 4 | 40.00 | 64244 |
| Palisades | Jersey City | 120 STEVENS AVE | 4 | 35.00 | 69648 |
| Palisades | Jersey City | 11 PARNELL PL | 4 | 40.00 | 63055 |
| Palisades | Jersey City | 72 WADE ST | 4 | 35.00 | 14007 |
| Palisades | Jersey City | 117 ARMSTRONG AVE | 4 | 40.00 | 60776 |
| Palisades | Jersey City | 65 THEODORE CONRAD D | 4 | 40.00 | 68624 |
| Palisades | Jersey City | 55 THEODORE CONRAD D | 4 | 35.00 | 69095 |
| Palisades | Jersey City | 1584 JOHN F KENNEDY BL | 4 | 40.00 | 63265 |
| Palisades | Jersey City | 1 THEODORE CONRAD DR | 4 | 35.00 | 70054 |
| Palisades | Jersey City | 189 GATES AVE | 4 | 40.00 | 62351 |

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|---|---|---|---|---|---|
| Palisades | Jersey City | 219 CUSTER AVE | 4 | 35.00 | 24601 |
| Palisades | Jersey City | 163 CUSTER AVE | 4 | 35.00 | 66160 |
| Palisades | Jersey City | 211 FOWLER AVE | 4 | 35.00 | 68115 |
| Palisades | Jersey City | 42 STERLING AVE | 4 | 40.00 | 63676D |
| Palisades | Jersey City | 90 PAMRAPO AVE | 4 | 40.00 | 63634 |
| Palisades | Jersey City | 79 TERHUNE AVE | 4 | 40.00 | 65273 |
| Palisades | Jersey City | 226 CATOR AVE | 4 | 40.00 | 63908 |
| Palisades | Jersey City | 66 STEVENS AVE | 4 | 40.00 | 60355 |
| Palisades | Jersey City | 56 WARNER AVE | 4 | 35.00 | 64740 |
| Palisades | Jersey City | 15 SHEFFIELD ST | 4 | 40.00 | 60108 |
| Palisades | Jersey City | 165 DANFORTH AVE | 4 | 40.00 | 67441 |
| Palisades | Jersey City | 191 DANFORTH AVE | 4 | 40.00 | 60036 |
| Palisades | Jersey City | 223 DANFORTH AVE | 4 | 35.00 | 60823 |
| Palisades | Jersey City | 157 DANFORTH AVE | 4 | 35.00 | 67442 |
| Palisades | Jersey City | 124 LINDEN AVE | 4 | 40.00 | 60573 |
| Palisades | Jersey City | 9 COLONY RD | 4 | 35.00 | 72332 |
| Palisades | Jersey City | 45 COLONY RD | 4 | 40.00 | 71338 |
| Palisades | Fort Lee Boro | 269 VIRGINIA AVE | 4 | 40.00 | 61541 |
| Palisades | Jersey City | 18 ALBERT PL | 4 | 35.00 | 67129 |
| Palisades | Jersey City | 52 ALBERT PL | 4 | 35.00 | 67130 |
| Palisades | Jersey City | 33 LINDEN CT | 4 | 40.00 | 70703 |
| Palisades | Jersey City | 174 LINDEN AVE E | 4 | 35.00 | 18916 |
| Palisades | Jersey City | 82 BROWN PL | 4 | 40.00 | 61337 |
| Palisades | Jersey City | 9 MURYLU DR | 4 | 35.00 | 67733 |
| Palisades | Jersey City | 460 PRINCentralTON AVE | 4 | 40.00 | 63125 |
| Palisades | Jersey City | 118 SEAVIEW AVE | 4 | 45.00 | 61844 |
| Palisades | Jersey City | 54 CROSSGATE RD | 4 | 35.00 | 67824 |
| Palisades | Jersey City | 34 CROSSGATE RD | 4 | 35.00 | 67823 |
| Palisades | Jersey City | 82 GARFIELD AVE | 4 | 40.00 | 68776 |
| Palisades | Fort Lee Boro | 1109 EDGEWOOD LN | 4 | 35.00 | 60110 |
| Palisades | Fort Lee Boro | 1160 ANDERSON AVE | 4 | 45.00 | 60412 |
| Palisades | Fort Lee Boro | 18 HORIZON RD | 4 | 35.00 | 2319 |
| Palisades | Fort Lee Boro | 1914 DUNCAN RD | 4 | 40.00 | 62393 |
| Palisades | Fort Lee Boro | 69 VIRGINIA AVE | 4 | 40.00 | 60882 |
| Palisades | Fort Lee Boro | 1088 BERGEN BLVD | 4 | 35.00 | 61653 |
| Palisades | Fort Lee Boro | 1057 ANDERSON AVE | 4 | 40.00 | 60210 |
| Southern | Moorestown Twp | 454 FAIRVIEW AVE | 4 | 35.00 | 62152 |
| Southern | Moorestown Twp | 356 EVERGREEN DR | 4 | 35.00 | 61620 |
| Southern | Moorestown Twp | 127 N COLONIAL RIDGE RI | 4 | 35.00 | 61074 |
| Southern | Moorestown Twp | 2 S COLONIAL RIDGE RD | 4 | 40.00 | 62191 |
| Southern | Moorestown Twp | 704 E CAMDEN AVE | 4 | 40.00 | 64716 |
| Southern | Moorestown Twp | 730 E CAMDEN AVE | 4 | 40.00 | 63334 |
| Southern | Moorestown Twp | 14 GREENVALE RD | 4 | 40.00 | 62282 |
| Southern | Moorestown Twp | 724 BEACON RD | 4 | 40.00 | 62347 |
| Southern | Moorestown Twp | 859 BEACON ST | 4 | 40.00 | 62805 |
| Southern | Moorestown Twp | 70 OVERBROOK CIR | 4 | 40.00 | 62810 |
| Southern | Moorestown Twp | 82 WESTBROOK DR | 4 | 40.00 | 62503 |

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|---|---|---|---|---|---|
| Southern | Moorestown Twp | 693 DEVON RD | 4 | 35.00 | 61810 |
| Southern | Moorestown Twp | 244 MANNION ST | 4 | 35.00 | 61132 |
| Southern | Moorestown Twp | 297 W 3RD ST | 4 | 40.00 | 60847 |
| Southern | Moorestown Twp | 254 W 2ND ST | 4 | 40.00 | 60336 |
| Southern | Moorestown Twp | 150 UNION ST | 4 | 35.00 | 61129 |
| Southern | Moorestown Twp | 172 LOCUST ST | 4 | 35.00 | 60329 |
| Southern | Moorestown Twp | 229 W MAIN ST | 4 | 35.00 | 63477 |
| Southern | Moorestown Twp | 325 W MAIN ST | 4 | 40.00 | 60092 |
| Southern | Moorestown Twp | 272 W MAIN ST | 4 | 40.00 | 63345 |
| Southern | Moorestown Twp | 118 W 2ND ST | 4 | 40.00 | 60347 |
| Southern | Moorestown Twp | 317 N WASHINGTON AVE | 4 | 35.00 | 64378 |
| Southern | Moorestown Twp | 698 GLEN CT | 4 | 40.00 | 64550 |
| Southern | Moorestown Twp | 107 W CentralNTRAL AVE | 4 | 35.00 | 60757 |
| Southern | Moorestown Twp | 147 W CentralNTRAL AVE | 4 | 35.00 | 60165 |
| Southern | Moorestown Twp | 425 DAWSON ST | 4 | 35.00 | 60754 |
| Southern | Moorestown Twp | 436 GLEN AVE | 4 | 35.00 | 62734 |
| Southern | Moorestown Twp | 599 IRVING CT | 4 | 35.00 | 60033 |
| Southern | Moorestown Twp | 516 N CHURCH ST | 4 | 40.00 | 106 |
| Southern | Moorestown Twp | 92 ROBERTS AVE | 4 | 40.00 | 2585 |
| Southern | Moorestown Twp | 125 CLARK AVE | 4 | 40.00 | 60259 |
| Southern | Moorestown Twp | 544 N CHURCH ST | 4 | 40.00 | 1557 |
| Southern | Moorestown Twp | 300 FARMDALE RD | 4 | 40.00 | 1578 |
| Southern | Moorestown Twp | 100 E 3RD ST | 4 | 30.00 | 64252 |
| Southern | Moorestown Twp | 351 FLYNN AVE | 4 | 35.00 | 62708 |
| Southern | Moorestown Twp | 109 PLUM ST | 4 | 35.00 | 61331 |
| Southern | Moorestown Twp | 8 E 3RD ST | 4 | 40.00 | 64419 |
| Southern | Moorestown Twp | 199 STANLEY AVE | 4 | 35.00 | 62323 |
| Southern | Moorestown Twp | 307 MILL ST | 4 | 40.00 | 62102 |
| Southern | Moorestown Twp | 1078 N CHURCH ST | 4 | 35.00 | 62479 |
| Southern | Moorestown Twp | 195 PERRY AVE | 4 | 35.00 | 63177 |
| Southern | Moorestown Twp | 3389 MARNE HWY | 4 | 35.00 | 5603 |
| Southern | Moorestown Twp | 185 ROCKLAND AVE | 4 | 35.00 | 63638 |
| Southern | Moorestown Twp | 104 ROUTE 38 | 4 | 40.00 | 3263 |
| Southern | Moorestown Twp | 421 N WASHINGTON AVE | 4 | 40.00 | 64561 |
| Southern | Moorestown Twp | 7 PN TOM BROWN RD | 4 | 35.00 | 64103 |
| Southern | Moorestown Twp | 345 TOM BROWN RD | 4 | 35.00 | 63727 |
| Southern | Moorestown Twp | 165 E MAIN ST | 4 | 35.00 | 62973 |
| Southern | Moorestown Twp | 328 TOM BROWN RD | 4 | 35.00 | 63427 |
| Southern | Moorestown Twp | 182 ROUTE 38 | 4 | 40.00 | 63106 |
| Southern | Moorestown Twp | 204 EASTBOURNE TER | 4 | 35.00 | 62978 |
| Southern | Moorestown Twp | 113 E 3RD ST | 4 | 35.00 | 62413 |
| Southern | Moorestown Twp | 812 RIVERTON RD | 4 | 35.00 | 64584 |
| Southern | Moorestown Twp | 300 NEWBOLD AVE | 4 | 40.00 | 61847 |
| Southern | Moorestown Twp | 220 W ROUTE 38 | 4 | 40.00 | 63026 |
| Southern | Moorestown Twp | 169 E 3RD ST | 4 | 35.00 | 62977 |
| Southern | Moorestown Twp | 278 W ROUTE 38 | 4 | 40.00 | 63021 |
| Southern | Moorestown Twp | 260 W ROUTE 38 | 4 | 30.00 | 3502 |

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| Southern | Moorestown Twp | 698 LIPPINCOTT AVE | 4 | 40.00 | 62330 |
| Southern | Moorestown Twp | 311 W ROUTE 38 | 4 | 40.00 | 63233 |
| Southern | Moorestown Twp | 370 TOM BROWN RD | 4 | 35.00 | 64473 |
| Southern | Moorestown Twp | 231 LINDEN ST | 4 | 35.00 | 3049 |
| Southern | Moorestown Twp | 421 CHESTNUT ST | 4 | 40.00 | 64637 |
| Southern | Moorestown Twp | 163 E CentralNTRAL AVE | 4 | 40.00 | 64638 |
| Southern | Moorestown Twp | 25 W PROSPECT AVE | 4 | 40.00 | 60786 |
| Southern | Moorestown Twp | 235 STRAWBRIDGE DR | 4 | 35.00 | 5083 |
| Southern | Moorestown Twp | 100 E OAK AVE | 4 | 40.00 | 63248 |
| Southern | Moorestown Twp | 461 CHESTNUT ST | 4 | 35.00 | 64634 |
| Southern | Moorestown Twp | 204 HEDGEMAN RD | 4 | 35.00 | 63555 |
| Southern | Moorestown Twp | 22 CARDINAL DR | 4 | 40.00 | 62634 |
| Southern | Moorestown Twp | 5 E HAINES DR | 4 | 35.00 | 61416 |
| Southern | Moorestown Twp | 4 E HAINES DR | 4 | 35.00 | 61419 |
| Southern | Moorestown Twp | 381 S CHURCH ST | 4 | 35.00 | 60778 |
| Southern | Moorestown Twp | 293 S CHURCH ST | 4 | 35.00 | 60774 |
| Southern | Moorestown Twp | 882 N LENOLA RD | 4 | 40.00 | 63625 |
| Southern | Moorestown Twp | 236 S CHURCH ST | 4 | 40.00 | 63838 |
| Southern | Moorestown Twp | 900 N LENOLA RD | 4 | 35.00 | 63746 |
| Southern | Moorestown Twp | 118 S CHURCH ST | 4 | 35.00 | 60763 |
| Southern | Moorestown Twp | 904 N LENOLA RD | 4 | 40.00 | 63626 |
| Southern | Moorestown Twp | 203 FELLOWSHIP RD | 4 | 35.00 | 60074 |
| Southern | Moorestown Twp | 19 W HARRIS AVE | 4 | 35.00 | 62141 |
| Southern | Moorestown Twp | 602 NEW ALBANY RD | 4 | 40.00 | 61979 |
| Southern | Moorestown Twp | 360 S WASHINGTON AVE | 4 | 35.00 | 60802 |
| Southern | Moorestown Twp | 566 NEW ALBANY RD | 4 | 40.00 | 61428 |
| Southern | Moorestown Twp | 268 PLEASANT VALLEY AV | 4 | 35.00 | 60615 |
| Southern | Moorestown Twp | 394 PLEASANT VALLEY AV | 4 | 35.00 | 60625 |
| Southern | Cinnaminson Twp | 1503 TAYLORS LN | 4 | 40.00 | 63218 |
| Southern | Moorestown Twp | 21 W SUTTON AVE | 4 | 40.00 | 61675 |
| Southern | Moorestown Twp | 228 ANDREWS AVE | 4 | 40.00 | 64188 |
| Southern | Moorestown Twp | 50 E WALNUT ST | 4 | 35.00 | 62328 |
| Southern | Moorestown Twp | 678 LIPPINCOTT AVE | 4 | 35.00 | 62124 |
| Southern | Moorestown Twp | 667 LIPPINCOTT AVE | 4 | 35.00 | 62125 |
| Southern | Moorestown Twp | 176 FOREST RD | 4 | 35.00 | 63916 |
| Southern | Moorestown Twp | 680 MILL ST | 4 | 35.00 | 63856 |
| Southern | Moorestown Twp | 197 FOREST RD | 4 | 35.00 | 63004 |
| Southern | Moorestown Twp | 315 SPRINGHOUSE LN | 4 | 35.00 | 62914 |
| Southern | Moorestown Twp | 662 MAPLE CT | 4 | 35.00 | 61328 |
| Southern | Moorestown Twp | 200 SPRINGHOUSE LN | 4 | 35.00 | 62908 |
| Southern | Moorestown Twp | 118 W MAPLE AVE | 4 | 35.00 | 61322 |
| Southern | Moorestown Twp | 55 SPRUCentral CT | 4 | 35.00 | 62250 |
| Southern | Moorestown Twp | 337 SPRINGHOUSE LN | 4 | 35.00 | 62919 |
| Southern | Moorestown Twp | 294 E CAMDEN AVE | 4 | 40.00 | 62293 |
| Southern | Moorestown Twp | 48 COTTAGE AVE | 4 | 35.00 | 64084 |
| Southern | Moorestown Twp | 1 SPRUCentral CT | 4 | 40.00 | 62145 |
| Southern | Moorestown Twp | 77 E CAMDEN AVE | 4 | 40.00 | 61653 |

| | | | | | |
|---|---|---|---|---|---|
| Southern | Moorestown Twp | 208 WINDING WAY | 4 | 35.00 | 63048 |
| Southern | Moorestown Twp | 9 E SPRUCentral ST | 4 | 35.00 | 61764 |
| Southern | Moorestown Twp | 341 TOTY RD | 4 | 35.00 | 63599 |
| Southern | Moorestown Twp | 142 RAMBLEWOOD RD | 4 | 35.00 | 63211 |
| Southern | Moorestown Twp | 611 N WASHINGTON AVE | 4 | 35.00 | 60739 |
| Southern | Moorestown Twp | 33 ROBIN RD | 4 | 40.00 | 62897 |
| Southern | Moorestown Twp | 1003 WESTFIELD RD | 4 | 40.00 | 64544 |
| Southern | Moorestown Twp | 177 HAINES DR | 4 | 35.00 | 62185 |
| Southern | Moorestown Twp | 104 MALL RING RD | 4 | 35.00 | 64937 |
| Southern | Moorestown Twp | 133 FOXWOOD DR | 4 | 35.00 | 64799 |
| Southern | Moorestown Twp | 155 MOUNT LAUREL RD | 4 | 35.00 | 62820 |
| Southern | Moorestown Twp | 196 COLONIAL AVE | 4 | 40.00 | 60876 |
| Southern | Moorestown Twp | 127 S SOMERS CT | 4 | 35.00 | 63404 |
| Southern | Moorestown Twp | 437 EDGEMOOR DR | 4 | 35.00 | 2901 |
| Southern | Moorestown Twp | 2 MOORFIELD LN | 4 | 40.00 | 64470 |
| Southern | Moorestown Twp | 2 MINDY DR | 4 | 40.00 | 60903 |
| Southern | Cinnaminson Twp | 2503 NEW ALBANY RD | 4 | 35.00 | 62451 |
| Southern | Moorestown Twp | 624 GARWOOD RD | 4 | 35.00 | 63571 |
| Southern | Moorestown Twp | 703 MARNE HWY | 4 | 40.00 | 65071 |
| Southern | Haddonfield Boro | 45 HARDING AVE | 4 | 35.00 | 60852 |
| Southern | Moorestown Twp | 735 MARNE HWY | 4 | 35.00 | 64282 |
| Southern | Moorestown Twp | 753 MARNE HWY | 4 | 40.00 | 65200 |
| Southern | Moorestown Twp | 530 WESTFIELD RD | 4 | 40.00 | 60269 |
| Southern | Moorestown Twp | 613 E MAIN ST | 4 | 40.00 | 2126 |
| Southern | Moorestown Twp | 194 PANCOAST AVE | 4 | 40.00 | 64593 |
| Southern | Moorestown Twp | 464 E MAIN ST | 4 | 35.00 | 63491 |
| Southern | Cinnaminson Twp | 2603 BURLINGTON PIKE | 4 | 40.00 | 63578 |
| Southern | Moorestown Twp | 508 OLDERSHAW AVE | 4 | 35.00 | 63591 |
| Southern | Haddonfield Boro | 103 MARNE AVE | 4 | 40.00 | 61892 |
| Southern | Moorestown Twp | 545 CREEK RD | 4 | 35.00 | 63834 |
| Southern | Moorestown Twp | 374 BORTONS LANDING R | 4 | 35.00 | 3118 |
| Southern | Audubon Boro | 75 HAMPSHIRE AVE | 4 | 40.00 | 61252 |
| Southern | Haddonfield Boro | 171 WINDING WAY | 4 | 35.00 | 61095 |
| Southern | Cinnaminson Twp | 609 HAMILTON DR | 4 | 35.00 | 63715 |
| Southern | Audubon Boro | 105 HAMPSHIRE AVE | 4 | 35.00 | 61234 |
| Southern | Haddonfield Boro | 20 CHEWS LANDING RD | 4 | 40.00 | 60446 |
| Southern | Haddonfield Boro | 252 MOORE LN | 4 | 35.00 | 61675 |
| Southern | Haddonfield Boro | 264 MOORE LN | 4 | 35.00 | 61676 |
| Southern | Haddonfield Boro | 290 MOORE LN | 4 | 35.00 | 61678 |
| Southern | Haddonfield Boro | 95 LANE OF ACRES | 4 | 35.00 | 61135 |
| Southern | Haddonfield Boro | 84 LANE OF ACRES | 4 | 40.00 | 61020 |
| Southern | Haddonfield Boro | 30 LANE OF ACRES | 4 | 35.00 | 61638 |
| Southern | Haddonfield Boro | 122 LAFAYETTE AVE | 4 | 35.00 | 60546 |
| Southern | Audubon Boro | 475 CHESTNUT ST | 4 | 35.00 | 60261 |
| Southern | Woodlynne Boro | 1556 WOODLYNNE AVE | 4 | 40.00 | 60208 |
| Southern | Woodlynne Boro | 1660 WOODLYNNE AVE | 4 | 40.00 | 60207 |
| Southern | Woodlynne Boro | 1810 WOODLYNNE AVE | 4 | 40.00 | 60182 |

| | | | | | |
|---|---|---|---|---|---|
| Southern | Woodlynne Boro | 297 POWELTON AVE | 4 | 30.00 | 60260 |
| Southern | Haddonfield Boro | 30 LAFAYETTE AVE | 4 | 35.00 | 60577 |
| Southern | Woodlynne Boro | 1629 CROSSLYNNE AVE | 4 | 35.00 | 60314 |
| Southern | Woodlynne Boro | 162 MAPLE AVE | 4 | 35.00 | 60211 |
| Southern | Woodlynne Boro | 1654 CROSSLYNNE AVE | 4 | 35.00 | 60263 |
| Southern | Woodlynne Boro | 1648 FERRY AVE | 4 | 40.00 | 60132 |
| Southern | Audubon Boro | 246 WYOMING AVE | 4 | 40.00 | 60195 |
| Southern | Audubon Boro | 145 CHESTNUT ST | 4 | 35.00 | 60236 |
| Southern | Woodlynne Boro | 124 POWELTON AVE | 4 | 35.00 | 60001 |
| Southern | Woodlynne Boro | 114 CentralDAR AVE | 4 | 35.00 | 60018 |
| Southern | Woodlynne Boro | 2064 S 4TH ST | 4 | 35.00 | 304 |
| Southern | Woodlynne Boro | 188 CHESTNUT AVE | 4 | 40.00 | 60034 |
| Southern | Woodlynne Boro | 2044 WOODLYNNE AVE | 4 | 40.00 | 60199 |
| Southern | Audubon Boro | 155 CORNELL RD | 4 | 35.00 | 487 |
| Southern | Woodlynne Boro | 211 COOPER AVE | 4 | 35.00 | 60048 |
| Southern | Woodlynne Boro | 380 COOPER AVE | 4 | 35.00 | 60226 |
| Southern | Woodlynne Boro | 246 EVERGREEN AVE | 4 | 35.00 | 128 |
| Southern | Chesterfield Twp | 432 CHESTERFIELD JACOI | 4 | 35.00 | 60458 |
| Southern | Bellmawr Boro | 51 WILSON AVE | 4 | 35.00 | 60728 |
| Southern | Mansfield Twp Bur | 495 ROUTE 68 | 4 | 35.00 | 62623 |
| Southern | Bellmawr Boro | 212 WELSH AVE | 4 | 35.00 | 62084 |
| Southern | Bellmawr Boro | 542 FIR PL | 4 | 35.00 | 60481 |
| Southern | Bellmawr Boro | 9 N BLACK HORSE PIKE | 4 | 35.00 | 61371 |
| Southern | Chesterfield Twp | 29 OLD YORK RD | 4 | 35.00 | 61376 |
| Southern | Bellmawr Boro | 290 MEYNER DR | 4 | 35.00 | 61331 |
| Southern | Chesterfield Twp | 33 WHITE PINE RD | 4 | 30.00 | 61089 |
| Southern | Bellmawr Boro | 87 PRINCentralTON AVE | 4 | 35.00 | 60465 |
| Southern | Chesterfield Twp | 61 WHITE PINE RD | 4 | 35.00 | 60238 |
| Southern | Bellmawr Boro | 516 W BROWNING RD | 4 | 40.00 | 60410 |
| Southern | Chesterfield Twp | 318 BORDENTOWN RD | 4 | 35.00 | 61145 |
| Southern | Bellmawr Boro | 448 WINDSOR DR | 4 | 40.00 | 61155 |
| Southern | Bellmawr Boro | 312 PEACH RD | 4 | 35.00 | 61771 |
| Southern | Bellmawr Boro | 297 BOOTH DR | 4 | 35.00 | 61790 |
| Southern | Bellmawr Boro | 141 S BELL RD | 4 | 35.00 | 61730 |
| Southern | Bellmawr Boro | 522 LINCOLN AVE | 4 | 35.00 | 60171 |
| Southern | Maple Shade Twp | 3 W MAIN ST | 4 | 35.00 | 60230 |
| Southern | Maple Shade Twp | 113 BROADWAY RD | 4 | 35.00 | 60567 |
| Southern | Bellmawr Boro | 23 HELLER RD | 4 | 40.00 | 61766 |
| Southern | Maple Shade Twp | 432 W FRONT ST | 4 | 35.00 | 60507 |
| Southern | Maple Shade Twp | 454 BUTTONWOOD AVE | 4 | 35.00 | 61415 |
| Southern | Eastampton Twp | 20 CentralDAR MILL RD | 4 | 35.00 | 60535 |
| Southern | Eastampton Twp | 25 RABBIT RUN | 4 | 35.00 | 60283 |
| Southern | Maple Shade Twp | 25 BIRCH AVE | 4 | 40.00 | 61338 |
| Southern | Maple Shade Twp | 41 BIRCH AVE | 4 | 40.00 | 61736 |
| Southern | Maple Shade Twp | 77 BIRCH AVE | 4 | 40.00 | 61732 |
| Southern | Mansfield Twp Bur | 28490 SCHOOL HOUSE RD | 4 | 40.00 | 61250 |
| Southern | Maple Shade Twp | 449 ELM AVE | 4 | 35.00 | 60385 |

| | | | | | |
|---|---|---|---|---|---|
| Southern | Maple Shade Twp | 384 ELM AVE | 4 | 35.00 | 60049 |
| Southern | Maple Shade Twp | 464 E LAURELTON AVE | 4 | 40.00 | 61040 |
| Southern | Maple Shade Twp | 359 SPRUCentral AVE | 4 | 35.00 | 60536 |
| Southern | Maple Shade Twp | 184 S POPLAR AVE | 4 | 35.00 | 60529 |
| Southern | Maple Shade Twp | 137 THOMAS AVE | 4 | 35.00 | 60427 |
| Southern | Maple Shade Twp | 6 S FORKLANDING RD | 4 | 40.00 | 60790 |
| Southern | Deptford Twp | 692 FOX RUN RD | 4 | 35.00 | 3854 |
| Southern | Deptford Twp | 304 TARPY DR | 4 | 35.00 | 63426 |
| Southern | Deptford Twp | 1633 COOPER ST | 4 | 40.00 | 63373 |
| Southern | Maple Shade Twp | 286 S PINE AVE | 4 | 35.00 | 60603 |
| Southern | Deptford Twp | 2 MARGARET AVE | 4 | 40.00 | 60303 |
| Southern | Deptford Twp | 612 TACOMA BLVD | 4 | 40.00 | 62468 |
| Southern | Maple Shade Twp | 21 COLLINS RD | 4 | 35.00 | 61971 |
| Southern | Deptford Twp | 1027 DELSEA DR | 4 | 35.00 | 64655 |
| Southern | South Brunswick Twp | 10 RAILROAD AVE | 4 | 35.00 | 1980 |
| Southern | Maple Shade Twp | 31 WILLOW RD | 4 | 35.00 | 2480 |
| Southern | South Brunswick Twp | 7 SULEMAN RD | 4 | 35.00 | 60592 |
| Southern | South Brunswick Twp | 4120 US HIGHWAY 1 | 4 | 40.00 | 60479 |
| Southern | South Brunswick Twp | L 561 LINCOLN HWY | 4 | 40.00 | 61033 |
| Southern | South Brunswick Twp | 4334 MAIN ST | 4 | 35.00 | 61040 |
| Southern | South Brunswick Twp | 4362 MAIN ST | 4 | 40.00 | 61037 |
| Southern | South Brunswick Twp | 852 RIDGE RD | 4 | 35.00 | 63464 |

**Schedule EFG-IAP-9 Conventional Underground Cable Replacement**

| Circuit | Miles |
|---|---|
| BAO8011 | 1.08 |
| SOS8016 | 0.08 |
| FOU8012 | 0.34 |
| DUM4003 | 0.11 |
| MAD8031 | 0.22 |
| CUT8003 | 1.35 |
| CUT8032 | 0.51 |
| SPF8022 | 0.36 |
| LAF8011 | 0.47 |
| CAT4006 | 0.10 |
| KUS8009 | 0.37 |
| SMV8024 | 0.08 |
| ADA8012 | 0.27 |
| LEO8041 | 1.47 |
| CUT8007 | 1.22 |
| DFD8033 | 0.82 |
| DFD8007 | 0.54 |
| LAF8022 | 0.19 |
| BEE4007 | 0.09 |
| LUM8014 | 0.11 |
| LEO8004 | 2.64 |
| BRA8012 | 0.67 |
| LOC8004 | 0.58 |
| LEO8043 | 0.91 |
| KUS8042 | 0.64 |
| MAR8018 | 0.44 |
| CUT8041 | 0.36 |
| SOH8022 | 0.44 |
| HOM8032 | 1.92 |
| BEN8014 | 0.22 |
| BEN8022 | 0.29 |
| HOE8044 | 1.05 |
| DFD8041 | 0.48 |
| HAT8014 | 0.60 |
| DOR8044 | 0.76 |
| BEN8026 | 0.63 |
| MAR8013 | 0.81 |
| DOR8034 | 0.55 |
| LCE8045 | 0.86 |
| EAO4001 | 1.88 |
| LAF8015 | 0.76 |
| CUT8001 | 2.22 |
| BEA8004 | 0.18 |

| | |
|---|---|
| DFD8032 | 1.48 |
| MAY8015 | 0.96 |
| EAO4002 | 1.85 |
| SMV8012 | 0.40 |

**Schedule EFG-IAP-10 Spacer Upgrade Project**

| Station | Circuit | Mileage |
|---|---|---|
| Springfield Road | SPF 8022 | 3.71 |
| Marion Drive | MAI 8011 | 3.80 |
| Kuller Road | KUL 8013 | 4.39 |
| Springfield Road | SPF 8012 | 2.36 |
| Belmont | BEM 8001 | 3.13 |
| Clifton | CLF 8015 | 2.95 |
| Aldene Sub | ALD 8025 | 4.73 |
| Penhorn | PEH 8015 | 3.00 |
| South Second Street | SOS 8016 | 7.09 |
| Meadow Road | MEA 8026 | 6.68 |
| Doremus Place | DOR 8034 | 4.93 |
| Branchbrook | BRA 8011 | 2.78 |
| Springfield Road | SPF 8013 | 5.27 |
| Leonia | LEO 8041 | 5.95 |
| Foundry St | FOU 8012 | 0.99 |
| Maywood | MAY 8015 | 4.08 |
| Doremus Place | DOR 8035 | 4.18 |
| Cook Rd | COR 8044 | 1.64 |
| Ridgefield | RFL 8024 | 2.49 |
| Branchbrook | BRA 8012 | 2.72 |
| Aldene Sub | ALD 8012 | 4.58 |
| Doremus Place | DOR 8043 | 3.84 |
| Leonia | LEO 8005 | 3.60 |
| Saddle Brook | SAD 8034 | 2.20 |
| Ridgefield | RFL 8043 | 3.96 |
| Hawthorne | HAW 8032 | 5.47 |
| Hinchmans | HNC 8012 | 2.63 |
| Doremus Place | DOR 8032 | 2.12 |
| Deptford | DFD 8007 | 3.30 |
| Cedar Grove | CED 8022 | 5.66 |
| Ridgefield | RFL 8034 | 1.61 |
| Jackson Rd | JAC 8032 | 5.14 |
| Aldene Sub | ALD 8023 | 6.39 |
| Fanwood | FAW 8024 | 7.45 |
| Cedar Grove | CED 8021 | 2.86 |
| Kingsland | KIN 8025 | 3.20 |
| Hinchmans | HNC 8023 | 1.46 |
| Warinanco | WAN 8011 | 5.50 |
| East Rutherford Sub | EAT 8024 | 1.52 |
| Ridgefield | RFL 8035 | 0.71 |
| Adams | ADA 8011 | 0.73 |
| St Pauls | STP 8001 | 1.78 |
| New Milford | NEW 8022 | 1.47 |

| | | |
|---|---|---|
| Green Brook | GBK 8013 | 5.00 |
| Marion Drive | MAI 8012 | 1.51 |
| Kuller Road | KUL 8022 | 2.62 |
| Homestead | HOM 8033 | 1.30 |
| Bayonne Sub | BAO 8013 | 2.29 |
| Doremus Place | DOR 8044 | 1.40 |
| Brunswick Sub | BRU 8012 | 7.45 |
| Aldene Sub | ALD 8015 | 5.49 |
| Clifton | CLF 8022 | 3.90 |
| Cuthbert Blvd | CUT 8043 | 3.27 |
| Aldene Sub | ALD 8016 | 5.14 |
| Clifton | CLF 8024 | 4.78 |
| Aldene Sub | ALD 8026 | 4.10 |
| Leonia | LEO 8004 | 0.73 |
| Doremus Place | DOR 8022 | 1.65 |
| Saddle Brook | SAD 8042 | 3.91 |
| Hillsdale | HID 8044 | 6.32 |
| Lafayette Road | LAF 8011 | 2.48 |
| Marion Drive | MAI 8024 | 1.06 |
| Kilmer | KIL 8022 | 4.99 |
| Bennetts Lane | BEN 8012 | 3.76 |
| Adams | ADA 8022 | 3.38 |
| Saddle Brook | SAD 8044 | 1.01 |
| Doremus Place | DOR 8015 | 6.49 |
| Laurel Ave | LAU 8036 | 3.91 |
| Bennetts Lane | BEN 8013 | 4.55 |
| Cedar Grove | CED 8011 | 2.10 |
| North Bergen | NRB 8022 | 2.10 |
| Laurel Ave | LAU 8011 | 2.99 |
| Lafayette Road | LAF 8022 | 4.74 |
| West Caldwell | WEW 8021 | 5.65 |
| Warinanco | WAN 8021 | 4.54 |
| Warinanco | WAN 8013 | 3.82 |
| New Milford | NEW 8031 | 5.03 |
| Laurel Ave | LAU 8015 | 3.73 |
| Adams | ADA 8016 | 2.37 |
| Minue Street | MIN 8013 | 4.65 |
| Doremus Place | DOR 8042 | 1.01 |
| Green Brook | GBK 8021 | 7.71 |
| Laurel Ave | LAU 8046 | 3.38 |

**Schedule EFG-IAP-11 Voltage Optimization**

| Voltage | Station | Division | Capacitors |
|---|---|---|---|
| 13kV | Levittown | SO | 141 |
| 13kV | Minue St | CE | 58 |
| 13kV | Bustleton | SO | 86 |
| 13kV | Deptford | SO | 75 |
| 13kV | Devils Brook | SO | 81 |
| 13kV | Kilmer | CE | 110 |
| 13kV | Lumberton | SO | 83 |
| 13kV | Meadow Rd | CE | 66 |
| 13kV | Crosswicks | SO | 78 |
| 13kV | Sunnymeade | CE | 93 |
| 13kV | Penhorn | PA | 33 |
| 13kV | Pierson Ave | CE | 60 |
| 13kV | West Caldwell | ME | 97 |
| 13kV | Saddle Brook | PA | 101 |
| 13kV | Homestead | PA | 60 |
| 13kV | Bayonne | PA | 55 |
| 13kV | Doremus Place | ME | 91 |
| 13kV | Jackson Rd | ME | 70 |
| 13kV | Laurel Ave | ME | 76 |
| 13kV | Kingsland | PA | 64 |

**Schedule EFG-IAP-12 Spacer Cable Conversion Project**

| Station | Circuit | Voltage | Miles of Open Wire |
|---|---|---|---|
| New Milford | NEW 8033 | 13 | 3.1 |
| Penns Neck | PEK 8022 | 13 | 2.5 |
| Penns Neck | PEK 8013 | 13 | 3.8 |
| Waldwick | WAD 8025 | 13 | 1.5 |
| Plainsboro | PLI 8004 | 13 | 6.4 |
| Penns Neck | PEK 8023 | 13 | 2.1 |
| Kuser Rd | KUS 8041 | 13 | 5.5 |
| New Milford | NEW 8013 | 13 | 3.8 |
| Cinnaminson | CIN 8043 | 13 | 4.6 |
| Plainsboro | PLI 8003 | 13 | 2.7 |
| New Milford | NEW 8035 | 13 | 1.5 |
| Cinnaminson | CIN 8006 | 13 | 1.3 |
| Penns Neck | PEK 8026 | 13 | 0.5 |
| Mount Rose | MRO 8022 | 13 | 3.4 |
| Leonia | LEO 8035 | 13 | 3.6 |
| Cuthbert Blvd | CUT 8004 | 13 | 7.4 |
| Marlton | MAR 8020 | 13 | 4.0 |

**ATTACHMENT 3**

# 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 Infrastructure Advancement Program

**BPU Docket No. _______________**

## DIRECT TESTIMONY

## OF

## STEPHEN SWETZ
## SR. DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

**November 4, 2021**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**
**DIRECT TESTIMONY**
**OF**
**STEPHEN SWETZ**
**SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS**

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

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS- IAP-1.

**Q. Please describe your responsibilities as the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation.**

A. As Senior Director - Corporate Rates and Revenue Requirements, my primary duties are to plan, develop, and direct Public Service Electric and Gas Company's (PSE&G or the Company) calculation of electric and gas revenue requirements for the Company's base rates as well as all cost recovery clauses. I also direct the retail pricing strategies, retail rate design, embedded and marginal cost studies, and development and interpretation of tariff provisions.

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

A. My testimony provides the details for the calculation of PSE&G's Infrastructure Advancement Program (IAP or the Program) revenue requirements, the associated cost recovery methodology and rate design for the IAP Petition filed with the New Jersey Board of Public Utilities (BPU or the Board). This testimony also provides detailed schedules setting forth the projected revenue requirements, rates and bill impacts over the expected Program life.

**Q. Please briefly describe PSE&G's proposed IAP cost recovery methodology.**

A**.** PSE&G's proposed IAP cost recovery mechanism is consistent with the BPU's "Infrastructure Investment And Recovery" regulation under which utilities may propose Infrastructure Investment Programs (IIP)[1]. The IAP cost recovery proposal is also consistent with the PSE&G's, BPU approved, cost recovery mechanism set forth in Energy Strong II (ES II). This program was approved by the Board in Docket Nos. Docket Nos. EO18060629 and GO18060630 on September 11, 2019 (ES II Order). The details of the costs to be recovered, as well as the mechanism to recover such costs, are set forth in my following testimony.

**Q. How does PSE&G propose to calculate the revenue requirements?**

A. PSE&G proposes to calculate the revenue requirements associated with the IAP's costs using the following formula:

*Revenue Requirements = ((After Tax Cost of Capital * Rate Base) + Net of Tax Amortization and/or Depreciation + Tax Adjustment)* Revenue Factor*

This calculation is the same as the calculations utilized in PSE&G's Infrastructure Programs as approved by the Board in the respective Board Orders. The Company is proposing to recover the revenue requirements through semi-annual rate adjustment filings as described below, consistent with the BPU's IIP regulations.

**Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.**

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation. The term "Cost of Capital" is PSE&G's overall weighted average cost of capital

[1]. N.J.A.C. 14:3-2A.

(WACC) for the Program. PSE&G is proposing a return on its IAP rate base based upon an authorized return on equity (ROE) and capital structure including income tax effects. The Company is proposing to utilize the latest cost of capital authorized by the Board in the Company's base rate case proceeding. The Company's first base rate adjustment proceeding as a result of this Program is not anticipated to occur until 2024. Thus, under PSE&G's proposal the IAP investments should earn at the WACC approved in our last base rate case. . See Schedule SS-IAP-3 for the calculation of the current After-Tax WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in any subsequent electric, gas, or combined base rate case would be reflected in the appropriate corresponding rate adjustment filing explained in more detail below. Any changes to current Federal or State tax rates would also be reflected in an adjustment to the After-Tax WACC.

The term "Rate Base" refers to Gross Plant less the associated accumulated depreciation and/or amortization and less Accumulated Deferred Income Taxes (ADIT). Gross Plant is equal to all Plant In-Service, Construction Work in Progress (CWIP) that is transferred into Service, and Allowance of Funds Used during Construction (AFUDC) – both debt and equity components.

The book recovery of each asset class will be based on the Board approved depreciation rates in effect at the time of each rate adjustment proceeding. While the IAP's proposed revenue requirements are based on the depreciation rates approved in PSEG's last base rate case proceeding, any change to depreciation rates in a future base rate case proceeding authorized by the Board would then be reflected in the revenue requirement calculation for subsequent IAP filings.

ADIT is calculated as Book Depreciation (Tax Basis) less Tax Depreciation, multiplied by the Company's effective tax rate, which is currently 28.11%. Cost of Removal expenditures are depreciated 100% in the year incurred for tax purposes. Please see the table below for the book and tax depreciation rates for each proposed sub-program.

| **Subprograms** | **Annual Book Depreciation Rates** | | **Tax Depreciation (Years) - MACRS**[2] | |
|---|---|---|---|---|
| | Range | As Modeled | Range | As Modeled |
| **Electric** | | | | |
| Substation Modernization | 0.99% - 2.06% | 2.06% | 20 - 39 | 20 |
| Outside Plant | 1.66% - 3.71% | 1.80% | 20 | 20 |
| EV Charging Infrastructure | 0.99% - 10.0% | 3.87%* | 5 - 39 | 16* |
| | | | | |
| **Gas** | | | | |
| M&R Upgrade | 1.01% | 1.01% | 20 | 20 |
| EV Charging Infrastructure | 0.99% - 10.0% | 4.96%* | 5 - 20 | 14* |

*Based on investment based weighted average of EV Depreciation Rates

While current Tax legislation does not allow bonus depreciation tax deductibility for utility investment, at this time, any future changes to the book, or tax depreciation rates, such as, but not limited to, reinstatement of "bonus depreciation" during the construction period of the Program and at the time of each base rate adjustment, will be reflected in the accumulated depreciation and/or ADIT calculation described above. The "Net of Tax Depreciation and/or Amortization" allows for recovery of the Company's investment in the Program assets over the useful book life of each asset class. PSE&G proposes to depreciate IAP assets in accordance with the Company's BPU approved depreciation rates. The book recovery of each asset class will be based on their respective depreciation rates. For Plant in Service investment,

[2] "MACRS" = Modified Accelerated Cost Recovery System

the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. For CWIP projects that accrue AFUDC because they are not yet in service, there is no tax deduction for the equity portion of the capitalized AFUDC. As a result, the net of tax depreciation expense is calculated as the depreciation expense associated with the Gross Plant (defined above), excluding the equity portion of AFUDC, multiplied by one minus the current tax rate. Since the equity portion of AFUDC will not be included in the tax basis of the Program assets, the equity portion must be grossed-up for taxes in order for the Company to earn its allowed rate of return. Any future changes to the book depreciation or tax rates during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the net of tax depreciation expense calculation described above.

The term "Tax Adjustment" refers to any applicable tax items that may impact the revenue requirement calculation for the Program. For the electric portion of IAP, like that for ESI and ESII, the tax adjustment forecasted for the program at this time includes the flow through of cost of removal expenditures on pre-1981 assets. The tax expense for electric cost of removal expenditures associated with pre-1981 assets are currently flowed through to ratepayers over a five year amortization period rather than normalized over the life of the asset as is the tax treatment for post-1981 electric and all gas related cost of removal expenditures. The proposed tax flow-through methodology for pre-1981 electric cost of removal expenditures applied to IAP cost of removal expenditures on pre-1981 assets is consistent with the treatment of base rate assets. The Tax Adjustment for the IAP revenue requirement is calculated as the Cost of Removal expenditures multiplied by the percentage of electric pre-1981 asset retirements for the year and divided by five for the five-year amortization period.

For forecasting purposes, the percentage of electric assets with a vintage before 1981 is estimated at 8.54%, which is based on retirements through July 2021, and it is updated annually by the Company. Any future changes impacting the tax adjustment during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the tax adjustment described above.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes, the BPU and Rate Counsel (RC) Annual Assessments Fees and for Gas Revenue Uncollectibles, which is applicable only to the revenue requirements for the Gas portion of IAP. The tax rates reflect the current federal tax rate of 21%. The BPU/RC Assessment Expenses consist of payments, based upon a percentage of revenues collected (updated annually), to the State based on the electric and gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2021 fiscal year assessment. The percentage used to calculate the gas uncollectible expense is based upon the rate approved in the Company's last base rate case. Any change in the uncollectible rate in any future base rate case proceeding will be reflected in the any subsequent IAP rate adjustment proceeding calculation. Any future changes impacting the revenue factor during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the revenue factor described above.

**Q. Please describe the type of expenditures to be included in Rate Base?**

A. The Program will include requests for recovery in its IAP rates of all capital expenditures associated with IAP projects, including actual costs of engineering, design and construction, cost of removal (net of salvage) and property acquisition, including actual labor, materials, overhead, and capitalized AFUDC associated with the projects (the "Capital Investment Costs"). Capital Investment Costs will be recorded, during construction, in an associated CWIP account or in a Plant In-Service account upon the respective project being deemed used and useful.

**Q. Are there any items that may affect the tax impacts of the Program?**

A. It is standard practice that the tax impacts are subject to changes in tax law, changes in interpretation of existing law, issuance of authoritative guidance, etc. The Company wishes to make the BPU aware that the House Ways and Means Committee approved an infrastructure bill and Build Back Better Act (combined "proposal(s)"), if enacted as drafted the proposals would make certain changes to existing tax law. The tax provisions in the Proposals are subject to change and enactment of either is uncertain. The impact on the program cannot be determined at this time.

Additionally, various tax deductions are based on estimates. The estimates are updated to actuals in the subsequent program filing. Changes in estimates can be driven by a number of items such as the actual tax return deduction as compared to the estimated deduction (aka return to accrual), actual retirements and plant additions to name a few.

**Q. Will any of the IAP expenditures be eligible for AFUDC?**

A. Yes, but only for projects that meet the Company's criteria for accrual of AFUDC. AFUDC is a component of construction costs representing the net cost of borrowed funds and an equity return rate used during the period of construction. Under the Company's current policy, only projects that have both costs exceeding $5,000 and a construction period longer than 60 days are eligible for accruing AFUDC. Some of the investments under this Program are not anticipated to be eligible to accrue AFUDC because they will take less than 60 days to construct. However, most projects will require more than 60 days of construction and will therefore accrue AFUDC. In the event the Company's criteria for the accrual of AFUDC changes, the Company's criteria in place at that time the expenditures are incurred would then be applied.

**Q. How will AFUDC be calculated on eligible projects?**

A. The Company accrues AFUDC on eligible projects at a rate that is calculated utilizing the "full FERC method" as set forth in FERC Order 561. AFUDC is accrued monthly and added to CWIP until the project is placed into service[3].

**Q. Will the Company utilize AFUDC once the projects are placed into service?**

A. No. Consistent with the IIP regulations, the Company will not accrue any additional AFUDC on projects once they are placed into service.

**Q. What is the source of the capital expenditures you use to calculate the revenue requirements?**

A. The projected monthly cash flow for the Program projects was provided by Mr. Edward Gray for electric infrastructure and Mr. Wade Miller for gas infrastructure. See Schedules EFG-IAP-3 and WEM-IAP-3, respectively.

**Q. Is the Company planning capital expenditures similar to those included in IAP not to be recovered via IAP?**

A. Yes, the Company plans to make similar capital expenditures on projects of at least 10% of the approved IAP expenditures. These capital expenditures shall be made in the normal

[3] Construction Work in Progress (CWIP) is an account into which the costs are recorded that are directly associated with constructing an asset which is not yet in-service.

course of business and recovered in future base rate proceedings and shall not be subject to recovery via the IAP cost recovery mechanism.

**Q. Is there a schedule showing the calculation of the revenue requirements?**

A. Yes. See Schedule SS-IAP-2E for the calculation of the IAP electric revenue requirements for all forecasted electric rate adjustments based on the forecasted cash flow provided in Schedule EFG-IAP-3. See Schedule SS-IAP-2G for the calculation of the IAP gas revenue requirements for all forecasted gas rate adjustments based on the forecasted cash flow provided in Schedule WEM-IAP-3.

**Q. How does the Company propose to recover the revenue requirements as described above?**

A. The Company proposes to recover the revenue requirements associated with the Program via new IAP rate components of its Infrastructure Investment Program Charges ("IIPCs") for Electric and Gas Tariffs respectively. The Company plans to recover the revenue requirements through semi-annual rate adjustment filings, which is in compliance with the BPU's IIP regulations.

The schedule for the Initial Filing, Investment as Of, Update for Actuals Filing, and Rates Effective dates for all electric and electric rate adjustment filings, assuming Board approval of the Program by March 31, 2022, are listed below.

Each Initial Filing shall provide the actual cost and forecast for investment data, revenue requirement calculations, proposed IAP rates, and related data to support rates based on IAP capital costs, including engineering costs, commencing upon the Board's approval of the Program as indicted the schedule below.

The Update for Actuals Filing, updates all forecasted cost and investment data, revenue requirement calculations, proposed IAP rates, and related information from the Initial Filing to data based on all actual historical data. IAP investments included in rates in the Update for Actuals Filing shall only include IAP investment not in the Company's base rates and actually placed in-service according to the schedule below.

The Rates Effective dates for each filing below shall be as indicated below – the first day of the month following five months following the due date of the Initial Filing. Thus, the Initial filing due October 31, 2023 would result in rates effective April 1, 2024 subject to Board approval.

| IAP Rate Adjustment Schedule | | | | |
|---|---|---|---|---|
| Rate Adj# | Initial Filing | Investment as Of | Update for Actuals Filing | Rates Effective |
| 1 | 10/31/22 | 12/31/22 | 1/31/23 | 4/1/23 |
| 2 | 4/30/23 | 6/30/23 | 7/31/23 | 10/1/23 |
| 3 | 10/31/23 | 12/31/23 | 1/31/24 | 4/1/24 |
| 4 | 4/30/24 | 6/30/24 | 7/31/24 | 10/1/24 |
| 5 | 10/31/24 | 12/31/24 | 1/31/25 | 4/1/25 |
| 6 | 4/30/25 | 6/30/25 | 7/31/25 | 10/1/25 |
| 7 | 10/31/25 | 12/31/25 | 1/31/26 | 4/1/26 |
| 8 | TBD* | TBD + 2 mo | TBD + 3 mo | TBD + 5 mo + 1 Day |

The IIP regulations limit each electric and gas rate adjustment request to a minimum investment level of 10 percent of each respective electric and gas program. Therefore, actual rate adjustments filings may occur less frequently then reflected in the table above. Based upon the Company's estimated investment expenditures, the first rate adjustment filing is projected to occur on 10/31/2023.

Assuming Board approval by March 2022, the IAP is scheduled to be complete by June 30, 2026, except for certain close out work that may occur for up to 3 to 6 months following the conclusion of the Program. Without a firm date for completion of this close out work, the Company is proposing a rate filing no later than December 31, 2026 comprised of all actual cost data (as opposed to projected) for rates effective April 1, 2027. Given the nature of the close out work, the final roll-in may be less than 10% of the Program, but is appropriate to provide completion of the Program.

**Q. Is the Company proposing a minimum investment level to request a rate adjustment?**

A. Yes. Consistent with the IIP regulations, the Company proposes to limit each electric and gas base rate adjustment request to a minimum investment level of 10 percent of the total for each respective portion of the program investment, respectively, with the exception of end of the Program work as previously discussed. The program investment is defined as all capital expenditures as defined previously in my testimony excluding AFUDC.

**Q. Is there any other proposed limit that could impact the amount of investment to be included in a rate base adjustment?**

A. Yes, the Company is also proposing to limit the amount of investment to be included in the rate base adjustment by an earnings test. If the Company exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more for the most recent twelve (12) month period, the pending base rate adjustment shall not be allowed for the applicable filing period.

**Q. How does the Company propose to calculate this earnings test?**

A. Per IIP regulations, the earnings test shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.

**Q. What is the corresponding period for the earnings test?**

A. The Company will utilize the 12 month period corresponding to the latest available SEC quarterly/annual filing. In the same manner as capital expenditures, the Company will provide 9 months of actual data and 3 months of forecast data at the time of its initial filing. The 3 months of forecasted data will be updated with actual information at the same time the Company updates investment for actuals per the schedule above.

**Q. So how do you propose to calculate the starting and ending common equity balance for the earnings test?**

A. I'm proposing the Common Equity balance to be used in the Company's earnings test be calculated based on the starting and ending Net Plant balances multiplied by the ratio of Net Plant to Common Equity determined in the Company's most recently approved base rate case.

**Q. Is there precedence for this earnings test calculation methodology?**

A. Yes. This is the same methodology utilized in the Company's Board-approved ES II, GSMP II and Conservation Incentive Program (CIP).

**Q. Under this proposal, what opportunity will the BPU and/or Rate Counsel have to review the actual expenditures of the Program?**

A. Upon BPU approval of the Program, PSE&G will make semi-annual filings, pursuant with the IIP regulations, subject to the minimum investment level of 10 percent of the total program investment, with actual expenditures based on the schedule described above. BPU Staff and Rate Counsel can review each base rate adjustment filing to ensure the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the Program. The actual prudency of the Company's expenditures involved in implementing IAP will be reviewed as part of PSE&G's subsequent base rate case(s) following the base rate adjustment(s).

**Q. Does the Company plan to file a base rate case in connection to the proposed IAP?**

A. Yes. The IIP regulations require a base rate case filing no later than 5 years from the start of the Program[4]. As part of the ES II order, The Company is already mandated file an electric and gas base rate case no later than January 1, 2024. Therefore, the base case requirement in ES II satisfies the base case requirement for the proposed IAP.

**Q. What is the electric and gas revenue requirements for the initial rate adjustment?**

A. The electric and gas revenue requirement for the first rate adjustment is currently forecasted for plant in-service from Board approval through December 31, 2023, and is currently forecasted to be $10.5 million and $3.5 million respectively. See Schedule SS-IAP-2E. and Schedule SS-IAP-2G.

**Q. Does the Company plan to do additional engineering work once Board approval is received for IAP?**

A. Yes. While engineering work has been done on the IAP projects, the Company anticipates conducting more detailed engineering work as soon as Board approval is received and would include those costs in the base rate adjustments.

[4] See N.J.A.C § 14:3-2A.6(f) Infrastructure Investment Program expenditure recovery

**Q. What rate design is the Company proposing to use for this base rate adjustment?**

A. The detailed calculations supporting the electric and gas rate design for the first forecasted rate adjustment is shown in Schedule SS-IAP-4 and Schedule SS-IAP-5, respectively. The rate design for all of the estimated IAP rate adjustments would use the same methodology as approved by the Board in the latest approved base rate case. The Company reserves the right to request changes in rate design for the program. In addition, Schedule SS-IAP-6 and Schedule SS-IAP-7 provide a summary of the proposed IAP rates for all forecasted IAP revenue requirements for electric and gas, respectively. The weather normalized billing determinants approved in the 2018 Base Rate Case were used to estimate the change in base rates for this Program to reflect current usage.

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

A. Based upon the forecasted IAP rates shown in Schedule SS-IAP-4 and Schedule SS-IAP-5, the typical annual bill impacts for a typical residential customer as well as rate class average customers compared to rates as of November 1, 2021 are set forth in Schedule SS-IAP-8 and Schedule SS-IAP-9.[5] The initial annual impact is forecasted to be effective on April 1, 2024 for electric and gas customers. Based on the estimated IAP rates provided in Schedule SS-IAP-6, the initial annual impact of the proposed rates for the first base rate adjustment to the typical residential electric customer who uses 740 kWh in a summer month and 6,920 kWh annually is an increase of \$4.52 or approximately 0.34%. The forecasted **<u>cumulative</u>** impact (impact from the entire Program) on the typical residential electric customer is an increase of

[5]The bill impacts assume that customers receive commodity service from PSE&G under the applicable Basic Generation Service (BGS) or Basic Gas Supply Service (BGSS) rate.

approximately 2.08% on an average annual bill or about a $2.30 increase in their average monthly bill. Based on the estimated IAP rates provided in Schedule SS-IAP-7, the initial annual impact of the proposed IAP rates to the typical residential gas heating customer who uses 172 therms in a winter month and 1,040 therms annually is an increase of $1.96 or approximately 0.21%. The forecasted **cumulative** impact (impact from the entire Program) on the typical residential gas heating customer is an increase of approximately 1.25% on an average annual bill or about a $0.95 increase in their average monthly bill. The total impact for a combined typical electric and gas residential customer would average about 0.43%% per year over the four year period.

**Q. Will the Company hold public comment hearings?**

A. Although PSE&G is not proposing a rate increase at this time, the Company proposes public comment hearings similar to those held when rate increases are proposed. A proposed form of public notice of filing and public hearings, including the forecasted rates and bill impacts attributable to the proposed implementation of the Program are set forth in Attachment 7 to the Petition.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**ATTACHMENT 3**

## SCHEDULE INDEX

| | |
|---|---|
| Schedule SS-IAP-1 | Credentials of Stephen Swetz |
| Schedule SS-IAP-2E | Electric Revenue Requirements Calculation |
| Schedule SS-IAP-2G | Gas Revenue Requirements Calculation |
| Schedule SS-IAP-3 | Weighted Average Cost of Capital (WACC) |
| Schedule SS-IAP-4 | Electric Rate Design |
| Schedule SS-IAP-5 | Gas Rate Design |
| Schedule SS-IAP-6 | Electric Rate Summary |
| Schedule SS-IAP-7 | Gas Rate Summary |
| Schedule SS-IAP-8 | Electric Bill Impact Summary |
| Schedule SS-IAP-9 | Gas Bill Impact Summary |

## ELECTRONIC WORKPAPER INDEX

WP-SS-IAP-1E.xlsx

WP-SS-IAP-1G.xlsx

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

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

**<u>WORK EXPERIENCE</u>**

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

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

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

**<u>EDUCATIONAL BACKGROUND</u>**

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

LIST OF PRIOR TESTIMONIES

| Company | Utility | Docket | Testimony | Date | Case / Topic |
|---|---|---|---|---|---|
| Public Service Electric & Gas Company | E/G | ER21111209 and GR21111210 | written | Nov-21 | The Second Energy Strong Program (Energy Strong II) |
| Public Service Electric & Gas Company | E/G | ER21101201 and GR21101202 | written | Oct-21 | Tax Adjustment Clauses (TACs) |
| Public Service Electric & Gas Company | E/G | ER21070965 and GR21070966 | written | Jul-21 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | G | ER21060952 | written | Jun-21 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | G | GR21060949 | written | Jun-21 | Gas System Modernization Program II (GSMPII) - Fifth Roll-In |
| Public Service Electric & Gas Company | E | ER21060948 | written | Jun-21 | SPRC 2021 |
| PSEG New Haven LLC | PSEG New Haven LLC | 21-06-40 | written | Jun-21 | PSEG 2022 AFRR |
| Public Service Electric & Gas Company | G | GR21060882 | written | Jun-21 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER21050859 | written | May-21 | Community Solar Cost Recovery |
| Public Service Electric & Gas Company | G | GR20120771 | written | Dec-20 | Gas System Modernization Program II (GSMPII) - Forth Roll-In |
| Public Service Electric & Gas Company | E/G | GR20120763 | written | Dec-20 | Remediation Adjustment Charge-RAC 28 |
| Public Service Electric & Gas Company | E | ER20120736 | written | Nov-20 | The Second Energy Strong Program (Energy Strong II) |
| Public Service Electric & Gas Company | E/G | ER20100685 & GR20100686 | written | Oct-20 | Tax Adjustment Clauses (TACs) |
| Public Service Electric & Gas Company | E | ER20100658 | written | Oct-20 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER20060467 & GR20060468 | written | Jun-20 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | G | GR20060464 | written | Jun-20 | Gas System Modernization Program II (GSMPII) - Third Roll-In |
| Public Service Electric & Gas Company | E | ER20060454 | written | Jun-20 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR20060470 | written | Jun-20 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | G | GR20060384 | written | Jun-20 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER20040324 | written | Apr-20 | Transitional Renewable Energy Certificate Program (TREC) |
| Public Service Electric & Gas Company | E/G | GR20010073 | written | Jan-20 | Remediation Adjustment Charge-RAC 27 |
| Public Service Electric & Gas Company | G | GR19120002 | written | Dec-19 | Gas System Modernization Program II (GSMPII) - Second Roll-In |
| Public Service Electric & Gas Company | E/G | ER19091302 & GR19091303 | written | Aug-19 | Tax Adjustment Clauses (TACs) |
| Public Service Electric & Gas Company | E/G | ER19070850 | written | Jul-19 | Societal Benefits Charge (SBC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER19060764 & GR19060765 | written | Jun-19 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | G | GR19060766 | written | Jun-19 | Gas System Modernization Program II (GSMPII) - First Roll-In |
| Public Service Electric & Gas Company | G | GR19060761 | written | Jun-19 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E | ER19060741 | written | Jun-19 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | EO18060629 - GO18060630 | oral | Jun-19 | Energy Strong II / Revenue Requirements & Rate Design |
| Public Service Electric & Gas Company | G | GR19060698 | written | May-19 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER19040523 | written | May-19 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | EO18101113 - GO18101112 | oral | May-19 | Clean Energy Future - Energy Efficiency Program Approval |
| Public Service Electric & Gas Company | E | ER19040530 | written | Apr-19 | Madison 4kV Substation Project (Madison & Marshall) |
| Public Service Electric & Gas Company | E/G | EO18101113 - GO18101112 | written | Dec-18 | Clean Energy Future - Energy Efficiency Program Approval |
| Public Service Electric & Gas Company | E/G | GR18121258 | written | Nov-18 | Remediation Adjustment Charge-RAC 26 |
| Public Service Electric & Gas Company | E | EO18101115 | written | Oct-18 | Clean Energy Future - Energy Cloud Program (EC) |
| Public Service Electric & Gas Company | E | EO18101111 | written | Oct-18 | Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES) |
| Public Service Electric & Gas Company | G | GR18070831 | written | Jul-18 | Gas System Modernization Program (GSMP) - Third Roll-In |
| Public Service Electric & Gas Company | E/G | ER18070688 - GR18070689 | written | Jun-18 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER18060681 | written | Jun-18 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR18060675 | written | Jun-18 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E/G | EO18060629 - GO18060630 | written | Jun-18 | Energy Strong II / Revenue Requirements & Rate Design |
| Public Service Electric & Gas Company | G | GR18060605 | written | Jun-18 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER18040358 - GR18040359 | written | Mar-18 | Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in |
| Public Service Electric & Gas Company | E/G | ER18030231 | written | Mar-18 | Tax Cuts and Job Acts of 2017 |
| Public Service Electric & Gas Company | E/G | GR18020093 | written | Feb-18 | Remediation Adjustment Charge-RAC 25 |
| Public Service Electric & Gas Company | E/G | ER18010029 and GR18010030 | written | Jan-18 | Base Rate Proceeding / Cost of Service & Rate Design |
| Public Service Electric & Gas Company | E | ER17101027 | written | Sep-17 | Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in |
| Public Service Electric & Gas Company | G | GR17070776 | written | Jul-17 | Gas System Modernization Program II (GSMP II) |
| Public Service Electric & Gas Company | G | GR17070775 | written | Jul-17 | Gas System Modernization Program (GSMP) - Second Roll-In |
| Public Service Electric & Gas Company | G | GR17060720 | written | Jul-17 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER17070724 - GR17070725 | written | Jul-17 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER17070723 | written | Jul-17 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR17060593 | written | Jun-17 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER17030324 - GR17030325 | written | Mar-17 | Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in |
| Public Service Electric & Gas Company | E/G | EO14080897 | written | Mar-17 | Energy Efficiency 2017 Program |
| Public Service Electric & Gas Company | E/G | ER17020136 | written | Feb-17 | Societal Benefits Charge (SBC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | GR16111064 | written | Nov-16 | Remediation Adjustment Charge-RAC 24 |
| Public Service Electric & Gas Company | E | ER16090918 | written | Sep-16 | Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in |
| Public Service Electric & Gas Company | E | EO16080788 | written | Aug-16 | Construction of Mason St Substation |
| Public Service Electric & Gas Company | E | ER16080785 | written | Aug-16 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR16070711 | written | Jul-16 | Gas System Modernization Program (GSMP) - First Roll-In |
| Public Service Electric & Gas Company | G | GR16070617 | written | Jul-16 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER16070613 - GR16070614 | written | Jul-16 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER16070616 | written | Jul-16 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR16060484 | written | Jun-16 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E | EO16050412 | written | May-16 | Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design |
| Public Service Electric & Gas Company | E/G | ER16030272 - GR16030273 | written | Mar-16 | Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in |
| Public Service Electric & Gas Company | E/G | GR15111294 | written | Nov-15 | Remediation Adjustment Charge-RAC 23 |
| Public Service Electric & Gas Company | E | ER15101180 | written | Sep-15 | Energy Strong / Revenue Requirements & Rate Design - Third Roll-in |
| Public Service Electric & Gas Company | E/G | ER15070757-GR15070758 | written | Jul-15 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER15060754 | written | Jul-15 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR15060748 | written | Jul-15 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | G | GR15060646 | written | Jun-15 | Margin Adjustment Charge (MAC) / Cost Recovery |

LIST OF PRIOR TESTIMONIES

| Company | Utility | Docket | Testimony | Date | Case / Topic |
|---|---|---|---|---|---|
| Public Service Electric & Gas Company | E/G | ER15050558 | written | May-15 | Societal Benefits Charge (SBC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER15050558 | written | May-15 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER15030389-GR15030390 | written | Mar-15 | Energy Strong / Revenue Requirements & Rate Design - Second Roll-in |
| Public Service Electric & Gas Company | G | GR15030272 | written | Feb-15 | Gas System Modernization Program (GSMP) |
| Public Service Electric & Gas Company | E/G | GR14121411 | written | Dec-14 | Remediation Adjustment Charge-RAC 22 |
| Public Service Electric & Gas Company | E/G | ER14091074 | written | Sep-14 | Energy Strong / Revenue Requirements & Rate Design - First Roll-in |
| Public Service Electric & Gas Company | E/G | EO14080897 | written | Aug-14 | EEE Ext II |
| Public Service Electric & Gas Company | G | ER14070656 | written | Jul-14 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER14070651-GR14070652 | written | Jul-14 | Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER14070650 | written | Jul-14 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR14050511 | written | May-14 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | GR14040375 | written | Apr-14 | Remediation Adjustment Charge-RAC 21 |
| Public Service Electric & Gas Company | E/G | ER13070603-GR13070604 | written | Jun-13 | Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery |
| Public Service Electric & Gas Company | E | ER13070605 | written | Jul-13 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR13070615 | written | Jun-13 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | G | GR13060445 | written | May-13 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | EO13020155-GO13020156 | written/oral | Mar-13 | Energy Strong / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | G | GO12030188 | written/oral | Mar-13 | Appliance Service / Tariff Support |
| Public Service Electric & Gas Company | E | ER12070599 | written | Jul-12 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER12070606-GR12070605 | written | Jul-12 | RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery |
| Public Service Electric & Gas Company | E | EO12080721 | written/oral | Jul-12 | Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E | EO12080721 | written/oral | Jul-12 | Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | G | GR12060489 | written | Jun-12 | Margin Adjustment Charge (MAC) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR12060583 | written | Jun-12 | Weather Normalization Charge / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER12030207 | written | Mar-12 | Societal Benefits Charge (SBC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER12030207 | written | Mar-12 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | G | GR11060338 | written | Jun-11 | Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | G | GR11060395 | written | Jun-11 | Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E | EO11010030 | written | Jan-11 | Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E/G | ER10100737 | written | Oct-10 | RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery |
| Public Service Electric & Gas Company | E/G | ER10080550 | written | Aug-10 | Societal Benefits Charge (SBC) / Cost Recovery |
| Public Service Electric & Gas Company | E | ER10080550 | written | Aug-10 | Non-Utility Generation Charge (NGC) / Cost Recovery |
| Public Service Electric & Gas Company | E/G | GR09050422 | written/oral | Mar-10 | Base Rate Proceeding / Cost of Service & Rate Design |
| Public Service Electric & Gas Company | E | ER10030220 | written | Mar-10 | Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery |
| Public Service Electric & Gas Company | E | EO09030249 | written | Mar-09 | Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E/G | EO09010056 | written | Feb-09 | Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E | EO09020125 | written | Feb-09 | Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E | EO08080544 | written | Aug-08 | Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval |
| Public Service Electric & Gas Company | E/G | ER10100737 | written | Jun-08 | Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval |

**PSE&G Infrastructure Advancement Program** Schedule SS-IAP-2E
**Electric Revenue Requirments**
in ($000)

| Roll-in Filing | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 |
|---|---|---|---|---|---|
| Rate Effective Date | 4/1/2024 | 10/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| Plant In Service as of Date | 12/31/2023 | 6/30/2024 | 12/31/2024 | 12/31/2025 | 6/30/2026 |
| Rate Base Balance as of Date | 3/1/2024 | 9/1/2024 | 3/1/2025 | 3/1/2026 | 9/1/2026 |

**RATE BASE CALCULATION**

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 | Total | |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Plant | $89,940,140 | $53,261,206 | $55,973,551 | $318,517,142 | $40,535,603 | $558,227,642 | = ln 16 |
| 2 | Accumulated Depreciation | $6,939,039 | $7,476,406 | $7,681,445 | $14,369,518 | $3,886,545 | $40,352,954 | = ln 19 |
| 3 | Net Plant | $96,879,180 | $60,737,612 | $63,654,997 | $332,886,660 | $44,422,148 | $598,580,596 | = ln 1 + ln 2 |
| 4 | Accumulated Deferred Taxes | (3,970,879) | (2,573,752) | (3,212,399) | (9,030,132) | (1,412,841) | -$20,200,002 | = See "Dep-" Wkps Row 724 |
| 5 | Rate Base | $92,908,300 | $58,163,860 | $60,442,598 | $323,856,528 | $43,009,307 | $578,380,594 | = ln 3 + ln 4 |
| 6 | Rate of Return - After Tax (Schedule WACC) | 6.48% | 6.48% | 6.48% | 6.48% | 6.48% | 0.00% | See Schedule SS-IAP-3 |
| 7 | Return Requirement (After Tax) | $6,022,121 | $3,770,059 | $3,917,762 | $20,991,699 | $2,787,773 | $37,489,413 | = ln 5 * ln 6 |
| 8 | Depreciation Exp, net | $1,518,770 | $890,805 | $931,033 | $4,349,473 | $573,785 | $8,263,867 | = ln 25 |
| 9 | Tax Adjustment | -$31,149 | -$29,039 | -$29,880 | -$64,246 | -$15,540 | -$169,853 | N/A |
| 10 | Revenue Factor | 1.3948 | 1.3948 | 1.3948 | 1.3948 | 1.3948 | 1.3948 | |
| 11 | **Total Revenue Requirement** | **$10,474,588** | **$6,460,470** | **$6,721,424** | **$35,256,256** | **$4,667,026** | **$63,579,764** | = (ln 7 + ln 8 + ln 9) * ln 10 |

## SUPPORT

### Gross Plant

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 | Total | |
|---|---|---|---|---|---|---|---|---|
| 12 | Plant in-service | $81,735,352 | $49,130,766 | $51,758,556 | $92,875,535 | $37,844,967 | $313,345,176 | = See "Dep-" Wkps Row 702 |
| 13 | CWIP Transferred into Service | $7,992,000 | $3,996,000 | $3,996,000 | $207,551,941 | $2,664,000 | $226,199,941 | = See "Dep-" Wkps Row 703 |
| 14 | AFUDC on CWIP Transferred Into Service - Debt | $53,514 | $33,810 | $55,075 | $4,549,400 | $6,699 | $4,698,499 | = See "Dep-" Wkps Row 704 |
| 15 | AFUDC on CWIP Transferred Into Service - Equity | $159,273 | $100,629 | $163,920 | $13,540,266 | $19,938 | $13,984,026 | = See "Dep-" Wkps Row 705 |
| 16 | **Total Gross Plant** | **$89,940,140** | **$53,261,206** | **$55,973,551** | **$318,517,142** | **$40,535,603** | **$558,227,642** | = ln 12 + ln 13 + ln 14 + ln 15 |

### Accumulated Depreciation

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 | Total | |
|---|---|---|---|---|---|---|---|---|
| 17 | Accumulated Depreciation | -$1,746,882 | -$621,118 | -$650,630 | -$3,545,795 | -$446,826 | -$7,011,251 | = See "Dep-" Wkps Row 711 |
| 18 | Cost of Removal | $8,685,921 | $8,097,524 | $8,332,075 | $17,915,313 | $4,333,371 | $47,364,205 | = See "Dep-" Wkps Row 706 |
| 19 | **Net Accumulated Depreciation** | **$6,939,039** | **$7,476,406** | **$7,681,445** | $14,369,518 | $3,886,545 | **$40,352,954** | = ln 17 + ln 18 |

### Depreciation Expense (Net of Tax)

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 | Total | |
|---|---|---|---|---|---|---|---|---|
| 20 | Depreciable Plant (xAFUDC-E) | $89,780,867 | $53,160,576 | $55,809,632 | $304,976,876 | $40,515,666 | $544,243,616 | = ln 12 + ln 13 + ln 14 |
| 21 | AFUDC-E | 159,273 | 100,629 | 163,920 | 13,540,266 | 19,938 | $13,984,026 | = ln 15 |
| 22 | Depreciation Rates - Composite/Blended Rate | 2.35% | 2.33% | 2.31% | 1.90% | 1.97% | 10.86% | = ln 23 / ln 20 |
| 23 | Depreciation Expense | $2,112,630 | $1,239,122 | $1,295,081 | $6,050,179 | $798,143 | $11,495,155 | = See "Dep-" Wkps Row 706 |
| 24 | Tax @28.11% | $593,860 | $348,317 | $364,047 | $1,700,705 | $224,358 | $3,231,288.1 | = ln 20 * ln 22 * Tax Rate |
| 25 | Depreciation Expense (Net of Tax) | **$1,518,770** | **$890,805** | **$931,033** | **$4,349,473** | **$573,785** | **$8,263,867** | = ln 23 - ln 24 |

### Tax Adjustment

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Roll-in 7 | Total | |
|---|---|---|---|---|---|---|---|---|
| 26 | Cost of Removal* | $8,685,921 | $8,097,524 | $8,332,075 | $17,915,313 | $4,333,371 | $43,030,834 | = ln 18 |
| 27 | Estimated pre-1981 % | 9% | 9% | 9% | 9% | 9% | 9% | = See "Dep-UPCI" Wkp |
| 28 | Amortization Period | 5 | 5 | 5 | 5 | 5 | 5 | = See "Dep-UPCI" Wkp |
| 29 | Tax Amortization | $148,326.75 | $138,278.88 | $142,284.23 | $305,934.16 | $73,999.61 | $734,824 | = ln 26 * ln 27 / ln 28 |
| 30 | Federal Tax Rate | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | = See "WACC" Wkp |
| 31 | Tax Adjustment | $31,149 | $29,039 | $29,880 | $64,246 | $15,540 | $154,313 | = ln 29 * ln 30 |

* Does not apply to Gas assets that have a COR allowance instead of COR in depreciation rate

# PSE&G Infrastructure Advancement Program



## Gas Revenue Requirements

in ($000)

**Roll-in Filing**

| | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 |
|---|---|---|---|---|
| Rate Effective Date | 4/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| Plant In Service as of Date | 12/31/2023 | 12/31/2024 | 12/31/2025 | 6/30/2026 |
| Rate Base Balance as of Date | 3/1/2024 | 3/1/2025 | 3/1/2026 | 9/1/2026 |

**RATE BASE CALCULATION**

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Total | |
|---|---|---|---|---|---|---|---|
| 1 | Gross Plant | $27,548,132 | $99,548,141 | $43,506,285 | $6,128,882 | $176,731,441 | = ln 16 |
| 2 | Accumulated Depreciation | $199,564 | $306,778 | $76,499 | $56,673 | $639,515 | = ln 19 |
| 3 | Net Plant | $27,747,697 | $99,854,919 | $43,582,785 | $6,185,555 | $177,370,956 | = ln 1 + ln 2 |
| 4 | Accumulated Deferred Taxes | (901,797) | (2,054,447) | (915,573) | (92,559) | -$3,964,377 | = See "Dep-" Wkps Row 724 |
| 5 | Rate Base | $26,845,899 | $97,800,472 | $42,667,211 | $6,092,996 | $173,406,579 | = ln 3 + ln 4 |
| 6 | Rate of Return - After Tax (Schedule WACC) | 6.48% | 6.48% | 6.48% | 6.48% | 0.00% | See Schedule SS-IAP-3 |
| 7 | Return Requirement (After Tax) | $1,740,095 | $6,339,221 | $2,765,599 | $394,935 | $11,239,850 | = ln 5 * ln 6 |
| 8 | Depreciation Exp, net | $747,841 | $1,747,253 | $785,524 | $132,163 | $3,412,780 | = ln 25 |
| 9 | Tax Adjustment | $0 | $0 | $0 | $0 | $0 | N/A |
| 10 | Revenue Factor | 1.4175 | 1.4175 | 1.4175 | 1.4175 | 1.4175 | |
| 11 | **Total Revenue Requirement** | **$3,526,648** | **$11,462,576** | **$5,033,717** | **$747,161** | **$20,770,103** | = (ln 7 + ln 8 + ln 9) * ln 10 |

## SUPPORT

### Gross Plant

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Total | |
|---|---|---|---|---|---|---|---|
| 12 | Plant in-service | $18,030,484 | $25,725,246 | $12,507,837 | $6,128,882 | $62,392,449 | = See "Dep-" Wkps Row 702 |
| 13 | CWIP Transferred into Service | $9,290,306 | $71,868,615 | $30,111,222 | $0 | $111,270,143 | = See "Dep-" Wkps Row 703 |
| 14 | AFUDC on CWIP Transferred Into Service - Debt | $57,175 | $491,485 | $223,130 | $0 | $771,790 | = See "Dep-" Wkps Row 704 |
| 15 | AFUDC on CWIP Transferred Into Service - Equity | $170,168 | $1,462,794 | $664,096 | $0 | $2,297,059 | = See "Dep-" Wkps Row 705 |
| 16 | **Total Gross Plant** | **$27,548,132** | **$99,548,141** | **$43,506,285** | **$6,128,882** | **$176,731,441** | = ln 12 + ln 13 + ln 14 + ln 15 |

### Accumulated Depreciation

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Total | |
|---|---|---|---|---|---|---|---|
| 17 | Accumulated Depreciation | -$700,445 | -$1,112,456 | -$565,218 | -$93,487 | -$2,471,606 | = See "Dep-" Wkps Row 711 |
| 18 | Cost of Removal | $900,009 | $1,419,235 | $641,717 | $150,160 | $3,111,122 | = See "Dep-" Wkps Row 706 |
| 19 | **Net Accumulated Depreciation** | **$199,564** | **$306,778** | **$76,499** | $56,673 | **$639,515** | = ln 17 + ln 18 |

### Depreciation Expense (Net of Tax)

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Total | |
|---|---|---|---|---|---|---|---|
| 20 | Depreciable Plant (xAFUDC-E) | $27,377,964 | $98,085,347 | $42,842,189 | $6,128,882 | $174,434,382 | = ln 12 + ln 13 + ln 14 |
| 21 | AFUDC-E | 170,168 | 1,462,794 | 664,096 | - | $2,297,059 | = ln 15 |
| 22 | Depreciation Rates - Composite/Blended Rate | 3.78% | 2.44% | 2.51% | 3.00% | 11.73% | = ln 23 / ln 20 |
| 23 | Depreciation Expense | $1,040,257 | $2,430,453 | $1,092,675 | $183,840 | $4,747,225 | = See "Dep-" Wkps Row 706 |
| 24 | Tax @28.11% | $292,416 | $683,200 | $307,151 | $51,677 | $1,334,445.1 | = ln 20 * ln 22 * Tax Rate |
| 25 | Depreciation Expense (Net of Tax) | **$747,841** | **$1,747,253** | **$785,524** | **$132,163** | **$3,412,780** | = ln 23 - ln 24 |

### Tax Adjustment

| | | Roll-in 3 | Roll-in 4 | Roll-in 5 | Roll-in 6 | Total | |
|---|---|---|---|---|---|---|---|
| 26 | Cost of Removal* | $900,009 | $1,419,235 | $641,717 | $150,160 | $3,111,122 | = ln 18 |
| 27 | Estimated pre-1981 % | 0% | 0% | 0% | 0% | 0% | = See "Dep-UPCI" Wkp |
| 28 | Amortization Period | 5 | 5 | 5 | 5 | 5 | = See "Dep-UPCI" Wkp |
| 29 | Tax Amortization | $0.00 | $0.00 | $0.00 | $0.00 | $0 | = ln 26 * ln 27 / ln 28 |
| 30 | Federal Tax Rate | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | = See "WACC" Wkp |
| 31 | Tax Adjustment | $0 | $0 | $0 | $0 | $0 | = ln 29 * ln 30 |

* Does not apply to Gas assets that have a COR allowance instead of COR in depreciation rate

**PSE&G Infrastructure Advancement Program**
**Weighted Average Cost of Capital (WACC)**

Schedule SS-IAP-3

| | Percent | Embedded Cost | Weighted Cost | Pre-Tax Weighted Cost | After Tax Weighted Cost |
|---|---|---|---|---|---|
| Common Equity | 54.00% | 9.60% | 5.18% | 7.21% | 5.18% |
| Customer Deposits | 0.47% | 0.87% | 0.00% | 0.00% | 0.00% |
| Other Capital | 45.53% | 3.96% | 1.80% | 1.80% | 1.30% |
| Total | 100.00% | | 6.99% | 9.02% | 6.48% |

| | |
|---|---|
| Federal Income Tax | 21.00% |
| State NJ Business Incm Tax | 9.00% |
| Tax Rate | 28.11% |

## Electric Revenue Requirement Allocation Explanation of Format

Pages 2 through 5 presented in Schedule SS-IAP-4 are the four relevant pages from the complete cost of service and revenue requirement allocation methodology based on the 2018 Base Rate Case Settlement, approved by the Board on October 29, 2018. Page 2 Part 1 shows the “Final” revenue requirement allocation to each rates class and its associated functions as defined in the 2018 PSE&G Base Rate Case (Rate Case). Part 2 allocates the Infrastructure Advancement Program Revenue Increase in accordance with the Rate Case Board Order. Pages 3 and 4 provide the interclass revenue allocations based upon the rate rules approved in the Rate Case. Page 5 provides the service charge calculations for each rate class by which are calculated in accordance with the Rate Case Board Order.

## Electric Rate Design Explanation of Format

The summary provides by rate schedule, the Annualized Weather Normalized (all customers assumed to be on BGS) revenue based on current tariff rates and the proposed rate change.

The pages presented in Schedule SS-IAP-4 are the selected applicable columns of the relevant pages from the complete rate change workpapers from the Company’s 2018 Electric Base Rate Case and have been appropriately modified per my testimony to reflect the Infrastructure Advancement Program Initial Rate Adjustment.

## Annualized Weather Normalized (all customers assumed to be on BGS) and the Proposed Detailed Rate Design.

In the detailed rate design pages, all the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charge, Green Programs Recovery Charge, Tax Adjustment Credit, Miscellaneous items, and Unbilled Revenue.

Column (1) shows the annualized weather normalized billing units. Column (2) shows present Delivery rates (without Sales and Use Tax, SUT) effective October 1, 2021.

The Supply-BGS rates in the Column (2) reflect the rates in effect as of June 1, 2021 and for CIEP energy, reflect the class average hourly rates from July 1, 2020 to June 30, 2021. Column (3) presents annualized revenue assuming all customers are provided service under their applicable BGS provision. Column (4) repeats the billing units of Column (1). Column (5) shows the proposed rates without SUT that result in the proposed revenues shown in Column (6). Columns (7) and (8) show the proposed base rate revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

**Cost of Service and Rate Design Sync**

**Step 1: Initial Sync**

| line # | (1) Rate Schedule | (2) Streetlighting | (3) Access | (4) Local Delivery | (5) System Delivery | (6) Customer Service | (7) Measurement | (8) Total |
|---|---|---|---|---|---|---|---|---|
| 1 | RS | $ - | $ 31,883,843.32 | $ 323,259,297 | $ 196,397,486 | $ 88,062,886 | $ 63,782,402 | $ 703,385,915 |
| 2 | RHS | $ - | $ 247,509.64 | $ 3,206,927 | $ 917,179 | $ 512,204 | $ 335,069 | $ 5,218,889 |
| 3 | RLM | $ - | $ 325,933.79 | $ 4,287,442 | $ 3,373,454 | $ 592,245 | $ 447,425 | $ 9,026,499 |
| 4 | WH | $ - | $ 2,088.26 | $ 2,632 | $ - | $ 46,207 | $ 83,817 | $ 134,745 |
| 5 | WHS | $ - | $ 29.99 | $ 24 | $ - | $ 599 | $ 1,199 | $ 1,852 |
| 6 | HS | $ - | $ - | $ 406,414 | $ 203,930 | $ 42,894 | $ 28,324 | $ 681,562 |
| 7 | BPL | $ 43,197,026 | $ - | $ 2,255,948 | $ - | $ 164,743 | $ - | $ 45,617,717 |
| 8 | BPL-POF | $ 277,921 | $ - | $ 104,947 | $ - | $ 3,734 | $ - | $ 386,601 |
| 9 | PSAL | $ 13,992,547 | $ - | $ 1,078,327 | $ - | $ 863,023 | $ - | $ 15,933,896 |
| 10 | GLP | $ - | $ 16,043,581.09 | $ 104,679,788 | $ 95,813,438 | $ 15,957,512 | $ 12,567,316 | $ 245,061,635 |
| 11 | LPL-S | $ - | $ 1,087,951.24 | $ 91,704,794 | $ 100,522,764 | $ 3,345,120 | $ 13,261,282 | $ 209,921,911 |
| 12 | LPL-P | $ - | $ 96,111.08 | $ 14,632,266 | $ 24,934,124 | $ 296,271 | $ 1,425,940 | $ 41,384,713 |
| 13 | HTS-S | $ - | $ 56,886.71 | $ 19,648,753 | $ 13,820,570 | $ 76,587 | $ 811,434 | $ 34,414,231 |
| 14 | HTS-HV | $ - | $ 47,606.29 | $ 37,257 | $ - | $ 5,882 | $ 72,631 | $ 163,377 |
| 15 | Total | $ 57,467,494 | $ 49,791,541 | $ 565,304,816 | $ 435,982,944 | $ 109,969,906 | $ 92,816,841 | $ 1,311,333,542 |
| Notes: | | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | 2018 Rate Case Schedule SS-E8 R-2, page 2, lines 1-15 | Sum (Col 2 - Col 7) |

**Step 2: IAP Sync**

| line | | | |
|---|---|---|---|
| 16 | Total Rev Req Increase to be Recovered Through Rates | $ 10,474,588 | Schedule SS-IAP-2E |
| 17 | Total Target Distribution Revenue Requirements | $ 1,231,689,469 | = Line 16 + page 4, Col 3, Line 21 |
| 18 | Rate Case Minus Streetlight Fixtures | $ 1,253,866,048 | = col 8, line 15 - col 2, line 15 |
| 19 | Target Minus Streetlight Fixtures | $ 1,174,221,975 | = line 17 - col 2, line 15 |
| 20 | Final Sync Adjustment Factor | 0.93648 | = line 19 / line 18 |

| line | Rate Schedule | Streetlighting | Access | Local Delivery | System Delivery | Cust Svs | Measurement | Total |
|---|---|---|---|---|---|---|---|---|
| 21 | RS | $ - | $ 29,858,620 | $ 302,726,253 | $ 183,922,552 | $ 82,469,236 | $ 59,731,020 | $ 658,707,681 |
| 22 | RHS | $ - | $ 231,788 | $ 3,003,227 | $ 858,921 | $ 479,669 | $ 313,786 | $ 4,887,392 |
| 23 | RLM | $ - | $ 305,231 | $ 4,015,109 | $ 3,159,176 | $ 554,626 | $ 419,005 | $ 8,453,147 |
| 24 | WH | $ - | $ 1,956 | $ 2,465 | $ - | $ 43,272 | $ 78,493 | $ 126,186 |
| 25 | WHS | $ - | $ 28 | $ 23 | $ - | $ 561 | $ 1,122 | $ 1,734 |
| 26 | HS | $ - | $ - | $ 380,599 | $ 190,976 | $ 40,170 | $ 26,525 | $ 638,270 |
| 27 | BPL | $ 43,197,026 | $ - | $ 2,112,653 | $ - | $ 154,279 | $ - | $ 45,463,958 |
| 28 | BPL-POF | $ 277,921 | $ - | $ 98,280 | $ - | $ 3,496 | $ - | $ 379,698 |
| 29 | PSAL | $ 13,992,547 | $ - | $ 1,009,833 | $ - | $ 808,205 | $ - | $ 15,810,584 |
| 30 | GLP | $ - | $ 15,024,512 | $ 98,030,653 | $ 89,727,483 | $ 14,943,910 | $ 11,769,055 | $ 229,495,613 |
| 31 | LPL-S | $ - | $ 1,018,846 | $ 85,879,815 | $ 94,137,678 | $ 3,132,642 | $ 12,418,941 | $ 196,587,922 |
| 32 | LPL-P | $ - | $ 90,006 | $ 13,702,842 | $ 23,350,338 | $ 277,453 | $ 1,335,366 | $ 38,756,005 |
| 33 | HTS-S | $ - | $ 53,273 | $ 18,400,688 | $ 12,942,704 | $ 71,722 | $ 759,893 | $ 32,228,280 |
| 34 | HTS-HV | $ - | $ 44,582 | $ 34,891 | $ - | $ 5,508 | $ 68,018 | $ 152,999 |
| 35 | Total | $ 57,467,494 | $ 46,628,842 | $ 529,397,329 | $ 408,289,828 | $ 102,984,749 | $ 86,921,226 | $ 1,231,689,469 |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| Notes: | | Step 1 Rev Req * Line 20 | Step 1 Rev Req * Line 20 | Step 1 Rev Req * Line 20 | Step 1 Rev Req * Line 20 | Step 1 Rev Req * Line 20 | Step 1 Rev Req * Line 20 | Sum (Col 2 - Col 7) |

**Inter Class Revenue Increase Allocations**

Calculation of Increase Limits

| line # | | (in $1,000) | | Notes: |
|---|---|---|---|---|
| 1 | Requested Revenue Increase to be recovered from rate schedule charges = | $ 10,475 | | Schedule SS-IAP-2E |
| 2 | Present Distribution Revenue = | $ 1,221,215 | | Page 4, col 3, line 21 |
| 3 | Present Total Customer Bills (all on BGS) = | $ 5,859,725 | | Page 4, col 5, line 21 |
| 4 | Average Distribution Increase = | 0.858% | | = Line 1 / Line 2 |
| 5 | Average Total Bill Increase = | 0.179% | | = Line 1 / Line 3 |
| 6 | Lower Distribution increase limit = | 0.429% | in Distribution charges | = 0.5 * Line 4 |
| 7 | Upper Distribution increase limit #1 = | 1.502% | in Distribution charges | = 1.75 * Line 4 |
| 8 | Upper Bill increase limit #2 = | 0.358% | in Bill Increase | = 2.0 * Line 5 |

all rounded to 0.001%

**Inter Class Revenue Increase Calculations**

Calculation of Increases

| line # | (1) Rate Schedule | (2) Proposed Distribution Revenue Requirement (from COS) (in $1,000) | (3) Present Distribution Revenue (in $1,000) | (4) Unlimited COS Distribution Charge $ Increase (in $1,000) | (5) Present Total Bill Revenue (all on BGS) (in $1,000) | (6) Unlimited Distribution Charge Increase (%) | (7) Limited Final Distribution Charge Increase (%) | (8) Proposed Total Bill Increase (%) | (9) Proposed Distribution Revenue Increase (in $1,000) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | RS | $ 658,708 | $ 572,806 | $ 85,902 | $ 2,314,644 | 14.997% | 1.361% | 0.337% | $ 7,796 |
| 2 | RHS | $ 4,887 | $ 4,223 | $ 664 | $ 17,160 | 15.733% | 1.428% | 0.350% | $ 60 |
| 3 | RLM | $ 8,453 | $ 7,483 | $ 970 | $ 37,839 | 12.965% | 1.177% | 0.233% | $ 88 |
| 4 | WH * | $ 126.186 | $ 51.002 | $ 75.184 | $ 119.922 | 147.414% | 0.841% | 0.358% | $ 0.429 |
| 5 | WHS * | $ 1.734 | $ 0.153 | $ 1.581 | $ 1.176 | 1033.275% | 1.502% | 0.170% | $ 0.002 |
| 6 | HS | $ 638 | $ 730 | $ (92) | $ 2,786 | -12.566% | 0.429% | 0.108% | $ 3 |
| 7 | BPL | $ 45,464 | $ 56,032 | | $ 73,457 | | | | |
| 8 | Distribution Only | $ 2,267 | $ 1,916 | $ 351 | | 18.316% | 0.468% | 0.012% | $ 9 |
| 9 | Luminaires and Poles | $ 43,197 | $ 54,116 | $ (10,919) | | 0.000% | 0.000% | 0.000% | $ - |
| 10 | BPL-POF * | $ 379.698 | $ 320.726 | | $ 1,189.032 | | | | |
| 11 | Distribution Only | $ 101.777 | $ 97.726 | $ 4.051 | | 4.145% | 0.429% | 0.035% | $ 0.419 |
| 12 | Luminaires and Poles | $ 277.921 | $ 223.000 | $ 54.921 | | 0.000% | 0.000% | 0.000% | $ - |
| 13 | PSAL | $ 15,811 | $ 27,800 | | $ 37,314 | | | | |
| 14 | Distribution Only | $ 1,818 | $ 1,093 | $ 725 | | 66.335% | 0.478% | 0.013% | $ 5 |
| 15 | Luminaires and Poles | $ 13,993 | $ 26,707 | $ (12,714) | | 0.000% | 0.000% | 0.000% | $ - |
| 16 | GLP | $ 229,496 | $ 261,080 | $ (31,584) | $ 1,222,463 | -12.098% | 0.429% | 0.092% | $ 1,120 |
| 17 | LPL-S | $ 196,588 | $ 220,698 | $ (24,110) | $ 1,359,157 | -10.924% | 0.429% | 0.070% | $ 947 |
| 18 | LPL-P | $ 38,756 | $ 38,444 | $ 312 | $ 339,372 | 0.812% | 0.429% | 0.049% | $ 165 |
| 19 | HTS-S | $ 32,228 | $ 29,244 | $ 2,984 | $ 421,553 | 10.205% | 0.926% | 0.064% | $ 271 |
| 20 | HTS-HV | $ 153 | $ 2,303 | $ (2,150) | $ 32,670 | -93.357% | 0.429% | 0.031% | $ 10 |
| 21 | Total | $ 1,231,689 | $ 1,221,215 | $ 10,475 | $ 5,859,725 | 0.858% | 0.858% | 0.179% | $ 10,475 |
| | * WH, WHS and & BPL-POF shown to 3 decimal points | | | | | | | | |
| Notes: | | Page 2, Step 2, col 8 | | = (2) - (3) | Page 6 | = (4) / (3) | calculated on limits | = (9) / (5) | = (3) * (7) |

**Service Charge Calculations**

Service charges are comprised of revenue requirements for the Distribution Access and Measurement segments related to Minimum Size Facilities, plus the Revenue Requirements for the Customer Service segment.

| line # | (1) Rate Schedule | (2) Access Segment Revenue Requirement | (3) Measurement Segment Revenue Requirement | (4) Customer Service Segment Revenue Requirements | (5) Rev Req to be recovered through Service Charge | (6) # of Customers | (7) Cost Based Monthly Service Charge ($/month) | (8) Current Monthly Service Charge ($/month) | (9) Proposed Limited Monthly Service Charge ($/month) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Average Distribution Increase = | 0.858% | page 3, Line 4 | | | | | | | |
| 2 | RS | $ 29,858,620 | $ 59,731,020 | $ 82,469,236 | $ 172,058,876 | 1,868,649 | $ 7.67 | $ 4.64 | $ 4.64 | see Note 1 |
| 3 | RHS | $ 231,788 | $ 313,786 | $ 479,669 | $ 1,025,244 | 9,233 | $ 9.25 | $ 4.64 | $ 4.64 | see Note 1 |
| 4 | RLM | $ 305,231 | $ 419,005 | $ 554,626 | $ 1,278,862 | 12,158 | $ 8.77 | $ 13.07 | $ 13.07 | see Note 2 |
| 5 | WH | no service charge | | | | | | | | |
| 6 | WHS | $ 28 | $ 1,122 | $ 561 | $ 1,711 | 18 | $ 7.95 | $ 0.60 | $ 0.61 | see Note 2 |
| 7 | HS | $ - | $ 26,525 | $ 40,170 | $ 66,695 | 1,091 | $ 5.09 | $ 3.57 | $ 3.62 | see Note 2 |
| 8 | BPL | no service charge | | | | | | | | |
| 9 | BPL-POF | no service charge | | | | | | | | |
| 10 | PSAL | no service charge | | | | | | | | |
| 11 | GLP | $ 15,024,512 | $ 1,335,366 | $ 14,943,910 | | 261,946 | | | | |
| 12 | GLP Metered | | | | | 256,116 | $ 9.97 | $ 4.54 | $ 4.60 | see Note 3 |
| 13 | GLP Unmetered | | | | | 5,766 | $ 9.53 | $ 2.10 | $ 2.13 | see Note 4 |
| 14 | GLP-NU | | | | | 64 | | | $ 347.77 | set equal to LPL-S |
| 15 | LPL-S | $ 1,018,846 | $ 12,418,941 | $ 3,132,642 | $ 16,570,429 | 8,645 | $ 159.73 | $ 347.77 | $ 347.77 | see Note 2 |
| 16 | LPL-P | $ 90,006 | $ 1,335,366 | $ 277,453 | $ 1,702,825 | 754 | $ 188.26 | $ 347.77 | $ 347.77 | see Note 2 |
| 17 | LPL-P <100 kW | | | | | | $ 157.17 | $ 20.52 | $ 20.78 | see Note 5 |
| 18 | HTS-S | $ 53,273 | $ 759,893 | $ 71,722 | $ 884,889 | 193 | $ 381.56 | $ 1,911.39 | $ 1,911.39 | see Note 2 |
| 19 | HTS-HV | $ 44,582 | $ 68,018 | $ 5,508 | $ 118,109 | 14 | $ 711.90 | $ 1,720.25 | $ 1,720.25 | see Note 2 |
| Source: | | for Cols 2, 3 and 4 from Page 2, Cols 3, 6 & 7 from Step 2 | | | = (2) + (3) + (4) | 2018 Rate Case SS-E8 R-2, Step 2, Col 1 | = (5) / (6) / 12 | From Tariff | based on methodology described | |

Notes:
1 Agreed upon in Settlement
2 Move toward cost limited at no decrease from current service charge and no increase greater than 1.5 times the overall average distribution % increase.
3 Access and Customer Service Rev Req per total GLP Customer plus Measurement Rev Req divided by the number of metered customers divided by 12; limits the same as Note 2
4 Access and Customer Service Rev Req per total GLP Customer divided by 12; limits the same as Note 2
5 Calculated at the GLP Access Segment per customer plus the GLP Customer Service Segment Revenue Requirements per customer plus the LPL-P Measurement Segment per customer divided by 12; limits the same as Note 2

# ELECTRIC PROOF OF REVENUE
## SUMMARY
## ELECTRIC RATE INCREASE
## Schedule SS-IAP-4
(kWhrs & Revenue in Thousands)

| Rate Schedule | | Annualized Weather Normalized | | Proposed | | Increase | |
|---|---|---|---|---|---|---|---|
| | | kWhrs | Revenue | kWhrs | Revenue | Revenue | Percent |
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| Residential | RS | 12,934,045 | $2,314,644 | 12,934,045 | $2,322,440 | $7,796 | 0.34 |
| Residential Heating | RHS | 126,581 | 17,160 | 126,581 | 17,220 | 60 | 0.35 |
| Residential Load Management | RLM | 211,824 | 37,839 | 211,824 | 37,927 | 88 | 0.23 |
| Water Heating | WH | 1,086 | 119.922 | 1,086 | 120.351 | 0.429 | 0.36 |
| Water Heating Storage | WHS | 16 | 1.176 | 16 | 1.178 | 0.002 | 0.17 |
| | | | | | | | |
| Building Heating | HS | 16,145 | 2,786 | 16,145 | 2,789 | 3 | 0.11 |
| General Lighting and Power | GLP | 7,764,699 | 1,222,463 | 7,764,699 | 1,223,583 | 1,120 | 0.09 |
| Large Power & Lighting-Sec | LPL-S | 11,276,802 | 1,359,157 | 11,276,802 | 1,360,104 | 947 | 0.07 |
| Large Power & Lighting-Pri | LPL-P | 3,235,414 | 339,372 | 3,235,414 | 339,537 | 165 | 0.05 |
| High Tension-Subtr. | HTS-S | 4,566,472 | 421,553 | 4,566,472 | 421,824 | 271 | 0.06 |
| High Tension-HV | HTS-HV | 417,997 | 32,670 | 417,997 | 32,680 | 10 | 0.03 |
| | | | | | | | |
| Body Politic Lighting | BPL | 282,858 | 73,457 | 282,858 | 73,466 | 9 | 0.01 |
| Body Politic Lighting-POF | BPL-POF | 14,450 | 1,189.032 | 14,450 | 1,189.451 | 0.419 | 0.04 |
| Private Street & Area Lighting | PSAL | 151,732 | 37,314 | 151,732 | 37,319 | 5 | 0.01 |
| | | | | | | | |
| Totals | | 41,000,121 | $5,859,725 | 41,000,121 | $5,870,200 | $10,475 | 0.18 |

Notes: All customers assumed to be on BGS.
WH, WHS & BPL-POF revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021

**RATE SCHEDULE RS**
**RESIDENTIAL SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 22,423.79 | $4.64 | $104,046 | 22,423.79 | $4.64 | $104,046 | $0 | 0.00 |
| 2 | Distribution 0-600 June - September | 3,528,124 | 0.039972 | 141,026 | 3,528,124 | 0.041414 | 146,114 | 5,088 | 3.61 |
| 3 | Distribution 0-600 October - May | 5,657,900 | 0.033344 | 188,657 | 5,657,900 | 0.033344 | 188,657 | 0 | 0.00 |
| 4 | Distribution over 600 June - September | 1,931,618 | 0.043793 | 84,591 | 1,931,618 | 0.045235 | 87,377 | 2,786 | 3.29 |
| 5 | Distribution over 600 October - May | 1,816,403 | 0.033344 | 60,566 | 1,816,403 | 0.033344 | 60,566 | 0 | 0.00 |
| 6 | SBC | 12,934,045 | 0.009023 | 116,704 | 12,934,045 | 0.009023 | 116,704 | 0 | 0.00 |
| 7 | NGC | 12,934,045 | 0.000024 | 310 | 12,934,045 | 0.000024 | 310 | 0 | 0.00 |
| 8 | STC-TBC | 12,934,045 | 0.000000 | - | 12,934,045 | 0.000000 | 0 | 0 | 0.00 |
| 9 | STC-MTC-Tax | 12,934,045 | 0.000000 | - | 12,934,045 | 0.000000 | 0 | 0 | 0.00 |
| 10 | ZECRC | 12,934,045 | 0.003845 | 49,731 | 12,934,045 | 0.003845 | 49,731 | 0 | 0.00 |
| 11 | Solar Pilot Recovery Charge | 12,934,045 | 0.000085 | 1,099 | 12,934,045 | 0.000085 | 1,099 | 0 | 0.00 |
| 12 | Green Programs Recovery Charge | 12,934,045 | 0.002195 | 28,390 | 12,934,045 | 0.002195 | 28,390 | 0 | 0.00 |
| 13 | Tax Adjustment Credit | 12,934,045 | (0.007087) | (91,664) | 12,934,045 | (0.007087) | (91,664) | 0 | 0.00 |
| 14 | Green Enabling Mechanism | 12,934,045 | 0.000000 | - | 12,934,045 | 0.000000 | 0 | 0 | 0.00 |
| 15 | Facilities Chg. | | | - | | | 0 | 0 | 0.00 |
| 16 | Minimum | | | - | | | 0 | 0 | 0.00 |
| 17 | Miscellaneous | | | (240) | | | (239) | 1 | (0.42) |
| 18 | Delivery Subtotal | 12,934,045 | | $683,216 | 12,934,045 | | $691,091 | $7,875 | 1.15 |
| 19 | Unbilled Delivery | | | (6,896) | | | (6,975) | (79) | 1.15 |
| 20 | Delivery Subtotal w unbilled | | | $676,320 | | | $684,116 | $7,796 | 1.15 |
| 21 | | | | | | | | | |
| 22 | **Supply-BGS** | | | | | | | | |
| 23 | BGS 0-600 June - September | 3,528,124 | 0.124715 | $440,010 | 3,528,124 | 0.124715 | $440,010 | $0 | 0.00 |
| 24 | BGS 0-600 October - May | 5,657,900 | 0.127149 | 719,396 | 5,657,900 | 0.127149 | 719,396 | 0 | 0.00 |
| 25 | BGS over 600 June - September | 1,931,618 | 0.133796 | 258,443 | 1,931,618 | 0.133796 | 258,443 | 0 | 0.00 |
| 26 | BGS over 600 October - May | 1,816,403 | 0.127149 | 230,954 | 1,816,403 | 0.127149 | 230,954 | 0 | 0.00 |
| 27 | BGS Reconciliation-RSCP | 12,934,045 | 0.000000 | 0 | 12,934,045 | 0.000000 | 0 | 0 | 0.00 |
| 28 | Miscellaneous | | | (1) | | | (1) | 0 | 0.00 |
| 29 | Supply Subtotal | 12,934,045 | | $1,648,802 | 12,934,045 | | $1,648,802 | $0 | 0.00 |
| 30 | Unbilled Supply | | | (10,478) | | | (10,478) | 0 | 0.00 |
| 31 | Supply Subtotal w unbilled | | | $1,638,324 | | | $1,638,324 | $0 | 0.00 |
| 32 | | | | | | | | | |
| 33 | Total Delivery + Supply | 12,934,045 | | $2,314,644 | 12,934,045 | | $2,322,440 | $7,796 | 0.34 |
| 34 | | | | | | | | | |
| 35 | | | | | | | | | |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE RHS**
**RESIDENTIAL HEATING SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 110.79 | $4.64 | $514 | 110.79 | $4.64 | $514 | $0 | 0.00 |
| 2 | Distribution 0-600 June - September | 19,973 | 0.049594 | 991 | 19,973 | 0.050404 | 1,007 | 16 | 1.61 |
| 3 | Distribution 0-600 October - May | 41,979 | 0.033234 | 1,395 | 41,979 | 0.033613 | 1,411 | 16 | 1.15 |
| 4 | Distribution over 600 June - September | 10,227 | 0.054494 | 557 | 10,227 | 0.055304 | 566 | 9 | 1.62 |
| 5 | Distribution over 600 October - May | 54,402 | 0.015634 | 851 | 54,402 | 0.016013 | 871 | 20 | 2.35 |
| 6 | SBC | 126,581 | 0.009023 | 1,142 | 126,581 | 0.009023 | 1,142 | 0 | 0.00 |
| 7 | NGC | 126,581 | 0.000024 | 3 | 126,581 | 0.000024 | 3 | 0 | 0.00 |
| 8 | STC-TBC | 126,581 | 0.000000 | - | 126,581 | 0.000000 | 0 | 0 | 0.00 |
| 9 | STC-MTC-Tax | 126,581 | 0.000000 | - | 126,581 | 0.000000 | 0 | 0 | 0.00 |
| 10 | Zero Emission Certificate Recovery Charge | 126,581 | 0.003845 | 487 | 126,581 | 0.003845 | 487 | 0 | 0.00 |
| 11 | Solar Pilot Recovery Charge | 126,581 | 0.000085 | 11 | 126,581 | 0.000085 | 11 | 0 | 0.00 |
| 12 | Green Programs Recovery Charge | 126,581 | 0.002195 | 278 | 126,581 | 0.002195 | 278 | 0 | 0.00 |
| 13 | Tax Adjustment Credit | 126,581 | (0.008028) | (1,016) | 126,581 | (0.008028) | (1,016) | 0 | 0.00 |
| 14 | Green Enabling Mechanism | 126,581 | 0.000000 | - | 126,581 | 0.000000 | 0 | 0 | 0.00 |
| 15 | Facilities Chg. | | | - | | | 0 | 0 | 0.00 |
| 16 | Minimum | | | - | | | 0 | 0 | 0.00 |
| 17 | Miscellaneous | | | (2) | | | (2) | 0 | 0.00 |
| 18 | Delivery Subtotal | 126,581 | | $5,211 | 126,581 | | $5,272 | $61 | 1.17 |
| 19 | Unbilled Delivery | | | (101) | | | (102) | (1) | 0.99 |
| 20 | Delivery Subtotal w unbilled | | | $5,110 | | | $5,170 | $60 | 1.17 |
| 21 | | | | | | | | | |
| 22 | **Supply-BGS** | | | | | | | | |
| 23 | BGS 0-600 June - September | 19,973 | 0.091522 | $1,828 | 19,973 | 0.091522 | $1,828 | $0 | 0.00 |
| 24 | BGS 0-600 October - May | 41,979 | 0.096770 | 4,062 | 41,979 | 0.096770 | 4,062 | 0 | 0.00 |
| 25 | BGS over 600 June - September | 10,227 | 0.103664 | 1,060 | 10,227 | 0.103664 | 1,060 | 0 | 0.00 |
| 26 | BGS over 600 October - May | 54,402 | 0.096770 | 5,264 | 54,402 | 0.096770 | 5,264 | 0 | 0.00 |
| 27 | BGS Reconciliation-RSCP | 126,581 | 0.000000 | 0 | 126,581 | 0.000000 | 0 | 0 | 0.00 |
| 28 | Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 29 | Supply Subtotal | 126,581 | | $12,214 | 126,581 | | $12,214 | $0 | 0.00 |
| 30 | Unbilled Supply | | | (164) | | | (164) | 0 | 0.00 |
| 31 | Supply Subtotal w unbilled | | | $12,050 | | | $12,050 | $0 | 0.00 |
| 32 | | | | | | | | | |
| 33 | Total Delivery + Supply | 126,581 | | $17,160 | 126,581 | | $17,220 | $60 | 0.35 |
| 34 | | | | | | | | | |
| 35 | | | | | | | | | |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE RLM**
**RESIDENTIAL LOAD MANAGEMENT SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 145.90 | 13.07 | $1,907 | 145.899 | 13.07 | $1,907 | $0 | 0.00 |
| 2 | Distribution June - September On Peak | 43,971 | 0.071911 | 3,162 | 43,971 | 0.073025 | 3,211 | 49 | 1.55 |
| 3 | Distribution June - September Off Peak | 48,084 | 0.015007 | 722 | 48,084 | 0.015245 | 733 | 11 | 1.52 |
| 4 | Distribution October - May On Peak | 51,653 | 0.015007 | 775 | 51,653 | 0.015245 | 787 | 12 | 1.55 |
| 5 | Distribution October - May Off Peak | 68,116 | 0.015007 | 1,022 | 68,116 | 0.015245 | 1,038 | 16 | 1.57 |
| 6 | SBC | 211,824 | 0.009023 | 1,911 | 211,824 | 0.009023 | 1,911 | 0 | 0.00 |
| 7 | NGC | 211,824 | 0.000024 | 5 | 211,824 | 0.000024 | 5 | 0 | 0.00 |
| 8 | STC-TBC | 211,824 | 0.000000 | 0 | 211,824 | 0.000000 | 0 | 0 | 0.00 |
| 9 | STC-MTC-Tax | 211,824 | 0.000000 | 0 | 211,824 | 0.000000 | 0 | 0 | 0.00 |
| 10 | Zero Emission Certificate Recovery Charge | 211,824 | 0.003845 | 814 | 211,824 | 0.003845 | 814 | 0 | 0.00 |
| 11 | Solar Pilot Recovery Charge | 211,824 | 0.000085 | 18 | 211,824 | 0.000085 | 18 | 0 | 0.00 |
| 12 | Green Programs Recovery Charge | 211,824 | 0.002195 | 465 | 211,824 | 0.002195 | 465 | 0 | 0.00 |
| 13 | Tax Adjustment Credit | 211,824 | (0.006023) | (1,276) | 211,824 | (0.006023) | (1,276) | 0 | 0.00 |
| 14 | Green Enabling Mechanism | 211,824 | 0.000000 | 0 | 211,824 | 0.000000 | 0 | 0 | 0.00 |
| 15 | Facilities Chg. | | | 0 | | | 0 | 0 | 0.00 |
| 16 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 17 | Miscellaneous | | | (9) | | | (8) | 1 | (11.11) |
| 18 | Delivery Subtotal | 211,824 | | $9,516 | 211,824 | | $9,605 | $89 | 0.94 |
| 19 | Unbilled Delivery | | | (121) | | | (122) | (1) | 0.83 |
| 20 | Delivery Subtotal w unbilled | | | $9,395 | | | $9,483 | $88 | 0.94 |
| 21 | | | | | | | | | |
| 22 | **Supply-BGS** | | | | | | | | |
| 23 | BGS June - September On Peak | 43,971 | 0.254102 | $11,173 | 43,971 | 0.254102 | $11,173 | $0 | 0.00 |
| 24 | BGS June - September Off Peak | 48,084 | 0.038801 | 1,866 | 48,084 | 0.038801 | 1,866 | 0 | 0.00 |
| 25 | BGS October - May On Peak | 51,653 | 0.247734 | 12,796 | 51,653 | 0.247734 | 12,796 | 0 | 0.00 |
| 26 | BGS October - May Off Peak | 68,116 | 0.042679 | 2,907 | 68,116 | 0.042679 | 2,907 | 0 | 0.00 |
| 27 | BGS Reconciliation-RSCP | 211,824 | 0.000000 | 0 | 211,824 | 0.000000 | 0 | 0 | 0.00 |
| 28 | Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 29 | Supply Subtotal | 211,824 | | $28,742 | 211,824 | | $28,742 | $0 | 0.00 |
| 30 | Unbilled Supply | | | (298) | | | (298) | 0 | 0.00 |
| 31 | Supply Subtotal w unbilled | | | $28,444 | | | $28,444 | $0 | 0.00 |
| 32 | | | | | | | | | |
| 33 | Total Delivery + Supply | 211,824 | | $37,839 | 211,824 | | $37,927 | $88 | 0.23 |
| 34 | | | | | | | | | |
| 35 | | | | | | | | | |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE WH**
**WATER HEATING SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Distribution Sum | 329.000 | 0.047884 | $15.754 | 329.000 | 0.048279 | $15.884 | $0.130 | 0.83 |
| 2 | Distribution Win | 757 | 0.047884 | $36.248 | 757 | 0.048279 | $36.547 | $0.299 | 0.82 |
| 3 | SBC | 1,086 | 0.009023 | $9.799 | 1,086 | 0.009023 | $9.799 | $0.000 | 0.00 |
| 4 | NGC | 1,086 | 0.000024 | $0.026 | 1,086 | 0.000024 | $0.026 | $0.000 | 0.00 |
| 5 | STC-TBC | 1,086 | 0.000000 | $0.000 | 1,086 | 0.000000 | $0.000 | $0.000 | 0.00 |
| 6 | STC-MTC-Tax | 1,086 | 0.000000 | $0.000 | 1,086 | 0.000000 | $0.000 | $0.000 | 0.00 |
| 7 | Zero Emission Certificate Recovery Charge | 1,086 | 0.003845 | $4.176 | 1,086 | 0.003845 | $4.176 | $0.000 | 0.00 |
| 8 | Solar Pilot Recovery Charge | 1,086 | 0.000085 | $0.092 | 1,086 | 0.000085 | $0.092 | $0.000 | 0.00 |
| 9 | Green Programs Recovery Charge | 1,086 | 0.002195 | $2.384 | 1,086 | 0.002195 | $2.384 | $0.000 | 0.00 |
| 10 | Tax Adjustment Credit | 1,086 | 0.000000 | $0.000 | 1,086 | 0.000000 | $0.000 | $0.000 | 0.00 |
| 11 | Green Enabling Mechanism | 1,086 | 0.000000 | $0.000 | 1,086 | 0.000000 | $0.000 | $0.000 | 0.00 |
| 12 | Facilities Chg. | | | $0.000 | | | $0.000 | $0.000 | 0.00 |
| 13 | Minimum | | | $0.000 | | | $0.000 | $0.000 | 0.00 |
| 14 | Miscellaneous | | | $0.000 | | | $0.007 | $0.007 | 0.00 |
| 15 | Delivery Subtotal | 1,086 | | $68.479 | 1,086 | | $68.915 | $0.436 | 0.64 |
| 16 | Unbilled Delivery | | | -$1.161 | | | -$1.168 | -$0.007 | 0.60 |
| 17 | Delivery Subtotal w unbilled | | | $67.318 | | | $67.747 | $0.429 | 0.64 |
| 19 | **Supply-BGS** | | | | | | | | |
| 20 | BGS Summer | 329 | 0.047245 | $15.544 | 329 | 0.047245 | $15.544 | $0.000 | 0.00 |
| 21 | BGS Winter | 757 | 0.048956 | $37.060 | 757 | 0.048956 | $37.060 | $0.000 | 0.00 |
| 22 | BGS Reconciliation-RSCP | 1,086 | 0.000000 | $0.000 | 1,086 | 0.000000 | $0.000 | $0.000 | 0.00 |
| 23 | Miscellaneous | | | $0.000 | | | $0.000 | $0.000 | 0.00 |
| 24 | Supply Subtotal | 1,086 | | $52.604 | 1,086 | | $52.604 | $0.000 | 0.00 |
| 25 | Unbilled Supply | | | $0.000 | | | $0.000 | $0.000 | 0.00 |
| 26 | Supply Subtotal w unbilled | | | $52.604 | | | $52.604 | $0.000 | 0.00 |
| 28 | Total Delivery + Supply | 1,086 | | $119.922 | 1,086 | | $120.351 | $0.429 | 0.36 |

Notes:
All customers assumed to be on BGS.
WH, WHS & BPL-POF revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021

**RATE SCHEDULE WHS**
**WATER HEATING STORAGE SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 0.215 | 0.60 | $0.129 | 0.215 | 0.61 | $0.131 | $0.002 | 1.55 |
| 2 | Distribution June - September | 3.646 | 0.001677 | 0.006 | 3.646 | 0.001677 | 0.006 | 0.000 | 0.00 |
| 3 | Distribution October - May | 12.454 | 0.001677 | 0.021 | 12.454 | 0.001677 | 0.021 | 0.000 | 0.00 |
| 4 | SBC | 16.100 | 0.009023 | 0.145 | 16.100 | 0.009023 | 0.145 | 0.000 | 0.00 |
| 5 | NGC | 16.100 | 0.000024 | 0.000 | 16.100 | 0.000024 | 0.000 | 0.000 | 0.00 |
| 6 | STC-TBC | 16.100 | 0.000000 | 0.000 | 16.100 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 7 | STC-MTC-Tax | 16.100 | 0.000000 | 0.000 | 16.100 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 8 | Zero Emission Certificate Recovery Charge | 16.100 | 0.003845 | 0.062 | 16.100 | 0.003845 | 0.062 | 0.000 | 0.00 |
| 9 | Solar Pilot Recovery Charge | 16.100 | 0.000085 | 0.001 | 16.100 | 0.000085 | 0.001 | 0.000 | 0.00 |
| 10 | Green Programs Recovery Charge | 16.100 | 0.002195 | 0.035 | 16.100 | 0.002195 | 0.035 | 0.000 | 0.00 |
| 11 | Tax Adjustment Credit | 16.100 | 0.000000 | 0.000 | 16.100 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 12 | Green Enabling Mechanism | 16.100 | 0.000000 | 0.000 | 16.100 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 13 | Facilities Chg. | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 14 | Minimum | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 15 | Miscellaneous | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 16 | Delivery Subtotal | 16 | | $0.399 | 16 | | $0.401 | $0.002 | 0.50 |
| 17 | Unbilled Delivery | | | (0.008) | | | (0.008) | 0.000 | 0.00 |
| 18 | Delivery Subtotal w unbilled | | | $0.391 | | | $0.393 | $0.002 | 0.51 |
| 19 | | | | | | | | | |
| 20 | **Supply-BGS** | | | | | | | | |
| 21 | BGS- June - September | 3.646 | 0.047454 | $0.173 | 3.646 | 0.047454 | $0.173 | $0.000 | 0.00 |
| 22 | BGS- October - May | 12.454 | 0.050177 | 0.625 | 12.454 | 0.050177 | 0.625 | 0.000 | 0.00 |
| 23 | BGS Reconciliation-RSCP | 16.100 | 0.000000 | 0.000 | 16.100 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 24 | Miscellaneous | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 25 | Supply Subtotal | 16.100 | | 0.798 | 16.100 | | 0.798 | $0.000 | 0.00 |
| 26 | Unbilled Supply | | | (0.013) | | | (0.013) | 0.000 | 0.00 |
| 27 | Supply Subtotal w unbilled | | | $0.785 | | | $0.785 | $0.000 | 0.00 |
| 28 | | | | | | | | | |
| 29 | Total Delivery + Supply | 16.100 | | $1.176 | 16.100 | | $1.178 | $0.002 | 0.17 |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 34 | | WH, WHS & BPL-POF revenues shown to 3 decimals. | | | | | | | |
| 35 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |
| 36 | | | | | | | | | |
| 37 | | | | | | | | | |
| 38 | | | | | | | | | |

**RATE SCHEDULE HS**
**BUILDING HEATING SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 13.093 | 3.57 | $47 | 13.093 | 3.62 | $47 | $0 | 0.00 |
| 2 | Distribution June - September | 3,469 | 0.096570 | 335 | 3,469 | 0.097146 | 337 | 2 | 0.60 |
| 3 | Distribution October - May | 12,676 | 0.028952 | 367 | 12,676 | 0.029031 | 368 | 1 | 0.27 |
| 4 | SBC | 16,145 | 0.009023 | 146 | 16,145 | 0.009023 | 146 | 0 | 0.00 |
| 5 | NGC | 16,145 | 0.000024 | 0 | 16,145 | 0.000024 | 0 | 0 | 0.00 |
| 6 | STC-TBC | 16,145 | 0.000000 | 0 | 16,145 | 0.000000 | 0 | 0 | 0.00 |
| 7 | STC-MTC-Tax | 16,145 | 0.000000 | 0 | 16,145 | 0.000000 | 0 | 0 | 0.00 |
| 8 | Zero Emission Certificate Recovery Charge | 16,145 | 0.003845 | 62 | 16,145 | 0.003845 | 62 | 0 | 0.00 |
| 9 | Solar Pilot Recovery Charge | 16,145 | 0.000085 | 1 | 16,145 | 0.000085 | 1 | 0 | 0.00 |
| 10 | Green Programs Recovery Charge | 16,145 | 0.002195 | 35 | 16,145 | 0.002195 | 35 | 0 | 0.00 |
| 11 | Tax Adjustment Credit | 16,145 | -0.003590 | -58 | 16,145 | -0.003590 | -58 | 0 | 0.00 |
| 12 | Green Enabling Mechanism | 16,145 | 0.000000 | 0 | 16,145 | 0.000000 | 0 | 0 | 0.00 |
| 13 | Facilities Chg. | | | 0 | | | 0 | 0 | 0.00 |
| 14 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 15 | Miscellaneous | | | (1) | | | (1) | 0 | 0.00 |
| 16 | Delivery Subtotal | 16,145 | | $934 | 16,145 | | $937 | $3 | 0.32 |
| 17 | Unbilled Delivery | | | (22) | | | (22) | 0 | 0.00 |
| 18 | Delivery Subtotal w unbilled | | | $912 | | | $915 | $3 | 0.33 |
| 19 | | | | | | | | | |
| 20 | **Supply-BGS** | | | | | | | | |
| 21 | BGS- June - September | 3,469 | 0.118082 | $410 | 3,469 | 0.118082 | $410 | $0 | 0.00 |
| 22 | BGS- October - May | 12,676 | 0.117926 | 1495 | 12,676 | 0.117926 | 1495 | 0 | 0.00 |
| 23 | BGS Reconciliation-RSCP | 16,145 | 0.000000 | 0 | 16,145 | 0.000000 | 0 | 0 | 0.00 |
| 24 | Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 25 | Supply Subtotal | 16,145 | | $1,905 | 16,145 | | $1,905 | $0 | 0.00 |
| 26 | Unbilled Supply | | | (31) | | | (31) | 0 | 0.00 |
| 27 | Supply Subtotal w unbilled | | | $1,874 | | | $1,874 | $0 | 0.00 |
| 28 | | | | | | | | | |
| 29 | Total Delivery + Supply | 16,145 | | $2,786 | 16,145 | | $2,789 | $3 | 0.11 |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 34 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |
| 35 | | | | | | | | | |
| 36 | | | | | | | | | |
| 37 | | | | | | | | | |
| 38 | | | | | | | | | |

**RATE SCHEDULE GLP**
**GENERAL LIGHTING AND POWER SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 3,042.260 | 4.54 | $13,812 | 3,042.260 | 4.60 | $13,994 | $182 | 1.32 |
| 2 | Service Charge-unmetered | 100.329 | 2.10 | 211 | 100.329 | 2.13 | 214 | 3 | 1.42 |
| 3 | Service Charge-Night Use | 0.767 | 347.77 | 267 | 0.767 | 347.77 | 267 | 0 | 0.00 |
| 4 | Distrib. KW Annual | 28,477 | 3.7103 | 105,658 | 28,477 | 3.7243 | 106,057 | 399 | 0.38 |
| 5 | Distrib. KW Summer | 10,394 | 9.3044 | 96,710 | 10,394 | 9.3394 | 97,074 | 364 | 0.38 |
| 6 | Distribution kWhr, June-September | 2,784,306 | 0.003033 | 8,445 | 2,784,306 | 0.003044 | 8,475 | 30 | 0.36 |
| 7 | Distribution kWhr, October-May | 4,958,973 | 0.007742 | 38,392 | 4,958,973 | 0.007771 | 38,536 | 144 | 0.38 |
| 8 | Distribution kWhr, Night use, June-September | 7,441 | 0.007742 | 58 | 7,441 | 0.007771 | 58 | 0 | 0.00 |
| 9 | Distribution kWhr, Night use, October-May | 13,979 | 0.007742 | 108 | 13,979 | 0.007771 | 109 | 1 | 0.93 |
| 10 | SBC | 7,764,699 | 0.009023 | 70,061 | 7,764,699 | 0.009023 | 70,061 | 0 | 0.00 |
| 11 | NGC | 7,764,699 | 0.000024 | 186 | 7,764,699 | 0.000024 | 186 | 0 | 0.00 |
| 12 | STC-TBC | 7,764,699 | 0.000000 | 0 | 7,764,699 | 0.000000 | 0 | 0 | 0.00 |
| 13 | STC-MTC-Tax | 7,764,699 | 0.000000 | 0 | 7,764,699 | 0.000000 | 0 | 0 | 0.00 |
| 14 | Zero Emission Certificate Recovery Charge | 7,764,699 | 0.003845 | 29,855 | 7,764,699 | 0.003845 | 29,855 | 0 | 0.00 |
| 15 | Solar Pilot Recovery Charge | 7,764,699 | 0.000085 | 660 | 7,764,699 | 0.000085 | 660 | 0 | 0.00 |
| 16 | Green Programs Recovery Charge | 7,764,699 | 0.002195 | 17,044 | 7,764,699 | 0.002195 | 17,044 | 0 | 0.00 |
| 17 | Tax Adjustment Credit | 7,764,699 | -0.002027 | -15,739 | 7,764,699 | -0.002027 | -15,739 | 0 | 0.00 |
| 18 | Green Enabling Mechanism | 7,764,699 | 0.000000 | 0 | 7,764,699 | 0.000000 | 0 | 0 | 0.00 |
| 19 | Duplicate Svc (Same Sub/Different Sub) | | $2.22/$3.20 | 5 | | $2.22/$3.20 | 5 | 0 | 0.00 |
| 20 | Facilities Chg. | | 1.45% | 63 | | 1.45% | 63 | 0 | 0.00 |
| 21 | Minimum | | | 42 | | | 42 | 0 | 0.00 |
| 22 | Distrib. Miscellaneous | | | (1,726) | | | (1,725) | 1 | -0.06 |
| 23 | Delivery Subtotal | 7,764,699 | | $364,112 | 7,764,699 | | $365,236 | $1,124 | 0.31 |
| 24 | Unbilled Delivery | | | (1,342) | | | (1,346) | (4) | 0.30 |
| 25 | Delivery Subtotal w unbilled | | | $362,770 | | | $363,890 | $1,120 | 0.31 |

**RATE SCHEDULE GLP**
**GENERAL LIGHTING AND POWER SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Supply-BGS** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Generation Capacity Obl June-September | 10,134 | 5.2396 | $53,098 | 10,134 | 5.2396 | $53,098 | $0 | 0.00 |
| 2 | Generation Capacity Obl October-May | 20,198 | 5.2396 | 105,829 | 20,198 | 5.2396 | 105,829 | 0 | 0.00 |
| 3 | Transmission Capacity Obl | 26,597 | 12.0345 | 320,082 | 26,597 | 12.0345 | 320,082 | 0 | 0.00 |
| 4 | BGS kWhr June - September not night use | 2,784,306 | 0.048555 | 135,192 | 2,784,306 | 0.048555 | 135,192 | 0 | 0.00 |
| 5 | BGS kWhr October - May not night use | 4,958,973 | 0.049374 | 244,844 | 4,958,973 | 0.049374 | 244,844 | 0 | 0.00 |
| 6 | BGS kWhr June - September night use | 7,441 | 0.042374 | 315 | 7,441 | 0.042374 | 315 | 0 | 0.00 |
| 7 | BGS kWhr October - May night use | 13,979 | 0.046066 | 644 | 13,979 | 0.046066 | 644 | 0 | 0.00 |
| 8 | BGS Reconciliation-RSCP | 7,764,699 | 0.000000 | 0 | 7,764,699 | 0.000000 | 0 | 0 | 0.00 |
| 9 | BGS Miscellaneous | | | (145) | | | (145) | 0 | 0.00 |
| 10 | Supply Subtotal | 7,764,699 | | $859,859 | 7,764,699 | | $859,859 | $0 | 0.00 |
| 11 | Unbilled Supply | | | (166) | | | (166) | 0 | 0.00 |
| 12 | Supply Subtotal w unbilled | | | $859,693 | | | $859,693 | $0 | 0.00 |
| 13 | | | | | | | | | |
| 14 | Total Delivery + Supply | 7,764,699 | | $1,222,463 | 7,764,699 | | $1,223,583 | $1,120 | 0.09 |
| 15 | | | | | | | | | |
| 16 | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | | | | | | | | | |
| 19 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 20 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE LPL-Sec**
**LARGE POWER & LIGHTING SERVICE-SECONDARY**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 103.740 | 347.77 | $36,078 | 103.740 | 347.77 | $36,078 | $0 | 0.00 |
| 2 | Distrib. KW Annual | 28,389 | 3.5501 | 100,784 | 28,389 | 3.5682 | 101,298 | 514 | 0.51 |
| 3 | Distrib. KW June - September | 10,139 | 8.4460 | 85,634 | 10,139 | 8.4891 | 86,071 | 437 | 0.51 |
| 4 | Distribution kWhr On Peak June-September | 1,986,049 | 0.000000 | 0 | 1,986,049 | 0.000000 | 0 | 0 | 0.00 |
| 5 | Distribution kWhr Off Peak June-September | 2,006,262 | 0.000000 | 0 | 2,006,262 | 0.000000 | 0 | 0 | 0.00 |
| 6 | Distribution kWhr On Peak October-May | 3,504,143 | 0.000000 | 0 | 3,504,143 | 0.000000 | 0 | 0 | 0.00 |
| 7 | Distribution kWhr Off Peak October-May | 3,780,348 | 0.000000 | 0 | 3,780,348 | 0.000000 | 0 | 0 | 0.00 |
| 8 | SBC | 11,276,802 | 0.009023 | 101,751 | 11,276,802 | 0.009023 | 101,751 | 0 | 0.00 |
| 9 | NGC | 11,276,802 | 0.000024 | 271 | 11,276,802 | 0.000024 | 271 | 0 | 0.00 |
| 10 | STC-TBC | 11,276,802 | 0.000000 | 0 | 11,276,802 | 0.000000 | 0 | 0 | 0.00 |
| 11 | STC-MTC-Tax | 11,276,802 | 0.000000 | 0 | 11,276,802 | 0.000000 | 0 | 0 | 0.00 |
| 12 | Zero Emission Certificate Recovery Charge | 11,276,802 | 0.003845 | 43,359 | 11,276,802 | 0.003845 | 43,359 | 0 | 0.00 |
| 13 | Solar Pilot Recovery Charge | 11,276,802 | 0.000085 | 959 | 11,276,802 | 0.000085 | 959 | 0 | 0.00 |
| 14 | CIEP Standby Fee | 4,018,143 | 0.000150 | 603 | 4,018,143 | 0.000150 | 603 | 0 | 0.00 |
| 15 | Green Programs Recovery Charge | 11,276,802 | 0.002195 | 24,753 | 11,276,802 | 0.002195 | 24,753 | 0 | 0.00 |
| 16 | Tax Adjustment Credit | 11,276,802 | -0.001195 | -13,476 | 11,276,802 | -0.001195 | -13,476 | 0 | 0.00 |
| 17 | Green Enabling Mechanism | 11,276,802 | 0.000000 | 0 | 11,276,802 | 0.000000 | 0 | 0 | 0.00 |
| 18 | Duplicate Svc (Same Sub/Different Sub) | | $2.22/$3.20 | 128 | | $2.22/$3.20 | 128 | 0 | 0.00 |
| 19 | Facilities Chg. | | 1.45% | 247 | | 1.45% | 247 | 0 | 0.00 |
| 20 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 21 | Dist. Miscellaneous | | | (1,202) | | | (1,202) | 0 | 0.00 |
| 22 | Delivery Subtotal | 11,276,802 | | $379,889 | 11,276,802 | | $380,840 | $951 | 0.25 |
| 23 | Unbilled Delivery | | | (1,662) | | | (1,666) | (4) | 0.24 |
| 24 | Delivery Subtotal w unbilled | | | $378,227 | | | $379,174 | $947 | 0.25 |

**RATE SCHEDULE LPL-Sec**
**LARGE POWER & LIGHTING SERVICE-SECONDARY**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Supply-BGS** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| | **0-499** | | | | | | | | |
| 1 | Generation Capacity Obl - June-September | 6,439 | 5.2396 | $33,738 | 6,439 | 5.2396 | $33,738 | $0 | 0.00 |
| 2 | Generation Capacity Obl - October-May | 12,996 | 5.2396 | 68,094 | 12,996 | 5.2396 | 68,094 | 0 | 0.00 |
| 3 | Transmission Capacity Obl | 16,672 | 12.0345 | 200,639 | 16,672 | 12.0345 | 200,639 | 0 | 0.00 |
| 4 | BGS kWhr June-September On Peak | 1,302,213 | 0.053875 | 70,157 | 1,302,213 | 0.053875 | 70,157 | 0 | 0.00 |
| 5 | BGS kWhr June-September Off Peak | 1,315,466 | 0.042374 | 55,742 | 1,315,466 | 0.042374 | 55,742 | 0 | 0.00 |
| 6 | BGS kWhr October-May On Peak | 2,297,596 | 0.052390 | 120,371 | 2,297,596 | 0.052390 | 120,371 | 0 | 0.00 |
| 7 | BGS kWhr October-May Off Peak | 2,478,699 | 0.046066 | 114,184 | 2,478,699 | 0.046066 | 114,184 | 0 | 0.00 |
| 8 | **500+** | | | | | | | | |
| 9 | Generation Capacity Obl - June-September | 3,422 | 10.6854 | 36,565 | 3,422 | 10.6854 | 36,565 | 0 | 0.00 |
| 10 | Generation Capacity Obl - October-May | 6,784 | 10.6854 | 72,490 | 6,784 | 10.6854 | 72,490 | 0 | 0.00 |
| 11 | Transmission Capacity Obl | 8,643 | 12.0345 | 104,014 | 8,643 | 12.0345 | 104,014 | 0 | 0.00 |
| 12 | BGS kWhr June-September | 1,374,632 | 0.030240 | 41,569 | 1,374,632 | 0.030240 | 41,569 | 0 | 0.00 |
| 13 | Spare | 0 | 0.030240 | 0 | 0 | 0.030240 | 0 | 0 | 0.00 |
| 14 | BGS kWhr October-May | 2,508,196 | 0.033883 | 84,985 | 2,508,196 | 0.033883 | 84,985 | 0 | 0.00 |
| 15 | Spare | 0 | 0.033883 | 0 | 0 | 0.033883 | 0 | 0 | 0.00 |
| 16 | | | | | | | | | |
| 17 | BGS Reconciliation-RSCP | 7,393,974 | 0.000000 | 0 | 7,393,974 | 0.000000 | 0 | 0 | 0.00 |
| 18 | BGS Reconciliation-CIEP | 3,882,828 | 0.000000 | 0 | 3,882,828 | 0.000000 | 0 | 0 | 0.00 |
| 19 | BGS Miscellaneous | | | (102) | | | (102) | 0 | 0.00 |
| 20 | Supply Subtotal | 11,276,802 | | $1,002,446 | 11,276,802 | | $1,002,446 | $0 | 0.00 |
| 21 | Unbilled Supply | | | (21,516) | | | (21,516) | 0 | 0.00 |
| 22 | Supply Subtotal w unbilled | | | $980,930 | | | $980,930 | $0 | 0.00 |
| 23 | | | | | | | | | |
| 24 | Total Delivery + Supply | 11,276,802 | | $1,359,157 | 11,276,802 | | $1,360,104 | $947 | 0.07 |
| 25 | | | | | | | | | |
| 26 | | | | | | | | | |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 30 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE LPL-Pri**
**LARGE POWER & LIGHTING SERVICE-PRIMARY**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 8.672 | 347.77 | $3,016 | 8.672 | 347.77 | $3,016 | $0 | 0.00 |
| 2 | Service Charge-Alternate | 0.373 | 20.52 | 8 | 0.373 | 20.78 | 8 | 0 | 0.00 |
| 3 | Distrib. KW Annual | 7,243 | 1.6538 | 11,978 | 7,243 | 1.6617 | 12,036 | 58 | 0.48 |
| 4 | Distrib. KW June - September | 2,493 | 9.1809 | 22,888 | 2,493 | 9.2246 | 22,997 | 109 | 0.48 |
| 5 | Distribution kWhr On Peak June-September | 543,764 | 0.000000 | 0 | 543,764 | 0.000000 | 0 | 0 | 0.00 |
| 6 | Distribution kWhr Off Peak June-September | 627,198 | 0.000000 | 0 | 627,198 | 0.000000 | 0 | 0 | 0.00 |
| 7 | Distribution kWhr On Peak October-May | 938,452 | 0.000000 | 0 | 938,452 | 0.000000 | 0 | 0 | 0.00 |
| 8 | Distribution kWhr Off Peak October-May | 1,126,000 | 0.000000 | 0 | 1,126,000 | 0.000000 | 0 | 0 | 0.00 |
| 9 | SBC | 3,235,414 | 0.008868 | 28,692 | 3,235,414 | 0.008868 | 28,692 | 0 | 0.00 |
| 10 | NGC | 3,235,414 | 0.000024 | 78 | 3,235,414 | 0.000024 | 78 | 0 | 0.00 |
| 11 | STC-TBC | 3,235,414 | 0.000000 | 0 | 3,235,414 | 0.000000 | 0 | 0 | 0.00 |
| 12 | STC-MTC-Tax | 3,235,414 | 0.000000 | 0 | 3,235,414 | 0.000000 | 0 | 0 | 0.00 |
| 13 | Zero Emission Certificate Recovery Charge | 3,235,414 | 0.003845 | 12,440 | 3,235,414 | 0.003845 | 12,440 | 0 | 0.00 |
| 14 | Solar Pilot Recovery Charge | 3,235,414 | 0.000085 | 275 | 3,235,414 | 0.000085 | 275 | 0 | 0.00 |
| 15 | CIEP Standby Fee | 3,235,414 | 0.000150 | 485 | 3,235,414 | 0.000150 | 485 | 0 | 0.00 |
| 16 | Green Programs Recovery Charge | 3,235,414 | 0.002195 | 7,102 | 3,235,414 | 0.002195 | 7,102 | 0 | 0.00 |
| 17 | Tax Adjustment Credit | 3,235,414 | -0.000726 | -2,349 | 3,235,414 | -0.000726 | -2,349 | 0 | 0.00 |
| 18 | Green Enabling Mechanism | 3,235,414 | 0.000000 | 0 | 3,235,414 | 0.000000 | 0 | 0 | 0.00 |
| 19 | Duplicate Svc (Same Sub/Different Sub) | | $2.22/$3.20 | 557 | | $2.22/$3.20 | 557 | 0 | 0.00 |
| 20 | Facilities Chg. | | 1.45% | 439 | | 1.45% | 439 | 0 | 0.00 |
| 21 | Minimum | | | 7 | | | 7 | 0 | 0.00 |
| 22 | Dist. Miscellaneous | | | (304) | | | (305) | -1 | 0.33 |
| 23 | Delivery Subtotal | 3,235,414 | | $85,312 | 3,235,414 | | $85,478 | $166 | 0.19 |
| 24 | Unbilled Delivery | | | (322) | | | (323) | (1) | 0.31 |
| 25 | Delivery Subtotal w unbilled | | | $84,990 | | | $85,155 | $165 | 0.19 |

**RATE SCHEDULE LPL-Pri**
**LARGE POWER & LIGHTING SERVICE-PRIMARY**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| | **Supply-BGS** | | | | | | | | |
| 1 | Generation Capacity Obl June-September | 2,368 | 10.6854 | $25,303 | 2,368 | 10.6854 | $25,303 | $0 | 0.00 |
| 2 | Generation Capacity Obl October-May | 4,724 | 10.6854 | 50,478 | 4,724 | 10.6854 | 50,478 | 0 | 0.00 |
| 3 | Transmission Capacity Obl | 6,170 | 12.0345 | 74,253 | 6,170 | 12.0345 | 74,253 | 0 | 0.00 |
| 4 | BGS kWhr June-September On Peak | 543,764 | 0.028851 | 15,688 | 543,764 | 0.028851 | 15,688 | 0 | 0.00 |
| 5 | BGS kWhr June-September Off Peak | 627,198 | 0.028851 | 18,095 | 627,198 | 0.028851 | 18,095 | 0 | 0.00 |
| 6 | BGS kWhr October-May On Peak | 938,452 | 0.032551 | 30,548 | 938,452 | 0.032551 | 30,548 | 0 | 0.00 |
| 7 | BGS kWhr October-May Off Peak | 1,126,000 | 0.032551 | 36,652 | 1,126,000 | 0.032551 | 36,652 | 0 | 0.00 |
| 8 | BGS Reconciliation-CIEP | 3,235,414 | 0.000000 | 0 | 3,235,414 | 0.000000 | 0 | 0 | 0.00 |
| 9 | BGS Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 10 | Supply Subtotal | 3,235,414 | | $251,017 | 3,235,414 | | $251,017 | $0 | 0.00 |
| 11 | Unbilled Supply | | | 3,365 | | | 3,365 | 0 | 0.00 |
| 12 | Supply Subtotal w unbilled | | | $254,382 | | | $254,382 | $0 | 0.00 |
| 13 | | | | | | | | | |
| 14 | Total Delivery + Supply | 3,235,414 | | $339,372 | 3,235,414 | | $339,537 | $165 | 0.05 |

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021

**RATE SCHEDULE HTS-SUBTR.**
**HIGH TENSION SERVICE-SUBTRANSMISSION**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 2.319 | 1,911.39 | $4,433 | 2.319 | 1,911.39 | $4,433 | $0 | 0.00 |
| 2 | Distrib. KW Annual | 11,987 | 1.0863 | 13,021 | 11,987 | 1.0983 | 13,165 | 144 | 1.11 |
| 3 | Distrib. KW June - September | 2,962 | 3.9268 | 11,631 | 2,962 | 3.9701 | 11,759 | 128 | 1.10 |
| 4 | Distribution kWhr On Peak | 1,616,031 | 0.000000 | 0 | 1,616,031 | 0.000000 | 0 | 0 | 0.00 |
| 5 | Spare | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 6 | Distribution kWhr On Peak | 2,950,441 | 0.000000 | 0 | 2,950,441 | 0.000000 | 0 | 0 | 0.00 |
| 7 | Spare | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 8 | SBC | 4,566,472 | 0.008792 | 40,148 | 4,566,472 | 0.008792 | 40,148 | 0 | 0.00 |
| 9 | NGC | 4,566,472 | 0.000023 | 105 | 4,566,472 | 0.000023 | 105 | 0 | 0.00 |
| 10 | STC-TBC | 4,566,472 | 0.000000 | 0 | 4,566,472 | 0.000000 | 0 | 0 | 0.00 |
| 11 | STC-MTC-Tax | 4,566,472 | 0.000000 | 0 | 4,566,472 | 0.000000 | 0 | 0 | 0.00 |
| 12 | Zero Emission Certificate Recovery Charge | 4,566,472 | 0.003845 | 17,558 | 4,566,472 | 0.003845 | 17,558 | 0 | 0.00 |
| 13 | Solar Pilot Recovery Charge | 4,566,472 | 0.000085 | 388 | 4,566,472 | 0.000085 | 388 | 0 | 0.00 |
| 14 | CIEP Standby Fee | 4,566,472 | 0.000150 | 685 | 4,566,472 | 0.000150 | 685 | 0 | 0.00 |
| 15 | Green Programs Recovery Charge | 4,566,472 | 0.002195 | 10,023 | 4,566,472 | 0.002195 | 10,023 | 0 | 0.00 |
| 16 | Tax Adjustment Credit | 4,566,472 | -0.000733 | -3,347 | 4,566,472 | -0.000733 | -3,347 | 0 | 0.00 |
| 17 | Green Enabling Mechanism | 4,566,472 | 0.000000 | 0 | 4,566,472 | 0.000000 | 0 | 0 | 0.00 |
| 18 | Duplicate Svc (Same Sub/Different Sub) | | $1.83/$2.20 | 105 | | $1.83/$2.20 | 105 | 0 | 0.00 |
| 19 | Facilities Chg. | | 1.45% | 686 | | 1.45% | 686 | 0 | 0.00 |
| 20 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 21 | Dist. Miscellaneous | | | (527) | | | (527) | 0 | 0.00 |
| 22 | Delivery Subtotal | 4,566,472 | | $94,909 | 4,566,472 | | $95,181 | $272 | 0.29 |
| 23 | Unbilled Delivery | | | (339) | | | (340) | (1) | 0.29 |
| 24 | Delivery Subtotal w unbilled | | | $94,570 | | | $94,841 | $271 | 0.29 |

**RATE SCHEDULE HTS-SUBTR.**
**HIGH TENSION SERVICE-SUBTRANSMISSION**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Supply-BGS** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Generation Capacity Obl June-September | 2,724 | 10.6854 | $29,107 | 2,724 | 10.6854 | $29,107 | $0 | 0.00 |
| 2 | Generation Capacity Obl October-May | 5,423 | 10.6854 | 57,947 | 5,423 | 10.6854 | 57,947 | 0 | 0.00 |
| 3 | Transmission Capacity Obl | 7,276 | 12.0345 | 87,563 | 7,276 | 12.0345 | 87,563 | 0 | 0.00 |
| 4 | BGS kWhr June-September | 1,616,031 | 0.028292 | 45,721 | 1,616,031 | 0.028292 | 45,721 | 0 | 0.00 |
| 5 | Spare | 0 | 0.028292 | 0 | 0 | 0.028292 | 0 | 0 | 0.00 |
| 6 | BGS kWhr October-May | 2,950,441 | 0.031759 | 93,703 | 2,950,441 | 0.031759 | 93,703 | 0 | 0.00 |
| 7 | Spare | 0 | 0.031759 | 0 | 0 | 0.031759 | 0 | 0 | 0.00 |
| 8 | BGS Reconciliation-CIEP | 4,566,472 | 0.000000 | 0 | 4,566,472 | 0.000000 | 0 | 0 | 0.00 |
| 9 | BGS Miscellaneous | | | (24) | | | (24) | 0 | 0.00 |
| 10 | Supply Subtotal | 4,566,472 | | $314,017 | 4,566,472 | | $314,017 | $0 | 0.00 |
| 11 | Unbilled Supply | | | 12,966 | | | 12,966 | 0 | 0.00 |
| 12 | Supply Subtotal w unbilled | | | $326,983 | | | $326,983 | $0 | 0.00 |
| 13 | | | | | | | | | |
| 14 | Total Delivery + Supply | 4,566,472 | | $421,553 | 4,566,472 | | $421,824 | $271 | 0.06 |
| 15 | | | | | | | | | |
| 16 | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | | | | | | | | | |
| 19 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 20 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE HTS-HV**
**HIGH TENSION SERVICE-HIGH VOLTAGE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 0.166 | 1,720.25 | $286 | 0.166 | 1,720.25 | $286 | $0 | 0.00 |
| 2 | Distrib. KW Annual | 3,286 | 0.6203 | 2,038 | 3,286 | 0.6233 | 2,048 | 10 | 0.49 |
| 3 | Distrib. KW June - September | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 4 | Distribution kWhr June - September | 148,652 | 0.000000 | 0 | 148,652 | 0.000000 | 0 | 0 | 0.00 |
| 5 | Spare | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 6 | Distribution kWhr October - May | 269,345 | 0.000000 | 0 | 269,345 | 0.000000 | 0 | 0 | 0.00 |
| 7 | Spare | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 8 | SBC | 417,997 | 0.008724 | 3,647 | 417,997 | 0.008724 | 3,647 | 0 | 0.00 |
| 9 | NGC | 417,997 | 0.000023 | 10 | 417,997 | 0.000023 | 10 | 0 | 0.00 |
| 10 | STC-TBC | 417,997 | 0.000000 | 0 | 417,997 | 0.000000 | 0 | 0 | 0.00 |
| 11 | STC-MTC-Tax | 417,997 | 0.000000 | 0 | 417,997 | 0.000000 | 0 | 0 | 0.00 |
| 12 | Zero Emission Certificate Recovery Charge | 417,997 | 0.003845 | 1,607 | 417,997 | 0.003845 | 1,607 | 0 | 0.00 |
| 13 | Solar Pilot Recovery Charge | 417,997 | 0.000085 | 36 | 417,997 | 0.000085 | 36 | 0 | 0.00 |
| 14 | CIEP Standby Fee | 417,997 | 0.000150 | 63 | 417,997 | 0.000150 | 63 | 0 | 0.00 |
| 15 | Green Programs Recovery Charge | 417,997 | 0.002195 | 918 | 417,997 | 0.002195 | 918 | 0 | 0.00 |
| 16 | Tax Adjustment Credit | 417,997 | -0.000311 | -130 | 417,997 | -0.000311 | -130 | 0 | 0.00 |
| 17 | Green Enabling Mechanism | 417,997 | 0.000000 | 0 | 417,997 | 0.000000 | 0 | 0 | 0.00 |
| 18 | Facilities Chg. | | | 33 | | | 33 | 0 | 0.00 |
| 19 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 20 | Dist. Miscellaneous | | | (79) | | | (79) | 0 | 0.00 |
| 21 | Delivery Subtotal | 417,997 | | $8,429 | 417,997 | | $8,439 | $10 | 0.12 |
| 22 | Unbilled Delivery | | | 94 | | | 94 | 0 | 0.00 |
| 23 | Delivery Subtotal w unbilled | | | $8,523 | | | $8,533 | $10 | 0.12 |

**RATE SCHEDULE HTS-HV**
**HIGH TENSION SERVICE-HIGH VOLTAGE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Supply-BGS** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Generation Capacity Obl June-September | 208 | 10.6854 | $2,223 | 208 | 10.6854 | $2,223 | $0 | 0.00 |
| 2 | Generation Capacity Obl October-May | 452 | 10.6854 | 4,830 | 452 | 10.6854 | 4,830 | 0 | 0.00 |
| 3 | Transmission Capacity Obl | 561 | 12.0345 | 6,751 | 561 | 12.0345 | 6,751 | 0 | 0.00 |
| 4 | BGS kWhr June-September | 148,652 | 0.022773 | 3,385 | 148,652 | 0.022773 | 3,385 | 0 | 0.00 |
| 5 | Spare | 0 | 0.022773 | 0 | 0 | 0.022773 | 0 | 0 | 0.00 |
| 6 | BGS kWhr October-May | 269,345 | 0.025833 | 6,958 | 269,345 | 0.025833 | 6,958 | 0 | 0.00 |
| 7 | Spare | 0 | 0.025833 | 0 | 0 | 0.025833 | 0 | 0 | 0.00 |
| 8 | BGS Reconciliation-CIEP | 417,997 | 0.000000 | 0 | 417,997 | 0.000000 | 0 | 0 | 0.00 |
| 9 | BGS Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 10 | Supply Subtotal | 417,997 | | $24,147 | 417,997 | | $24,147 | $0 | 0.00 |
| 11 | Unbilled Supply | | | 0 | | | 0 | 0 | 0.00 |
| 12 | Supply Subtotal w unbilled | | | $24,147 | | | $24,147 | $0 | 0.00 |
| 13 | | | | | | | | | |
| 14 | Total Delivery + Supply | 417,997 | | $32,670 | 417,997 | | $32,680 | $10 | 0.03 |
| 15 | | | | | | | | | |
| 16 | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | | | | | | | | | |
| 19 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 20 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

# RATE SCHEDULE BPL
## BODY POLITIC LIGHTING SERVICE
## Schedule SS-IAP-4
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | High Pressure Sodium | 2,266.536 | 0 | $ 25,814 | 2,266.536 | 0 | $ 25,814 | $0 | 0.00 |
| 2 | Metal Halide | 281.316 | 0 | 6,365 | 281.316 | 0 | 6,365 | 0 | 0.00 |
| 3 | Filament | 153.684 | 0 | 577 | 153.684 | 0 | 577 | 0 | 0.00 |
| 4 | Mercury Vapor | 1,702.464 | 0 | 18,768 | 1,702.464 | 0 | 18,768 | 0 | 0.00 |
| 5 | Fluorescent | 0.204 | 0 | 3 | 0.204 | 0 | 3 | 0 | 0.00 |
| 6 | | | | | | | | | |
| 7 | Distribution June-September | 72,030 | 0.006774 | $488 | 72,030 | 0.006806 | $490 | 2 | 0.41 |
| 8 | Distribution October-May | 210,828 | 0.006774 | 1,428 | 210,828 | 0.006806 | 1,435 | 7 | 0.49 |
| 9 | SBC | 282,858 | 0.009023 | 2,552 | 282,858 | 0.009023 | 2,552 | 0 | 0.00 |
| 10 | NGC | 282,858 | 0.000024 | 7 | 282,858 | 0.000024 | 7 | 0 | 0.00 |
| 11 | STC-TBC | 282,858 | 0.000000 | 0 | 282,858 | 0.000000 | 0 | 0 | 0.00 |
| 12 | STC-MTC-Tax | 282,858 | 0.000000 | 0 | 282,858 | 0.000000 | 0 | 0 | 0.00 |
| 13 | Zero Emission Certificate Recovery Charge | 282,858 | 0.003845 | 1,088 | 282,858 | 0.003845 | 1,088 | 0 | 0.00 |
| 14 | Solar Pilot Recovery Charge | 282,858 | 0.000085 | 24 | 282,858 | 0.000085 | 24 | 0 | 0.00 |
| 15 | Green Programs Recovery Charge | 282,858 | 0.002195 | 621 | 282,858 | 0.002195 | 621 | 0 | 0.00 |
| 16 | Tax Adjustment Credit | 282,858 | 0.000000 | 0 | 282,858 | 0.000000 | 0 | 0 | 0.00 |
| 17 | Green Enabling Mechanism | 282,858 | 0.000000 | 0 | 282,858 | 0.000000 | 0 | 0 | 0.00 |
| 18 | | | | | | | | | |
| 19 | Pole Charges | 555.636 | | 2,237 | 555.636 | | 2,237 | 0 | 0.00 |
| 20 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 21 | Miscellaneous | | | 352 | | | 352 | 0 | 0.00 |
| 22 | Delivery Subtotal | | | $60,324 | | | $60,333 | $9 | 0.01 |
| 23 | Unbilled Delivery | | | 0 | | | 0 | 0 | 0.00 |
| 24 | Delivery Subtotal w unbilled | | | $60,324 | | | $60,333 | $9 | 0.01 |
| 25 | | | | | | | | | |
| 26 | **Supply-BGS** | | | | | | | | |
| 27 | BGS June-September | 72,030 | 0.044045 | 3,173 | 72,030 | 0.044045 | 3,173 | 0 | 0.00 |
| 28 | BGS October-May | 210,828 | 0.047735 | 10,064 | 210,828 | 0.047735 | 10,064 | 0 | 0.00 |
| 29 | BGS Reconciliation-RSCP | 282,858 | 0.000000 | 0 | 282,858 | 0.000000 | 0 | 0 | 0.00 |
| 30 | Miscellaneous | | | (104) | | | (104) | 0 | 0.00 |
| 31 | Supply Subtotal | | | $13,133 | | | $13,133 | $0 | 0.00 |
| 32 | Unbilled Supply | | | 0 | | | 0 | 0 | 0.00 |
| 33 | Supply Subtotal w unbilled | | | $13,133 | | | $13,133 | $0 | 0.00 |
| 34 | | | | | | | | | |
| 35 | Total Delivery + Supply | 282,858 | | $73,457 | 282,858 | | $73,466 | $9 | 0.01 |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE BPL-POF**
**BODY POLITIC LIGHTING SERVICE-POF**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | High Pressure Sodium | 125.460 | 0 | $ 181.000 | 125.460 | 0 | $ 181.000 | $0.000 | 0.00 |
| 2 | Metal Halide | 1.476 | 0 | $ 5.000 | 1.476 | 0 | $ 5.000 | $0.000 | 0.00 |
| 3 | Filament | 5.916 | 0 | $ 22.000 | 5.916 | 0 | $ 22.000 | $0.000 | 0.00 |
| 4 | Mercury Vapor | 4.236 | 0 | $ 4.000 | 4.236 | 0 | $ 4.000 | $0.000 | 0.00 |
| 5 | Fluorescent | 0.024 | 0 | $ - | 0.024 | 0 | $ - | $0.000 | 0.00 |
| 6 | | | | | | | | | |
| 7 | Distribution June-September | 4,259 | 0.006763 | $ 28.804 | 4,259 | 0.006792 | $ 28.927 | $0.123 | 0.43 |
| 8 | Distribution October-May | 10,191 | 0.006763 | $ 68.922 | 10,191 | 0.006792 | $ 69.217 | $0.295 | 0.43 |
| 9 | SBC | 14,450 | 0.009023 | $ 130.382 | 14,450 | 0.009023 | $ 130.382 | $0.000 | 0.00 |
| 10 | NGC | 14,450 | 0.000024 | $ 0.347 | 14,450 | 0.000024 | $ 0.347 | $0.000 | 0.00 |
| 11 | STC-TBC | 14,450 | 0.000000 | $ - | 14,450 | 0.000000 | $ - | $0.000 | 0.00 |
| 12 | STC-MTC-Tax | 14,450 | 0.000000 | $ - | 14,450 | 0.000000 | $ - | $0.000 | 0.00 |
| 13 | Zero Emission Certificate Recovery Charge | 14,450 | 0.003845 | $ 55.560 | 14,450 | 0.003845 | $ 55.560 | $0.000 | 0.00 |
| 14 | Solar Pilot Recovery Charge | 14,450 | 0.000085 | $ 1.228 | 14,450 | 0.000085 | $ 1.228 | $0.000 | 0.00 |
| 15 | Green Programs Recovery Charge | 14,450 | 0.002195 | $ 31.718 | 14,450 | 0.002195 | $ 31.718 | $0.000 | 0.00 |
| 16 | Tax Adjustment Credit | 14,450 | -0.001729 | $ (24.984) | 14,450 | -0.001729 | $ (24.984) | $0.000 | 0.00 |
| 17 | Green Enabling Mechanism | 14,450 | 0.000000 | $ - | 14,450 | 0.000000 | $ - | $0.000 | 0.00 |
| 18 | | | | | | | | | |
| 19 | Pole Charges | | | $ - | | | $ - | $0.000 | 0.00 |
| 20 | Minimum | | | $ - | | | $ - | $0.000 | 0.00 |
| 21 | Miscellaneous | | | $ 11.000 | | | $ 11.001 | $0.001 | 0.01 |
| 22 | Delivery Subtotal | | | $ 514.977 | | | $ 515.396 | $0.419 | 0.08 |
| 23 | Unbilled Delivery | | | $ - | | | $ - | $0.000 | 0.00 |
| 24 | Delivery Subtotal w unbilled | | | $ 514.977 | | | $ 515.396 | $0.419 | 0.08 |
| 25 | | | | | | | | | |
| 26 | **Supply-BGS** | | | | | | | | |
| 27 | BGS June-September | 4,259 | 0.044045 | $ 187.588 | 4,259 | 0.044045 | $ 187.588 | $0.000 | 0.00 |
| 28 | BGS October-May | 10,191 | 0.047735 | $ 486.467 | 10,191 | 0.047735 | $ 486.467 | $0.000 | 0.00 |
| 29 | BGS Reconciliation-RSCP | 14,450 | 0.000000 | $ - | 14,450 | 0.000000 | $ - | $0.000 | 0.00 |
| 30 | Miscellaneous | | | $ - | | | $ - | $0.000 | 0.00 |
| 31 | Supply Subtotal | | | $ 674.055 | | | $ 674.055 | $0.000 | 0.00 |
| 32 | Unbilled Supply | | | $ - | | | $ - | $0.000 | 0.00 |
| 33 | Supply Subtotal w unbilled | | | $ 674.055 | | | $ 674.055 | $0.000 | 0.00 |
| 34 | | | | | | | | | |
| 35 | Total Delivery + Supply | 14,450 | | $ 1,189.032 | 14,450 | | $ 1,189.451 | $0.419 | 0.04 |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | WH, WHS & BPL-POF revenues shown to 3 decimals. | | | | | | | |
| 39 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**RATE SCHEDULE PSAL**
**PRIVATE STREET AND AREA LIGHTING SERVICE**
**Schedule SS-IAP-4**
(Units & Revenue in Thousands)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | High Pressure Sodium | 818.700 | 0 | $ 15,407 | 818.700 | 0 | $ 15,407 | $0 | 0.00 |
| 2 | Metal Halide | 231.864 | 0 | 6,308 | 231.864 | 0 | 6,308 | 0 | 0.00 |
| 3 | Filament | 0.792 | 0 | 4 | 0.792 | 0 | 4 | 0 | 0.00 |
| 4 | Mercury Vapor | 102.132 | 0 | 1,509 | 102.132 | 0 | 1,509 | 0 | 0.00 |
| 5 | Fluorescent | 0.012 | 0 | - | 0.012 | 0 | - | 0 | 0.00 |
| 6 | | | | | | | | | |
| 7 | Distribution June-September | 41,200 | 0.007223 | $298 | 41,200 | 0.007256 | $299 | 1 | 0.34 |
| 8 | Distribution October-May | 110,532 | 0.007223 | 798 | 110,532 | 0.007256 | 802 | 4 | 0.50 |
| 9 | SBC | 151,732 | 0.009023 | 1,369 | 151,732 | 0.009023 | 1,369 | 0 | 0.00 |
| 10 | NGC | 151,732 | 0.000024 | 4 | 151,732 | 0.000024 | 4 | 0 | 0.00 |
| 11 | STC-TBC | 151,732 | 0.000000 | 0 | 151,732 | 0.000000 | 0 | 0 | 0.00 |
| 12 | STC-MTC-Tax | 151,732 | 0.000000 | 0 | 151,732 | 0.000000 | 0 | 0 | 0.00 |
| 13 | Zero Emission Certificate Recovery Charge | 151,732 | 0.003845 | 583 | 151,732 | 0.003845 | 583 | 0 | 0.00 |
| 14 | Solar Pilot Recovery Charge | 151,732 | 0.000085 | 13 | 151,732 | 0.000085 | 13 | 0 | 0.00 |
| 15 | Green Programs Recovery Charge | 151,732 | 0.002195 | 333 | 151,732 | 0.002195 | 333 | 0 | 0.00 |
| 16 | Tax Adjustment Credit | 151,732 | 0.000000 | 0 | 151,732 | 0.000000 | 0 | 0 | 0.00 |
| 17 | Green Enabling Mechanism | 151,732 | 0.000000 | 0 | 151,732 | 0.000000 | 0 | 0 | 0.00 |
| 18 | | | | | | | | | |
| 19 | Pole Charges | 427.500 | | 3,510 | 427.500 | | 3,510 | 0 | 0.00 |
| 20 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 21 | Miscellaneous | | | 53 | | | 53 | 0 | 0.00 |
| 22 | Delivery Subtotal | | | $30,189 | | | $30,194 | $5 | 0.02 |
| 23 | Unbilled Delivery | | | (94) | | | (94) | 0 | 0.00 |
| 24 | Delivery Subtotal w unbilled | | | $30,095 | | | $30,100 | $5 | 0.02 |
| 25 | | | | | | | | | |
| 26 | **Supply-BGS** | | | | | | | | |
| 27 | BGS June-September | 41,200 | 0.044045 | 1,815 | 41,200 | 0.044045 | 1,815 | 0 | 0.00 |
| 28 | BGS October-May | 110,532 | 0.047735 | 5,276 | 110,532 | 0.047735 | 5,276 | 0 | 0.00 |
| 29 | BGS Reconciliation-RSCP | 151,732 | 0.000000 | 0 | 151,732 | 0.000000 | 0 | 0 | 0.00 |
| 30 | Miscellaneous | | | 190 | | | 190 | 0 | 0.00 |
| 31 | Supply Subtotal | | | $7,281 | | | $7,281 | $0 | 0.00 |
| 32 | Unbilled Supply | | | (62) | | | (62) | 0 | 0.00 |
| 33 | Supply Subtotal w unbilled | | | $7,219 | | | $7,219 | $0 | 0.00 |
| 34 | | | | | | | | | |
| 35 | Total Delivery + Supply | 151,732 | | $37,314 | 151,732 | | $37,319 | $5 | 0.01 |
| 36 | | | | | | | | | |
| 37 | Notes: | All customers assumed to be on BGS. | | | | | | | |
| 38 | | Annualized Weather Normalized Revenue reflects Delivery rates in effect 10/1/2021 | | | | | | | |

**Gas Revenue Requirement Allocation Explanation of Format**

Pages 2 through 5 presented in Schedule SS-IAP-5 are the 4 relevant pages from the complete cost of service and revenue requirement allocation methodology based on the 2018 Base Rate Case Settlement, approved by the Board on October 29, 2018. Page 2 Part 1 shows the "Final" revenue requirement allocation to the each rates class and its associated functions as defined in the 2018 PSE&G Base Rate Case (Rate Case). Part 2 allocates the Infrastructure Advancement Program Revenue Increase in accordance with the Rate Case Board Order. Pages 3 and 4 provide the interclass revenue allocations based upon the rate rules approved in the Rate Case. Page 5 provides the service charges calculations for each rate class by which are calculated in accordance with the Rate Case Board Order.

**Gas Rate Design Explanation of Format**

The summary provides by rate schedule the Annualized Weather Normalized (all customers assumed to be on BGSS) revenue based on current tariff rates and the proposed initial rate change.

Pages 6 through 14 presented in Schedule SS-IAP-5 are the 9 relevant pages from the complete rate change workpapers from the Company's 2018 Gas Base Rate Case and have been appropriately modified per my testimony to reflect this Infrastructure Advancement Program Initial Rate Adjustment..

**Annualized Weather Normalized (all customers assumed to be on BGSS) and the Proposed Detailed Rate Design.**

In the detailed rate design pages, all the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Balancing, Societal Benefits Charge, Margin Adjustment Charge, Weather Normalization Charge, Green Programs Recovery Charge, Tax Adjustment Credit, Miscellaneous items, and Unbilled Revenue.

Column (1) shows the annualized weather normalized billing units. Column (2) shows present Delivery rates (without Sales and Use Tax, SUT) effective October 1, 2021. The commodity rates in the Column (2) reflects December 2020 and January 2021 through November 2021's class-weighted averages (BGSS-RSG uses the rate as of 6/1/2021). Column (3) presents annualized revenue assuming all customers are provided service under their applicable BGSS provision. Column (4) repeats the billing units of Column (1). Column (5) shows the proposed rates without SUT that result in the proposed revenues shown in Column (6). Columns (7) and (8) show the proposed base rate revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

**Cost of Service and Rate Design Sync**

**Part 1: 2018 Base Rate Case Final Revenue Allocation**

| | | Total | RSG | GSG | LVG | SLG | Notes: |
|---|---|---|---|---|---|---|---|
| 1 | Requested increase in Revenue Requirements | | | $ 123,141,000 | | | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 16 |
| 2 | Total Target Distribution Revenue Requirements | | | $ 888,460,440 | | | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 17 |
| 3 | Sum of Initial Sync Revenue Requirements | | | $ 893,411,330 | | | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 18 |
| 4 | Final Sync Adjustment Factor | | | 0.99446 | | | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 19 |
| 5 | Distribution Access | $ 348,181,228 | $ 285,567,880 | $ 40,848,700 | $ 21,728,392 | $ 36,257 | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 20 |
| 6 | Distribution Delivery | $ 362,951,052 | $ 231,037,735 | $ 42,604,570 | $ 89,282,536 | $ 26,211 | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 21 |
| 7 | Streetlighting Fixtures | $ 417,670 | $ 0 | $ 0 | $ 0 | $ 417,670 | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 22 |
| 8 | Customer Service | $ 80,199,946 | $ 72,101,419 | $ 6,313,852 | $ 1,783,392 | $ 1,284 | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 23 |
| 9 | Measurement | $ 96,710,544 | $ 70,884,585 | $ 16,046,249 | $ 9,779,669 | $ 41 | 2018 Rate Case Schedule SS-G7 R-2, pg 2, line 24 |
| 10 | Total | $ 888,460,440 | $ 659,591,618 | $ 105,813,371 | $ 122,573,988 | $ 481,463 | |

**Part 2: IAP Rate Adjustment Revenue Allocation**

| | | Total | RSG | GSG | LVG | SLG | Notes |
|---|---|---|---|---|---|---|---|
| 11 | Requested increase in Revenue Requirements | | | $ 3,526,648 | | | Schedule SS-IAP-2G |
| 12 | Total Target Distribution Revenue Requirements | | | $ 1,001,396,723 | | | = line 11 + page 3, line 2 |
| 13 | Rate Case Minus Streetlight Fixtures | | | $ 888,042,770 | | | = line 10 - line 7 |
| 14 | Target Minus Streetlight Fixtures | | | $ 1,000,979,054 | | | = line 12 - line 7 |
| 15 | Final Sync Adjustment Factor | | | 1.12717 | | | = line 14 / line 13 |
| 16 | Distribution Access | $ 392,460,958 | $ 321,884,796 | $ 46,043,607 | $ 24,491,687 | $ 40,868 | = line 5 * line 15 |
| 17 | Distribution Delivery | $ 409,109,124 | $ 260,419,814 | $ 48,022,780 | $ 100,636,986 | $ 29,544 | = line 6 * line 15 |
| 18 | Streetlighting Fixtures | $ 417,670 | $ 0 | $ 0 | $ 0 | $ 417,670 | = line 7 |
| 19 | Customer Service | $ 90,399,324 | $ 81,270,871 | $ 7,116,812 | $ 2,010,193 | $ 1,447 | = line 8 * line 15 |
| 20 | Measurement | $ 109,009,647 | $ 79,899,288 | $ 18,086,921 | $ 11,023,392 | $ 47 | = line 9 * line 15 |
| 21 | Total | $ 1,001,396,723 | $ 743,474,770 | $ 119,270,120 | $ 138,162,258 | $ 489,576 | |

**Inter Class Revenue Allocations**
Calculation of Increase Limits

| line # | | (in $1,000) | | Notes: |
|---|---|---|---|---|
| | Requested Revenue Increase to be | | | |
| 1 | recovered from rate schedule charges = | $ 3,527 | | Schedule SS-IAP-2G |
| 2 | Present Distribution Revenue = | $ 997,870 | from RSG, GSG, LVG & SLG | Page 4, col 3, line 11 |
| 3 | Present Total Customer Bills (all on BGSS) = | $ 2,141,687 | | Page 4, col 5, line 11 |
| 4 | Average Distribution Increase = | 0.353% | | = Line 1 / Line 2 |
| 5 | Average Total Bill Increase = | 0.165% | | = Line 1 / Line 3 |
| 6 | Lower Distribution increase limit = | 0.177% | in Distribution charges | = 0.5 * Line 4 |
| 7 | Upper Distribution increase limit #1 = | 0.530% | in Distribution charges | = 1.5 * Line 4 |
| 8 | Upper Bill increase limit #2 = | 0.330% | in Bill Increase | = 2.0 * Line 5 |

all rounded to 0.001%

**Inter Class Revenue Allocations**
Calculation of Increases

| line # | Rate Schedule | Proposed Distribution Revenue Requirement (from COS) (in $1,000) | Present Distribution Revenue (in $1,000) | Unlimited COS Distribution Charge $ Increase (in $1,000) | Present Total Bill Revenue (all on BGSS) (in $1,000) | Unlimited Distribution Charge Increase (%) | Change in MAC & BGSS credits (in $1,000) | Limited Final Distribution Charge Increase (%) | Proposed Total Bill Increase (%) | Proposed Distribution Revenue Increase (in $1,000) |
|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| | Calculation of TSG-F Increase | | | | | | | | | |
| 1 | TSG-F | $ 3,304 | $ 3,504 | $ (200) | $ 18,927 | -5.709% | $ (0.393) | 0.177% | 0.031% | $ 6 |
| | Calculation of TSG-NF & CIG Increase | | | | | | | | | |
| 2 | TSG-NF | ---- | $ 11,251 | ---- | $ 109,168 | ---- | | 0.353% | 0.037% | $ 40 |
| 3 | CIG | ---- | $ 3,278 | ---- | $ 23,558 | ---- | | 0.353% | 0.051% | $ 12 |
| 4 | CSG[1] | ---- | $ 7,427 | ---- | $ 7,931 | ---- | | ---- | 0.050% | $ 4 |
| | Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase | | | | | | | | | |
| 5 | RSG | $ 743,475 | $ 740,895 | $ 2,580 | $ 1,242,285 | 0.348% | $ (39) | 0.354% | 0.208% | $ 2,620 |
| 6 | GSG | $ 119,270 | $ 118,857 | $ 413 | $ 304,674 | 0.348% | $ (6) | 0.353% | 0.136% | $ 420 |
| 7 | LVG | $ 138,162 | $ 137,683 | $ 479 | $ 593,549 | 0.348% | $ (15) | 0.354% | 0.080% | $ 487 |
| 8 | SLG | $ 489.576 | $ 435.075 | | $ 1,179.251 | | | | | |
| 9 | Distribution Only | $ 71.906 | $ 20.483 | $ 51.423 | | 251.052% | $ (0.015) | 0.530% | 0.008% | $ 0.109 |
| 10 | Fixtures | $ 417.670 | $ 414.592 | $ 3.078 | | 0.742% | | 0.000% | 0.000% | $ - |
| 11 | Total for Margin Rates | $ 1,001,397 | $ 997,870 | $ 3,527 | $ 2,141,687 | 0.353% | $ (60.015) | 0.353% | 0.162% | $ 3,527 |
| Notes: | | for TSG-F - from 2018 Rate Case Schedule SS-G7 R-2, pg 1, col 6, line 6; for RSG, GSG, LVG & SLG from page 1, line 21 | IAP workpapers | = (2) - (3) | Page 6 | = (4) / (3) | IAP workpapers | calculated on limits | = (Col 10 + Col 7) / Col 5 | = (3) * (8) |

[1] CSG Credits all flow back through BGSS

**Service Charge Calculations**

| line # | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | Notes: |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | Average Distribution Increase = | | 0.353% | | | | | page 3, line 4 |
| | Rate Schedule | Distribution Access Rev Req (in $1,000) | Customer Service Rev Req (in $1,000) | Measurement Rev Req (in $1,000) | COS Indicated Total Rev Req (in $1,000) | # of Customers | Cost Based Monthly Service Charge ($/month) | Current Monthly Service Charge ($/month) | Proposed Limited Monthly Service Charge ($/month) | |
| 2 | RSG | 321,885 | 81,271 | 79,899 | 483,055 | 1,635,900 | $ 24.61 | $ 8.08 | $ 8.08 | Fixed per 2018 Base Rate Case |
| 3 | GSG | 46,044 | 7,117 | 18,087 | 71,247 | 140,771 | $ 42.18 | $ 16.65 | $ 16.74 | move to costs, limited @ 1.5 times overall avg Distribution % increase |
| 4 | LVG | 24,492 | 2,010 | 11,023 | 37,525 | 18,375 | $ 170.19 | $ 147.80 | $ 148.58 | move to costs, limited @ 1.5 times overall avg Distribution % increase |
| 5 | TSG-F | 530 | 400 | | 930 | 37 | $ 2,095.57 | $ 791.61 | $ 795.81 | move to costs, limited @ 1.5 times overall avg Distribution % increase |
| 6 | TSG-NF | | | | | | | $ 791.61 | $ 795.81 | set equal to new TSG-F Service Charge |
| 7 | CIG | | | | | | | $ 182.37 | $ 183.01 | increase current @ average Distribution % increase |
| 8 | CSG | | | | | | | $ 791.61 | $ 795.81 | set equal to new TSG-F Service Charge |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | |

Notes:

- (2)–(4): values for RSG, GSG & LVG for Cols 2, 3, & 4 from page 2, lines 16, 19 & 20; values for TSG-F for Cols 2, 3 & 4 from 2018 Rate Case Schedule SS-G7 R-2, page 1, lines 1, 4 & 5
- (5): = (2) + (3) + (4)
- (6): RSG, GSG & LVG from 2018 Rate Case Schedule SS-G7 R-2, page 2, line 1; TSG-F from COS workpapers
- (7): = Col 5 * 1000 / Col 6 / 12 rounded to $0.01
- (8): From Tariff
- (9): based on methodology described

**GAS PROOF OF REVENUE**
**SUMMARY**
**GAS RATE INCREASE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | Rate Schedule | | Annualized Weather Normalized | | Proposed | | Difference | |
|---|---|---|---|---|---|---|---|---|
| | | | Therms | Revenue | Therms | Revenue | Revenue | Percent |
| | | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | RSG | | 1,494,928 | $1,242,285 | 1,494,928 | $1,244,889 | $2,604 | 0.21 |
| 2 | GSG | | 297,484 | 304,674 | 297,484 | 305,093 | 419 | 0.14 |
| 3 | LVG | | 740,103 | 593,549 | 740,103 | 594,032 | 483 | 0.08 |
| 6 | SLG | | 679 | 1,179.251 | 679 | 1,179.356 | 0.105 | 0.01 |
| 7 | | Subtotal | 2,533,194 | 2,141,687 | 2,533,194 | 2,145,193 | 3,506 | 0.16 |
| 8 | | | | | | | | |
| 9 | TSG-F | | 25,950 | 18,927.011 | 25,950 | 18,933.213 | 6.202 | 0.03 |
| 10 | TSG-NF | | 179,184 | 109,168 | 179,184 | 109,208 | 40 | 0.04 |
| 11 | CIG | | 41,067 | 23,558 | 41,067 | 23,570 | 12 | 0.05 |
| 12 | CSG | | 789,848 | 7,931 | 789,848 | 7,935 | 4 | 0.05 |
| 13 | | Subtotal | 1,036,049 | 159,584 | 1,036,049 | 159,646 | 62 | 0.04 |
| 14 | | | | | | | | |
| 15 | | Totals | 3,569,243 | 2,301,271 | 3,569,243 | 2,304,839 | $3,568 | 0.16 |
| 16 | | | | | | | | |
| 17 | | | | | | | | |
| 18 | | | | | Less change in MAC included above | | $41 | |
| 19 | | | | | | | | |
| 20 | | | | | Gas Revenue Requirement | | $3,527 | |
| 21 | | | | | | | | |
| 22 | | | | | | | | |

| | | | Increase Before Mac Adjustment | Increase Above | MAC Adjustment |
|---|---|---|---|---|---|
| 23 | | | | | |
| 24 | RSG | | $2,580 | $2,604 | 24 |
| 25 | GSG | | 414 | 419 | 5 |
| 26 | LVG | | 471 | 483 | 12 |
| 27 | SLG | | 0.093 | 0.105 | 0.012 |
| 28 | | Subtotal | 3,465 | 3,506 | 41 |
| 29 | | | | | |
| 30 | TSG-F | | 5.783 | 6.202 | 0.419 |
| 31 | TSG-NF | | 40 | 40 | 0 |
| 32 | CIG | | 12 | 12 | 0 |
| 33 | CSG | | 4 | 4 | 0 |
| 34 | | Subtotal | 62 | 62 | 0 |
| 35 | | | | | |
| 36 | | Totals | $3,527 | $3,568 | 41 |
| 37 | | | | | |
| 38 | | | | | |

39 Notes:
40 All customers assumed to be on BGSS.
41 SLG units and revenues shown to 3 decimals.
42 TSG-F revenues shown to 3 decimals.
43 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
44 plus applicable BGSS charges.

**RATE SCHEDULE RSG**
**RESIDENTIAL SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 19,630.803 | 8.08 | $158,617 | 19,630.803 | 8.08 | $158,617 | 0 | 0.00 |
| 2 | Distribution Charge | 1,494,872 | 0.391767 | 585,642 | 1,494,872 | 0.393528 | 588,274 | 2,632 | 0.45 |
| 3 | Off-Peak Dist | 56 | 0.195884 | 11 | 56 | 0.196764 | 11 | 0 | 0.00 |
| 4 | Balancing Charge | 917,326 | 0.080397 | 73,750 | 917,326 | 0.080397 | 73,750 | 0 | 0.00 |
| 5 | SBC | 1,494,928 | 0.049297 | 73,695 | 1,494,928 | 0.049297 | 73,695 | 0 | 0.00 |
| 6 | Margin Adjustment | 1,494,928 | (0.006519) | (9,745) | 1,494,928 | (0.006519) | (9,745) | 0 | 0.00 |
| 7 | Weather Normalization | 917,326 | (0.001050) | (963) | 917,326 | -0.001050 | (963) | 0 | 0.00 |
| 8 | Green Programs Recovery Charge | 1,494,928 | 0.006923 | 10,349 | 1,494,928 | 0.006923 | 10,349 | 0 | 0.00 |
| 9 | Tax Adjustment Credit | 1,494,928 | (0.060650) | (90,667) | 1,494,928 | (0.060650) | (90,667) | 0 | 0.00 |
| 10 | Green Enabling Mechanism | 1,494,928 | 0.000000 | 0 | 1,494,928 | 0.000000 | 0 | 0 | 0.00 |
| 11 | Facilities Charges | | | 0 | | | 0 | 0 | 0.00 |
| 12 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 13 | Miscellaneous | | | (15) | | | (15) | 0 | 0.00 |
| 14 | Delivery Subtotal | 1,494,928 | | $800,674 | 1,494,928 | | $803,306 | $2,632 | 0.33 |
| 15 | Unbilled Delivery | | | (3,614) | | | (3,626) | (12) | 0.33 |
| 16 | Delivery Subtotal w unbilled | | | $797,060 | | | $799,680 | $2,620 | 0.33 |
| 17 | | | | | | | | | |
| 18 | **Supply** | | | | | | | | |
| 19 | BGSS-RSG | 1,494,872 | 0.300109 | $448,625 | 1,494,872 | 0.300109 | $448,625 | $0 | 0.00 |
| 20 | Emergency Sales Service | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 21 | BGSS Contrib. from TSG-F, TSG-NF & CIG | 0 | 0.000000 | 0 | 1,494,928 | (0.000011) | (16) | (16) | 0.00 |
| 22 | Off-Peak Comm. Charge | 46 | 0.303758 | 14 | 46 | 0.303758 | 14 | 0 | 0.00 |
| 23 | | | | | | | | | |
| 24 | Miscellaneous | | | (1) | | | (1) | 0.00 | 0.00 |
| 25 | Supply subtotal | 1,494,918 | | $448,638 | 1,494,918 | | $448,622 | (16.00) | 0.00 |
| 26 | Unbilled Supply | | | (3,413) | | | (3,413) | 0.00 | 0.00 |
| 27 | Supply Subtotal w unbilled | | | $445,225 | | | $445,209 | (16.00) | 0.00 |
| 28 | | | | | | | | | |
| 29 | Total Delivery + Supply | 1,494,928 | | $1,242,285 | 1,494,928 | | $1,244,889 | 2,604.00 | 0.21 |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | Notes: | | | | | | | | |
| 34 | All customers assumed to be on BGSS. | | | | | | | | |
| 35 | Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021 | | | | | | | | |
| 36 | plus applicable BGSS charges. | | | | | | | | |
| 37 | | | | | | | | | |

**RATE SCHEDULE GSG**
**GENERAL SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 1,689.246 | 16.65 | $28,126 | 1,689.246 | 16.74 | $28,278 | $152 | 0.54 |
| 2 | Distribution Charge - Pre 7/14/97 | 2,183 | 0.304859 | 666 | 2,183 | 0.305757 | 667 | 1 | 0.15 |
| 3 | Distribution Charge - All Others | 295,256 | 0.304859 | 90,011 | 295,256 | 0.305757 | 90,277 | 266 | 0.30 |
| 4 | Off-Peak Dist Charge - Pre 7/14/97 | 0 | 0.152430 | 0 | 0 | 0.152879 | 0 | 0 | 0.00 |
| 5 | Off-Peak Dist Charge - All Others | 45 | 0.152430 | 7 | 45 | 0.152879 | 7 | 0 | 0.00 |
| 6 | Balancing Charge | 173,170 | 0.080397 | 13,922 | 173,170 | 0.080397 | 13,922 | 0 | 0.00 |
| 7 | SBC | 297,484 | 0.049297 | 14,665 | 297,484 | 0.049297 | 14,665 | 0 | 0.00 |
| 8 | Margin Adjustment | 297,484 | (0.006519) | (1,939) | 297,484 | (0.006519) | (1,939) | 0 | 0.00 |
| 9 | Weather Normalization | 173,170 | (0.001050) | (182) | 173,170 | (0.001050) | (182) | 0 | 0.00 |
| 10 | Green Programs Recovery Charge | 297,484 | 0.006923 | 2,059 | 297,484 | 0.006923 | 2,059 | 0 | 0.00 |
| 11 | Tax Adjustment Credit | 297,484 | (0.050734) | (15,093) | 297,484 | (0.050734) | (15,093) | 0 | 0.00 |
| 12 | Green Enabling Mechanism | 297,484 | 0.000000 | 0 | 297,484 | 0.000000 | 0 | 0 | 0.00 |
| 13 | Facilities Charges | | | 0 | | | 0 | 0 | 0.00 |
| 14 | Minimum | | | 2 | | | 2 | 0 | 0.00 |
| 15 | Miscellaneous | | | (313) | | | (313) | 0 | 0.00 |
| 16 | Delivery Subtotal | 297,484 | | $131,931 | 297,484 | | $132,350 | $419 | 0.32 |
| 17 | Unbilled Delivery | | | 398 | | | 399 | 1 | 0.25 |
| 18 | Delivery Subtotal w unbilled | | | $132,329 | | | $132,749 | $420 | 0.32 |
| 19 | | | | | | | | | |
| 20 | **Supply** | | | | | | | | |
| 21 | BGSS | 297,484 | 0.542564 | $161,404 | 297,484 | 0.542564 | $161,404 | $0 | 0.00 |
| 22 | Emergency Sales Service | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 23 | BGSS Contrib. from TSG-F, TSG-NF & CIG | 0 | 0.000000 | 0 | 297,484 | (0.000005) | (1) | (1) | 0.00 |
| 24 | | | | | | | | | |
| 25 | Miscellaneous | | | (51) | | | (51) | 0 | 0.00 |
| 26 | Supply subtotal | 297,484 | | $161,353 | 297,484 | | $161,352 | (1) | 0.00 |
| 27 | Unbilled Supply | | | 10,992 | | | 10,992 | 0 | 0.00 |
| 28 | Supply Subtotal w unbilled | | | $172,345 | | | $172,344 | (1) | 0.00 |
| 29 | | | | | | | | | |
| 30 | Total Delivery + Supply | 297,484 | | $304,674 | 297,484 | | $305,093 | $419 | 0.14 |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | | | | | | | | | |

34 Notes:
35 All customers assumed to be on BGSS.
36 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
37 plus applicable BGSS charges.
38

**RATE SCHEDULE LVG**
**LARGE VOLUME SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 220.495 | 147.80 | $32,589 | 220.495 | 148.58 | $32,761 | $172 | 0.53 |
| 2 | Demand Charge | 18,017 | 4.0632 | 73,207 | 18,017 | 4.0754 | 73,426 | 219 | 0.30 |
| 3 | Distribution Charge 0-1,000 pre 7/14/97 | 8,974 | 0.043725 | 392 | 8,974 | 0.043336 | 389 | (3) | (0.77) |
| 4 | Distribution Charge over 1,000 pre 7/14/97 | 45,378 | 0.043078 | 1,955 | 45,378 | 0.043344 | 1,967 | 12 | 0.61 |
| 5 | Distribution Charge 0-1,000 post 7/14/97 | 145,700 | 0.043725 | 6,371 | 145,700 | 0.043336 | 6,314 | (57) | (0.89) |
| 6 | Distribution Charge over 1,000 post 7/14/97 | 540,051 | 0.043078 | 23,264 | 540,051 | 0.043344 | 23,408 | 144 | 0.62 |
| 7 | Balancing Charge | 361,999 | 0.080397 | 29,104 | 361,999 | 0.080397 | 29,104 | 0 | 0.00 |
| 8 | SBC | 740,103 | 0.049297 | 36,485 | 740,103 | 0.049297 | 36,485 | 0 | 0.00 |
| 9 | Margin Adjustment | 740,103 | (0.006519) | (4,825) | 740,103 | (0.006519) | (4,825) | 0 | 0.00 |
| 10 | Weather Normalization | 361,999 | (0.001050) | (380) | 361,999 | (0.001050) | (380) | 0 | 0.00 |
| 11 | Green Programs Recovery Charge | 740,103 | 0.006923 | 5,124 | 740,103 | 0.006923 | 5,124 | 0 | 0.00 |
| 12 | Tax Adjustment Credit | 740,103 | (0.023609) | (17,473) | 740,103 | (0.023609) | (17,473) | 0 | 0.00 |
| 13 | Green Enabling Mechanism | 740,103 | 0.000000 | $0 | 740,103 | 0.000000 | $0 | 0 | 0.00 |
| 14 | Facilities Charges | | | 1 | | | 1 | 0 | 0.00 |
| 15 | Minimum | | | 218 | | | 218 | 0 | 0.00 |
| 16 | Miscellaneous | | | (279) | | | (279) | (0) | 0.08 |
| 17 | Delivery Subtotal | 740,103 | | $185,753 | 740,103 | | $186,240 | $487 | 0.26 |
| 18 | Unbilled Delivery | | | (47) | | | (47) | 0 | 0.00 |
| 19 | Delivery Subtotal w unbilled | | | $185,706 | | | $186,193 | $487 | 0.26 |
| 20 | | | | | | | | | |
| 21 | | | | | | | | | |
| 22 | **Supply** | | | | | | | | |
| 23 | BGSS | 740,103 | 0.549609 | $406,767 | 740,103 | 0.549609 | $406,767 | $0 | 0.00 |
| 24 | Emergency Sales Service | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 25 | BGSS Contrib. from TSG-F, TSG-NF & CIG | 0 | 0.000000 | 0 | 740,103 | (0.000005) | (4) | (4) | 0.00 |
| 26 | | | | | | | | | |
| 27 | Miscellaneous | | | (143) | | | (143) | 0 | 0.00 |
| 28 | Supply Subtotal | 740,103 | | $406,624 | 740,103 | | $406,620 | ($4) | 0.00 |
| 29 | Unbilled Supply | | | 1,219 | | | 1,219 | 0 | 0.00 |
| 30 | Supply Subtotal w unbilled | | | $407,843 | | | $407,839 | ($4) | 0.00 |
| 31 | | | | | | | | | |
| 32 | Total Delivery + Supply | 740,103 | | $593,549 | 740,103 | | $594,032 | $483 | 0.08 |
| 33 | | | | | | | | | |
| 34 | | | | | | | | | |
| 35 | | | | | | | | | |

36 Notes:
37 All customers assumed to be on BGSS.
38 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
39 plus applicable BGSS charges.

**RATE SCHEDULE SLG**
**STREET LIGHTING SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Single | 10.392 | 13.2351 | $137.539 | 10.392 | 13.2351 | $137.539 | $0.000 | 0.00 |
| 2 | Double Inverted | 0.108 | 13.2351 | 1.429 | 0.108 | 13.2351 | 1.429 | 0.000 | 0.00 |
| 3 | Double Upright | 0.588 | 13.2351 | 7.782 | 0.588 | 13.2351 | 7.782 | 0.000 | 0.00 |
| 4 | Triple prior to 1/1/93 | 18.096 | 13.2351 | 239.502 | 18.096 | 13.2351 | 239.502 | 0.000 | 0.00 |
| 5 | Triple on and after 1/1/93 | 0.420 | 67.4762 | 28.340 | 0.420 | 67.4762 | 28.340 | 0.000 | 0.00 |
| 6 | Distribution Therm Charge | 678.777 | 0.049343 | 33.493 | 678.777 | 0.049504 | 33.602 | 0.109 | 0.33 |
| 7 | SBC | 678.777 | 0.049297 | 33.462 | 678.777 | 0.049297 | 33.462 | 0.000 | 0.00 |
| 8 | Margin Adjustment | 678.777 | (0.006519) | (4.425) | 678.777 | (0.006519) | (4.425) | 0.000 | 0.00 |
| 9 | Green Programs Recovery Charge | 678.777 | 0.006923 | 4.699 | 678.777 | 0.006923 | 4.699 | 0.000 | 0.00 |
| 10 | Tax Adjustment Credit | 678.777 | (0.094881) | (64.403) | 678.777 | (0.094881) | (64.403) | 0.000 | 0.00 |
| 11 | Green Enabling Mechanism | 678.777 | 0.000000 | 0.000 | 678.777 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 12 | Facilities Charges | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 13 | Minimum | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 14 | Miscellaneous | | | (13.010) | | | (13.010) | 0.000 | 0.00 |
| 15 | Delivery Subtotal | 678.777 | | $404.408 | 678.777 | | $404.517 | $0.109 | 0.03 |
| 16 | Unbilled Delivery | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 17 | Delivery Subtotal w unbilled | | | $404.408 | | | $404.517 | $0.109 | 0.03 |
| 18 | | | | | | | | | |
| 19 | **Supply** | | | | | | | | |
| 20 | BGSS | 678.777 | 0.567450 | $385.172 | 678.777 | 0.567450 | $385.172 | $0.000 | 0.00 |
| 21 | Emergency Sales Service | 0.000 | 0.000000 | 0.000 | 0.000 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 22 | BGSS Contrib. from TSG-F, TSG-NF & CIG | 0.000 | 0.000000 | 0.000 | 678.777 | (0.000005) | (0.003) | (0.003) | 0.00 |
| 23 | Miscellaneous | | | 131.390 | | | 131.390 | 0.000 | 0.00 |
| 24 | Supply Subtotal | 678.777 | | $516.562 | 678.777 | | $516.559 | ($0.003) | 0.00 |
| 25 | Unbilled Supply | | | 258.281 | | | 258.280 | (0.001) | 0.00 |
| 26 | Supply Subtotal w unbilled | | | $774.843 | | | $774.839 | ($0.004) | 0.00 |
| 27 | | | | | | | | | |
| 28 | Total Delivery + Supply | 678.777 | | $1,179.251 | 678.777 | | $1,179.356 | $0.105 | 0.01 |
| 29 | | | | | | | | | |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |

32 Notes:
33 All customers assumed to be on BGSS.
34 SLG units and revenues shown to 3 decimals.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
36 plus applicable BGSS charges.

**RATE SCHEDULE CIG**
**COGENERATION INTERRUPTIBLE SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Units** | **Rate** | **Revenue** | **Units** | **Rate** | **Revenue** | **Revenue** | **Percent** |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 0.166 | 182.37 | $30 | 0.166 | 183.01 | $30 | $0 | 0.00 |
| 2 | Margin 0-600,000 | 32,835 | 0.081631 | 2,680 | 32,835 | 0.081923 | 2,690 | 10 | 0.37 |
| 3 | Margin over 600,000 | 8,232 | 0.071631 | 590 | 8,232 | 0.071923 | 592 | 2 | 0.34 |
| 4 | Extended Gas Service | 0 | 0.150000 | 0 | 0 | 0.150000 | 0 | 0 | 0.00 |
| 5 | SBC | 41,067 | 0.049297 | 2,024 | 41,067 | 0.049297 | 2,024 | 0 | 0.00 |
| 6 | Green Programs Recovery Charge | 41,067 | 0.006923 | 284 | 41,067 | 0.006923 | 284 | 0 | 0.00 |
| 7 | Tax Adjustment Credit | 41,067 | (0.007753) | (318) | 41,067 | (0.007753) | (318) | 0 | 0.00 |
| 8 | Green Enabling Mechanism | 41,067 | 0.000000 | 0 | 41,067 | 0.000000 | 0 | 0 | 0.00 |
| 9 | Facilities Charges | | | 0 | | | 0 | 0 | 0.00 |
| 10 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 11 | Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 12 | Delivery Subtotal | 41,067 | | $5,290 | 41,067 | | $5,302 | $12 | 0.23 |
| 13 | Unbilled Delivery | | | (36) | | | (36) | 0 | 0.00 |
| 14 | Delivery Subtotal w unbilled | | | $5,254 | | | $5,266 | $12 | 0.23 |
| 15 | | | | | | | | | |
| 16 | **Supply** | | | | | | | | |
| 17 | Commodity Component | 41,067 | 0.381864 | $15,682 | 41,067 | 0.381864 | $15,682 | $0 | 0.00 |
| 18 | Pilot Use | 1,249 | 1.89 | 2,361 | 1,249 | 1.89 | 2,361 | 0 | 0.00 |
| 19 | Penalty Use | 0 | | 0 | 0 | | 0 | 0 | 0.00 |
| 20 | Extended Gas Service | 5 | | 338 | 5 | | 338 | 0 | 0.00 |
| 21 | Miscellaneous | | | 0 | | | 0 | 0 | 0.00 |
| 22 | Supply Subtotal | 42,321 | | $18,381 | 42,321 | | $18,381 | $0 | 0.00 |
| 23 | Unbilled Supply | | | (77) | | | (77) | 0 | 0.00 |
| 24 | Supply Subtotal w unbilled | | | $18,304 | | | $18,304 | $0 | 0.00 |
| 25 | | | | | | | | | |
| 26 | Total Delivery + Supply | 41,067 | | $23,558 | 41,067 | | $23,570 | $12 | 0.05 |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |

30 Notes:
31 All customers assumed to be on BGSS.
32 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
33 plus applicable BGSS charges.
34

**RATE SCHEDULE TSG-F**
**FIRM TRANSPORTATION GAS SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 0.494 | 791.61 | $391.055 | 0.494 | 795.81 | $393.130 | $2.075 | 0.53 |
| 2 | Demand Charge | 487 | 2.1205 | 1,032.684 | 487 | 2.1233 | 1,034.047 | 1.363 | 0.13 |
| 3 | Demand Charge, Agreements | 0 | 0.0000 | 0.000 | 0 | 0.0000 | 0.000 | 0.000 | 0.00 |
| 4 | Distribution Charge | 25,950 | 0.081055 | 2,103.377 | 25,950 | 0.081160 | 2,106.102 | 2.725 | 0.13 |
| 5 | Distribution Charge, Agreements | 0 | 0.000000 | 0.000 | 0 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 6 | SBC | 25,950 | 0.049297 | 1,279.257 | 25,950 | 0.049297 | 1,279.257 | 0.000 | 0.00 |
| 7 | SBC, Agreements | 0 | 0.000000 | 0.000 | 0 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 8 | Margin Adjustment | 25,950 | (0.006519) | (169.168) | 25,950 | (0.006519) | (169.168) | 0.000 | 0.00 |
| 9 | Margin Adjustment, Agreements | 0 | (0.006519) | 0.000 | 0 | (0.006519) | 0.000 | 0.000 | 0.00 |
| 10 | Green Programs Recovery Charge | 25,950 | 0.006923 | 179.652 | 25,950 | 0.006923 | 179.652 | 0.000 | 0.00 |
| 11 | Green Programs Recovery Charge, Agreements | 0 | 0.000000 | 0.000 | 0 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 12 | Tax Adjustment Credit | 25,950 | (0.018498) | (480.023) | 25,950 | (0.018498) | (480.023) | 0.000 | 0.00 |
| 13 | Green Enabling Mechanism | 25,950 | 0.000000 | 0.000 | 25,950 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 14 | Facilities Charges | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 15 | Minimum | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 16 | Miscellaneous | | | (54.034) | | | (54.050) | (0.016) | 0.03 |
| 17 | Delivery Subtotal | 25,950 | | 4,282.800 | 25,950 | | 4,288.947 | 6.147 | 0.14 |
| 18 | Unbilled Delivery | | | 38.211 | | | 38.266 | 0.055 | 0.14 |
| 19 | Delivery Subtotal w unbilled | | | 4,321.011 | | | 4,327.213 | 6.202 | 0.14 |
| 20 | | | | | | | | | |
| 21 | **Supply** | | | | | | | | |
| 22 | Commodity Charge, BGSS-F | 25,950 | 0.562852 | $14,606.000 | 25,950 | 0.562852 | $14,606.000 | $0.000 | 0.00 |
| 23 | Emergency Sales Service | 0 | 0.000000 | 0.000 | 0 | 0.000000 | 0.000 | 0.000 | 0.00 |
| 24 | Miscellaneous | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 25 | Supply Subtotal | 25,950 | | $14,606.000 | 25,950 | | $14,606.000 | $0.000 | 0.00 |
| 26 | Unbilled Supply | | | 0.000 | | | 0.000 | 0.000 | 0.00 |
| 27 | Supply Subtotal w unbilled | | | $14,606.000 | | | $14,606.000 | $0.000 | 0.00 |
| 28 | | | | | | | | | |
| 29 | Total Delivery + Supply | 25,950 | | $18,927.011 | 25,950 | | $18,933.213 | $6.202 | 0.03 |

30
31
32
33 Notes:
34 All customers assumed to be on BGSS.
35 TSG-F revenues shown to 3 decimals.
36 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
37 plus applicable BGSS charges.
38

**RATE SCHEDULE TSG-NF**
**NON-FIRM TRANSPORTATION GAS SERVICE**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge | 2.218 | 791.61 | $1,756 | 2.218 | 795.81 | $1,765 | $9 | 0.51 |
| 2 | Dist Charge 0-50,000 | 99,839 | 0.090843 | 9,070 | 99,839 | 0.091148 | 9,100 | 30 | 0.33 |
| 3 | Dist Charge 0-50,000, Agreements | 600 | 0.023333 | 14 | 600 | 0.023333 | 14 | 0 | 0.00 |
| 4 | Dist Charge over 50,000 | 67,427 | 0.090843 | 6,125 | 67,427 | 0.091148 | 6,146 | 21 | 0.34 |
| 5 | Dist Charge over 50,000, Agreements | 11,318 | 0.023502 | 266 | 11,318 | 0.023502 | 266 | 0 | 0.00 |
| 6 | SBC | 167,266 | 0.049297 | 8,246 | 167,266 | 0.049297 | 8,246 | 0 | 0.00 |
| 7 | SBC, Agreements | 11,918 | 0.042876 | 511 | 11,918 | 0.042876 | 511 | 0 | 0.00 |
| 8 | Green Programs Recovery Charge | 167,266 | 0.006923 | 1,158 | 167,266 | 0.006923 | 1,158 | 0 | 0.00 |
| 9 | Green Programs Recovery Charge, Agreements | 11,918 | 0.005370 | 64 | 11,918 | 0.005370 | 64 | 0 | 0.00 |
| 10 | Tax Adjustment Credit | 167,266 | (0.006487) | (1,085) | 167,266 | (0.006487) | (1,085) | 0 | 0.00 |
| 11 | Green Enabling Mechanism | 167,266 | 0.000000 | 0 | 167,266 | 0.000000 | 0 | 0 | 0.00 |
| 12 | Facilities Charges | | | 5 | | | 5 | 0 | 0.00 |
| 13 | Minimum | | | 0 | | | 0 | 0 | 0.00 |
| 14 | Miscellaneous | | | (277) | | | (277) | 0 | 0.00 |
| 15 | Delivery Subtotal | 179,184 | | $25,853 | 179,184 | | $25,913 | $60 | 0.23 |
| 16 | Unbilled Delivery | | | (8,699) | | | (8,719) | (20) | 0.23 |
| 17 | Delivery Subtotal w unbilled | | | $17,154 | | | $17,194 | $40 | 0.23 |
| 18 | | | | | | | | | |
| 19 | **Supply** | | | | | | | | |
| 20 | Commodity Charge, BGSS-I | 179,184 | 0.531158 | $95,175 | 179,184 | 0.531158 | $95,175 | $0 | 0.00 |
| 21 | Emergency Sales Service | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 22 | Pilot Use | 26 | 1.890000 | 49 | 26 | 1.890000 | 49 | 0 | 0.00 |
| 23 | Penalty Use | 19 | 0.473684 | 9 | 19 | 0.473684 | 9 | 0 | 0.00 |
| 24 | Miscellaneous | | | 2 | | | 2 | 0 | 0.00 |
| 25 | Supply Subtotal | 179,229 | | $95,235 | 179,229 | | $95,235 | $0 | 0.00 |
| 26 | Unbilled Supply | | | (3,221) | | | (3,221) | 0 | 0.00 |
| 27 | Supply Subtotal w unbilled | | | $92,014 | | | $92,014 | $0 | 0.00 |
| 28 | | | | | | | | | |
| 29 | Total Delivery + Supply | 179,184 | | $109,168 | 179,184 | | $109,208 | $40 | 0.04 |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
36 plus applicable BGSS charges.
37

**RATE SCHEDULE CSG**
**CONTRACT SERVICES**
**Schedule SS-IAP-5**
(Therms & Revenue - Thousands, Rate - $/Therm)

| | | Annualized Weather Normalized | | | Proposed | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|
| | | Units | Rate | Revenue | Units | Rate | Revenue | Revenue | Percent |
| | **Delivery** | (1) | (2) | (3=1*2) | (4) | (5) | (6=4*5) | (7=6-3) | (8=7/3) |
| 1 | Service Charge - Power | 0.0800 | 791.61 | $63 | 0.0800 | 795.81 | $64 | $1 | 1.59 |
| 2 | Service Charge - Power- Non Firm | 0.0120 | 791.61 | 9 | 0.0120 | 795.81 | 10 | 1 | 11.11 |
| 3 | Service Charge - Other | 0.1090 | 791.61 | 86 | 0.1090 | 795.81 | 87 | 1 | 1.16 |
| 4 | Distribution Charge - Power | 599,445 | 0.006051 | 3,627 | 599,445 | 0.006051 | 3,627 | 0 | 0.00 |
| 5 | Distribution Charge - Power- Non Firm | 4,755 | 0.090843 | 432 | 4,755 | 0.091148 | 433 | 1 | 0.23 |
| 6 | Distribution Charge - Other | 185,648 | 0.011904 | 2,210 | 185,648 | 0.011904 | 2,210 | 0 | 0.00 |
| 7 | Maintenance - Power | 599,445 | 0.000142 | 85 | 599,445 | 0.000142 | 85 | 0 | 0.00 |
| 8 | Maintenance - Power- Non Firm | 4,755 | 0.000000 | 0 | 4,755 | 0.000000 | 0 | 0 | 0.00 |
| 9 | Maintenance - Other | 185,648 | 0.000113 | 21 | 185,648 | 0.000113 | 21 | 0 | 0.00 |
| 10 | Pilot Use | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 11 | Penalty Use | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 12 | Balancing Charge (applicable only if customer uses BGSS-F) | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 13 | SBC | 789,848 | 0.049297 | 980 | 789,848 | 0.049297 | 980 | 0 | 0.00 |
| 14 | Green Programs Recovery Charge | 789,848 | 0.006923 | 149 | 789,848 | 0.006923 | 149 | 0 | 0.00 |
| 15 | Tax Adjustment Credit | 789,848 | (0.000846) | (668) | 789,848 | (0.000846) | (668) | 0 | 0.00 |
| 16 | Green Enabling Mechanism | 789,848 | 0.000000 | 0 | 789,848 | 0.000000 | 0 | 0 | 0.00 |
| 17 | Facilities Chg. | | | 840 | | | 840 | 0 | 0.00 |
| 18 | Minimum | | | 271 | | | 271 | 0 | 0.00 |
| 19 | Sales Tax Discount - Delivery | | | (428) | | | (428) | 0 | 0.00 |
| 20 | Misc. | | | 300 | | | 300 | 0 | 0.00 |
| 21 | Delivery Subtotal | 789,848 | | 7,977 | 789,848 | | 7,981 | 4 | 0.05 |
| 22 | Unbilled Delivery | | | (95) | | | (95) | 0 | 0.00 |
| 23 | Delivery Subtotal w/ Unbilled | 789,848 | | 7,882 | 789,848 | | 7,886 | 4 | 0.05 |
| 24 | | | | | | | | | |
| 25 | **Supply** | | | | | | | | |
| 26 | BGSS-Firm - Power | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 27 | BGSS-Firm - Power- Non Firm | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 28 | BGSS-Firm - Other | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 29 | | | | | | | | | |
| 30 | BGSS-Interruptible - Power | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 31 | BGSS-Interruptible - Power- Non Firm | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 32 | BGSS-Interruptible - Other | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 33 | | | | | | | | | |
| 34 | Emergency Sales Svc. - Power | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 35 | Emergency Sales Svc. - Power- Non Firm | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 36 | Emergency Sales Svc - Other | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 37 | | | | | | | | | |
| 38 | Pilot Use | 26 | 1.89 | 49 | 26 | 1.89 | 49 | 0 | 0.00 |
| 39 | Penalty Use | 0 | 0.000000 | 0 | 0 | 0.000000 | 0 | 0 | 0.00 |
| 40 | Misc. | 19 | | 0 | 19 | | 0 | 0 | 0.00 |
| 41 | Supply Subtotal | 45 | | 49 | 45 | | 49.140 | 0 | 0.00 |
| 42 | Unbilled Supply | 0 | | 0 | 0 | | 0 | 0 | 0.00 |
| 43 | Supply Subtotal w/ Unbilled | 45 | | 49 | 45 | | 49.140 | 0 | 0.00 |
| 44 | | | | | | | | | |
| 45 | **Total Delivery & Supply** | 789,893 | | 7,931 | 789,893 | | 7,935 | 4.00 | 0.05 |
| 46 | | | | | | | | | |

47 Notes:
48 All customers assumed to be on BGSS.
49 Annualized Weather Normalized Revenue reflects Delivery rates as of 10/1/2021
50 plus applicable BGSS charges.

| Rate Schedule | | Present IAP 10/1/2021 Charge w/o SUT | Present IAP 10/1/2021 Charge Including SUT | Rate Adjustment 3 4/1/2024 Charge w/o SUT | Rate Adjustment 3 4/1/2024 Charge Including SUT | Rate Adjustment 4 10/1/2024 Charge w/o SUT | Rate Adjustment 4 10/1/2024 Charge Including SUT | Rate Adjustment 5 4/1/2025 Charge w/o SUT | Rate Adjustment 5 4/1/2025 Charge Including SUT | Rate Adjustment 6 4/1/2026 Charge w/o SUT | Rate Adjustment 6 4/1/2026 Charge Including SUT | Rate Adjustment 7 10/1/2026 Charge w/o SUT | Rate Adjustment 7 10/1/2026 Charge Including SUT | Total IIPC Rate Adjustments Charge w/o SUT | Total IIPC Rate Adjustments Charge Including SUT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RS** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distribution 0-600 Sum | $0.000000 | $0.000000 | $0.001442 | $0.001538 | $0.000889 | $0.000948 | $0.000926 | $0.000987 | $0.004848 | $0.005169 | $0.000643 | $0.000686 | $0.008748 | $0.009328 |
| | Distribution 0-600 Win | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| | Distribution over 600 Sum | $0.000000 | $0.000000 | $0.001442 | $0.001538 | $0.000889 | $0.000948 | $0.000926 | $0.000987 | $0.004848 | $0.005169 | $0.000643 | $0.000686 | $0.008748 | $0.009328 |
| | Distribution over 600 Win | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **RHS** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distribution 0-600 Sum | $0.000000 | $0.000000 | $0.000810 | $0.000863 | $0.000524 | $0.000559 | $0.000546 | $0.000582 | $0.002743 | $0.002925 | $0.000375 | $0.000400 | $0.004998 | $0.005329 |
| | Distribution 0-600 Win | $0.000000 | $0.000000 | $0.000379 | $0.000404 | $0.000230 | $0.000245 | $0.000244 | $0.000260 | $0.001257 | $0.001341 | $0.000173 | $0.000184 | $0.002283 | $0.002434 |
| | Distribution over 600 Sum | $0.000000 | $0.000000 | $0.000810 | $0.000864 | $0.000524 | $0.000559 | $0.000546 | $0.000582 | $0.002743 | $0.002925 | $0.000375 | $0.000399 | $0.004998 | $0.005329 |
| | Distribution over 600 Win | $0.000000 | $0.000000 | $0.000379 | $0.000404 | $0.000230 | $0.000245 | $0.000244 | $0.000260 | $0.001257 | $0.001341 | $0.000173 | $0.000184 | $0.002283 | $0.002434 |
| | Common Use | $0.000000 | $0.000000 | $0.000810 | $0.000864 | $0.000524 | $0.000559 | $0.000546 | $0.000582 | $0.002743 | $0.002925 | $0.000375 | $0.000399 | $0.004998 | $0.005329 |
| **RLM** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distrib. kWhr Summer On | $0.000000 | $0.000000 | $0.001114 | $0.001188 | $0.000705 | $0.000752 | $0.000728 | $0.000776 | $0.003957 | $0.004219 | $0.000523 | $0.000558 | $0.007027 | $0.007493 |
| | Distrib. kWhr Summer Off | $0.000000 | $0.000000 | $0.000238 | $0.000254 | $0.000143 | $0.000152 | $0.000155 | $0.000166 | $0.000823 | $0.000877 | $0.000113 | $0.000121 | $0.001472 | $0.001570 |
| | Distrib. kWhr Winter On | $0.000000 | $0.000000 | $0.000238 | $0.000254 | $0.000143 | $0.000152 | $0.000155 | $0.000166 | $0.000823 | $0.000877 | $0.000113 | $0.000121 | $0.001472 | $0.001570 |
| | Distrib. kWhr Winter Off | $0.000000 | $0.000000 | $0.000238 | $0.000254 | $0.000143 | $0.000152 | $0.000155 | $0.000166 | $0.000823 | $0.000877 | $0.000113 | $0.000121 | $0.001472 | $0.001570 |
| **WH** | Distribution | $0.000000 | $0.000000 | $0.000395 | $0.000421 | $0.000243 | $0.000260 | $0.000252 | $0.000268 | $0.001334 | $0.001423 | $0.000178 | $0.000189 | $0.002402 | $0.002561 |
| **WHS** | Service Charge | $0.00 | $0.00 | $0.01 | $0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.03 | $0.03 | $0.00 | $0.00 | $0.04 | $0.04 |
| | Distribution | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000062 | $0.000066 | $0.000062 | $0.000066 | $0.000062 | $0.000066 | $0.000062 | $0.000067 | $0.000248 | $0.000265 |
| **HS** | Service Charge | $0.00 | $0.00 | $0.05 | $0.05 | $0.03 | $0.03 | $0.03 | $0.03 | $0.16 | $0.17 | $0.02 | $0.03 | $0.29 | $0.31 |
| | Distribution June-September | $0.000000 | $0.000000 | $0.000576 | $0.000614 | $0.000000 | $0.000000 | $0.000288 | $0.000307 | $0.000865 | $0.000922 | $0.000000 | $0.000000 | $0.001729 | $0.001843 |
| | Distribution October-May | $0.000000 | $0.000000 | $0.000079 | $0.000084 | $0.000079 | $0.000085 | $0.000079 | $0.000084 | $0.000394 | $0.000420 | $0.000000 | $0.000000 | $0.000631 | $0.000673 |
| **GLP** | Service Charge | $0.00 | $0.00 | $0.06 | $0.06 | $0.04 | $0.05 | $0.04 | $0.04 | $0.20 | $0.21 | $0.03 | $0.04 | $0.37 | $0.40 |
| | Service Charge-unmetered | $0.00 | $0.00 | $0.03 | $0.03 | $0.02 | $0.02 | $0.02 | $0.02 | $0.09 | $0.10 | $0.01 | $0.01 | $0.17 | $0.18 |
| | Service Charge-Night Use | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distrib. KW Annual | $0.0000 | $0.0000 | $0.0140 | $0.0149 | $0.0085 | $0.0091 | $0.0088 | $0.0094 | $0.0466 | $0.0497 | $0.0059 | $0.0063 | $0.0838 | $0.0894 |
| | Distrib. KW Summer | $0.0000 | $0.0000 | $0.0350 | $0.0373 | $0.0213 | $0.0227 | $0.0222 | $0.0237 | $0.1167 | $0.1244 | $0.0149 | $0.0159 | $0.2101 | $0.2240 |
| | Distribution kWhr, June-September | $0.000000 | $0.000000 | $0.000011 | $0.000012 | $0.000007 | $0.000007 | $0.000007 | $0.000008 | $0.000038 | $0.000040 | $0.000005 | $0.000005 | $0.000068 | $0.000072 |
| | Distribution kWhr, October-May | $0.000000 | $0.000000 | $0.000029 | $0.000031 | $0.000017 | $0.000018 | $0.000018 | $0.000019 | $0.000097 | $0.000104 | $0.000013 | $0.000013 | $0.000174 | $0.000185 |
| | Distribution kWhr, Night use, June-September | $0.000000 | $0.000000 | $0.000029 | $0.000031 | $0.000017 | $0.000018 | $0.000018 | $0.000019 | $0.000097 | $0.000104 | $0.000013 | $0.000013 | $0.000174 | $0.000185 |
| | Distribution kWhr, Night use, October-May | $0.000000 | $0.000000 | $0.000029 | $0.000031 | $0.000017 | $0.000018 | $0.000018 | $0.000019 | $0.000097 | $0.000104 | $0.000013 | $0.000013 | $0.000174 | $0.000185 |
| **LPL-Secondary** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distrib. KW Annual | $0.0000 | $0.0000 | $0.0181 | $0.0193 | $0.0112 | $0.0119 | $0.0116 | $0.0124 | $0.0604 | $0.0644 | $0.0079 | $0.0084 | $0.1092 | $0.1164 |
| | Distrib. KW Summer | $0.0000 | $0.0000 | $0.0431 | $0.0460 | $0.0266 | $0.0284 | $0.0275 | $0.0293 | $0.1436 | $0.1531 | $0.0189 | $0.0202 | $0.2597 | $0.2770 |
| | Distribution kWhr | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **LPL-Primary** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Service Charge-Alternate | $0.00 | $0.00 | $0.26 | $0.28 | $0.16 | $0.17 | $0.17 | $0.18 | $0.90 | $0.96 | $0.12 | $0.13 | $1.61 | $1.72 |
| | Distrib. KW Annual | $0.0000 | $0.0000 | $0.0079 | $0.0084 | $0.0048 | $0.0051 | $0.0050 | $0.0053 | $0.0262 | $0.0280 | $0.0034 | $0.0036 | $0.0473 | $0.0504 |
| | Distrib. KW Summer | $0.0000 | $0.0000 | $0.0437 | $0.0466 | $0.0269 | $0.0287 | $0.0277 | $0.0295 | $0.1453 | $0.1550 | $0.0190 | $0.0202 | $0.2626 | $0.2800 |
| | Distribution kWhr | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **HTS-Subtransmission** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distrib. KW Annual | $0.0000 | $0.0000 | $0.0120 | $0.0128 | $0.0075 | $0.0080 | $0.0080 | $0.0085 | $0.0448 | $0.0478 | $0.0060 | $0.0064 | $0.0783 | $0.0835 |
| | Distrib. KW Summer | $0.0000 | $0.0000 | $0.0433 | $0.0461 | $0.0272 | $0.0290 | $0.0288 | $0.0307 | $0.1620 | $0.1728 | $0.0217 | $0.0231 | $0.2830 | $0.3017 |
| | Distribution kWhr | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **HTS-HV** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distrib. KW Annual | $0.0000 | $0.0000 | $0.0030 | $0.0032 | $0.0018 | $0.0019 | $0.0018 | $0.0019 | $0.0100 | $0.0107 | $0.0012 | $0.0013 | $0.0178 | $0.0190 |
| | Distribution kWhr | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **BPL** | Distribution Sum | $0.000000 | $0.000000 | $0.000032 | $0.000032 | $0.000021 | $0.000022 | $0.000021 | $0.000023 | $0.000106 | $0.000113 | $0.000014 | $0.000015 | $0.000194 | $0.000205 |
| | Distribution Winter | $0.000000 | $0.000000 | $0.000032 | $0.000032 | $0.000021 | $0.000022 | $0.000021 | $0.000023 | $0.000106 | $0.000113 | $0.000014 | $0.000015 | $0.000194 | $0.000205 |
| **BPL-POF** | Distribution Sum | $0.000000 | $0.000000 | $0.000029 | $0.000029 | $0.000018 | $0.000019 | $0.000019 | $0.000020 | $0.000139 | $0.000149 | $0.000019 | $0.000020 | $0.000224 | $0.000237 |
| | Distribution Winter | $0.000000 | $0.000000 | $0.000029 | $0.000029 | $0.000018 | $0.000019 | $0.000019 | $0.000020 | $0.000139 | $0.000149 | $0.000019 | $0.000020 | $0.000224 | $0.000237 |
| **PSAL** | Distribution Sum | $0.000000 | $0.000000 | $0.000033 | $0.000033 | $0.000020 | $0.000021 | $0.000020 | $0.000021 | $0.000118 | $0.000126 | $0.000007 | $0.000008 | $0.000198 | $0.000209 |
| | Distribution Winter | $0.000000 | $0.000000 | $0.000033 | $0.000033 | $0.000020 | $0.000021 | $0.000020 | $0.000021 | $0.000118 | $0.000126 | $0.000007 | $0.000008 | $0.000198 | $0.000209 |

**PSE&G IAP Component of IIPC**
**Gas Tariff Rate Summary**

**Schedule SS-IAP-7**


| | | Present IAP 10/1/2021 | | Rate Adjustment 3 4/1/2024 | | Rate Adjustment 4 4/1/2025 | | Rate Adjustment 5 4/1/2026 | | Rate Adjustment 6 10/1/2026 | | Total IIPC Rate Adjustments | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Schedule | | Charge w/o SUT | Charge Including SUT | Charge w/o SUT | Charge Including SUT | Charge w/o SUT | Charge Including SUT | Charge w/o SUT | Charge Including SUT | Charge w/o SUT | Charge Including SUT | Charge w/o SUT | Charge Including SUT |
| **RSG** | Service Charge | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | Distribution Charges | $0.000000 | $0.000000 | $0.001761 | $0.001877 | $0.005721 | $0.006100 | $0.002512 | $0.002679 | $0.000373 | $0.000397 | $0.010367 | $0.011053 |
| | Balancing Charge | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| | Off-Peak Use | $0.000000 | $0.000000 | $0.000880 | $0.000939 | $0.002861 | $0.003050 | $0.001256 | $0.001339 | $0.000186 | $0.000199 | $0.005183 | $0.005527 |
| **GSG** | Service Charge | $0.00 | $0.00 | $0.09 | $0.10 | $0.29 | $0.31 | $0.13 | $0.14 | $0.02 | $0.02 | $0.53 | $0.57 |
| | Distribution Charge - Pre July 14, 1997 | $0.000000 | $0.000000 | $0.000898 | $0.000957 | $0.002935 | $0.003130 | $0.001267 | $0.001351 | $0.000188 | $0.000200 | $0.005288 | $0.005638 |
| | Distribution Charge - All Others | $0.000000 | $0.000000 | $0.000898 | $0.000957 | $0.002935 | $0.003130 | $0.001267 | $0.001351 | $0.000188 | $0.000200 | $0.005288 | $0.005638 |
| | Balancing Charge | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| | Off-Peak Use Dist Charge - Pre July 14, 1997 | $0.000000 | $0.000000 | $0.000449 | $0.000479 | $0.001467 | $0.001564 | $0.000634 | $0.000676 | $0.000094 | $0.000101 | $0.002644 | $0.002820 |
| | Off-Peak Use Dist Charge - All Others | $0.000000 | $0.000000 | $0.000449 | $0.000479 | $0.001467 | $0.001564 | $0.000634 | $0.000676 | $0.000094 | $0.000101 | $0.002644 | $0.002820 |
| **LVG** | Service Charge | $0.00 | $0.00 | $0.78 | $0.83 | $2.55 | $2.72 | $1.13 | $1.21 | $0.17 | $0.18 | $4.63 | $4.94 |
| | Demand Charge | $0.0000 | $0.0000 | $0.0122 | $0.0130 | $0.0394 | $0.0420 | $0.0173 | $0.0185 | $0.0025 | $0.0026 | $0.0714 | $0.0761 |
| | Distribution Charge 0-1,000 pre July 14, 1997 | $0.000000 | $0.000000 | -$0.000389 | -$0.000415 | -$0.001279 | -$0.001364 | -$0.000619 | -$0.000660 | -$0.000087 | -$0.000092 | -$0.002374 | -$0.002531 |
| | Distribution Charge over 1,000 pre July 14, 1997 | $0.000000 | $0.000000 | $0.000266 | $0.000284 | $0.000868 | $0.000925 | $0.000394 | $0.000420 | $0.000057 | $0.000061 | $0.001585 | $0.001690 |
| | Distribution Charge 0-1,000 post July 14, 1997 | $0.000000 | $0.000000 | -$0.000389 | -$0.000415 | -$0.001279 | -$0.001364 | -$0.000619 | -$0.000660 | -$0.000087 | -$0.000092 | -$0.002374 | -$0.002531 |
| | Distribution Charge over 1,000 post July 14, 1997 | $0.000000 | $0.000000 | $0.000266 | $0.000284 | $0.000868 | $0.000925 | $0.000394 | $0.000420 | $0.000057 | $0.000061 | $0.001585 | $0.001690 |
| | Balancing Charge | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| **SLG** | Single-Mantle Lamp | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| | Double-Mantle Lamp, inverted | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| | Double Mantle Lamp, upright | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| | Triple-Mantle Lamp, prior to January 1, 19933 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| | Triple-Mantle Lamp, on and after January 1, 1993 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| | Distribution Therm Charge | $0.000000 | $0.000000 | $0.000161 | $0.000172 | $0.000522 | $0.000556 | $0.000230 | $0.000245 | $0.000000 | $0.000000 | $0.000913 | $0.000973 |
| **TSG-F** | Service Charge | $0.00 | $0.00 | $4.20 | $4.48 | $13.67 | $14.58 | $6.04 | $6.44 | $0.90 | $0.96 | $24.81 | $26.46 |
| | Demand Charge | $0.0000 | $0.0000 | $0.0028 | $0.0030 | $0.0089 | $0.0095 | $0.0039 | $0.0041 | $0.0006 | $0.0007 | $0.0162 | $0.0173 |
| | Distribution Charges | $0.000000 | $0.000000 | $0.000105 | $0.000112 | $0.000341 | $0.000363 | $0.000148 | $0.000158 | $0.000022 | $0.000024 | $0.000616 | $0.000657 |
| **TSG-NF** | Service Charge | $0.00 | $0.00 | $4.20 | $4.48 | $13.67 | $14.58 | $6.04 | $6.44 | $0.90 | $0.96 | $24.81 | $26.46 |
| | Distribution Charge 0-50,000 | $0.000000 | $0.000000 | $0.000305 | $0.000326 | $0.000981 | $0.001046 | $0.000430 | $0.000458 | $0.000060 | $0.000064 | $0.001776 | $0.001894 |
| | Distribution Charge over 50,000 | $0.000000 | $0.000000 | $0.000305 | $0.000326 | $0.000981 | $0.001046 | $0.000430 | $0.000458 | $0.000060 | $0.000064 | $0.001776 | $0.001894 |
| | Special Provision (d) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| **CIG** | Service Charge | $0.00 | $0.00 | $0.64 | $0.68 | $2.10 | $2.24 | $0.92 | $0.98 | $0.14 | $0.15 | $3.80 | $4.05 |
| | Distribution Charge 0-600,000 | $0.000000 | $0.000000 | $0.000292 | $0.000311 | $0.000901 | $0.000961 | $0.000414 | $0.000442 | $0.000048 | $0.000051 | $0.001655 | $0.001765 |
| | Distribution Charge over 600,000 | $0.000000 | $0.000000 | $0.000292 | $0.000311 | $0.000901 | $0.000961 | $0.000414 | $0.000441 | $0.000048 | $0.000051 | $0.001655 | $0.001764 |
| | Special Provision (c) 1st para | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| **BGSS RSG** | Commodity Charge including Losses | $0.000000 | $0.000000 | ($0.000011) | ($0.000012) | ($0.000035) | ($0.000037) | ($0.000014) | ($0.000015) | ($0.000001) | ($0.000001) | ($0.000061) | ($0.000065) |
| **CSG** | Service Charge | $0.00 | $0.00 | $4.20 | $4.48 | $13.67 | $14.58 | $6.04 | $6.44 | $0.90 | $0.96 | $24.81 | $26.46 |
| | Distribution Charge - Non-Firm | $0.000000 | $0.000000 | $0.000305 | $0.000326 | $0.000981 | $0.001046 | $0.000430 | $0.000458 | $0.000060 | $0.000064 | $0.001776 | $0.001894 |

# PSE&G IAP Component of IIPC
# Electric Annual Bill Impact Summary



**Incremental Typical Annual Bill Impacts By Rate Class**

| Rate Class | If Your Annual kWhr Use Is: | Current Bill ($) | Rate Adjustment Date | | | | | End of Program Customer Bill ($) |
|---|---|---|---|---|---|---|---|---|
| | | | 4/1/2024 | 10/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 | |
| RS | 6,920 | 1,324.24 | 4.52 | 2.84 | 2.92 | 15.32 | 2.00 | 1,351.84 |
| RHS | 14,068 | 2,062.72 | 7.20 | 4.52 | 4.76 | 24.16 | 3.32 | 2,106.68 |
| RLM | 17,656 | 3,398.24 | 7.96 | 4.88 | 5.20 | 27.68 | 3.76 | 3,447.72 |
| GLP | 29,560 | 4,994.80 | 4.68 | 2.84 | 2.92 | 15.32 | 2.00 | 5,022.56 |
| LPL-S | 1,304,431 | 171,417.08 | 117.32 | 72.44 | 75.16 | 391.04 | 51.28 | 172,124.32 |
| LPL-P | 4,291,000 | 474,802.32 | 234.84 | 143.84 | 148.40 | 781.48 | 101.32 | 476,212.20 |
| HTS-S | 23,660,477 | 2,257,788.56 | 1502.52 | 941.96 | 999.04 | 5620.76 | 752.08 | 2,267,604.92 |

**Incremental Annual Percent Change From Current Typical Annual Bill By Rate Class[1]**

| Rate Class | If Your Annual kWhr Use Is: | Current Bill ($) | Rate Adjustment Date | | | | | Total Percent Change from Current Bill |
|---|---|---|---|---|---|---|---|---|
| | | | 4/1/2024 | 10/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 | |
| RS | 6,920 | 1,324.24 | 0.34% | 0.21% | 0.22% | 1.16% | 0.15% | 2.08% |
| RHS | 14,068 | 2,062.72 | 0.35% | 0.22% | 0.23% | 1.17% | 0.16% | 2.13% |
| RLM | 17,656 | 3,398.24 | 0.23% | 0.14% | 0.15% | 0.81% | 0.11% | 1.44% |
| GLP | 29,560 | 4,994.80 | 0.09% | 0.06% | 0.06% | 0.31% | 0.04% | 0.56% |
| LPL-S | 1,304,431 | 171,417.08 | 0.07% | 0.04% | 0.04% | 0.23% | 0.03% | 0.41% |
| LPL-P | 4,291,000 | 474,802.32 | 0.05% | 0.03% | 0.03% | 0.16% | 0.02% | 0.29% |
| HTS-S | 23,660,477 | 2,257,788.56 | 0.07% | 0.04% | 0.04% | 0.25% | 0.03% | 0.43% |

[1]Total percent change may not tie to the cumulative percent due to rounding

# PSE&G IAP Component of IIPC
# Electric Annual Bill Impact Summary



**Cumulative Typical Annual Bill Impacts By Rate Class**

| Rate Class | If Your Annual kWhr Use Is: | Current Bill ($) | Rate Adjustment Date | | | | |
|---|---|---|---|---|---|---|---|
| | | | 4/1/2024 | 10/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| RS | 6,920 | 1,324.24 | 4.52 | 7.36 | 10.28 | 25.60 | 27.60 |
| RHS | 14,068 | 2,062.72 | 7.20 | 11.72 | 16.48 | 40.64 | 43.96 |
| RLM | 17,656 | 3,398.24 | 7.96 | 12.84 | 18.04 | 45.72 | 49.48 |
| GLP | 29,560 | 4,994.80 | 4.68 | 7.52 | 10.44 | 25.76 | 27.76 |
| LPL-S | 1,304,431 | 171,417.08 | 117.32 | 189.76 | 264.92 | 655.96 | 707.24 |
| LPL-P | 4,291,000 | 474,802.32 | 234.84 | 378.68 | 527.08 | 1,308.56 | 1,409.88 |
| HTS-S | 23,660,477 | 2,257,788.56 | 1,502.52 | 2,444.48 | 3,443.52 | 9,064.28 | 9,816.36 |

**Cumulative Percent Changes From Current Typical Annual Bill By Rate Class**

| Rate Class | If Your Annual kWhr Use Is: | Current Bill ($) | Rate Adjustment Date | | | | |
|---|---|---|---|---|---|---|---|
| | | | 4/1/2024 | 10/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| RS | 6,920 | 1,324.24 | 0.34% | 0.56% | 0.78% | 1.93% | 2.08% |
| RHS | 14,068 | 2,062.72 | 0.35% | 0.57% | 0.80% | 1.97% | 2.13% |
| RLM | 17,656 | 3,398.24 | 0.23% | 0.38% | 0.53% | 1.35% | 1.46% |
| GLP | 29,560 | 4,994.80 | 0.09% | 0.15% | 0.21% | 0.52% | 0.56% |
| LPL-S | 1,304,431 | 171,417.08 | 0.07% | 0.11% | 0.15% | 0.38% | 0.41% |
| LPL-P | 4,291,000 | 474,802.32 | 0.05% | 0.08% | 0.11% | 0.28% | 0.30% |
| HTS-S | 23,660,477 | 2,257,788.56 | 0.07% | 0.11% | 0.15% | 0.40% | 0.43% |

## PSE&G IAP Component of IIPC
## Gas Annual Bill Impact Summary

**Incremental Typical Annual Bill Impacts By Rate Class**

| Rate Class | If Your Annual Therm Use Is: | Current Bill ($) | Rate Adjustment Date 4/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 | End of Program Customer Bill ($) |
|---|---|---|---|---|---|---|---|
| **RSG** | 1,040 | 916.92 | 1.96 | 6.34 | 2.74 | 0.40 | 928.36 |
| **GSG** | 2,115 | 2,191.18 | 3.21 | 10.34 | 4.52 | 0.66 | 2,209.91 |
| **LVG** | 40,278 | 34,197.48 | 27.43 | 88.81 | 38.97 | 5.65 | 34,358.34 |
| **TSG-F** | 633,000 | 479,792.60 | 158.21 | 511.16 | 223.26 | 34.53 | 480,719.76 |
| **TSG-NF** | 969,000 | 687,331.76 | 369.65 | 1,188.56 | 521.06 | 73.57 | 689,484.60 |
| **CIG** | 3,023,000 | 1,482,826.64 | 890.37 | 2,748.94 | 1,262.55 | 146.78 | 1,487,875.28 |

**Incremental Annual Percent Change From Current Typical Annual Bill By Rate Class[1]**

| Rate Class | If Your Annual Therm Use Is: | Current Bill ($) | Rate Adjustment Date 4/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 | Total Percent Change from Current Bill |
|---|---|---|---|---|---|---|---|
| **RSG** | 1,040 | 916.92 | 0.21% | 0.69% | 0.30% | 0.04% | 1.24% |
| **GSG** | 2,115 | 2,191.18 | 0.15% | 0.47% | 0.21% | 0.03% | 0.86% |
| **LVG** | 40,278 | 34,197.48 | 0.08% | 0.26% | 0.11% | 0.02% | 0.47% |
| **TSG-F** | 633,000 | 479,792.60 | 0.03% | 0.11% | 0.05% | 0.01% | 0.20% |
| **TSG-NF** | 969,000 | 687,331.76 | 0.05% | 0.17% | 0.08% | 0.01% | 0.31% |
| **CIG** | 3,023,000 | 1,482,826.64 | 0.06% | 0.19% | 0.09% | 0.01% | 0.35% |

[1]Total percent change may not tie to the cumulative percent due to rounding

| Cumulative Typical Annual Bill Impacts By Rate Class | | | | | | |
|---|---|---|---|---|---|---|
| | | | Rate Adjustment Date | | | |
| Rate Class | If Your Annual Therm Use | Current Bill ($) | 4/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| RSG | 1,040 | 916.92 | 1.96 | 8.30 | 11.04 | 11.44 |
| GSG | 2,115 | 2,191.18 | 3.21 | 13.55 | 18.07 | 18.73 |
| LVG | 40,278 | 34,197.48 | 27.43 | 116.24 | 155.21 | 160.86 |
| TSG-F | 633,000 | 479,792.60 | 158.21 | 669.37 | 892.63 | 927.16 |
| TSG-NF | 969,000 | 687,331.76 | 369.65 | 1,558.21 | 2,079.27 | 2,152.84 |
| CIG | 3,023,000 | 1,482,826.64 | 890.37 | 3,639.31 | 4,901.86 | 5,048.64 |

| Cumulative Percent Changes From Current Typical Annual Bill By Rate Class | | | | | | |
|---|---|---|---|---|---|---|
| | | | Rate Adjustment Date | | | |
| Rate Class | If Your Annual Therm Use | Current Bill ($) | 4/1/2024 | 4/1/2025 | 4/1/2026 | 10/1/2026 |
| RSG | 1,040 | 916.92 | 0.21% | 0.91% | 1.20% | 1.25% |
| GSG | 2,115 | 2,191.18 | 0.15% | 0.62% | 0.82% | 0.85% |
| LVG | 40,278 | 34,197.48 | 0.08% | 0.34% | 0.45% | 0.47% |
| TSG-F | 633,000 | 479,792.60 | 0.03% | 0.14% | 0.19% | 0.19% |
| TSG-NF | 969,000 | 687,331.76 | 0.05% | 0.23% | 0.30% | 0.31% |
| CIG | 3,023,000 | 1,482,826.64 | 0.06% | 0.25% | 0.33% | 0.34% |

# 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 Infrastructure Advancement Program

**BPU Docket No. _______________**

# DIRECT TESTIMONY

# OF

# THE INFRASTRUCTURE ADVANCEMENT PROGRAM
# ELECTRIC AND NATURAL GAS COST-BENEFIT PANEL

**November 4, 2021**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**
**DIRECT TESTIMONY**
**OF THE INFRASTRUCTURE ADVANCEMENT PROGRAM**
**ELECTRIC AND NATURAL GAS COST-BENEFIT PANEL**

**Q. Please introduce the members of the Infrastructure Advancement Program – Electric and Natural Gas Cost-Benefit Panel (the "CBA Panel").**

A. The witnesses comprising the CBA Panel are Ralph Zarumba and Trent Winstone.

**Q. Mr. Zarumba, please state your name and business address.**

A. My name is Ralph Zarumba, and my business address is 11401 Lamar Avenue Overland Park, Kansas 66211.

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

A. I am a Managing Director, Management Consulting employed by Black & Veatch Management Consulting, LLC ("Black & Veatch"). I lead the Electric & Natural Gas Regulatory Practice at Black & Veatch.

**Q. Please describe your educational background and business experience.**

A. The information is provided in Schedule BV-IAP-1.

**Q. Mr. Winstone, please state your name and business address.**

A. My name is Trent Winstone, and my business address is 50 Minthorn Blvd., Suite 501, Markham, Ontario, Canada.

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

A. I am a Principal Consultant at Black & Veatch.

**Q. Please describe your educational background and business experience.**

A. The information is provided in Schedule BV-IAP-2.

**Q. Please describe Black and Veatch.**

A. Black & Veatch is a leading global engineering, consulting and construction company specializing in infrastructure development in energy, water, telecommunications, management consulting, federal and environmental matters. Black & Veatch is employee-owned and has more than a 100-year track record of innovation in sustainable infrastructure. Black & Veatch has over 10,000 employees worldwide.

**Q. What is the purpose of the CBA's Panel's testimony?**

A. The CBA Panel is sponsoring a cost-benefit analysis of the electric and natural gas portions of Public Service Electric and Gas Company's ("PSE&G" or "Company") Infrastructure Advancement Program ("IAP" or "Program"). Our full report ("Report") is provided in Schedule BV-IAP-3.

**Q. Please describe your understanding of the electric and natural gas portions of PSE&G's proposed IAP.**

A. PSE&G is requesting approval from the New Jersey Board of Public Utilities ("BPU") of a four-year IAP designed to accelerate investment in the construction and installation of electric and gas utility plant and facilities that enhance safety, reliability and resiliency. The programs will also provide sustained economic growth in New Jersey. For the purpose of preparing the cost-benefit analysis, the IAP is divided into electric and natural gas portions – which is the subject of our analysis and testimony – and a Fleet Electrification portion – which is being analyzed by the Fleet Electrification Cost-Benefit Panel. The proposed capital investments in the IAP will provide strong reliability and system hardening benefits to PSE&G's customers and safety benefits for the public. The electric programs included in the IAP include replacement of aging assets with modern infrastructure that will support the electrification of the transportation sector and aggressive adoption of Electric Vehicles ("EVs") along with the increased penetration of distributed energy resources ("DERs"). The natural gas program included in the IAP will provide technology upgrades to the Company's gas distribution system. The electric and natural gas portions of the IAP propose $713 million of investment in eleven electric programs and one gas program.

The IAP is intended to further PSE&G's corporate objectives, including:

- Last Mile Reliability and EV/DER Make-Ready (Electric Outside Plant) – projects that support the electrification of the transportation sector and increased use of DERs through performance and reliability improvements for outside electric plant.
- Station Modernization (Electric Inside Plant) – modernization of electric distribution substation equipment ranging in age from 50-92 years old. The drivers of these programs are defined under PSE&G's distribution planning criteria for substations, which consider condition, future needs, and the likelihood of failures.
- Gas Metering & Regulating (M&R) Upgrading – performance and reliability improvements that will be obtained by replacing aging equipment and facilities, modernizing supply configurations, and installing enhanced physical security measures.

**Q. What does the cost-benefit analysis of the electric and natural gas portions of the IAP entail?**

A. As explained in our Report, our team examined the proposed investments and a variety of data and information to develop a cost-benefit analysis of these investments. In this analysis, the costs are based on the estimated investment costs provided by PSE&G. Black & Veatch worked with the information provided by PSE&G related to these investments to identify and, where possible, quantify the benefits provided by these investments. We also identified benefits that could not be quantified and thus are qualitative in nature. Our analysis included a review of any positive and negative impacts on costs that result from these proposed investments.

**Q. Please describe the results of the cost-benefit analysis.**

A. Our team, under the assumptions of the study, estimates that over a 20-year period the quantified benefits of the electric and natural gas portions of the IAP exceed the costs of the Program by approximately $1.5 billion, resulting in ratio of quantifiable benefits to costs of 3.1. The study also identified many important but difficult to quantify and/or unquantifiable benefits that are not accounted for in this ratio, and the study is conservative in other fundamental respects as described more fully below.

**Q. How did Black & Veatch develop the quantification of benefits?**

A. Black & Veatch compared a “business as usual” scenario, in which PSE&G’s assumed operation is either to perform the investment in future years, or to replace equipment when it fails, to the investments proposed under the IAP. The IAP, other than the EV charging infrastructure portion of the program, proposes $713 million invested over a four year window from the third quarter of 2022 to the third quarter of 2026. We compared these two scenarios over a 20-year forecast period (2022-2041) to determine incremental costs and benefits. In performing our analysis, we utilized assumptions about failure rates and reliability impacts under both normal operating conditions and storm conditions. For the storm occurrences, based on our review of the data, we assumed that for the 20 forecast years the average yearly intensity of storm (outage) conditions would be the same as the intensities PSE&G experienced from 2011 to 2020. We also identified some areas of increased operations costs to support the investments over time. In contrast to our analysis of the electric projects, our analysis of the gas M&R upgrade project is based on the costs and benefits of accelerated station modernization and does not include storm related outages.

**Q. Please summarize the approach taken in your analysis to the evaluation of Program benefits.**

A. The Report provides a full discussion of our approach and the quantification of the costs and benefits of each program included in the IAP except for the EV charging infrastructure program which is being evaluated separately. Our approach identified the impacts of each electric project and determined whether the impacts of the electric projects were cost-related (an impact that reduces or avoids O&M and/or capital cost); outage-related (an impact that reduces outage frequency or duration, during normal "blue sky" conditions and/or major storms); or other-related (generally impacts on safety or compliance, or support for future grid needs such as providing additional capacity for electric vehicle adoption and the ability to better regulate circuit voltage).

Many of the proposed subprograms provide benefits in more than one of these impact areas.

**Q. Were all identified benefits quantified in your analysis?**

A. Not all benefits can be quantified. As noted, benefits can be either quantitative, and thus monetized, or "qualitative" which are difficult or impossible to quantify or monetize.

**Q. Please summarize the results of your quantitative analysis.**

A. Black & Veatch estimates that the IAP will reduce PSE&G costs (both capital and annual O&M expense), improve system reliability, and provide hardening benefits associated with major storm events, thereby resulting in a more hardened system with greater resiliency. Reducing the outage frequency and duration can be valued in terms of Value of Lost Load ("VoLL"), a measure of how customers and businesses perceive the value of improved system reliability, hardening, and resiliency. The estimated costs and benefits, and the resulting benefit-to-cost ratio, are detailed in our Report, and presented below:

**Benefit Results and Benefit-Cost-Ratio (2022-2041)**

| Project Category | Investment Cost | Total Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|
| **Electric Inside Plant Programs** | 276,823 | 369,294 | 1.3 |
| **Electric Outside Plant Program** | 297,003 | 1,643,638 | 5.5 |
| **Gas M&R Stations Program** | 139,594 | 170,712 | 1.2 |
| **Total** | $713,420 | $2,183,645 | 3.1 |

As discussed *supra*, the cost-benefit analysis results in the Table above are limited to those benefits that can be quantified and monetized. The results do not consider the additional value added by benefits that are qualitative in nature.

**Q. What are some of the qualitative benefits not reflected in the quantified benefits?**

A. These qualitative benefits include enhanced asset management and operational capabilities through advanced control systems, providing a safer and more flexible operating environment. Additionally, the investments will address capacity requirements for future EV adoption, and better voltage regulation to support future DER penetration. Furthermore, many of the investments will provide storm hardening benefits that will be less susceptible to failure and/or allow for easier restoration. Lastly, these investments will have a positive impact on both public safety (i.e. less failures) and the environment (i.e. replacement of oil filled equipment newer technology).

**Q. What types of qualitative benefits have been identified for the gas M&R Upgrade program?**

A. Upgrading the M&R substations will provide several qualitative benefits. The stations will be brought into conformance with PSE&G's current design standards, helping to improve operating and environmental performance. Noise levels will be reduced through improved layout, materials, and building structural materials. Upgrades at three stations will also result in the elimination of upstream relief valves, and the installation of a second regulator run, eliminating the pipeline company monitor regulators, and thereby simplifying the layout. Other equipment associated with these facilities such as scrubbers and heaters will also be evaluated for potential replacement if they are at risk of wearing out. For all the stations, obsolete, hard to find and difficult to repair equipment will be replaced, thereby ensuring that old equipment and parts do not cause undue maintenance problems in the future or raise station reliability risks. Site security upgrades will also enhance the safe operation of these stations.

**Q. You stated that your cost-benefit analysis is conservative in other fundamental respects; please explain.**

A. The analysis is conservative for the following reasons:

(i) The analysis is based on a 20-year forecast period, whereas many of the IAP investments are expected to be in service for many decades, well beyond the benefit forecast period;

(ii) The major outage event benefits are focused on the VoLL estimates, but there are additional indirect effects experienced during major events that are not included in VoLL.

(iii) The analysis recognizes, but does not monetize, several very important qualitative benefits, such as safety, and reduction or avoidance of many indirect outage-related costs.

**Q. What is the overall result of your cost-benefit study?**

A. The study provides a cost-benefit analysis of the proposed electric and natural gas portions of the IAP that show, over a simple payback period of 20 years that the monetized benefits exceed the costs. This result, coupled with consideration of the unquantified, but nonetheless real, qualitative benefits of the IAP supports PSE&G's decision to pursue the IAP.

**Q. Does this complete the Panel's testimony?**

A. Yes.

# EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE RALPH ZARUMBA

CAREER SUMMARY

Ralph Zarumba is an economist with 36 years of experience specializing in regulatory and system planning issues in the energy industry. For the past 25 years, he has been a consultant at various consulting firms focusing on regulatory and system planning issues. Prior to entering consulting, Mr. Zarumba was employed by various investor-owned utilities in the U.S. in the regulatory, system planning, and marketing functions. He currently serves as a Managing Director of Strategic Advisory for Black & Veatch Management Consulting leading the Electric and Natural Gas Regulatory Practice.

Mr. Zarumba has prepared as an expert as an expert witness in supporting several pricing and cost of service studies for natural gas and electric utilities. He has appeared as an expert witness or authored expert reports in 60 regulatory and legal proceedings in 18 jurisdictions in North America. Global advisement work has included engagements in the UK, the Middle East, Southeastern Europe, Central America, and the Pacific Rim.

EDUCATIONAL BACKGROUND

- MA, Economics, DePaul University, 1986
- BS, Economics, Illinois State University 1982

REPRESENTATIVE PROJECT EXPERIENCE

**Pricing**

- On behalf of Enbridge Gas New Brunswick appeared as an expert witness on the topic of marginal cost analysis and its application to pricing in the New Brunswick Power rate request.
- On behalf of Bermuda Electric Power Company prepared a marginal cost of service study, an allocated cost of service study and a pricing design proposal implementing movement to access charges.
- On behalf of the Puerto Rico Electric Power Authority managed that company's first regulated rate request and was the witness supporting pricing design, marginal cost of service, an embedded cost of service study, an electric rating period study, proposals for unbundling of tariffs into functional components, and detailed testimony addressing compensation for Distributed Energy Resources.
- As an advisor to the Ontario Energy Board assisted in the development of a proposal to change electric distribution pricing into a fully fixed tariff design and eliminate the volumetric (i.e., KWH charge) component.
- Prepared a Pricing Strategy for the South Carolina Public Service Company (Santee Cooper).

- Prepared testimony proposing Retail Conjunctive Billing Pricing filed in Illinois and Wisconsin which were filed before the Illinois Commerce Commission and the Wisconsin Public Service Commission.
- Negotiated complex service contracts with thermal energy customers which led to a major expansion of the Wisconsin Electric Steam System.
- Prepared proposals for ancillary services pricing based upon market-based mechanisms for San Diego Gas and Electric Company.

**Cost of Service**

- Mr. Zarumba lead an effort performed for the Province of Alberta which produced a comparison of the cost of providing distribution services for Rural Electric Associations versus Investor-Owned Utilities.
- Mr. Zarumba is the principal author and expert witness of an Electric Marginal Cost of Service Study for Montana-Dakota Utilities for their Montana service area.
- For Heritage Gas (Nova Scotia) prepared a cost allocation for a natural gas storage field which was presented before the Nova Scotia Utility and Review Board.
- Mr. Zarumba provided testimony in the proceedings reviewing the 2014 Nova Scotia Power Cost-of-Service study.
- Mr. Zarumba prepared and sponsored before the FERC and the NYISO a cost-of-service filing supporting a Reliability Must-Run filing on the Cayuga Operating Company.
- On behalf of the Ontario Energy Board prepared a white paper addressing the apportionment of regulatory commission costs to stakeholders.

**Revenue Requirements**

- Prepared several Cash Working Capital studies for various distributors and transmitters in the Province of Ontario.
- For a confidential client prepared a benchmarking analysis of the costs of regulatory proceedings associated with the introduction of new electric generation.
- Managed a project for Commonwealth Edison Company in their Electric Rate Request (Illinois Commerce Commission Docket No. 10-467) in which a Cash Working Capital study was provided.
- Assisted Indianapolis Power & Light in preparing a cost recovery plan for Energy Efficiency and Demand Side Management Expenditures.
- On behalf of the Missouri River Electric Cooperative managed a project team which completed a Remaining Life Study for the Western Minnesota Municipal Power Agency.

**Regulatory Policy**

- Prepared a white paper on rate mitigation mechanisms for the Ontario Energy Board.
- Prepared an analysis of pricing mechanisms for optional renewable energy products for a Midwestern public power association.

- Prepared a financial plan, electric rate design and phase-in plan for a new electric generation plan for Fayetteville (North Carolina) Public Works Commission.
- On behalf of the Ontario Energy Board Mr. Zarumba co-authored a study which identified factors that could potentially impede the combination of regulated distributors in that province.

**Valuations and Estimation of Damages**

- On behalf of the Government of the Province of Newfoundland prepared a valuation of certain hydroelectric generating units expropriated by the Province after the closure of the Abitibi Pulp and Paper Mill.
- Mr. Zarumba has prepared several studies preparing valuations of specific generating assets facing market-based pricing in North America.
- As a contractor to NERA Economics assisted in preparing a study quantifying the damages associated with an accident at the Hawthorne Generating Station.

**Generation Market Analysis**

- For a major public power generation owner prepared a strategy of internal coal versus natural gas generation dispatch protocols including the treatment of liquidated damages.
- On behalf of Nalcor Co-authored a report on the feasibility and economics of the proposed development of the Lower Churchill Hydroelectric project.
- Prepared several electric market price forecasts for many regions of the United States and Central America.
- Supported the electric pricing and infrastructure analysis for a Least-Cost Resource Plan for San Diego County.
- Prepared an analysis of the saturation of coal-fired electric generation technology in the Western Electric Coordinating Council.
- Developed a long-run electric expansion plan for the Railbelt System in Alaska.
- Managed a team that prepared a long-term capacity and energy forecast for a medium-sized municipal utility.
- For Manitowoc Public Utilities prepared a resource plan evaluating various generation expansion options.

**Management Audit and Affiliate Code of Conduct**

- Led the regulatory and financial review for a management audit of Jersey Central Power & Light on behalf of the New Jersey Board of Public Utilities.
- On behalf of a coalition of marketers and energy service companies Mr. Zarumba presented testimony before the Illinois Commerce Commission addressing affiliate rules and code of conduct.
- On behalf of a coalition of marketers and energy service companies Mr. Zarumba presented testimony before the Wisconsin Public Service Commission addressing affiliate rules and code of conduct.

**Demand Response**

- Assisted the Building Owners and Managers of Chicago (BOMA/Chicago) develop a program where they can bid demand response based ancillary services into the PJM market.
- Prepared a presentation for the Public Utilities Commission of Ohio on Commercial and Industrial Dynamic Pricing and Demand Response in an unregulated regulatory environment.

**Electric Transmission**

- Assisted the Long Island Power Authority to purchase distribution, transmission and regulatory assets and prepared that utility's non-jurisdictional open-access transmission tariff.
- Prepared the pricing portion of a FERC open access tariff (Docket No. ER96-96-43.000) for San Diego Gas and Electric Company; testified on revenue requirements and pricing including opportunity costs.
- Prepared a Reliability Must-Run for the Cuyahoga Generating Station which was filed with the Federal Energy Regulatory Commission and the New York Public Service Commission.

**Merger, Acquisition and Divesture**

- On behalf of the Minnesota Public Service Commission. Mr. Zarumba co-authored an analysis of the merger savings associated with the proposed Primergy Merger (the proposed combination of Northern States Power and Wisconsin Energy). The analysis included a detailed review of cost savings that would emanate from the merger and regulatory commitments made by the companies to regulatory authorities in Minnesota.
- For the Manitowoc Public Utilities prepared an analysis that evaluated the divesture of its transmission assets to the American Transmission Company.

**International**

- Assisted the Israel Public Utility Authority is electric tariff reviews for the Israel Electric Company and the Jerusalem District Electric Company.
- During the time period 2007 through 2017 assisted the Albanian Electric Regulator in several rate requests, taring of staff and negotiations involving the privatization of the electric distribution system.
- Mr. Zarumba assisted the electric regulator in the Republic of Macedonia with various regulatory issues including pricing design, revenue requirements and privatization issues. Included in the assistance was the development of market designs for the electricity sector.
- Completed a tariff implementation plan proposal for the privatization of the distribution companies of the Bulgarian Electric Utility.
- Led a team to implement regulatory procedures and methodology for the electric power industry in Bosnia and Herzegovina.
- Conducted a study of the electric power market in El Salvador including a quantification of the level of generation market power using the Lerner Index.

PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. 2016 – 2020**
Vice President

**Navigant Consulting 2008-2016**
Director

**Science Applications International Corporation 2004-2008**
Director

**Zarumba Consulting 2002-2004**
President

**Sargent & Lundy Consulting Group 2000-2002**
Management Consultant

**Analytical Support Network, Inc. 1997-2000**
President

**Synergic Resources Corporation 1996-1997**
Manager, Pricing Practice

**San Diego Gas & Electric Company 1994-1994**
Senior Analyst

**Wisconsin Electric Power Company 1990-1994**
Senior Analyst

**Eastern Utilities Associates 1988-1990**
Analyst

**Illinois Power Company 1985-1988**
Analyst

EXPERT WITNESS TESTIMONY

| SPONSOR | DATE | CASE/APPLICANT | DOCKET/CASE NO. | SUBJECT |
|---|---|---|---|---|
| **Federal Energy Regulatory Commission** | | | | |
| Cayuga Generating Company | 11/2012 | Cayuga Generating Company | ER-13-405-000 | Reliability Must-Run Tariff Cost of Service Support |
| San Diego Gas and Electric Company | 09/1995 | San Diego Gas and Electric Company | ER96-43 | Open-Access Transmission Tariff Filing – Calculation of Transmission Charges |
| **Illinois Commerce Commission** | | | | |
| The Building Owners and Managers Association of Chicago | 2/2008 | Commonwealth Edison Company | 07-0566 | Commonwealth Edison Company General Rate Case |
| The Building Owners and Managers Association of Chicago | 11/2007 | Commonwealth Edison Company | 07-0540 | Evaluation of an Energy Efficiency Plan for Commonwealth Edison Company |
| The National Association of Energy Service Companies and Blackhawk Energy Services | 02/1999 | Commonwealth Edison Company, et al | 98-0147 & 98-0148 | Functional Separation of Electric Utility Functions |
| The Building Owners and Managers Association of Chicago | 11/1998 | Commonwealth Edison Company, et al | 98-0650 | Customer Selection Proceeding – Lottery Rules |
| The Building Owners and Managers of Chicago, Johnson Controls, Inc., and Blackhawk Energy Services | 07/1998 | Commonwealth Edison Company | 98-0362 | Application of Commonwealth Edison to Approve Rate HEP – a Real Time Pricing Tariff |

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|---|---|---|---|---|
| The Building Owners and Managers Association of Chicago | 02/1997 | Commonwealth Edison Company | 96-0485 | Complaint against Commonwealth Edison Company's Conjunctive Billing Tariff |
| | | | | |
| **Kansas Corporation Commission** | | | | |
| Tysons Fresh Meats | 04/2014 | Tysons Fresh Meats | 14-WHLW-218-RTS | Abrogation of a Long-term Service Agreement by a Utility |
| **McHenry County, IL** | | | | |
| Indeck Pleasant Valley, L.L.C | 09/2002 | Indeck Pleasant Valley, L.L.C | | Deposition |
| | | | | |
| **Libertyville, IL Zoning Board** | | | | |
| Indeck Libertyville, L.L.C | 01/2000 | Indeck Libertyville, L.L.C | | Need for a combustion turbine facility |
| **Louisiana Pilotage Fee Commission** | | | | |
| Crescent River Port Pilots' Association | 7/2020 | Crescent River Port Pilots' Association | P20-001 | Benchmarking analysis of pilotage fees |
| **Massachusetts Department of Public Utilities** | | | | |
| Eastern Edison Company | 04/1990 | Eastern Edison Company | | Purchased Power Cost Adjustment Calculation |
| Eastern Edison Company | 02/1990 | Eastern Edison Company | 90-9A | Oil Conservation Adjustment Calculation |
| Eastern Edison Company | 02/1990 | Eastern Edison Company | 90-4A | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 12/1989 | Eastern Edison Company | 89-240 | Purchased Power Cost Adjustment Calculation |
| Eastern Edison Company | 11/1989 | Eastern Edison Company | 89-4D | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 05/1989 | Eastern Edison Company | 89-9D | Oil Conservation Adjustment Calculation |
| Eastern Edison Company | 08/1989 | Eastern Edison Company | 89-9B | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 08/1989 | Eastern Edison Company | 89-9C | Oil Conservation Adjustment Calculation |

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|---|---|---|---|---|
| Eastern Edison Company | 05/1989 | Eastern Edison Company | 89-4B | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 11/1989 | Eastern Edison Company | 89-9B | Oil Conservation Adjustment Calculation |
| Eastern Edison Company | 05/1989 | Eastern Edison Company | | Conservation Surcharge Adjustment |
| Eastern Edison Company | 02/1989 | Eastern Edison Company | 89-4A | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 02/1989 | Eastern Edison Company | 89-9A | Oil Conservation Adjustment Calculation |
| Eastern Edison Company | 11/1988 | Eastern Edison Company | 88-4D | Fuel Cost Adjustment Calculation |
| Eastern Edison Company | 11/1988 | Eastern Edison Company | 89-4D | Oil Conservation Adjustment Calculation |
| Eastern Edison Company | 05/1988 | Eastern Edison Company | | Conservation Service Charge |
| | | | | |
| **McHenry Country, IL Zoning Board of Appeals** | | | | |
| Indeck Pleasant Valley, L.L.C | 03/1999 | Indeck Pleasant Valley, L.L.C | 99-04 | Need for a combustion turbine facility |
| | | | | |
| **Minnesota Public Utilities Commission** | | | | |
| CenterPoint Energy Minnesota Gas | 11/2021 | CenterPoint Energy Minnesota Gas | G-008/GR-21-436 | Class Cost of Service and Rate Design |
| | | | | |
| **New Brunswick Energy and Utility Board** | | | | |
| Enbridge Gas New Brunswick | 12/2016 | NB Power Company | Matter 357 | Marginal Cost Pricing |
| Liberty Utility New Brunswick | 12/2019 | NB Power | Matter 458 | Marginal Cost Pricing |
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| **New Mexico Public Regulation Commission** | | | | |
| El Paso Electric Company | 07/2015 | El Paso Electric Company | 15-000127-UT | Cash Working Capital Study |
| | | | | |
| **New York Public Service Commission** | | | | |
| Cayuga Generating Company | 11/2012 | Cayuga Generating Company | 12-E-0400 | Reliability Must-Run Tariff Cost of Service Support |
| | | | | |
| **Nova Scotia Utility and Review Board** | | | | |
| Heritage Gas | 12/2014 | Heritage Gas | M06582 | Allocated Cost of Service Analysis |
| Port Hawkesbury Paper | 10/2013 | Port Hawkesbury Paper | P-892/M05473 | Allocated Cost-of-Service |
| | | | | |
| **Ontario Energy Board** | | | | |
| Hydro One Networks Inc. (transmission) | 05/2016 | Hydro One Networks Inc. (transmission) | EB-2016-0160 | Cash Working Capital Studies |
| Entegrus Powerlines Inc. | 12/2015 | Entegrus Powerlines Inc. | EB-2015-0061 | Cash Working Capital Study |
| Hydro Ottawa | 10/2015 | Hydro Ottawa | EB-2015-0004 | Cash Working Capital Study |
| Kingston Hydro | 09/2015 | Kingston Hydro | EB-2015-0083 | Cash Working Capital Study |
| North Bay Hydro | 07/2015 | North Bay Hydro | EB-2014-0099 | Cash Working Capital Study |
| Toronto Hydro-Electric System Limited | 06/2014 | Toronto Hydro-Electric System Limited | EB-2014-0116 | Cash Working Capital Study |
| Horizon Utilities | 03/2014 | Horizon Utilities | EB-2014-0002 | Cash Working Capital Study |

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|---|---|---|---|---|
| APPrO | 02/2013 | APPrO | EB-2012-0337 | Recovery of Energy Efficiency Costs from Electric Generators |
| Great Lakes Power Transmission | 07/2012 | Great Lakes Power Transmission | EB-2012-0300 | Corporate Shared Services Study |
| London Hydro | 07/2012 | London Hydro | EB-2012-146 | Determination of Working Capital Requirements |
| London Hydro | 07/2012 | London Hydro | EB-2012-146 | Cost Allocation of Revenue Cycle Services |
| Hydro One | 08/2012 | Hydro One | EB-2012-0031 | Cash Working Capital Studies |
| Hydro One Networks Inc. (distribution) | 12/2013 | Hydro One Networks Inc. (distribution) | EB-2013-0416 | Cash Working Capital Study |
| Ontario Energy Board | 01/2012 | Ontario Energy Board | EB-2012-0018 | Review of the Ontario Energy Board Cost Assessment Model |
| Ontario Energy Board | 11/2011 | Ontario Energy Board | EB-2010-0378 | Principal Author of Rate Mitigation White Paper |
| | | | | |
| **Public Hearings Held on Long Island** | | | | |
| Long Island Power Authority | 05/1998 | Long Island Power Authority | | Non-Jurisdictional Open-Access Transmission Tariff |
| | | | | |
| **Puerto Rico Energy Commission** | | | | |

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|---|---|---|---|---|
| Puerto Rico Electric Power Authority | 05/16 | Puerto Rico Electric Power Authority | CEPR-AP-2015-0001 | PREPA General Rate Case: Pricing Design; Embedded Cost of Service; Marginal Cost of Service; and, Provisional (Temporary) Rate |
| Puerto Rico Electric Power Authority | 04/16 | Puerto Rico Electric Power Authority | CEPR-AP-2016-0001 | Pricing Design and Cost Recovery Mechanism for Transition Charges |
| | | | | |
| **Rhode Island Public Utilities Commission** | | | | |
| Blackstone Valley Electric Company | 02/1989<br>06/1989<br>02/1990 | Blackstone Valley Electric Company | 1541 | Fuel Adjustment Clause Calculation |
| Blackstone Valley Electric Company | 02/1989<br>06/1989<br>02/1990 | Blackstone Valley Electric Company | 1856 | Purchased Power Cost Adjustment Calculation |
| Blackstone Valley Electric Company | 02/1989<br>06/1989<br>02/1990 | Blackstone Valley Electric Company | 1694 | Oil Conservation Adjustment Calculation |
| | | | | |
| **Texas Public Utilities Commission** | | | | |
| El Paso Electric Company | 08/2015 | El Paso Electric Company | 15-00127-UT | Cash Working Capital Study |
| **Wisconsin Public Service Commission** | | | | |

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|---|---|---|---|---|
| Johnson Controls, Inc., Harley-Davidson and WICOR Energy | 01/1998 | Johnson Controls, Inc., Harley-Davidson and WICOR Energy | 6630-UR-110 | Application of Wisconsin Electric Power Company for a Rate Increase for Electric, Gas and Steam Service |
| National Association of Energy Service Companies | 1/1999 | Wisconsin Public Service Commission | 05-BU-101 | Investigation on the Commission's Own Motion into Utility Business Activities and Into Transactions and Relationships of Utilities and Their Affiliates During the Transition to Restructured Electric and Gas Industries; Potential Effects of Increased Competition on Markets and Consumers |

# EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE TRENT WINSTONE

CAREER SUMMARY

Trent Winstone has 25 years of broad-based experience in both electricity and natural gas, specializing in regulatory compliance issues, tariffs, power procurement, financial forecasting, risk analysis and project feasibility. As a Principal Consultant for Black & Veatch, he plays a key role in the economic evaluation of various transmission and distribution projects, power generation projects, the negotiation of power purchase contracts, electricity price forecasts and long-term development strategies. Trent is adept at developing relevant and accurate financial models and integrating the results with qualitative considerations to recommend effective solutions. He has electricity sector experience in Canada, the United States of America, Turks and Caicos Islands, Ghana, India, Pakistan and Russia.

EDUCATION

- MBA, Finance, Queen's University
- Bachelor of Engineering Science (Civil), University of Western Ontario

WORK HISTORY

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|---|---|---|
| ▪ **Black & Veatch Management Consulting, LLC** | Principal Consultant | 2021 – Present |
| ▪ **Independent Consultant** | | 2017 – 2021 |
| ▪ **Navigant Consulting** | Associate Director | 2015 – 2017 |
| | Managing Consultant | 2011 – 2015 |
| ▪ **BDR North America** | Vice President | 2005 – 2011 |
| ▪ **Acres Management Consulting** | Senior Consultant | 2000 – 2005 |
| ▪ **Enbridge Consumers Gas,** | Supervisor Financial Studies | 1998 – 2000 |
| | Senior Financial Analyst | 1997 – 1998 |
| | Financial Analyst | 1995 – 1997 |
| ▪ **Ainley & Associates Limited,** | Consultant | 1990 – 1995 |

REPRESENTATIVE PROJECT EXPERIENCE

**Regulatory and Utility Policy**

- **Turks and Caicos Islands Government (TCIG)** – on behalf of the TCIG carried out a review of a Rate Variation Application (RVA) submitted by the vertically integrated electricity supplier FortisTCI. Completed a Cost-of-Service Study (COSS), a prudency assessment and a benchmarking analysis as part of a regulatory proceeding to review the requested rate increase.

- **EPCOR Southern Bruce Gas Inc.** – supported EPCOR's competitive bid to the Ontario Energy Board (OEB) for the rights to distribute natural gas to the South Bruce franchise area. Provided analytical and strategic support in the preparation of the application.
- **IGPC Ethanol Inc.** – intervened on behalf of IGPC in a rate application by Natural Resource Gas Limited to the OEB. Provided financial and analytical support in the cost of service / revenue requirement and cost allocation determinations, and the preparation of interrogatories and written argument.
- **Enbridge Gas Distribution** – determined a distribution avoided costs suitable for Enbridge to use in a DSM potential study and DSM program planning. Devised a methodology based on jurisdictional research and approaches previously used by Enbridge. Acted as an expert witness before the Ontario Energy Board.
- **City of Peterborough** – completed a review of Hydro One's offer to purchase Peterborough Distribution Inc. The study identified the impacts to shareholders, ratepayers and the municipality of the purchase offer relative to the status quo.
- **Greater Sudbury Hydro Inc.** – completed a strategic options analysis for the distribution utility that investigated "sale", "merge" and "status quo" scenarios. The analysis was completed from the perspective of all stakeholders – shareholders, ratepayers and the community.
- **North Bay Hydro Distribution Limited** – completed a strategic options analysis for the distribution utility that investigated "sale", "merge" and "status quo" scenarios. The analysis was completed from the perspective of all stakeholders – shareholders, ratepayers and the community.
- **Oklahoma Gas and Electric (OG&E)** – conducted an analysis of OG&E's SmartPower business case (advanced metering infrastructure, distribution automation and demand reduction) to support a request to the Oklahoma Corporation Commission (OCC) for cost recovery. This included a project feasibility and rate impact analysis and share price impact calculation.
- **Halton Hills Hydro Inc.** – review of municipally-owned electricity distribution company regarding ownership options, capital structure and financing. Completed valuations assuming "buy", "hold" and "merge" strategies.
- **Town of Markham** – advised on the assessment of its position as a significant shareholder of PowerStream in relation to its merger discussions with Barrie Hydro.
- **Ontario Energy Board** – cross-jurisdictional survey of regulatory approaches to address the impact of stray voltage on farm operations.
- **Energy East (RGE & NYSEG)** – researched regulatory precedents for approval of costs related to advanced metering which included a survey of US based gas and electric utilities (8 jurisdictions).
- **Electricity Company of Ghana (Ghana, West Africa)** – identified alternatives and made a recommendation for a methodology to calculate a capital contribution as part of establishing a customer connection policy.
- **Enbridge Gas Distribution** – business case analysis for gas automated meter reading (AMR). The analysis was completed from the perspective of the rate payer and included a revenue requirement and rate impact assessment.

- **Enbridge Gas Distribution** – completed an independent valuation of an oil pipeline to be used as justification of a transfer price before the Ontario Energy Board. This study utilized the asset replacement cost valuation methodology.
- **Oshawa PUC Networks Inc.** – conducted a study and made recommendations for a customer connection and capital contribution policy. The recommendations were designed to maximize shareholder returns while also ensuring the interests of new and existing customers, and the development community.
- **Peterborough Utilities** – an asset replacement cost study was completed for Peterborough Utilities to determine an initial "fair market" value as required by Ontario Regulation 162/01. The valuation is the basis for calculating capital cost allowance and payments in lieu of taxes.
- **Enbridge Gas Distribution** – completed rate of return schedules for ancillary programs including Natural Gas Vehicles (NGV) and the Heating Insurance & Parts (HIP).

**Cost Allocation**

- **EPCOR Southern Bruce Gas Inc.** – as part of a rate application prepared a cost allocation study which was defended in a written hearing before the OEB.
- **Independent Electricity System Operator (IESO)** – prepared an independent study of the IESO`s corporate cost allocation methodology for charges associated with staff and other resources used to provide select non-core services.
- **Ontario Energy Board** – reviewed the existing methodology used in the allocation of costs to street lighting configurations ("daisy-chain" and the one-to-one) and identified alternative allocation methods to address the disparity observed. The study recommendations were adopted and the OEB issued a new cost allocation policy for the street lighting rate class.
- **Great Lakes Power Transmission (GLPT)** – reviewed the allocation of corporate costs associated with services provided to GLPT from affiliated companies.
- **Toronto Hydro Electric System Limited** – completed a cost of service study investigation of cross-subsidy for suite-metered residential customers within the residential customer class.
- **Uttar Pradesh Power Corporation Limited (UPPCL), Uttar Pradesh, India** – completed cost of service studies (for 2 rate cases) for the integrated transmission and distribution Company and prepared evidence as part of the Annual Revenue Requirement submission to the state regulator. Also conducted training workshops and seminars, as well as individual training to UPPCL staff on this subject.
- **Water and Power Development Authority (WAPDA), Pakistan** – completed cost of service studies for the Lahore Electric Supply Company using both embedded and long-run marginal cost methodologies.

**Electricity Price Forecasting**

- **Ontario Energy Board Regulated Price Plan** – semi-annually prepared a forecast of electricity prices under the Regulated Price Plan based on gas price projections, terms of contracts between generators (OPG, Bruce Power, etc.) and the Ontario Power Authority, and the accumulated variance account, etc. This analysis included a short-term (18-month) electricity price forecast based on a regression analysis, the determination of out of market supply costs (Global Adjustment), and the calculation of both time of use and tiered rates.

**Tariff Design and Rate Impact Studies**

- Ontario Energy Board – assisted in the preparation of a discussion paper on potential rate mitigation measures, including alternative thresholds or triggers to determine when rate mitigation needs to be employed.
- Water and Power Development Authority (WAPDA), Pakistan – Completed the design of retail tariffs for the Lahore Electric Supply Company.
- Fortis Ontario – identified regulatory issues and financial benefits of connecting Cornwall Electric to the Ontario transmission system. The evaluation resulted in negotiating lower electricity supply costs from Cedars Rapids Transmission and Hydro Quebec.
- Great Lakes Power – completed a rate impact calculation for a transmission project leave to construct application to the Ontario Energy Board.
- Pikangikum Grid Extension Project (Pikangikum Indian Reservation, Ontario) – completed a rate impact analysis for the various alternatives to connect the Pikangikum Indian Reservation to the Ontario electricity grid. The purpose of the analysis was to determine the most cost effective (minimal rate impact) means of supplying power to the community.
- City of Cornwall – reviewed Cornwall Electric's rate application on behalf of the City of Cornwall to ensure compliance with contractual terms and conditions, including investigation of power purchase arrangements.
- West Perth Mitchell & Orangeville Distribution Utilities – unbundled tariff design and preparation of evidence for electricity distribution utilities in accordance with the Ontario Energy Board Electricity Rate Handbook.
- Enbridge Gas Distribution – feasibility and rate impact analysis for numerous system expansion leave to construct applications and preparation of written evidence. Acted as a witness before the Ontario Energy Board.

**Power Procurement Contracts**

- Ontario Electricity Finance Corporation (OEFC) – provided financial and analytical support for the Non-Utility Generation (NUG) contracts administered by OEFC. This included the re-negotiation and amendment of generation contracts for hydro-electric, combined heat and power, and biomass generation facilities.
- BC Hydro – completed a review of BC Hydro's Electricity Purchase Agreement (EPA) terms for hydro and wind generation procurements. The purpose of the study was to investigate if various EPA contract provisions could be made more flexible and shift less risk to the supplier, and ultimately achieve a better balance of costs and benefits for BC Hydro rate payers. The study included collaboration with stakeholders including independent power producers and lenders, and the development of a detailed financial model of the EPA contract provisions and proposed changes.
- Ontario Power Authority CHP Procurement – provided strategic advice to the Ontario Power Authority (OPA) on procurement process for CHP (cogeneration) capacity, including support in development of

the RFP, project qualification and proposal evaluation criteria, development of the CHP proposal evaluation model, communications with stakeholders at technical sessions, and development of the CHP contract and CHP Power Purchase Agreement.

- TransAlta – represented TransAlta in the financial settlement calculation of a power purchase contract recently signed with the Ontario Power Authority. Provided training to TransAlta staff on the financial settlement aspects of the contract.
- Ontario Power Authority (Early Movers Project) – Retained as an advisor to implement the June 15, 2005, Directive from the Minister of Energy to the OPA to negotiate and where feasible enter into contracts with the owners or operators (including CCGT, and co-generation plants) at a reasonable cost to Ontario consumers. Included analysis of hourly electricity prices (HOEP) and daily gas prices (Dawn) to evaluate the cost of the contracts to the rate payers.
- Lake Superior Power – completed a due diligence review of the existing contractual arrangements as part of an independent engineer's report for the acquisition of a cogeneration plant located in Sault Ste. Marie Ontario. Reviewed contracts for the purchase, transmission, distribution and re-sale of natural gas, and also the sale of electricity and steam.

**Capital Investment & Project Feasibility**

- Sault Ste. Marie Innovation Centre – completed a review of a business case analysis of a utility distribution microgrid project for PUC Distribution Inc. Reviewed the benefit- cost analysis performed by the project proponent, developed a potential regulatory framework for submission to the OEB, and assessed ratepayer and shareholder impacts of the project.
- Toronto Hydro-Electric System Limited – completed a valuation of THESL's suite metering customers assuming the business 1) continues to be included in the regulated distribution utility, and 2) are transferred to an un-regulated affiliate. A discounted cash flow financial model was prepared to evaluate both alternatives from the perspective of the shareholder, and the results were presented to senior executives.
- McCarthy Tetrault LLP. – provided a market valuation of five hydro-electric generating stations located in northern Ontario as part of a legal proceeding. Prepared a pro-forma financial model and report that was used as the basis of the market valuation for each of the facilities. The financial model and valuation basis were scrutinized and ultimately accepted by the opposing party in the legal proceeding.
- Guelph Hydro (Ecotricity Guelph Inc) – financial and analytic services to support the development of four cogeneration projects under the OPA's CHPSOP power procurement initiative. The various project configurations included cogeneration turbines and engines, auxiliary boilers, and district heating and cooling infrastructure. These assignments included the developed a detailed operational and financial model for scenario analysis, and financial optimization of the project.
- Post Power Purchase Agreement (PPA) Price Scenarios – determined the value of generation assets for the period following the PPA contract term for various confidential clients. The post PPA pricing scenarios identified include full replacement cost, the re-powering of existing facilities and merchant operation.

- **Nalcor** – estimated the potential value to the Ontario market of electricity from the Gull Island hydro generation project based on a comparison with the avoided cost of alternative generation technologies sourced in Ontario. The analysis included an estimate for the incremental value of electricity supply during high demand/ price hours (price duration curve).
- **Fortis Ontario** – Leave to Construct application to the OEB on behalf of Canadian Niagara Power Inc. Acted as the lead financial resource in the development of the project feasibility and rate impact calculations for a synchronous transmission intertie to New York State.
- **The Town(s) of Markham / Vaughn / Barrie** – on behalf of the shareholders of PowerStream, completed a due diligence review of PowerStream's proposed investment in solar generation under Ontario's FIT contracts and the Green Energy Act.
- **Unwin vs Crothers** – advised Plaintiff as to the appropriate fair market value of power assets located in the Turk & Caicos Islands in the Caribbean. Appeared as an expert valuation witness in arbitration proceedings under the umbrella of the Ontario Superior Court of Justice.
- **CMS Generation Company** – strategic and advisory services to support development of a response to Ontario Power Authority's RFP for a generation facility in the western Greater Toronto Area. Developed a detailed operational and financial model for scenario analysis and RFP bid optimization.
- **FortisOntario** – financial and analytic services in development of an RFP response to provide the electricity output of combined heat and power facilities to the Ontario electricity grid. Developed a detailed operational and financial model for scenario analysis and RFP bid optimization.
- **AECON** – evaluated the feasibility of constructing a tunnel (10 km) to provide additional conveyance capacity to the Sir Adam Beck hydro generation facility. This included a discounted cash flow financial model and a detailed probabilistic analysis of hydrology risk.
- **Kamchatsenergo (Kamchatka, Russia)** – constructed an integrated financial projection and evaluation model for the largest regional electricity and district heat supplier, Kamchatsenergo. Analyzed various system generation and capital investment alternatives to identify the optimal (least cost) plan. Liaised with regional government and utility officials.
- **Feasibility of Power Generation Projects** - completed numerous evaluations of hydro and thermal generation projects. Examples include:
  - **Radar Limon 750 to 1,000 MW thermal (coal) plant** – Colorado, USA,
  - **Irvings** – St. George 15-MW hydro project on the Magaguadavic River, St. George, New Brunswick.
  - **LZ Group** – generic financial model to evaluate small hydro and wind projects - incorporated the tax rates and incentive programs specific to projects located in Ontario.
- **Enbridge Gas Distribution** – on behalf of the Enbridge and Nova Scotia Power partnership, acted as the key financial resource on the Nova Scotia gas distribution project ($650 million). This included the development of a financial model, strategic issue identification, risk analysis, and senior management reporting.

- **Enbridge Gas Distribution** – investigated the feasibility of capital projects, including distribution system expansion, storage, cogeneration, district heating and cooling, and municipal water distribution.

**Other Projects**

- **Electricity Distributors Association (EDA) of Ontario** – acted as project manager for the preparation of a white paper to provide a vision for the future role of Local Distribution Companies (LDCs). The objective of the white paper was to identify the challenges and opportunities occurring in the rapidly changing energy landscape in order to allow LDC's to better prepare for the future. The report findings were presented to the EDA Board and membership.
- **Enbridge Gas Distribution** – investigated and presented an independent perspective on the existing and future role of natural gas in Ontario's electricity supply mix.
- **Electricity Company of Ghana (Ghana, West Africa)** – taught a 2-week course on engineering economics and finance to middle level managers.
- **Province of Alberta** – investigated potential electricity price measures to reduce the cost of electricity for large industrial customers (sodium chlorate manufacturing industry) in Alberta. Initiatives included over-the-counter trading, ancillary services (virtual generation) and time-of-use metering.

PROFESSIONAL ASSOCIATIONS

- **Member,** Professional Engineers of Ontario

# COST-BENEFIT ANALYSIS OF ELECTRIC AND NATURAL GAS CAPITAL INVESTMENTS

**B&V PROJECT NO. 409991**
**B&V FILE NO. 12.3456**



**PREPARED FOR**

Public Service Electric & Gas Company

26 OCTOBER 2021

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# LIST OF ACRONYMS

| Abbreviation | Description |
|---|---|
| BAU | Business as Usual |
| BPU | New Jersey Board of Public Utilities |
| BUD | Buried Underground Distribution |
| CMI | Customer Minutes Interrupted |
| DCF | Discounted Cash Flow |
| DER | Distributed Energy Resources |
| EV | Electric Vehicle |
| GSB | Gas Circuit Breaker |
| KVa | Kilovoltampere |
| KV | Kilovolt |
| LDV | Light Duty Vehicles |
| LoF | Likelihood of Failure |
| M&R | Metering & Regulating |
| NPV | Net Present Value |
| O&M | Operations & Maintenance Expense |
| OCB | Oil Circuit Breaker |
| OWS | Open Wire Secondary |
| PSE&G | Public Service Electric and Gas |
| SME | Subject Matter Experts |
| UG | Underground |
| VoLL | Value of Lost Load |
| WACC | Weighted Average Cost of Capital |

# Executive Summary

Public Service Electric and Gas (PSE&G) is a combination natural gas and electric utility operating in the State of New Jersey. The PSE&G system includes 2.2 million electric and 1.8 million natural gas customers. The PSE&G systems includes 100,000 miles of electric transmission and distribution lines, and 2,000 miles of natural gas pipelines.

PSE&G is requesting permission from the New Jersey Board of Public Utilities (BPU) for approval for its five-year Infrastructure Advancement Program (IAP) designed to accelerate investment in the construction and installation of utility plant and facilities that enhance safety, reliability, and resiliency. The programs will also provide sustained economic growth in New Jersey. The proposed capital investments will provide strong reliability and hardening benefits to PSE&G customers and safety benefits for the public. The IAP replaces aging assets with modern infrastructure that will support the electrification of the transportation sector and aggressive adoption of Electric Vehicles (EV), along with the penetration of distributed energy resources (DER). This report documents the cost-benefit analysis of the requested stimulus funding planned over a five-year period that begins in 2022 and concludes in 2026. The costs and benefits included in the analysis are estimated over a 20-year forecast period from 2022 to 2041.

This Cost benefit analysis addresses $713M of the IAP, which includes electric power system infrastructure modernization and gas metering and revenue (M&R) station investments. This cost benefit analysis does not include the EV infrastructure investments.

The requested IAP funding covers a considerable range of the utility's electric and natural gas distribution system assets. The requested funding for the electric distribution system is designed to improve the system's reliability, resiliency, and life cycle performance. The natural gas distribution system IAP funding will provide technology upgrades. The IAP includes 12 individual projects, which have been evaluated as a stand-alone cost-benefit initiative as presented in Figure 1 - Cost-Benefit Analysis Results below.

The IAP fully supports PSE&G's corporate initiatives, including:

- Outside Plant Subprogram - Last Mile Reliability and EV/DER Make-Ready (Electric Outside Plant) – projects that support the electrification of the transportation sector and DER through performance and reliability improvements for outside electric plant.

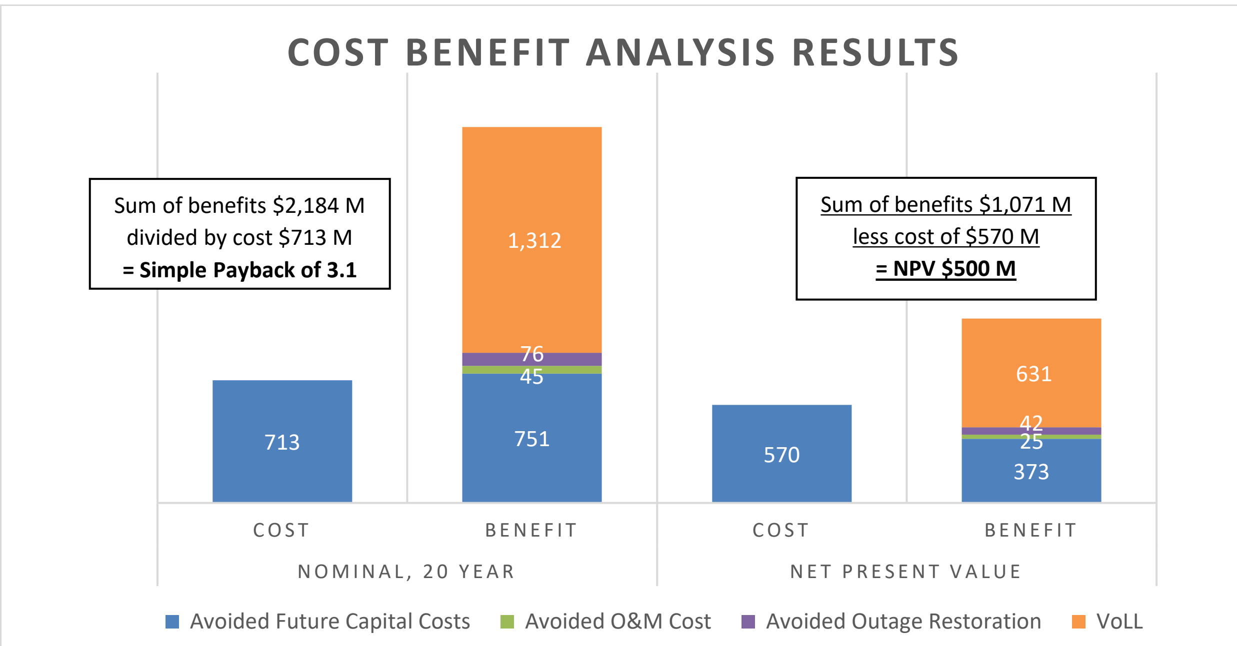
- Station Modernization Subprogram (Electric Inside Plant) – modernization of electric distribution substation equipment ranging in age from 60-92 years old. Drivers are defined under PSE&G's distribution planning criteria for substations, which considers condition, future needs, and the likelihood of failures.

- Gas Metering & Regulating (M&R) – performance and reliability improvements by replacing aging equipment and facilities, modernizing supply configurations, and installing enhanced physical security measures.

The financial metrics used to interpret the results of the CBA are a simple payback period and Net Present Value (NPV). The simple payback is calculated by dividing the sum of the annual benefit cash flows by the annual costs over the 20-year time horizon. A result greater than 1.0 indicates the benefits exceed costs, and the project is feasible from an economic perspective. A Discounted Cash Flow (DCF) analysis reflects the timing of the cash flows and is calculated by applying a discount rate to determine the present value of the costs and benefit cash flows over the 20-year time horizon. The NPV is the sum of the present value costs and benefits which has been calculated for the Stimulus 2021 overall. A NPV greater than zero indicates that the benefits exceed the costs on a present value basis.

Figure 1 - Cost-Benefit Analysis Results presents the results of the CBA for the IAP Program overall with the sum of the nominal program costs and benefits used for the simple payback analysis shown on the left side of the chart, and the present value of the costs and benefits used for the DCF on the right side of the chart. The result of the CBA is a simple payback of 3.1 and a NPV of $500 million indicating the IAP is feasible from an economic perspective. The CBA simple payback results for each of the three initiatives as described above are provided in Figure 1. Each initiative has a simple payback cost factor that is greater than 1.0, indicating economic viability. It should be noted that the CBA only includes those benefits which are readily quantified and does not reflect any value for other program benefits such as safety and reliability improvements which have not been quantified.

**Figure 1 - Cost-Benefit Analysis Results**



### Table 1 - Cost-Benefit Analyses Results

| Subprogram Category | Investment Cost ($1,000s) | Total Benefits ($1,000s) | Simple Benefit-Cost Factor | Net Present Value ($1,000s) |
|---|---|---|---|---|
| Substation Modernization | 276,823 | 369,294 | 1.3 | (36,199) |
| Outside Plant | 297,003 | 1,643,638 | 5.5 | 555,252 |
| **Electric Sub-total** | | | | 544,145 |
| Gas Metering & Regulation Stations | 139,594 | 170,712 | 1.2 | (18,714) |
| **Gas Subtotal** | | | | (18,714) |
| **Total** | $713,420 | $2,183,645 | 3.1 | 500,339 |

## Organization of the Report

This report is organized as follows: Section 1 provides an overview of the approach and framework used for the cost cost-benefit analysis and a summary of the results for the IAP Program by individual program and initiative. Section 2 of the report details the nature of the costs and benefits quantified in the cost-benefit analysis, qualitative benefits, and the supporting assumptions. Section 3 provides detailed descriptions of the cost-benefit analysis for each of the individual programs, and Section 4 provides a conclusion.

# 1.0 Approach

To perform the cost-benefit analysis, Black & Veatch relied on information and discussions with PSE&G Subject Matter Experts (SME) to:

- Develop the method of constructing a cost-benefit analysis.
- Define supporting assumptions and operating data.
- Identify the scenarios that underpin the analysis.

The cost-benefit analysis is developed based upon two scenarios. Each scenario represents a view of the PSE&G business over the 20-year forecast period (2022-2041). The first scenario is "Business as Usual" (BAU) which assumes the current capital and maintenance spending program and no IAP funding programs. The second scenario assumes the implementation of the IAP capital investment program. By comparing the costs and benefits of the two scenarios across a common time horizon, it is possible to estimate the incremental effects of the proposed IAP improvements.

### Cost-Benefit Analysis Framework

The cost-benefit analysis approach used by Black & Veatch is based on the following analytical framework:

- A focus on incremental investment effects.
- Adoption of an evaluation period that has a reasonable relationship to the lifecycle costs and benefits of the investments.
- Acknowledgment of the important contribution of qualitative benefits. Examples include safety improvements, voltage regulation, and added system capacity to facilitate future growth and the adoption of new customer services such as electric vehicles.
- Linking benefits to specific causes and other intermediary impacts, rooted in the judgment of how the technology functions.
- Identifying key assumptions, noting their degree of certainty, and evaluating how they influence results.

The cost-benefit analysis was modeled using nominal dollar values, with base year of 2021. An inflation adjustment has been applied to benefit factors. PSE&G has used the Weighted Average Cost of Capital (WACC) for a discount factor in previous BPU funding requests, and for consistency, has again used WACC as the discount factor in this CBA.

## 1.1 SUMMARY OF RESULTS

The financial metrics used to interpret the results of the CBA are a simple payback period and NPV. The simple payback is calculated by dividing the sum of the annual benefit cash flows by the annual costs over the 20-year time horizon. A result greater than 1.0 indicates the benefits exceed costs, and the project is feasible from an economic perspective. A DCF analysis reflects the timing of the cash flows and is calculated by applying a discount rate to determine the present value of the costs and benefit cash flows over the 20-year time horizon. The NPV, which has been calculated for the IAP overall, is the sum of the present value costs and benefits. An NPV greater than zero indicates that the benefits exceed the costs on a present value basis, and the program is feasible from an economic perspective. The cost benefit analysis results for each of the 13 individual IAP Projects and grouped by initiative as described above are provided in Table 2. The result of the CBA is that each program and initiative have a simple payback cost factor that is greater than 1.0, indicating economic viability. The result of the DCF analysis for the overall IAP is a positive NPV of $500 million as presented in Table 1, indicating that it is feasible from an economic perspective.

### Table 2 – Summary of Results of the Electric and Gas IAP Projects

| Project Category | Investment Cost | Total Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|
| **Substation Modernization** | | | |
| 26kV Station Upgrades | 33,200 | 40,558 | 1.2 |
| 4kV Substation Modernization | 172,220 | 244,306 | 1.4 |
| West Orange Switching Station | 71,403 | 84,430 | 1.2 |
| **Subtotal Substation Modernization** | **276,823** | **369,294** | 1.3 |
| **Outside Plant** | | | |
| Lashed Cable Replacement | 13,720 | 27,756 | 2.0 |
| Spacer Upgrade | 15,000 | 766,301 | 51.1 |
| Spacer Cable Conversion | 42,000 | 121,215 | 2.9 |
| Pole Upgrade | 31,995 | 46,650 | 1.5 |
| BUD Cable Replacement | 80,034 | 281,482 | 3.5 |
| Voltage Optimization | 54,950 | 73,266 | 1.3 |
| Open Wire Secondary Upgrade | 35,980 | 60,971 | 1.7 |
| Conventional Underground Cable Replacement | 23,324 | 265,998 | 11.4 |
| **Subtotal Outside Plant** | **297,003** | **1,695,338** | 6.0 |
| **Gas M&R Stations** | | | |
| Gas Metering & Regulation Stations | 139,594 | 170,712 | 1.2 |
| **Total** | **$713,420** | **$2,183,645** | **3.1** |

# 2.0 Cost-Benefit Analysis Methodology

A cost-benefit analysis provides a uniform and systematic methodology to evaluate the costs and benefits of a specific activity or program commonly used in decision making. As applied to the PSE&G's IAP, the CBA monetizes the cost of each program and compares those costs to the benefits to consumers. The benefits to consumers include improved reliability, resiliency, enhanced service offering, and safety.

## 2.1 OVERVIEW OF THE COST-BENEFIT METHODOLOGY

The cost-benefit analysis was performed for a 20-year period beginning in 2022. The 20-year period for the cost-benefit analysis was chosen because it represents a reasonable, albeit conservative estimate of the lives of each program. The program assets evaluated in this report have a service life exceeding 20 years and the benefits beyond year 20 have not been included in this CBA

The metrics used to interpret the results of the cost-benefit analysis are: 1) a simple payback analysis, and 2) a Discounted Cash Flow (DCF). The simple payback is calculated by dividing the sum of the annual benefit cash flows by the annual costs over the 20-year time horizon. For the simple payback a result greater than 1.0 indicates the benefits exceed costs, and the project is feasible from an economic perspective. The DCF analysis reflects the timing of the program cash flows by calculating the NPV which is the sum of the present value of the costs and benefits. A NPV that is greater than zero indicates the project is feasible from an economic perspective.

## 2.2 COST COMPONENTS

PSE&G provided Black & Veatch with the forecasted IAP Program costs, summarized in Table 2-1 of this report. The values included in the cost-benefit analysis are based on the best information available at the time of this report, without undue speculation. The overarching goal of these estimates is to identify new cost demands that can reasonably be expected and would not be recovered through current rates. The cost components included in the CBA are for capital investment costs over a 20-year period for both the BAU case and the IAP case. The IAP capital investments are for either new infrastructure or acceleration of the BAU capital investments over a compressed construction schedule.

### Table 2-1 – Program Costs

| Project Category | Investment Cost |
|---|---|
| **Substation Modernization** | |
| 26kV Station Upgrades | 33,200 |
| 4kV Substation Modernization | 172,220 |
| West Orange Switching Station | 71,403 |
| **Subtotal Electric Inside Plant** | **276,823** |
| **Outside Plant** | |
| Lashed Cable Replacement | 13,720 |
| Spacer Upgrade | 15,000 |
| Spacer Cable Conversion | 42,000 |
| Pole Upgrade | 31,995 |
| BUD Cable Replacement | 80,034 |
| Voltage Optimization | 54,950 |
| Open Wire Secondary Upgrade | 35,980 |
| Conventional Underground Cable Replacement | 23,324 |
| **Subtotal Outside Plant** | **297,003** |
| **Gas M&R Stations** | |
| Gas Measuring & Regulation Stations | 139,594 |
| **Total** | **$713,420** |

## 2.3 BENEFIT COMPONENTS

The IAP Program benefits were determined by identifying the nature of the improvements and assessing the impact on outages and other conditions. Then, working with PSE&G SMEs, Black & Veatch reviewed the benefits for inclusion in the cost-benefit analysis on either a quantitative or qualitative basis. Some of the expected beneficial outcomes were determined to be significant and could be reasonably quantified and further monetized, while others were determined to be substantial but difficult to quantify and were, therefore, qualitative in nature. Lastly, the cost-benefit analysis process included reviewing and analyzing the data obtained and following up with PSE&G SMEs to refine and complete the analysis.

The four types of benefits which have been quantified and included in the analysis are described below. Section 3.0 of this report details the specific benefits that apply to each of the 12 IAP projects.

### 2.3.1 Avoided Future Capital Costs

The cost-benefit analysis identifies an avoided cost related to each specific IAP project and how it influences PSE&G's base capital spending plan into the future. PSE&G has estimated a capital spending program over the 20-year forecast period under the BAU scenario for each program. Just as accelerated capital costs in the early years are considered a cost, Avoided Future Capital costs in later years are considered benefits. By accelerating the capital investment as part of the IAP, customers are relieved of this specific cost burden (and aging asset risk and exposure) as the costs under BAU are no longer incurred. This is an avoided cost – and therefore a benefit -- that is included in the cost-benefit analysis.

### 2.3.2 Avoided O&M Costs

A direct benefit of replacing older infrastructure assets with new infrastructure is lower operating and maintenance expenditures. PSE&G has provided a forecast of annual O&M costs over the 20-year forecast period for both the BAU and IAP scenarios. Those IAP projects that result in a lower O&M cost than the BAU case and avoided O&M cost has been included as a benefit in the cost-benefit analysis.

### 2.3.3 Avoided Outage Restoration Costs

A secondary benefit of replacing older infrastructure assets with new infrastructure is fewer equipment failures and lower equipment restoration costs. PSE&G has provided costs associated with projected equipment failures over the 20-year forecast period for both the BAU and IAP scenarios. For those IAP projects that result in lower outage restoration costs than the BAU case, avoided outage restoration costs have been included as a benefit in the cost-benefit analysis.

### 2.3.4 Value of Lost Load (VoLL)

Benefits related to outage reductions constitute the largest quantified benefit for the IAP cost-benefit analysis. Outage reduction benefits include both the VoLL and cost savings due to reductions in outage restoration and repair costs as described in Section 2.2.3 above. The metrics used to determine the VoLL is customer minutes of interruption or CMI. PSE&G has provided annual forecasts for the number of outages and CMI over the 20-year forecast period for both the BAU and IAP.

#### Value of Lost Load (VoLL) Reliability Factors

To translate the CMI reductions into value improvements, Black & Veatch applies a set of factors that relate customer class, outage durations, and load assumptions to economic value. These factors – which pertain to reliability-scale events -- have been developed for the specific purpose of estimating the value to customers of power outages. The economic losses associated with these factors are the Value of Lost Load, or VoLL.

### Table 2-2 – Interruption Costs per Event, Average kW and Unserved kWh by Duration and Customer Class

| Interruption Cost | Interruption Duration | | | | | |
|---|---|---|---|---|---|---|
| | Momentary | 30 Minutes | 1 Hour | 4 Hours | 8 Hours | 16 Hours |
| **Medium and Large C&I (Over 50,000 Annual kWh)** | | | | | | |
| Cost per Event | $12,952 | $15,241 | $17,804 | $39,458 | $84,083 | $165,482 |
| Cost per Average kW | $15.90 | $18.70 | $21.80 | $48.40 | $103.20 | $203.00 |
| Cost per Unserved kWh | $190.70 | $37.40 | $21.80 | $12.10 | $12.90 | $12.70 |
| | | | | | | |
| **Small C&I (Under 50,000 Annual kWh)** | | | | | | |
| Cost per Event | $412 | $520 | $647 | $1,880 | $4,690 | $9,055 |
| Cost per Average kW | $187.90 | $237.00 | $295.00 | $857.10 | $2,138.10 | $4,128.30 |
| Cost per Unserved kWh | $2,254.60 | $474.10 | $295.00 | $214.30 | $267.30 | $258.00 |
| | | | | | | |
| **Residential** | | | | | | |
| Cost per Event | $3.90 | $4.50 | $5.10 | $9.50 | $17.20 | $32.40 |
| Cost per Average kW | $2.60 | $2.90 | $3.30 | $6.20 | $11.30 | $21.20 |
| Cost per Unserved kWh | $30.90 | $5.90 | $3.30 | $1.60 | $1.40 | $1.30 |
| Source: ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, January 2015, LBNL-6941E | | | | | | |

These factors are shown in Table 2-2 and were originally published in the "Updated Value of Service Reliability Estimate for Electric Utility Customers in the United States." Under contract with the Lawrence Berkeley National Laboratory (LBNL), developed this report[1]. The cost-benefit analysis utilizes the cost per event factors in Table 2-2 based upon customer class. Black & Veatch finds that these factors have been widely cited and often applied

The VoLL factors reflect a microeconomic viewpoint that aims to capture the direct and privately borne costs of consumers and businesses facing outage events. The bearing on direct and privately borne costs is important: customers experience many types of costs and suffer many forms of inconvenience and harm during and because of outages, and these impacts are not well or completely accounted for in the VoLL factors. Therefore, additional direct and indirect costs, inconveniences, and harms, represent additional impacts not included in the VoLL factors. One outage study, in fact, estimates that indirect costs can exceed direct costs by a large factor. [2]

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[1] Sullivan, Schellenberg, and Blundell in collaboration with Nexant. Lawrence Berkeley National Laboratory (LBNL-6941E). Performed as part of DOE Contract No. DE-AC02-05CH11231. January 2015. Available online from http://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf.

[2] A reliability study conducted for Pacific Gas & Electric of a potential major electricity outage in downtown San Francisco found that indirect costs of the outage to businesses ranged from 50 percent to two times the size of the direct costs to business, according to testimony provided by Pacific Gas & Electric representatives during 2013 before the California Public Utility Commission. Refer to Pacific Gas & Electric's Opening Brief, Application No. 12-

In order to apply the VoLL factors to the estimated CMI reductions, Black & Veatch has applied the following analytical techniques:

- The VoLL factors represent the weighted average and predicted values from the LBNL-6941e report. Black & Veatch used the weighted average values (as shown in Table ES-1 of the report) because they address seasonality and time of day variables.[3]
- The VoLL factors take into account differences in value amongst customer classes, as indicated by Table 2-2. For example, there is a break point at 50,000 kWh annual consumption. Black & Veatch has applied customer mix assumptions by each subprogram to align with these splits.
- The VoLL factors are adjusted for inflationary impacts. The factors in Table 2-2 are expressed in 2013 dollars. Using data published by the Bureau of Labor and Statistics, an escalation factor equivalent to 1.61 percent per year has been applied to adjust these numbers to 2020 dollars. Similarly, a 2.1 percent annual adjustment is applied to projections through the forecast period.
- Black & Veatch additionally observes that the VoLL factors used are mainly based on data and studies conducted in Western, Midwestern, and Southern states.[4] Black & Veatch believes a specific application of the underlying regression model that supports the VoLL factors in Table 2-2 would yield higher VoLL factors when addressing northeast energy prices and conditions.

Based on PSEG experience, the value for customer-minutes of interruption used for most programs were those of a 1-hour cost per event with the following exceptions:

- A value of 2.5 hour cost per event was used for the BUD Cable Replacement and the Open Wire Secondary Upgrades projects.
- A value of 2.0 hour cost per event was used for the Conventional Underground (UG) Cable Replacement project.

PSE&G provided additional data for the Spacer Conversion Project which allowed for a calculation of CMI based on historical values for independent sections of the project. As such, the corresponding value for each section was applied. The CMI impacts estimated for each subprogram have resolution to the sub-hour. For example, CMI reduction calculation estimates appear as 2.4 or 6.2 hours, etc. To determine VoLL impacts, the CMI values are rounded up or down to the nearest 1/2 hour and linearly interpolated between the values shown in Table 2-2.

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12-004 (E 39 E), Page 12, which addresses its Application for Authorization to Construct a 230 kV Transmission Project. The study is referred to as “Downtown San Francisco Long Duration Outage Cost Study”, prepared by Dr. Michael Sullivan of Freeman, Sullivan & Co.

[3] Ibid, page xiii. The distribution of future interruptions by season and time of day is obviously unknown. The approach taken by Black & Veatch respects the weighted averages for these considerations embedded in the VoLL factors.

[4] Ibid, pg. 48.

The cost and benefits for each of the twelve IAP Programs is summarized in Table 2.3.

### Table 2-3 – Program Benefits

| Project Category | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Benefits |
|---|---|---|---|---|---|---|
| **Substation Modernization** | | | | | | |
| 26kV Station Upgrades | 33,200 | 161 | 27,146 | 10,167 | 3,084 | 40,558 |
| 4kV Substation Modernization | 172,220 | 580 | 237,728 | 5,998 | - | 244,306 |
| West Orange Switching Station | 71,403 | 310 | 82,746 | 1,374 | - | 84,430 |
| **Subtotal Electric Inside Plant** | **276,823** | **1,052** | **347,619** | **17,539** | **3,084** | **369,294** |
| **Outside Plant** | | | | | | |
| Lashed Cable Replacement | 13,720 | 150 | 17,875 | - | 9,732 | 27,756 |
| Spacer Upgrade | 15,000 | 8,273 | - | - | 758,027 | 766,301 |
| Spacer Cable Conversion | 42,000 | 582 | - | - | 120,633 | 121,215 |
| Pole Upgrade | 31,995 | - | 46,650 | - | - | 46,650 |
| BUD Cable Replacement | 80,034 | 31,682 | 100,294 | - | 149,506 | 281,482 |
| Voltage Optimization | 54,950 | 643 | 68,247 | 2,315 | 2,061 | 73,266 |
| Open Wire Secondary Upgrade | 35,980 | - | - | 55,943 | 5,028 | 60,971 |
| Conventional Underground Cable Replacement | 23,324 | 2,277 | - | - | 263,722 | 265,998 |
| **Subtotal Outside Plant** | **297,003** | **43,606** | **233,066** | **58,258** | **1,308,708** | **1,643,638** |
| **Gas M&R Stations** | | | | | | |
| Gas M&R Stations | 139,594 | - | 170,712 | - | - | 170,712 |
| **Total** | **$713,420** | **$44,658** | **$751,398** | **$75,797** | **$1,311,792** | **$2,183,645** |

## 2.4 QUALITATIVE BENEFITS

The above benefit estimates do not consider the additional value added by benefits identified as qualitative in nature. These include:

- The VoLL is an estimation tool that values outage events within certain parameters of duration extent. As it pertains to Major Events of significant outage duration, there are many other direct and indirect costs that are not reflected in VoLL. These have not been monetized and included in the cost-benefit analysis.
- The IAP Investments support advanced grid functions, such as supporting DERs, whose use will grow, and providing needed capacity for EV adoption.
- The programs will improve the safety of the system during all conditions. There will be fewer hazardous conditions that pose safety risks to employees and customers. There will be fewer damage locations on overhead conductors, fewer downed wires and poles, and generally safer work conditions in and around substations.
- Reduced systemic obsolescence risk of aging assets will allow PSE&G to promote the use of the grid and deliver added value to the customer and spend less time on system maintenance (essentially work-around activities).
- Failure of oil filled equipment poses environmental concerns, often significant. Quantitative benefit for environmental issues were not taken in the analysis.

## 2.5 SUPPORTING ASSUMPTIONS

The supporting assumptions used in the cost-benefit analysis are listed below.

| Assumption | Value |
|---|---|
| | |
| Escalation Rate | 2.1% |
| VoLL Escalation Factor (2017 to 2021) | 1.12 |
| Weighted Average Cost of Capital (WACC) | 6.48% |
| **VoLL Assumptions** | |
| Residential Customers | 85.4% |
| Small C&I Customer | 13.2% |
| Medium/Large C&I Customers | 0.4% |
| Spacer Cable Outage Improvement Factor | 61.0% |
| Major Event Forecast Factor | 100.0% |

# 3.0 Description of Each IAP Project and Corresponding Cost-Benefit Analysis

## 3.1 BUD CABLE REPLACEMENT

### Description

Most Buried Underground Distribution (BUD) cables are fed by two sources in a loop design with an "open" section in between. PSE&G has various amounts of cable types in its system, and we will be removing known problematic cable sections / circuits with new cable and replace single phase BUD transformers that have exhibited a large amount of rust or is leaking. Pad mounted transformers are units that are mounted on pads either above ground or contained in underground enclosures used to transform high distribution voltages to customer application voltages.

This project will replace cable to prevent future failures and increase reliability of the distribution system for customers supplied from the underground system. This program will also consider adding a second feed, per current PSE&G construction standards, to poor performing radial BUD's.

Since 1973, all new residential developments with greater than three homes are required to be supplied by underground facilities. In many of these older developments the cable, and in some cases the transformers, have reached the end of life, with increasing failure rates. The project is designed to replace the worst performing cable sections with new cable and replace single phase BUD transformers that have exhibited a large amount of rust or are leaking.

This project will replace approximately 1,400 of the worst performing sections with new cable and single-phase transformers, and, where needed, we will add a second cable source to improve design and outage restorations times. BUD cable will be replaced utilizing standard work procedures. Based on soil conditions and location, the cable will be replaced in conduit or pipe. For this replacement project, a weighted system was developed utilizing Project Cost Estimates and divided it over Customer Minutes Interrupted (POR data) to create a reliability score. This score is used to maximize the number of customers receiving this upgrade while being as cost efficient as possible.

This project replaces cable to prevent future failures and increases the reliability of the distribution system for customers supplied from the underground system. Additionally, this project will provide environmental and safety benefits.

### Cost

The total capital expenditures for both the BAU and IAP project is the same at $80.0 million dollars (real $2021). The IAP project accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

**Benefits**:

### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $100.3 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects from years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $31.7 million.

#### Avoided Outage Restoration Costs

To be conservative, the IAP project analysis did not consider avoided outage and restoration cost benefits. However, in some cases, given the circumstances PSE&G will replace a full cable section rather than repair the failed cable.

#### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon. The benefit value of the VoLL is $149.5 million on a nominal basis.

#### Additional Benefits

The new design is cable in conduit and the original design utilizes direct buried cable. Expected failure rates will decrease with the new design with a longer expected life. A portion of the project will also focus closing BUD loops (that are currently radial), which will result in a much faster and safer restoration.

## Cost Benefit Analysis

The sum of the IAP project benefits of $281.5 million divided by the investment cost of $80.0 million results in the Simple Benefit -Cost Factor of 3.5 indicating the project is economic.

**Table 3-1 BUD Cable Replacement**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| BUD Cable Replacement | $80,034.2 | $31,681.6 | $100,294.4 | $0.0 | $149,505.5 | $281,481.6 | 3.5 |

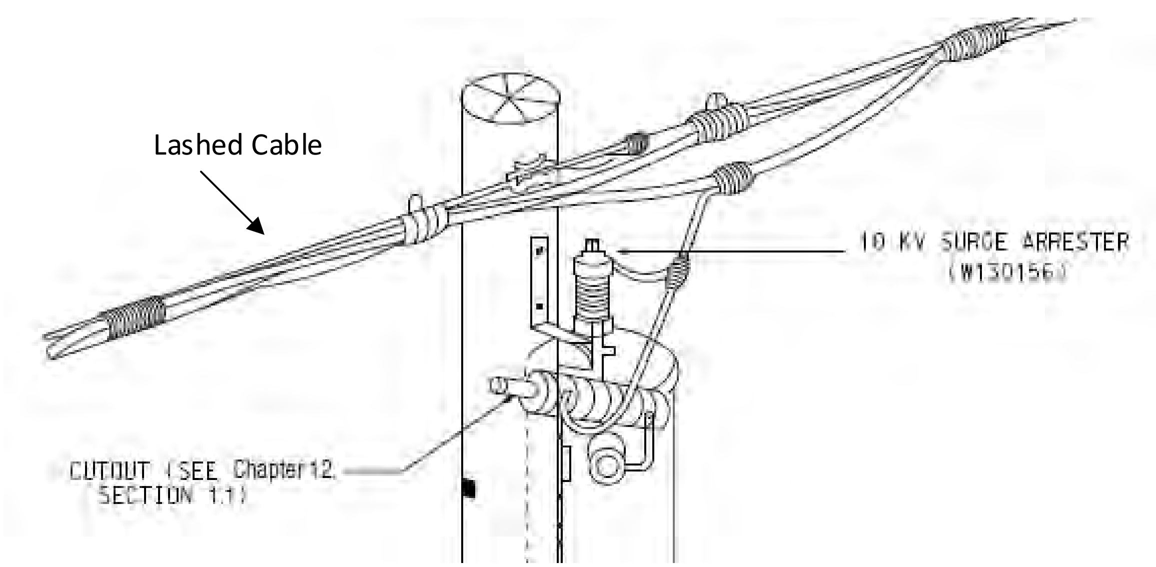
## 3.2 LASHED CABLE REPLACEMENT PROJECT

### Description

Lashed primary cable involves three conductors that are wrapped with a bonding ribbon to the neutral conductor and is suspended from pole to pole using clamps. This construction is used for 4kV applications and is usually found in urban areas, backyards or right of ways due to limited exposure with lack of pole spacing.

Lashed primary cable is one of the oldest assets on a pole with noticeably more outages than the traditional open wire on cross arms or brackets or spacer wire. With longer troubleshooting and repair times, lashed primary cable is increasingly becoming an unreliable asset and is now considered to be an obsolete construction method.

**Figure 3-1 – Illustration of Lashed Cable Construction**



By using POR data, the IAP project will replace approximately 14 miles of old aged and poor condition lashed cable with new spacer cable construction. This may involve replacing existing poles with class 2 poles.

**Cost and Assumptions**

The total capital expenditures for both the BAU and IAP project is the same at $13.7 million dollars (real $2021). The Lashed Cable Replacement Project in the IAP accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

## Benefits

The benefit of replacing old lashed primary cable with spacer construction is improved worker safety and reliability. The conductor covering on lashed primary cable are most likely weathered and with the exterior grounded bonding ribbon, a short circuit could happen while handling. It is expected that less failures will occur with the more robust spacer construction.

### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $17.9 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the project from years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $150.2 thousand.

#### Avoided Outage Restoration Costs

Although periodically, PSE&G will replace sections of cable following a failure, the typical response from PSE&G is to repair any failed cable. Therefore, conservatively, the Lashed Cable Replacement project analysis did not consider avoided outage and restoration cost benefits resulting from full section replacement.

#### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon and includes an inflation adjustment. The benefit value of the VoLL is $9.7 million.

### Additional Benefits

The newer spacer cable construction will provide storm hardening and improved reliability and allow for restoration work to be completed both safer and faster. Additionally, the newer spacer cable is now standard construction, allowing mutual aid contractors to make repairs when needed.

### Cost Benefit Analysis

The sum of the Lashed Cable Replacement project benefits of $27.8 million divided by the investment cost of $13.7 million results in the Simple Benefit -Cost Factor of 2.0 indicating the project is economic.

**Table 3-2 Lashed Cable Replacement**

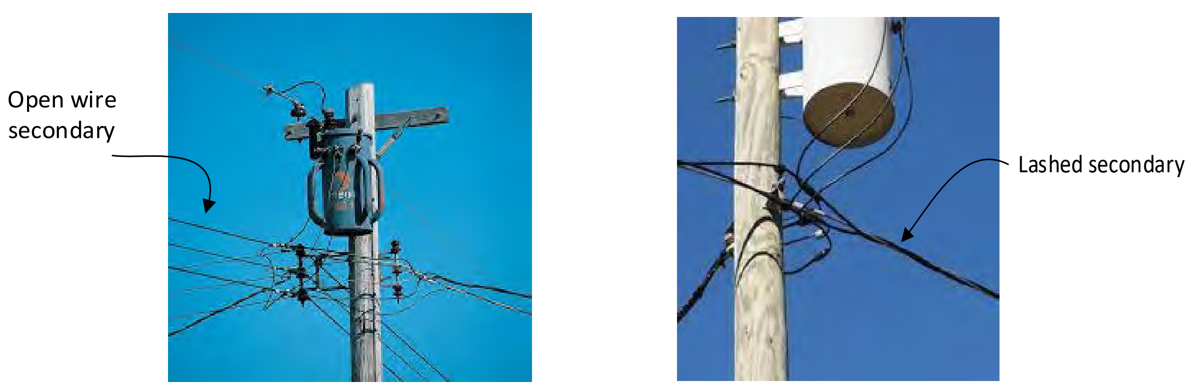
| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| 4kV Lashed Cable | $13,720.0 | $150.2 | $17,874.6 | $0.0 | $9,731.7 | $27,756.5 | 2.0 |

## 3.3 OPEN WIRE SECONDARY UPGRADE PROJECT

Open wire secondary (OWS) is an older, lower capacity construction type that has deteriorated over time and is increasingly experiencing short circuits and outages. Over time, the outer covering has deteriorated causing the aged conductors to become bare which makes these cables prone to short circuits and outages.

This project will replace 1,300 secondary locations of existing OWS with new secondary cable and services that have higher capacity and are also more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVA transformers in place, new larger capacity units will be installed.

**Figure 3-2 - Illustration of Older Open Wire Secondary and Current/Newer Secondary**




This project will involve replacing/upgrading existing OWS with new secondary cable.

**Cost and Assumptions**

There are no capital expenditures under the BAU scenario for the Open Wire Secondary Upgrade Project. The IAP Project proposes a $36.0 million dollars (real $2021) investment. The OWS Upgrade Project in the IAP makes proactively replaces the 1,300 locations during the 5-year IAP duration.

The anticipated Electric Vehicle (EV) adoption rates will pose a challenge to utilities in the near future. Existing capacity improvements on older secondary systems are needed to avoid customer issues as residential EV's become more prevalent. For the secondary systems targeted in this subprogram, it is estimated that if 2 customers fed from the same secondary system install a typical fast charger, the transformer feeding the customers in that system could become overloaded and potentially fail. Additional customer issues resulting from voltage fluctuations may also occur. The New Jersey Plug In Vehicle (PIV) Act calls for 330,000 new EV light duty vehicles (LDV's) on the road by 2025, and 2,000,000 EV LDV's by 2035.

## Benefits

This project will improve worker safety by reducing exposure to short circuit while performing work on secondary cable. Also, newer secondary cable will improve residential reliability and provide additional capacity for future load increases due to anticipated Electric Vehicle adoption.

### Avoided Future Capital

The Open Wire Secondary restoration project has not considered Avoided Future Capital expenditure benefits. However, this is a conservative analysis, as it can be reasonably expected that proactive replacements will be required in the future due new service requests, or as load growth requirements dictate.

### Avoided O&M

The Open Wire Secondary Upgrade project did not consider avoided Operations and Maintenance cost benefits. However, this is conservative, as it can be reasonably assumed that in the short term it can be expected that PSE&G would make O&M related repairs on secondary wiring due to the addition of EV load.

#### Avoided Outage Restoration Costs

The avoided Outage Restoration benefits have been estimated on an incremental basis by taking the difference between the costs for the BAU case and the IAP project case. This benefit is based on added EV chargers that could potentially overload an existing secondary system, at which point PSE&G would need to reactively replace the transformer and secondary wiring. The analysis includes the Avoided Outage Restoration costs for the 20-year time horizon and includes an inflation adjustment. The amount of Avoided Outage Restoration is $55.9 million.

### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon and includes an inflation adjustment. The benefit value of the VoLL is $5.0 million.

### Additional Benefits

The newer construction will provide storm hardening benefits. The lashed secondary and service wires will provide improved reliability during storm events and will reduce both the time and expense to complete repairs. Additionally, the newer secondary cables and increased transformer capacity will improve voltage regulation and lower failure rates.

**Cost Benefit Analysis**

The sum of the Open Wire Secondary Upgrade Project benefits of $61 million divided by the investment cost of $36 million results in the Simple Benefit -Cost Factor of 1.7 indicating the project is economic.

**Table 3-3 Open Wire Secondary Upgrades**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| OWS Upgrade | $35,980.0 | $0.0 | $0.0 | $55,942.8 | $5,028.5 | $60,971.3 | 1.7 |

## 3.4 POLE UPGRADE PROJECT

**Description**

Wood utility poles are the main supporting structures in an overhead distribution system. Defective wood poles are identified through periodic pole inspections. Depending on the results of the inspection, the recommended course of action for defective poles can either be reinforcement (restorable) or replacement (non-restorable). However, if action is not taken within the specified timeframe, the affected pole will continue to deteriorate and be prone to failure (especially during a storm event) presenting a potential safety and/or reliability issue.

This project will proactively replace 2,100 defective wood poles identified during periodic inspections with new ones designed to a higher and more resilient standard, bringing hardening and storm benefits.

**Cost and Assumptions**

The total capital expenditures for the BAU case is $34.1 million and IAP project is $32.0 million dollars (real $2021). The higher BAU spend is due to the extra step of reinforcing the affected poles. The Pole Upgrade project in the IAP Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

The BAU course of action for PSE&G would be to reinforce the poles in question, and replace in the future. Reinforcing the poles is a short-term remedy and with the only benefit being to delay the replacement of new poles. For the BAU analysis, it was assumed that poles the poles in question would be reinforced over the next 5 years and then replaced in the years 2032-2041. The analysis shows that replacing these poles over the next 5 years is more cost effective in the long run.

### Benefits

This project will improve reliability and public safety as upgraded poles and guying will decrease the likelihood of pole failures, particularly during weather related events.

#### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $46.6 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects, years 1 through 5 of the study period. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

#### Avoided O&M

The Pole Upgrade project did not consider avoided Operations and Maintenance cost benefits.

#### Avoided Outage Restoration Costs

Due to potential public safety concerns resulting from pole failures, PSE&G strives to manage the wood pole inventory to minimize pole failure rates. No quantifiable Avoided Outage Restoration cost benefits related to the Pole Upgrade program have been identified.

#### VoLL

As noted above, pole failures by themselves are not a large contributor to customer outages and, conservatively, were not quantified for this analysis.

#### Additional Benefits

The replacement of older, smaller Class 4 poles with larger Class 2 poles will provide storm hardening benefits which are not quantified in this analysis. Furthermore, a new pole is projected to have a useful life of over 50 years whereas the CBA is limited to a 20-year period and does not reflect any benefit for the remaining life of the asset beyond year 20. Upgrade of pole fixtures, transformers, crossarms, switches, ties, are also an added reliability benefit not quantified in this analysis.

**Cost Benefit Analysis**

The sum of the Pole Upgrades program benefits of $46.6 million divided by the investment cost of $32 million results in the Simple Benefit - Cost Factor of 1.5 indicating the project is economic.

**Table 3-4 Pole Upgrade Project**

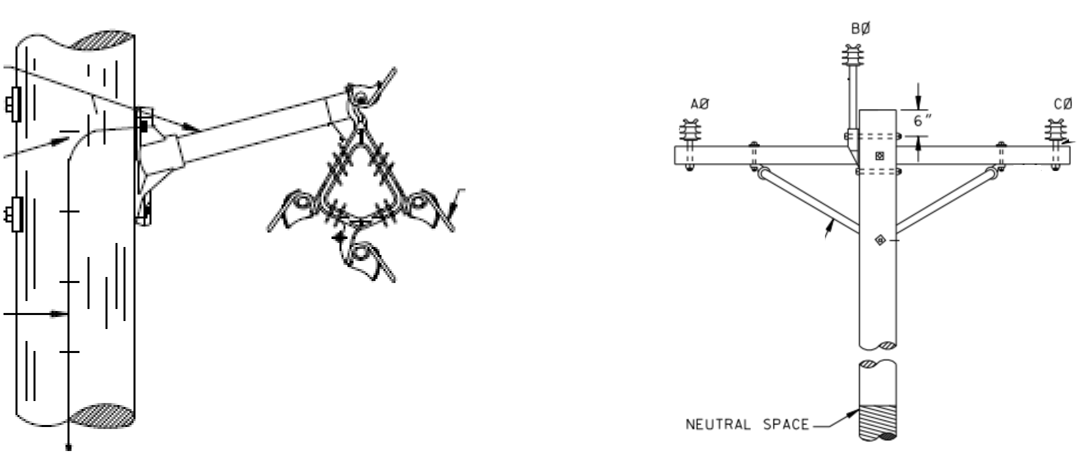
| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Pole Upgrade | $31,995.0 | $0.0 | $46,649.8 | $0.0 | $0.0 | $46,649.8 | 1.5 |

## 3.5 SPACER CABLE CONVERSION

**Description**

The Spacer Cable Conversion project involves replacing existing open wire (cross arm and armless) construction with spacer cable construction. This will improve reliability in vegetated areas where broken branches and trees can contact the conductors and cause outages. Spacer construction also has a smaller profile on a pole and the conductor is covered with a thick polymer covering making it resilient to branch and tree contacts. Replacement work may also require upgrading undersized, aged poles to class 2 poles.

**Figure 3-3 - Illustration of Spacer Construction (left) and Open Wire Construction (Right)**




This project will replace approximately 60 miles of aging 3-phase open wire construction (cross arm and armless) with new spacer cable type construction as shown above. Spacer cable is a more compact and reliable design that incorporates a conductor with a thick polymer covering, thereby making it especially resilient to branch and tree contacts. Where necessary, undersized, or aged poles will also be upgraded. Outage history will be utilized to identify poor performing open wire circuits for replacement.

### Benefits

#### Avoided Future Capital

The Spacer Cable Conversion Project did not consider Avoided Future Capital expenditure benefits. However, this is conservative, as poor performance of an open wire section of a circuit could potentially result in a proactive replacement of the open wire with spacer cable.

#### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $581.8 thousand.

#### Avoided Outage Restoration Costs

The Spacer Cable Conversion Project did not consider Avoided Outage Restoration cost benefits. However, in some cases, poor performance due to tree related outage of the open wire may dictate an upgrade to spacer.

#### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon and includes an inflation adjustment. The benefit value of the VoLL is $120.6 million.

Additional Benefits

New spacer cable will have a much better performance than open wire for tree related outages, and due to the strength of the cable/messenger system would also provide a public safety benefit.

### Cost Benefit Analysis

The sum of the Spacer Cable Conversion project has benefits of $121.2 million divided by the investment cost of $42 million results in the Simple Benefit - Cost Factor of 2.9 indicating the project is economic.

**Table 3-5 Spacer Cable Conversion**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Spacer Cable Conversion | $42,000.0 | $581.8 | $0.0 | $0.0 | $120,632.7 | $121,214.5 | 2.9 |

## 3.6 SPACER UPGRADE PROJECT

**Description**

Based on recent spacer circuit patrols, many spans or sections contained older spacers with broken ties, suspended by the conductors, not the messenger. Cracked or broken porcelain was also observed, all of which presents potentially unfavorable reliability and public safety conditions.

This project will involve the replacement of older style spacers with the new polyethylene 15” design. Also, worn, defective or metallic tangent bracket will be replaced with a newer fiberglass tangent bracket. Messenger ground wire will be installed at every pole. All automatic type inline splices will be replaced with compression type splices. This work may also require upgrading undersized, aged poles to class 2 poles and installing guying, as needed.

This project will replace aging spacer units along approximately 300 miles of existing construction with new hardware that is designed to a higher and more resilient standard. The new spacer standard has higher insulation values, improved material properties and better mechanical performance, and will improve the reliability on these circuits at a relatively low cost as compared to circuit reconstruction.

Outage history will be utilized to determine spacer circuits with the highest SAIFI and SAIDI results from spacer hardware issues. Circuit patrols will be performed to define specific upgrades required on each circuit.

**Cost and Assumptions**

There are no capital expenditures planned under the BAU scenario for the Spacer Hardware Upgrades program. Total capital expenditures under the IAP Program is $15 million dollars (real $2021). The Spacer Hardware Upgrade Project proactively replaces poor performing spacer hardware in the 5 year IAP program.

## Benefits

### Avoided Future Capital

The Spacer Upgrades Project analysis conservatively did not consider Avoided Future Capital expenditure benefits even though the degrading performance of spacer hardware may prompt PSE&G to consider a proactive equipment replacement program.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $8.3 million.

#### Avoided Outage Restoration Costs

PSE&G will typically repair the failed component on an O&M basis; therefore, the Spacer Upgrade project did not consider Avoided Outage Restoration cost benefits.

#### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon and includes an inflation adjustment. The benefit value of the VoLL is $758 million.

#### Additional Benefits

The replacement of spacer hardware, including spacers and brackets, provides a storm hardening benefit not quantified in the analysis. The higher design load and operating capacity provided by the new spacer equipment reduces the load on the remaining spacer equipment and will also extend the useful life of the equipment.

#### Cost Benefit Analysis

The sum of the Spacer Upgrade Project benefits of $766.3 million divided by the investment cost of $15 million results in the Simple Benefit - Cost Factor of 51.1 indicating the project is economic.

**Table 3-6 Spacer Upgrade Project**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Spacer Hardware | $15,000.0 | $8,273.2 | $0.0 | $0.0 | $758,027.4 | $766,300.6 | 51.1 |

## 3.7 26KV STATION UPGRADES PROJECT

#### Description

This project will replace 40 existing 26kV Oil Circuit Breakers (OCB's) with newer Gas Circuit Breakers (GCB's) at various switching and substations across our system. The OCB's have an average age of 60 years, require significant corrective maintenance, and pose environmental challenges. In addition, the associated disconnect switches and older protective relays will be replaced where appropriate

The 40 26kV OCB's were selected based on an analysis that was performed utilizing criteria including equipment age and condition, Likelihood of Failure (LoF) and maintenance costs. To maintain safe and reliable service, this equipment needs to be replaced with newer equipment.

#### Cost and Assumptions

The total capital expenditures for both the BAU and IAP Program is the same at $33.2 million dollars (real $2021). The 26kV Station Upgrades Project in the IAP Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

#### Benefits

### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $27.1 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects in years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $160.7 thousand.

### Avoided Outage Restoration Costs

The Avoided Outage Restoration benefits have been estimated on an incremental basis by taking the difference between the costs for the BAU case and the IAP Program case. The analysis includes the avoided Outage Restoration costs for the 20-year time horizon and includes an inflation adjustment. The amount of avoided Outage Restoration is $10.2 million.

### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon. The benefit value of the VoLL is $3.1 million.

### Additional Benefits

In addition to the environmental benefit, the replacement of these breakers and associated protection systems will result in a reliability improvement due to faster fault clearing, and a reduction in protection related O&M costs. Additionally, the newer breakers will provide improved worker safety.

**Cost Benefit Analysis**

The sum of the 26kV Station Upgrades Program benefits of $40.6 million divided by the investment cost of $33.2 million results in the Simple Benefit - Cost Factor of 1.2 indicating the project is economic.

**Table 3-7 26 kV Station Upgrades**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| 26kV Station Upgrades | $33,200.0 | $160.7 | $27,146.2 | $10,166.9 | $3,084.5 | $40,558.3 | 1.2 |

## 3.8 WEST ORANGE SWITCHING STATION

**Description**

The West Orange 26kV Replacement Project will replace the existing 92-year-old, 26kV Air Insulated Station (AIS) with new sheltered aisle switchgear. West Orange is a 26kV Supply Station and will not be replaced with 69kV. Switching stations are designed to supply power to multiple substations and 26kV customers. The project will include the reconfiguration, as required, of existing 26kV cables, the elimination of 26 kV Low Pressure Gas Filled (LPGF) Cables or installation of a Bulk Nitrogen System (after consulting with the Division) and any additional 26kV equipment that may be required. The exact location for the new switchgear within West Orange will be defined once active projects in the area have been established and construction schedules are developed. The new switchgear will either be constructed on the same footprint as the original station or will be constructed in a vacant area of the station, both of which will have minimal financial impact to the project and will allow for greater project flexibility as projects or conditions evolve. As a result, this project will provide PSE&G the ability to manage inventory of aging switching stations, thereby reducing exposure to outages, reducing maintenance costs, and providing a better substation design for enhanced reliability.

**Cost and Assumptions**

The total capital expenditures for both the BAU and IAP project is the same at $71.4 million dollars (real $2021). The West Orange Switching Station Project in the IAP Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

**Benefits**:

### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $82.7 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects in years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $310.4 thousand. A qualitative benefit is the improved safety and operational improvements of replacing an outdated facility that has been in service for as long as 92 years.

### Avoided Outage Restoration Costs

The avoided Outage Restoration benefits have been estimated on an incremental basis by taking the difference between the costs for the BAU case and the IAP project case. The analysis includes the avoided Outage Restoration costs for the 20-year time horizon and includes an inflation adjustment. The amount of avoided Outage Restoration is $1.4 million.

### VoLL

Although failed equipment as West Orange has resulted in customer outages in the past, because it is difficult to predict and quantify, conservatively, the analysis did not include quantifiable VoLL cost benefits.

### Additional Benefits

The West Orange Switching Station is 92 years old, and thus safety hazards associated with the existing structures, footings, ground grid and steel work will be eliminated through the improvement of upgraded facilities. The program eliminates environmental concerns related to oil filled circuit breakers and reduces the probability of failure and customer outages as the existing station is being replaced with a more reliable ring bus design. Microprocessor relays will allow for remote, high-speed communication, enhanced monitoring and advanced control systems. The new switchgear is also safer to operate than past designs. Lastly, the removal of older gas filled cable will bring our outside plant cable system up to current standards, reduce maintenance and there is a lower likelihood of failure.

**Cost Benefit Analysis**

The sum of the West Orange Switching Station Project benefits of $84.4 million divided by the investment cost of $71.4 million results in the Simple Benefit - Cost Factor of 1.2 indicating the project is economic.

**Table 3-8 West Orange Switching Station**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| West Orange Switching Station | $71,403.0 | $310.4 | $82,745.7 | $1,373.9 | $0.0 | $84,430.1 | 1.2 |

## 3.9 4KV STATION MODERNIZATION PROJECT

**Description**

The project will rebuild the 4kV portions of five substations: Tonnelle Avenue, Fortieth Street, Totowa, McLean Blvd, and Teaneck.

The 26kV equipment at these stations was recently upgraded to 69kV, but the 4kV was not upgraded. With the 5-year average LoF of 64%, along with no future plans to eliminate the 4kV, the 4kV at the stations need to be rebuilt.

This project will modernize 4kV switchgear at five electric distribution class C 69/4kV substations, including replacing/upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure.

**Cost and Assumptions:**

The total capital expenditures for both the BAU and IAP project is the same at $172.2 million dollars (real $2021). The Life Cycle Stations IAP Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

**Benefits**:

## Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $237.7 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects in years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

## Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP project case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $580.4 thousand.

### Avoided Outage Restoration Costs

The avoided Outage Restoration benefits have been estimated on an incremental basis by taking the difference between the costs for the BAU case and the IAP project case. The analysis includes the avoided Outage Restoration costs for the 20-year time horizon and includes an inflation adjustment. The amount of avoided Outage Restoration is $6.0 million.

### VoLL

The 4kV Substation Modernization Project analysis did not include VoLL cost benefits. Given that a substation failure event resulting in customer outages over the next 20 years is very possible, the exclusion of any VoLL benefits adds a degree of conservatism to this analysis.

### Additional Benefits

The average age of the five stations is 62 years old and there are safety hazards associated with the existing structures, footings, ground grid and steel work which will be eliminated with the upgraded facilities. The newer design allows for much better operational flexibility and operator safety and reduces the probability of failure and customer outages. The failure rates for the new equipment are expected to be much lower than the older design. From an operational perspective, microprocessor relays will allow for remote, high-speed communication, enhanced monitoring and advanced control systems.

**Cost Benefit Analysis**:

The sum of the 4kV Substation Modernization Project benefits of $244.3 million divided by the investment cost of $172.2 million results in the Simple Benefit - Cost Factor of 1.4 indicating the project is economic.

**Table 3-9 4kV Substation Modernization**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| 4kV Substation Modernization | $172,220.0 | $580.4 | $237,727.5 | $5,997.8 | $0.0 | $244,305.7 | 1.4 |

## 3.10 VOLTAGE OPTIMIZATION PROJECT

**Description**

This project will replace 1,600 aging 13kV pole top capacitors and switches that are increasingly failing and providing poor voltage regulation. The existing units also lack communication functionality, so failures cannot be detected without a visual inspection. The replacement systems will be equipped with advanced switches, voltage and current sensing, and the ability to communicate back to the DSCADA system, providing significant improvements in voltage regulation as distributed resources becomes more commonplace.

This project will replace existing 13kV pole top capacitors with new equipment. Older capacitors and switches are prone to failure, and the lack of a working capacitor can result in poor voltage regulation on the circuit. Additionally, the older equipment does not communicate; thus, failures and/or inoperability of the banks cannot be detected without a visual inspection. The newer systems will be equipped with vacuum switches (as opposed to older oil switches), 3-phase voltage and current sensing and the ability to communicate back to the DSCADA system.

**Cost and Assumptions**

The total capital expenditures for both the BAU and IAP project is the same at $55.0 million dollars (real $2021). The Voltage Optimization Project in the IAP Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

### Benefits

#### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $68.2 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects, years 1 through 5 of the study period. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

## Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP Program case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $642.9 thousand.

### Avoided Outage Restoration Costs

The avoided Outage Restoration benefits have been estimated on an incremental basis by taking the difference between the costs for the BAU case and the IAP project case. The analysis includes the avoided Outage Restoration costs for the 20-year time horizon and includes an inflation adjustment. The amount of avoided Outage Restoration is $2.3 million.

### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon and includes an inflation adjustment. The benefit value of the VoLL is $2.1 million.

### Additional Benefits

The project will provide the system capacity needed for the projected increase in load from both electric vehicles (EV) and distributed energy resources (DER). Additional EV load combined with accelerated DER penetration will provide a challenge for utility to maintain a proper voltage profile on the distribution circuits. The new capacitor control systems will have communication capability, which will allow the utility to ensure proper operation of the capacitor bank. Replacing the legacy equipment will provide the tools to ensure proper voltage regulation and avoid customer voltage complaints.

**Cost Benefit Analysis**

The sum of the Voltage Optimization Project benefits of $73.3 million divided by the investment cost of $55 million results in the Simple Benefit - Cost Factor of 1.3 indicating the project is economic.

**Table 3-10 Voltage Optimization**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Voltage Optimization Project | $54,950.0 | $642.9 | $68,247.1 | $2,315.5 | $2,060.5 | $73,266.1 | 1.3 |

## 3.11 CONVENTIONAL UNDERGROUND CABLE REPLACEMENT

**Description**

The underground cable system delivers electricity within urban environments and is the primary construction type for cable within PSE&G's territory. The underground cable asset class includes cable, splices, and terminations. The population of underground cable in PSE&G's territory is approximately 7,000 miles and consists of buried PIL, EPR, LPG, and XLPE technology technologies. There are approximately 140,000 segments of underground cable within PSE&G's service territory. This program will primarily focus on UG cables that near end of life. Information from GIS, POR, manhole inspections and tribal knowledge will be used to identify locations where UG Cables need replacement.

Conventional underground (UG) cable systems are most common in urban environments, and this asset class includes cable, splices, and terminations. This program will replace 34 miles of the poorest performing cables that are near reached end of life.

**Cost and Assumptions**

There are no capital expenditures planned under the BAU scenario for the Underground Cable Replacement program. Total capital expenditures under the IAP Program is $23.3 million dollars (real $2021).

**Benefits**:

### Avoided Future Capital

The Convention Underground Cable Replacement project did not consider Avoided Future Capital expenditure benefits, as no improvements are scheduled during the 5-year investment period of the program. Beyond the 5-year investment period when failure rates are likely to increase, the cost of any proactive underground cable replacement strategy has not been reflected in this analysis. This is a conservative approach.

### Avoided O&M

The avoided O&M benefits have been estimated on an incremental basis by taking the difference between the O&M costs for the BAU case and the IAP Program case. The analysis includes the avoided O&M for the 20-year time horizon and includes an inflation adjustment. The amount of avoided O&M is $2.3 million.

### Avoided Outage Restoration Costs

Although in some cases the replacement of a cable section due to failure may be appropriate, the Conventional Underground Cable Replacement Project analysis did not consider Avoided Outage Restoration cost benefits. This is a conservative approach.

### VoLL

The VoLL has been calculated on an incremental basis and in nominal terms for each year of the 20-year time horizon. The benefit value of the VoLL is $263.7 million.

### Additional Benefits

The benefits of the new replacement cable include a lower failure rate, ease of installation and a longer life.

**Cost Benefit Analysis**

The sum of the Conventional Underground Cable Replacement project benefits of $266 million divided by the investment cost of $23.3 million results in the Simple Benefit - Cost Factor of 11.4 indicating the project is economic.

**Table 3-11 Underground Cable Conversion**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Conventional UG Cable Replacement | $23,324.0 | $2,276.6 | $0.0 | $0.0 | $263,721.6 | $265,998.2 | 11.4 |

## 3.12 GAS METERING & REGULATING STATION MODERNIZATION

**Description**

This project will modernize seven gas metering & regulating (M&R) stations, including upgrading aging equipment and facilities, modernizing supply configurations to enhance reliability and reduce potential methane emissions, and installing enhanced physical security measures.

### BACKGROUND

As part of the previous ES I and ESII Funding Programs, PSE&G fully upgraded several stations. By continuing with additional station upgrades to conform with current, modern design practices and building codes, PSE&G will further reduce the risk that station failures pose to the gas distribution system and the public.

Black & Veatch has evaluated this Subprogram’s costs and benefits, which are presented in this section.

## STATION SELECTION PROCESS AND RESULTS

PSE&G has identified seven M&R stations for inclusion in its Stimulus 2021 Program based on the use of its Asset Management Risk model. This model prioritizes stations using a risk matrix. The two main components of the matrix are measurements of the consequence of failure and likelihood of failure of M&R station assets.

Consequence of failure is comprised of the following factors: safety impact, customer impact, asset reliability impact, and environmental impact. Each factor has specific criteria to calculate station consequence of failure, with examples such as stations located in sensitive areas, replacement part availability, and redundancy. Likelihood of failure is based upon equipment age, structural integrity, and station design. Equipment age and maintenance practices are used to plot assets along industry depreciation curves in order to calculate the likelihood of failure. The stations are organized in the risk matrix based upon their calculated consequence and likelihood of failure.

The seven M&R stations prioritized for inclusion in PSE&G’s M&R Upgrade Subprogram through use of the Risk model are as follows:

- **Brooklawn** - New piping rated for the full pipeline company MAOP will be installed. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.
- **Hillsboro** - Existing transmission piping that cannot be internally inspected would be replaced with piping with higher strength and/or thicker wall pipe eliminating the need for certain assessments that are required as part of the Federal code as well as enhancing the overall safety and integrity of the piping within the station. New piping rated for the full pipeline company MAOP will eliminate the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.

- **Hanover** - New piping rated for the full pipeline company MAOP will be installed. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.
- **Roseland** - New piping rated for the full pipeline company MAOP will be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.
- **Hamilton** - New piping rated for the full pipeline company MAOP will be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. The Hamilton M&R site is a newly identified TSA critical site in accordance with the recently published TSA physical security guidelines in 2021 and physical site security enhancements would be installed in accordance with TSA critical site standards.
- **Trenton** - New piping rated for the full pipeline company MAOP will be installed. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.
- **West Deptford** - Existing transmission piping that cannot be internally inspected would be replaced with piping with higher strength and/or thicker wall pipe eliminating the need for certain assessments that are required as part of the Federal code as well as enhancing the overall safety and integrity of the piping within the station. Series regulators with a working regulator and a monitor regulator for overpressure protection will be the new standard design. Downstream distribution system relief valves will also be installed as a second line of overpressure protection, enhancing safety and environmental performance. Physical site security enhancements would be installed in accordance with BPU Energy Sector Best Practices, TSA Pipeline Security Guidelines, and industry standards.

### Cost and Assumptions

The total capital expenditures for both the BAU and Stimulus 2021 Program is the same at $139.6 million dollars (real $2021). The Gas Metering and Regulating Station Modernization Stimulus 2021 Program accelerates the asset replacement schedule from 20 Years in the BAU case to 5 years.

**Benefits**:

### Avoided Future Capital

The Avoided Future Capital expenditure benefit has been determined based on the BAU planned capital investment during the 20-year study period. The total Avoided Future Capital benefit is $170.7 million. This includes the direct amount of Avoided Future Capital investment during the implementation of the projects in years 1 through 5. The amount of Avoided Future Capital investments beyond the investment period, years 6 through 20, are adjusted for inflation.

#### Avoided O&M

The Gas Metering and Regulating Station Modernization project has no directly quantifiable Avoided O&M cost benefits. However, it is expected that day-to-day operations will improve, and the overall burden of maintenance work will decline with upgraded stations that meet today's level of design practices. As equipment and piping continue to age, it is not unreasonable to assume that maintenance costs could climb further. A pattern of increased O&M costs is common with aging systems and infrastructure and would not be unexpected or unusual. In fact, at some point, it becomes impossible to repair equipment due to the inability to obtain parts needed to make repairs (or alternatively it becomes impractical, costly, and inefficient to have parts specially made to complete repairs).

The following are some examples of how station designs meeting current standards improve day- to-day operations:

- New stations components, equipment, and piping will be laid out in a manner that allows for easy operational access and maintenance, thus improving the overall ease of operation and the safety of station operations.
- A new station will achieve lower levels of noise emissions, benefiting both public and PSE&G workers.
- New piping and equipment improve operations and makes maintenance easier, faster, and generally safer to conduct.
- New stations may result in reduced greenhouse gas emissions due to the removal of high-pressure relief valves and installation of worker/monitor regulators.

#### Avoided Outage Restoration Costs

The Gas Metering and Regulating Station Modernization project has no quantifiable Avoided Outage Restoration cost benefits.

#### VoLL

The Gas Metering and Regulating Station Modernization project has no quantifiable VoLL benefits. To put the nature of the risks for the M&R stations into context, there are few hazard events outside of a flood that would "knock out" the stations in a single event, based on what PSE&G has observed in running its fleet of M&R stations over many decades. There are also few individual plant components that pose a high risk of taking the entire station offline should it fail. Rather, it is the growing trend of obsolescence, the increased costs associated with addressing corrective maintenance, the opportunity costs associated with increasing maintenance activities (diverting resources away from other plant needs), and the growing risk posed by these stations (as quantified in the risk model) that justify their replacement.[5]

**Cost Benefit Analysis**

The sum of the Gas Metering and Regulating Station Life Cycle project benefits of $170.7 million divided by the investment cost of $139.6 million results in the Simple Benefit - Cost Factor of 1.2 indicating the program is economic.

**Table 3-12 Gas M&R Stations**

| Project | Investment Cost | Avoided O&M Cost | Avoided Capital Investments | Avoided Outage Restoration Cost | VoLL | Total Monetized Benefits | Simple Benefit-Cost Factor |
|---|---|---|---|---|---|---|---|
| Gas M&R Stations | $139,593 | $0.0 | $170,712 | $0.0 | $0.0 | $170,712 | 1.2 |

The cost-benefit analysis for the M&R stations is based on avoided BAU investment costs, a wide range of strong qualitative benefits tied to modern design opportunities, and risk reduction benefits as identified through the risk modeling analysis. Many of the design features improve safety and improve overall environmental performance. While the formal monetary benefit-to-cost ratio is over 1, this

[5] Notwithstanding these observations, there are hazards that could take stations off-line, and these outages would impact customers directly. Under some set of assumptions related to temperature, the availability of supplies from PSE&G's LNG and LPG plants, and other operating conditions, there could be a large number of customer outages if a M&R station experienced a station-level failure. For purposes of the cost-benefit analysis, however, Black & Veatch recommended to PSE&G that this risk is sufficiently low to not form the basis of cost- benefit estimation. Rather the cost-benefit analysis for the M&R stations is based on avoided BAU investment costs, a wide range of strong qualitative benefits tied to modern design opportunities, and risk reduction benefits as identified through the risk modeling analysis.

quantitative result does not reflect or include the tremendous value of many qualitative benefits described above.

There are safety and building standard conformance opportunities that are identified for the new M&R stations. These opportunities represent important qualitative benefits for the M&R Subprogram cost-benefit analysis, and they reinforce the conclusions of the Risk model evaluation. In comparison to new M&R station designs, the existing seven M&R stations identified for replacement as part of the Infrastructure Advancement 2021 Gas Program rely on many mechanically and electrically outdated components and systems, even though the stations have historically provided reliable service.

- The upgraded M&R Stations will be designed and built to the latest version of the Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) Pipeline Safety Regulations Part 192 and to the American Society of Mechanical Engineers (ASME) B31.8 Gas Code.
- The upgraded M&R Stations will support the provisions in the PIPES Act of 2020 and PHMSA advisory 2021-0050 for minimizing releases of natural gas.
- The replacement M&R buildings will be built according to current local building codes addressing fire, safety, and other design features.
- The upgraded M&R stations will include an improved overpressure protection design, modern noise abatement design features, modern design for gear valves (improving ease of operation); improved cathodic protection for all underground piping; improved atmospheric corrosion protection on all aboveground piping using most current coating technology;
- Use of improved, modern materials and construction techniques; use of modern inspection techniques during all phases of construction.
- Improved recording keeping systems and documentation on equipment.
- Pressure testing of all newly installed piping and equipment (upon commissioning).
- All upgraded M&R stations will have enhanced site security measures installed. The Hamilton station will have security upgrades in accordance with the recent TSA physical security guidelines for a TSA critical site.

Modernizing the stations will also provide visible evidence within the community of PSE&G's IAP Gas Program and its commitment to improve the gas distribution system.

Some of these items are described in further detail below.

Additional benefits that can be achieved through this program:

- **PHMSA Pipeline Code** - The new station design will bring the M&R stations up to the current Department of Transportation PHMSA Part 192 Pipeline Safety Regulations code and to the ASME B31.8 Gas Code.
- PI**PES Act of 2020 and PHMSA Advisory –** The design configuration of the station will eliminate upstream relief valves and install series regulation minimizing vented emissions of natural gas to the atmosphere.
- **Replace Technically Outdated Equipment** – Equipment will be replaced with state-of-the-art equipment, vastly improving spare part availability, and the parts can be shipped in a timely and predictable manner.
- **New Buildings** - The new buildings that house the regulator stations will be built to the

current local building codes which will improve noise abatement to the surrounding areas. The buildings will be properly sized for the regulator station equipment and will be designed with modern security features, reducing risks related to vandalism and sabotage.

- **M&R Site Layout** - The new station piping and equipment will be laid out in a manner that allows personnel easy access for operations and maintenance activities, improving the safety and quality of these activities.
- **PSE&G's New Station Design** – The M&R stations will be built to PSE&G's current station design requirements and standards. This has many important benefits including incorporating multiple regulator runs instead of a single regulator run. This provides a redundant regulator run in case one regulator run becomes nonoperational.
- **Overpressure Protection** - The new underground piping from the gas supplier to the inlet of the regulator station will be rated for the transmission company's full maximum operating pressure. This eliminates the need for large capacity relief valves. PSE&G is also applying more modern and environmentally friendly worker and monitor regulators, which is consistent with PHMSA Part 192.197 overpressure protection standards.
- **Noise Reduction** - As the population has grown around the M&R stations, noise abatement has become an operational issue in relation to PSE&G's vigilance to maintain good community relations. The new regulators will assist in noise abatement for stations adjacent to public areas. The removal of the high-pressure relief valves will additionally reduce noise levels. The new stations will also include noise attenuation features incorporated into its design.
- **Relief Valves** - As an additional level of safety to the public, PSE&G will install downstream relief valves as a second line of overpressure protection in the unlikely event that the worker and monitor regulators fail simultaneously.
- **Valves** - New gear-operating ball valves will be installed that will be easier to operate and maintain as compared to the existing plug style valves that were commonly installed.
- **Cathodically Protected Piping** - All underground piping will be coated and cathodically protected with the most current pipeline coating system and protection systems. This helps prevent corrosion and maintain the integrity of the pipeline for many years.
- **Material Selection, Inspection and Construction Techniques** - Over the past decades pipeline materials, construction, and inspection techniques have improved, providing a superior product compared to just 40 years ago. The new M&R stations will benefit from these improvements.
- **Atmospheric Corrosion** - All new equipment and piping will be coated and/or painted with the most current coating technology to help prevent atmospheric corrosion.
- **Operating Pressure** - All proposed piping, fittings, and equipment will be designed and rated to safely operate up to the maximum allowable operating pressure of the system.
- **Documentation** - All new piping and equipment will have the proper written documentation to verify the integrity of the pipeline and equipment and to ensure that it can operate at the pressures and conditions required for the M&R stations.
- **Pressure Testing** - All new piping will be hydrostatically tested to PHMSA codes, ensuring that all piping, fittings, etc., are designed and constructed to handle the elevated pipeline pressures prior to regulation.
- **Public Perception** – New, well-constructed M&R stations enhance PSE&G's public presence, communicating to its customers that it is a modern, well-operated utility.

By modernizing these aging M&R stations these benefits will be secured. The inverse is also true.

Deferring the rebuilding of these stations means these benefits are not achieved. Additionally, the operational and maintenance risks associated with their continued operation grow.

## Table 3-13 Benefits of PSE&G's M&R Upgrade Subprogram

| | Attributes | | | Benefits of Replacement & Upgrade | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| M&R Station Priority | New Station | Proposed Construction Adjacent to Existing Station | Consolidate Existing Stations into New Building | Physical Security Enhancements | Replace Transmission pipe in HCA/MCA with higher strength pipe (< 20% SMYS at MAOP) | Remove Upstream Relief Valves - New Piping Rated at MAOP of Pipeline Company | New Design - Series Regulators with a Working Regulator and Monitor Regulator for Overpressure Protection | Downstream Relief Valves - 2nd Line of Overpressure Protection | Replacement of Obsolete Equipment - Hard to Repair - Hard to Find Suitable Replacement Parts | Reduces Methane Release Likelihood |
| Brooklawn | x | x | x | x | x | | x | x | x | x |
| Hillsborough | x | x | | x | x | x | x | x | x | x |
| Hanover | x | x | | x | | x | x | x | x | x |
| Roseland | x | x | | x | | x | x | x | x | x |
| Hamilton | x | x | x | x | | | x | x | x | x |
| Trenton | x | x | x | x | | | x | x | x | x |
| West Deptford | x | x | | x | x | | x | x | | x |

ATTACHMENT 5

# 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 Infrastructure Advancement Program

**BPU Docket No. _______________**

## DIRECT TESTIMONY

## OF

## THE INFRASTRUCTURE ADVANCEMENT PROGRAM
## EV CHARGING INFRASTRUCTURE
## COST-BENEFIT ANALYSIS PANEL

**November 4, 2021**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**
**DIRECT TESTIMONY**
**OF THE INFRASTRUCTURE ADVANCEMENT PROGRAM**
**EV CHARGING INFRASTRUCTURE COST-BENEFIT ANALYSIS PANEL**

**Q. Please introduce the members of the Infrastructure Advancement Program ("IAP") Electric Vehicle Charging Infrastructure Cost-Benefit Panel (the "CBA Panel" or "Panel").**

A. The witnesses comprising the EV Charging Infrastructure CBA Panel are Travis A. Bouslog and Joshua S. Loyd.

**Q. Mr. Bouslog, please state your name and business address.**

A. My name is Travis. A Bouslog, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

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

A. I am a Director, employed by 1898 & Co., a division of Burns & McDonnell Engineering Company ("Burns & McDonnell").

**Q. Please describe your educational background and business experience.**

A. The information is provided in Schedule EV-IAP-1.

**Q. Mr. Loyd, please state your name and business address.**

A. My name is Joshua S. Loyd, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114

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

A. I am a Consultant at 1898 & Co.

**Q. Please describe your educational background and business experience.**

A. The information is provided in Schedule EV-IAP-2.

**Q. Please describe 1898 & Co. and Burns & McDonnell.**

A. 1898 & Co. is a division of Burns & McDonnell and provides business technology and consulting services. Burns and McDonnell is a full service engineering, architecture, construction, environmental and consulting solutions firm. Among other things, Burns & McDonnell plans, designs, estimates, permits, procures and constructs electric vehicle charging infrastructure.

**Q. What is the purpose of the Panel's testimony?**

A. The Panel is sponsoring the cost-benefit analyses of the EV Charging Infrastructure Program ("Program") that is being proposed by Public Service Electric & Gas Company ("PSE&G" or "Company") as part of a larger Infrastructure Advancement Program with the New Jersey Board of Public Utilities ("BPU"). Our full report ("Report") is provided in Schedule EV-IAP-3.

**Q. What does your cost-benefit analysis entail?**

A. As explained in our Report and in the PSE&G testimony, the Program consists of a four-year program of investments that will enable PSE&G to convert its vehicle fleet to electrified technology, allowing PSE&G to decarbonize its fleet while maintaining day-to-day operations. Specifically, the Program includes the installation of more than 2,000 EV chargers and associated infrastructure at approximately 65 PSE&G locations at a total cost of approximately $134 million. It should be recognized that the EV Charging Infrastructure Program proposed by PSE&G does not include the conversion of its entire vehicle fleet to electric vehicles over a four-year period. The Company projects that nearly 74% of their vehicles will be electrified by 2030 and that the conversion will be completed over a 17-year period.

Our team examined the investments and a variety of data and information to develop a cost-benefit analysis of these investments. The study focuses strictly on evaluating the incremental costs required to electrify the fleet against the estimated benefits. In this analysis, the costs are based on the estimated investment costs provided by PSE&G, publicly available data, and in-house data available to 1898 & Co. Our team worked with the data and facts related to these investments to identify and, where possible, quantify the benefits provided by these investments. We also identified benefits that could not be quantified and thus are qualitative in nature.

**Q. The Program only includes investments in EV charging infrastructure, but the cost-benefit analysis evaluates the incremental costs and benefits associated with both electrified vehicles and EV charging infrastructure, please explain.**

To perform a proper cost-benefit analysis of vehicle fleet electrification, the electrified vehicles and EV charging infrastructure must both be considered as they are dependent of one another. Without electrified vehicles, EV charging infrastructure itself cannot realize benefits associated with vehicle electrification. Conversely, EV charging infrastructure is required to adopt and deploy electrified vehicles. While the Program is for EV charging infrastructure, it will enable the adoption of electrified vehicles.

**Q. Please describe the quantification of costs and benefits.**

A. Our team, under the assumptions of the study, estimates that over a 20-year period, cumulative total benefits, inclusive of societal benefits, exceed costs by approximately $31.5 million for a ratio of benefits to costs of 1.12. The study also identified important but difficult to quantify and/or unquantifiable benefits that are not accounted for in the ratios. In addition, the study is conservative in other aspects.

**Q. How did 1898 & Co. develop the quantification of benefits?**

A. 1898 & Co. used three scenarios that represent a view of the PSE&G business over the 20-year period. The first scenario assumes PSE&G continues to procure non-electrified vehicles, and is considered for study purposes only. The second scenario assumes PSE&G completes the required EV charging infrastructure as planned over a 9-year period ("Base Program"). The third scenario, the IAP, assumes PSE&G implements the Program on an accelerated schedule over a 4-year period. We compared the 3 scenarios over a 20-year forecast period (2022 – 2041) to determine incremental effects. The non-electric scenario was required to establish a baseline for fuel, maintenance, and societal costs that the IAP could be compared to. The Base Program was compared to the IPA to calculate the avoided future capital expense. As noted in our Report, assumptions were required for vehicle duty cycle, fuel economy and range, maintenance, and emissions on a vehicle basis. The assumptions were developed using PSE&G-provided operational data and publicly available data.

**Q. You stated your analysis focused strictly on incremental costs and benefits, please explain.**

A. PSE&G operates and maintains an existing vehicle fleet. Incremental costs are costs above and beyond operating and maintaining a non-electrified fleet that are required to transition to an electrified fleet. The incremental costs were categorized as follows: (1) electrified vehicle premium and (2) EV infrastructure and related costs. The electrified vehicle premium is the additional cost to electrify a vehicle, which is above the equivalent, conventional vehicle cost. This is further explained in our Report. The EV infrastructure and related costs include capital and O&M costs for new infrastructure required to support an electrified fleet. These are further explained in our Report.

The benefits in the study are those that could be realized by transitioning to an electrified fleet. Quantifiable benefits, those that could be quantified and monetized, were categorized as follows: (1) direct company cost related benefits (reduced fuel and maintenance costs), (2) avoided future capital expenses, and (3) societal-cost related benefits (reduced greenhouse gas and criteria pollutant emissions). Not all benefits were quantified in the analysis as further detailed below.

**Q. Please summarize the results of your quantitative analysis.**

A. The Panel estimates that the Program will reduce PSE&G's operating costs (both fuel and maintenance) and societal costs (reduction in air pollutants and greenhouse gases). The estimated costs and benefits, inclusive of societal benefits, and the resulting benefit-to-cost ratio, are detailed in our Report, and presented below:

**Benefit Results and Benefit-Cost-Ratio (in thousands)**

| | Total 20 Year Cost Estimate (A) | Total 20 Year Monetized Benefits (B) | Total 20 Year Net Benefit (Cost) (C) = (B) - (A) | Simple Benefit-Cost Factor (D) = (B) / (A) |
|---|---|---|---|---|
| TOTAL | $263,082 | $294,669 | $31,481 | 1.12 |

**Q. What are some of the qualitative benefits not reflected in the quantified benefits?**

A. The cost-benefit analysis results in the table above are limited to those benefits that can be quantified and monetized. The results do not consider the additional value added by benefits that are qualitative in nature. In our Report we identify qualitative benefits. In general, the qualitative benefits of this Program are categorized as follows: (1) supporting the state of New Jersey's commitment to a clean energy future and (2) PSE&G can demonstrate leadership in fleet electrification by electrifying its diverse fleet; promoting and advocating for fleet electrification that supports several policy and societal objectives within New Jersey. Additionally, as auto manufacturers expand their commitment to an electrified vehicle future, vehicle electrification is likely to be required, not a choice. By delaying the transition there is a potential for future costs by not acting today.

**Q. You stated that your analysis is conservative in other respects; please explain.**

A. In 1898 & Co.'s view, the analysis is conservative for the following reasons:

1. The study assumes that Plug-In Hybrid electric vehicle ("PHEV") and battery electric vehicle ("BEV") acquisition costs will not decrease over time.
2. The study does not monetize benefits associated with a reduction in noise pollution.
3. Anti-Idle Systems can reduce engine wear and associated maintenance costs. The study does not monetize any potential reduction in maintenance costs realized from these systems.
4. Light duty vehicles that transition to Anti-Idle Systems because of range limitations of BEVs or lack of availability of BEVs or PHEVs are assumed to use Anti-Idle Systems over the entire 20-year period.
5. The study does not contemplate any federal or state incentives.
6. The study assumes that medium and heavy duty vehicles will only adopt Anti-Idle Systems over the 20-year period.
7. The study assumes the capital costs of the Base Program are equivalent to those of the Accelerated Program

**Q. Please describe the sensitivity analyses contained in your report.**

A. We developed several sensitivities to explore the range of impacts related to key input variables and assumptions. Specifically, we considered:

1. An increase and decrease in fuel costs (gasoline and diesel);
2. An increase and decrease in Program capital costs;
3. A societal discount rate as the Program supports societal policy objectives;
4. An increase and decrease in the escalation rate;
5. Impact of higher than anticipated annual mileage;
6. Impact of higher than anticipated and lower than anticipated reduction in unit maintenance costs;
7. Removal of standby generation and mobile charging and battery systems from the Program;
8. Impact of electric vehicle supply equipment useful life extending beyond the forecast period;
9. A decrease in the risk and contingency included in the Program;
10. Fewer BEVs deployed in the transition than expected;
11. A delay in the adoption and deployment of electrified vehicles;
12. A decrease in the annual idle hours.

**Q. Can you summarize the results of those sensitivity analyses?**

A. The benefit-to-cost ratio is affected to varying degrees with 12% being the largest increase and 30% being the largest decrease. Of the 15 scenarios considered, only two (low fuel costs and decrease in annual idle hours) resulted in a benefit-to-cost ratio below 1.0.

**Q. What should one conclude from your study?**

A. The study provides a cost-benefit analysis of the Program that, when combined with all qualitative benefits, supports PSE&G's decision to pursue the Program.

**Q. Does this complete the Panel's testimony?**

A. Yes.

# Travis Bouslog, PE

## Director

Travis is a director at 1898 & Co., part of Burns & McDonnell is an experienced consultant and project manager focused on transportation electrification and zero-emission mobility. He has more than 10 years of engineering and consulting experience. Travis specializes in technical and economic evaluations, business case analysis, new business models, strategy roadmaps, data analysis and project management of zero-emission mobility projects for utility, transportation, commercial, and industrial customers. Travis is an active participant in the Alliance for Transportation Electrification's policy and regulatory committee and Smart Electric Power Alliance's electric vehicles working group.

Travis is the co-founder and co-creator of Burns & McDonnell's innovation program. To date, these innovation efforts have resulted in over 500 solution concepts to solve new and dynamic client challenges. The concepts have resulted in 100 detailed business cases, 25 pitches for investment, and five active products or services in full development. As the program administrator, he and his team guided participants through the competition and development process by providing education, training, and mentorship.

Travis serves as an ambassador to an investment fund that invests in companies shaping the energy landscape of the future. He oversees the company's investment and collaboration with portfolio companies including those specializing in electrification, distributed energy generation and control, energy financing, and smart cities.

Previously, Travis served as a project manager, engineering manager, and project engineer in Burns & McDonnell's Transmission & Distribution practice. He led engineering teams ranging in size from three to seven engineers on design and design-build projects or pursuits ranging in cost from $1M to $1B. He and his teams were responsible for conceptual engineering, engineering, estimating, developing subcontractor packages for both services and materials, performing risk analysis and mitigation plans, and supporting field engineers during implementation. During this role, Travis provided services for projects in North America, Africa, and South America as well as worked with vendors from Europe, Asia, and South America

### Education

Bachelor of Science | Civil Engineering | University of Iowa | 2010 | United States

### Registrations

- Registered Professional Engineer in the State of IA, IL, & KS
- Envision Sustainability Professional, ISI

### Experience

- **10 years** with 1898 & Co.
- **11 years** of experience

Visit my **LinkedIn** profile.

## PROJECT EXPERIENCE

### Strategic EV Planning Study | Midwest Energy

**Hays, KS | 2021**

**Advisor and Peer Reviewer.** Our team assisted with the creation of an electric vehicle vision, strategies, and tactics for the client's business planning initiatives. Project included an assessment of the EV market including vehicles and charging, EV trends, state policies and incentives, federal policies and incentives, and exploration of potential grid impacts from EV charging. A matrix of strategies and tactics that aligned with the client's vision for electrification was developed for inclusion into business plans.

## EV Charging Impact Study | Sunflower Electric

**Hays, KS | 2021**

**Advisor and Peer Reviewer.** Our team evaluated various vehicle electrification scenarios across the client's electric service territory to assess impacts to their network. We produced EV adoption forecasts with sensitivities to forecast annual energy requirements. In conjunction, we forecasted charging scenarios by zip code for various types of vehicles. These forecasts were visualized in PowerBI using ArcGIS online to produce heat maps of power and energy across the region. The forecast was used to inform next steps and decisions to analyze impacts to the electric grid.

## Fleet Electrification Roadmap | PSE&G

**Newark, NJ | 2021**

**Project Manager.** Our team assisted our client in the creation of a 10-year vehicle fleet electrification roadmap and strategy based on technical, economic, and operational feasibility. We evaluated and recommended commercially available and near-term vehicle technology, charging hardware, and software. A 10-year investment plan was created by using vehicle duty cycles, forecasting energy and power needs, and sizing EV charging infrastructure. We provided guidance on various electrified vehicle technologies and charging infrastructure and advised on process changes and potential risks associated with converting an ICE vehicle fleet to an electrified vehicle fleet.

## CAP Implementation & COVID Adaptation Strategy | LA Metro

**Los Angeles, CA | 2020**

**Advisor and Peer Reviewer.** Reviewed assumptions findings, and final deliverables. In 2019, LA Metro established 13 sustainability programs under their Climate Action & Adaptation Plan. The emergence of COVID-19 pandemic adversely impacted revenues and forced an evaluate of the deployment plans to explore reduction of capital investment impacts on these sustainability programs. We examined cost and benefit expectations of the programs and explored alternate investment strategies that reduced capital requirements in early years, resulting in a positive impact totaling millions in positive value.

## Municipal Fleet Electrification Strategy | City of Dubuque, IA

**Dubuque, IA | 2020**

**Advisor and Peer Reviewer.** Reviewed assumptions, findings and final deliverables. The city of Dubuque, IA desired to reduce emissions from their municipal fleet through electrification and charge the fleet with renewable energy. In collaboration with the City of Dubuque and Alliant Energy, we identified conversion candidates based on use case, vehicle age, duty cycle, and TCO to create a vehicle transition strategy. Additionally, we evaluated grid interconnection and integrated solar + EVSE energy systems to align forecasted energy consumption with energy production from PV.

## Electric Vehicle Market Assessment | Liberty Utilities

**MO, NH, CA | 2020**

**Advisor and Peer Reviewer.** Our team forecasted EV adoption for light, medium, and heavy duty vehicles within the client's electric service territory to identify peak impacts to system and created screening level costs for infrastructure required to support electrification.

## EV Fleet Electrification White Paper | APPA

**Kansas City, Missouri | 2019**

**Project Manager.** Led a team of technical consultants supporting APPA with the development and drafting of an EV fleet electrification white paper. Our team drafted a scope outline, provided primary and secondary research, performed literature reviews and recommendations, and reviewed the final white paper.

## EV Adoption System Impact Study | DTE Energy

**Detroit, MI | 2019**

**Advisor and Peer Reviewer.** Reviewed assumptions, findings, and final deliverables. The client wanted to understand distribution system impacts, if any, across their service territory from adoption of EVs over time. Using customer demographics enriched with publicly available and third-party data, we forecasted adoption and penetration across the client's service territory and vehicle classes. We created EV load profiles based on use cases. Coupling penetration with load profiles we tied forecasted EV load to circuits to identified system impacts over time. We identified and quantified time-phased impacts across the system and recommended mitigation strategies such as changes to standard equipment to minimize impacts.

## Electrification Market Assessment & Strategy | Confidential Client

**2019**

**Senior Consultant and Advisor.** Travis supported the comprehensive assessment of market potential for electrification within each utility's unique customer base and demographics. Potential energy consumption growth was quantified and forecasted for over 50 different usage conversions or growth from emerging technologies. Barriers evaluated for each major category and individual electrification opportunity. Potential and barriers are then compiled to derive organizational strategies around preparation, mitigation, policy management, and marketing to support customers' needs as they emerge.

## Vehicle Electrification and Depot Charging Infrastructure Planning Study | Port of Oakland

**Oakland, California | 2018-2019**

**Advisor and Peer Reviewer.** Reviewed assumptions, preliminary and final findings, and final deliverables. Our team develop load and charging profiles for converting various types of cargo handling equipment from diesel powertrains to electric powertrains. To create the loading profiles, each vehicle type was assessed based on its efficiency and daily energy usage. This information was then coupled with daily operation schedules, collected from interviews, in order to optimize charging times and power requirements to meet the needs of the terminal operators. The loading and charge profiles were then used to evaluate the necessary infrastructure upgrades that would be required to support the electrification of cargo handling equipment.

## In-Depot Charging Design Services | Foothill Transit

**West Covina, California | 2018**

**Advisor and Peer Reviewer.** Travis was responsible for developing Burns & McDonnell's proposal including scope, schedule, and budget. This included the identification and selection of key partners to support the Burns & McDonnell team during project execution. As an advisor, Travis supported the comprehensive assessment of electrifying 400 medium duty transit buses over a 10-year period. For each of Foothill's bus depots, our project team constructed hourly electric energy usage models based on depot operator schedules and telematics to determine fleet requirements and charging characteristics. The project team interviewed staff and collected detailed fleet replacement plans to assess how and when equipment would be replaced over a 10-year period. Vehicle and charging equipment market research was conducted to validate that vehicles and chargers were available within the planning periods. Depot charging infrastructure was sized and scoped to provide budgetary estimates of electrifying the 2 bus depots. In addition to the depot charging infrastructure, coordination with SCE was provided to ensure distribution circuit capacity could support the future load growth. A long-term plan showing the required infrastructure build out was provided to the Port. The project team also evaluated onsite solar and energy storage to provide power to the chargers. Backup power for emergency planning scenarios was also considered in the plan.

# PRIOR EXPERIENCE

**Project Manager, Engineering Manager, and Project Engineer.** During his time in Burns & McDonnell's Transmission & Distribution practice, Travis provided engineering related services on more than 75 different projects. Services included feasibility assessments, conceptual engineering, detailed engineering, field engineering, cost estimating, QA/QC, and other pertinent services. These services have been provided to multiple electric utilities and developers across North America under a variety of commercial arrangements. Detailed descriptions of these projects have not been provided.

# Joshua Loyd, PE

## Consultant

Joshua is a Consultant at 1898 & Co., part of Burns & McDonnell. He has worked on engineering design projects for EV supply equipment and electric utility communication systems. He works with clients to perform fleet electrification studies, develops EV strategies and tactics, and performs analysis and guidance on charging and load growth impacts that can be caused by electrification of light, medium, and heavy-duty vehicles. His experience in engineering design and management of utility communication systems, EV supply equipment installations, including load and charging forecasts, provides him a strong understanding of the challenges and solutions facing EV adoption.

### Education
Bachelor of Science | Electrical Engineering | Kansas State University | 2015 | United States

### Registrations
- Registered Professional Engineer in the State of KS

### Experience
- **6 years** with 1898 & Co.
- **6 years** of experience

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## PROJECT EXPERIENCE

### Strategic EV Planning Study / Midwest Energy
**Hays, KS / 2021**

**Consultant and Project Manager** developing an Electric Vehicle vision, strategies, and tactics for the client's business planning initiatives. The project including discussing the EV market including vehicles and charging, presenting EV adoption trends, exploring potential grid impacts from EV charging, reviewing the costs required to develop DC fast charging systems, rate design and demand response, and state and federal policies and incentives. The final deliverable included a matrix of strategies along with tactics that the client can implement into its business plans. The matrix was aligned with the client's vision for electrification.

### EV Charging Grid Impact Study / Sunflower Electric
**KS / 2021**

**Consultant and Project Manager** that evaluated various vehicle types that could transition to an electrified drive train across the client's electric service territory. As part of this study, I identified the potential vehicles that could electrify and then produced an EV adoption forecasts with low, medium, and high sensitivities to calculate the potential annual energy requirements. In conjunction with energy requirements, I also developed potential charging scenarios by zip code for the different vehicle types. This zip code-based analysis over a time horizon was then visualized in PowerBI using ArcGIS online to show a heat map forecast of power across the region. This forecast was then used by the client to inform next steps and decisions that can be used to analyze transmission or distribution impacts to the electric grid.

## Fleet Electrification Roadmap / PSE&G

**NJ / 2021**

**Consultant** that performed market research and data analytics on ICE vehicle inventory to develop a transition to an electrified fleet. I helped create vehicle personas that modelled the existing vehicle specifications including mileage driven, dwell times, vehicle efficiency, fuel efficiency, and weight to determine the feasibility of transitioning vehicles to electrified technology. The energy required for an electric vehicle was modeled to determine the infrastructure requirements at each facility and a time-phased roadmap of infrastructure and energy and power requirements was created for each facility based on the asset life of the vehicles. I also provided consulting and guidance on different electrified vehicle technology and charging infrastructure along with advising on processes, barriers, and risks for converting from a traditional ICE fleet an electrified vehicle fleet.

## Fleet Vehicle Electrification Study / City of Dubuque

**Dubuque, IA / 2020**

**Consultant** testing a hypothesis for minimizing grid impacts from electrifying fleet vehicles by utilizing renewable energy and battery storage to support EV charging. Project includes reviewing city fleet vehicles and estimating requirements for equivalent BEVs, assessing city locations for charging infrastructure requirements and renewable energy generation, and working with the local electric utility to assess potential grid impacts and strategies to avoid costly grid upgrades.

## Electric Vehicle Market Assessment / Liberty Utilities

**MO, NH, CA / 2020**

**Consultant** developing estimated adoption forecasts for electrification of light, medium, and heavy-duty vehicles within the client's electric service territory. Developed peak impacts to system and screening level costs for infrastructure required to support electrification.

## Electrification Market Assessments / Confidential Utility Clients

**2019/2020**

**Consultant** evaluating electrification potential of 50 different electrification technologies across industries including agriculture, transportation, airport operations, commercial and industrial, and residential. Forecasts of adoption were developed based on barriers to adoption including economics, policies, and asset life. Total cost of ownership for select electrification technologies was assessed to understand customer sentiment to adoption and identify potential areas of investment for the utility. Existing and comparable utility programs were benchmarked and a roadmap with potential actions along with strategies and market messaging was developed

## Vehicle Electrification and Depot Charging Infrastructure Planning Study / Port of Oakland

**Oakland, CA / 2018-2019**

**Analyst** developing loading information and charge profiles for converting various types of cargo handling equipment from diesel powertrains to electric powertrains. To create the loading profiles, each vehicle type was assessed based on its efficiency and daily energy usage. This information was then coupled with daily operation schedules, collected from interviews, in order to optimize charging times and power requirements to meet the needs of the terminal operators. The loading and charge profiles were then used to evaluate the necessary infrastructure upgrades that would be required to support the electrification of cargo handling equipment.

## Vehicle Electrification and Energy Storage Technical Planning Study / Rochester Public Utilities

**Rochester, MN / 2018-2019**

**Analyst** conducting market research and produced a report on the factors that are driving electric vehicle adoption including the current state of the market, expected future EV growth, EV technologies including batteries and charging equipment, and state and federal regulations and policies. The report also included the creation of load forecasts based on projections of EV growth in the city of Rochester and the assessment of rate structures and techniques for managing peak load from EV charging. Fleet and mass transit electrification was also assessed for potential impacts to Rochester Public Utilities system.

## Vehicle Innovation Center / New Flyer

**Anniston, Alabama / 2017**

**Design engineer** involved in scoping of project and supporting engineering efforts for electrical wiring diagrams and schematics for the installation of two 150kW DC fast chargers and one 300KW overhead pantograph charging system. Provided engineering support for installation of equipment.

## Supercharger Deployment / Confidential

**California and Nevada / 2015-2016**

**Utility design coordinator** responsible for coordinating the installation of commercial 3 phase 480VAC services to supply power for Tesla supercharging sites. In this role he worked with the utility contact to obtain the distribution design for the utility service including the transformer, transformer pad, pad mounted interrupters, junction boxes and conduit specifications. He also coordinated with Tesla and provided status updates to ensure accurate and timely construction. To expedite utility designs, Joshua read through utility specifications regarding distribution systems and incorporated them into the team's engineering package.

## Energizing the Future / First Energy

**Ohio, New Jersey, Pennsylvania / 2016-2018**

**Engineering team lead** responsible for six engineers that created detailed design packages for the deployment of large scale MPLS networks. These networks utilize both fiber optic cable and microwave communications backhaul to transport serial SCADA traffic collected by Remote Terminal Units (RTU's) in transmission substations. In addition to large scale MPLS networks, his engineering team creates detailed engineering design packages for the deployment of Field Area Networks for serial SCADA traffic. Backhaul communications for these networks included licensed 700MHZ radios, 900MHZ radios and 3G/4G leased cellular modems. Joshua provided regular updates on schedule and budget for his team's projects and worked with his engineers to provide solutions that mitigated project delays. Joshua communicated with installation contractors, project managers, and commissioning engineers to create successful project execution from engineering design through to commissioning and project completion.

## Remote Terminal Unit Replacement Project / Louisville Gas & Electric Kentucky

**Kentucky / 2016**

**Electrical engineer** responsible for preparing engineering drawings and programming the configuration file for the installation of a Cooper Systems SG-4250 Remote Terminal Unit. Joshua set up DNP 3.0 and configured the RTU for the client's first deployment of this RTU. He also programmed an SEL RTAC as well as a SEL 311L relay. He programmed custom logic for counting KYZ pulses into the RTU using the IEC-61131-3 standard used for programming a PLC. Finally, he set up a demonstration for the client to show the RTU ready and sending DNP data, including binary inputs, binary outputs, and analog inputs.

## Integration and Automation Lab / 1898 & Co.

**Kansas City, Missouri**

**Electrical engineer** who worked on several pieces of equipment in the 1898 & Co. Integration and Automation lab. Experience includes configuring and testing Xetawave 900 MHZ MAS radios and well as 200MHZ CalAmp Vipers radios. Have configured CISCO switches using command line interfaces.

SCHEDULE EV-IAP-3

# EV Charging Infrastructure Cost-Benefit Analysis

1898 & CO
PART OF BURNS & McDONNELL

PSEG

## Public Service Electric and Gas Company

EV Charging Infrastructure Cost Benefit Analysis
Project No. 131164

Revision 0
11/4/2021

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# LIST OF ABBREVIATIONS

| **Abbreviation** | **Term/Phrase/Name** |
|---|---|
| 1898 & Co. | 1898 & Co., part of Burns & McDonnell |
| Client | Public Service Electric and Gas Company |
| BEV | Battery Electric Vehicle |
| EEI | Edison Electric Institute |
| LDV | Light Duty Vehicle |
| MDV | Medium Duty Vehicle |
| HDV | Heavy Duty Vehicle |
| PHEV | Plug-in Hybrid Electric Vehicle |
| EV | Electric Vehicle |
| EVSE | Electric Vehicle Supply Equipment |
| Study | Cost-Benefit Analysis |
| Non-Electric Program | Non-Electrified Scenario |
| O&M | Operations & Maintenance |
| FHWA | Federal Highway Administration |
| Roadmap | Fleet Electrification Transition Roadmap |
| MSRP | Manufacturer's Suggested Retail Price |
| OEM | Original Equipment Manufacturer |
| NPV | Net Present Value |
| WACC | Weighted Average Cost of Capital |
| Program | EV Charging Infrastructure Program (part of IAP) |
| ICE | Internal Combustion Engine |
| Anti-Idle Systems | Anti-Idle Job Site Work Systems |
| Base Program | Planned EV charging infrastructure program over 9-year period |
| IAP | Infrastructure Advancement Program |

## DISCLAIMERS

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# 1.0 EXECUTIVE SUMMARY

1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (hereinafter called "1898 &Co.") was retained by Public Service Electric and Gas Company ("PSE&G") to perform a Cost-Benefit Analysis ("Study") for electrifying a portion of PSE&G's vehicle fleet. The purpose of the Study was to calculate the 20-year costs and benefits associated with electrifying a portion of the PSE&G vehicle fleet. The costs and benefits were developed by 1898 & Co. using data provided by PSE&G and in-house and publicly available data.

PSE&G aims to decarbonize its vehicle fleet, in support of the state of New Jersey's decarbonization goals[1]. To achieve these goals, PSE&G will transition vehicles to electrified technology such as Plug-in Hybrid Electric Vehicles ("PHEV"), Battery Electric Vehicles ("BEV"), and Anti-Idle Job Site Work Systems ("Anti-Idle Systems") and deploy the necessary infrastructure to fuel the electrified vehicles.

The cost-benefit analysis focuses strictly on evaluating the incremental costs required to electrify the fleet against the estimated benefits. The cost-benefit analysis relies on three scenarios that represent a view of the PSE&G business over the 20-year forecast period (2022 – 2041). The first scenario is a non-electrified scenario which assumes PSE&G does not implement Electric Vehicle ("EV") charging infrastructure and continues to procure non-electrified vehicles ("Non-Electric Program"). The second scenario assumes PSE&G implements EV charging infrastructure as planned over a 9-year period ("Base Program") and procures electrified vehicles. The third scenario assumes PSE&G implements the Infrastructure Advancement Program ("IAP") over a 4-year period and procures electrified vehicles (""). The IAP includes an EV Charging Infrastructure Program ("Program"). The Study uses all three scenarios to derive the incremental costs and benefits over 20-year forecast period. The Non-Electric Program is required to establish a baseline for fuel, maintenance, and societal costs that the EV Charging Infrastructure Program could be compared to. The Base Program is compared to the IAP to calculate the avoided future capital expense.

## 1.2 Cost-Benefit Results

1898 & Co. gathered program costs from PSE&G and estimated other long-term costs. 1898 & Co. estimated benefits for vehicle fleet electrification following industry accepted practices. The IAP will reduce PSE&G's vehicle fleet operating costs (both fuel and maintenance) and societal costs[2] (reduction in criteria air pollutants[3] – which contribute to smog, haze and health problems – and greenhouse gases[4]).

---

[1] The State of New Jersey's Energy Master Plan outlines seven key strategies to reach the administration's goal of 100 percent clean energy by 2050. The first strategy focuses on reducing energy consumption and emissions from the transportation sector by electrifying the transportation sector or utilizing technology to reduce emissions.
[2] Assuming PSE&G deploys electrified vehicles.
[3] Criteria air pollutants included in the Study are: Particulate Matter (PM2.5, PM10), Volatile Organic Compounds (VOCs), Nitrogen Dioxide ($NO_2$), and Sulfur Dioxide ($SO_2$).
[4] Greenhouse gases included in the Study are: Carbon Dioxide ($CO_2$), Methane ($CH_4$), and Nitrous Oxide ($N_2O$).

A simple comparison of cumulative costs and benefits, inclusive of escalation, reveals that the benefits exceed the costs (inclusive of societal benefits) by $31.5 million, resulting in a benefit-to-cost ratio of 1.12. If societal benefits are excluded, the simple comparison of cumulative costs and benefits, inclusive of escalation, reveals that the benefits exceed costs by $7.6 million, resulting in a benefit-to-cost ratio of 1.03.

The net present value (NPV) of the benefit and cost impacts is negative $26.8 million with societal benefits and negative $38.1 million without societal benefits, using a discount factor of 6.48% which aligns with the weighted average cost of capital (WACC) provided by PSE&G. This results in a benefit-to-cost ratio of 0.86 with societal benefits and 0.80 without societal benefits The NPV results are as expected as transitioning to an electrified fleet requires upfront investments to realize operational and societal savings over time.

A benefit-to-cost ratio of less than 1.0 for the entire program is not uncommon for a fleet exploring the transition to electrified technology today. Fleet electrification (and even consumer vehicle electrification) requires upfront capital investment for the vehicles and necessary fueling infrastructure while the benefits of the transition are realized over time. Like other fleets, a utility fleet is not immune from the infrastructure investments required.

Table 1 depicts the Study results on a NPV basis and Table 2 depicts the Study results on a cumulative total basis.

**Table 1: Cost-Benefit Analysis Results
($1,000s, NPV, 20-Year)**

| Result | Costs[5] [A] | Benefits [B] | Net Benefit (Cost) [C] = [B] – [A] | Simple Benefit Cost Factor [D] = [B] / [A] |
|---|---|---|---|---|
| **With Societal Benefits** | 194,383 | 167,535 | (26,848) | 0.86 |
| **Without Societal Benefits** | 194,383 | 156,310 | (38,073) | 0.80 |

**Table 2: Cost-Benefit Analysis Results
($1,000s, Cumulative Total, 20-Year)**

| Result | Costs[5] [A] | Benefits [B] | Net Benefit (Cost) [C] = [B] – [A] | Simple Benefit Cost Factor [D] = [B] / [A] |
|---|---|---|---|---|
| **With Societal Benefits** | 263,082 | 294,564 | 31,481 | 1.12 |

[5] Costs include the electrified vehicle premium which is above the equivalent, conventional vehicle cost and EV infrastructure and related costs which include capital and O&M costs for new infrastructure required to support an electrified fleet. Program costs are explained in section 3.0 Program Costs.

| | | | | |
|---|---|---|---|---|
| Without Societal Benefits | 263,082 | 270,669 | 7,587 | 1.03 |

To perform a proper cost-benefit analysis, the electrified vehicles and EV charging infrastructure must be considered as they are dependent of one another. While the IAP is for EV charging infrastructure only, it will enable the adoption of electrified vehicles. Thus, the Study presents the costs and benefits associated with electrifying the PSE&G vehicle fleet. Table 3 provides a detailed breakdown of the Study results on a cumulative total basis for the costs and benefits associated with IAP and the electrified vehicles. Benefits have been allocated to the IAP and vehicles in proportion to the cumulative total costs[6].

Table 3: Detailed Breakdown of Cost-Benefit Analysis Results
($1,000s, Cumulative Total, Escalated20-Year, With Societal Benefits)

| | Capital Costs [A] | Infrastructure O&M Costs [B] | Infrastructure Replacement Costs [C] | Total Costs [D] = [A] + [B] + [C] | Benefits [E] | Net Benefit (Cost) [F] = [E] – [D} | Simple Benefit Cost Factor [G] = [E] / [D] |
|---|---|---|---|---|---|---|---|
| IAP | 141,977 | 16,313 | 27,672 | 185,961 | 208,214 | 22,253 | 1.12 |
| Vehicles[7] | 77,121 | 0 | 0 | 77,121 | 86,349 | 9,228 | 1.12 |
| Total | 219,098 | 16,313 | 27,672 | 263,082 | 294,564 | 31,481 | 1.12 |

The Study evaluated 15 sensitivity scenarios, 13 of which resulted in a benefit-to-cost factor above 1.0 on a cumulative total basis. No sensitivity scenario resulted in a benefit-to-cost factor less than 0.79 on a cumulative total basis. The Fewer BEVs scenario, which reduces the number of BEVs deployed in the early years of the forecast period, and the Delayed Adopt., which assumes that the adoption and deployment of electrified vehicles is delayed by two years, are potentially likely scenarios to occur. Both scenarios maintain a benefit-to-cost factor above 1.0 on a cumulative total basis.

In 1898 & Co.'s view, the analysis is conservative for the following reasons:

- The Study assumes that PHEV and BEV acquisition costs will not decrease over time. Instead, it assumes the acquisition costs will remain constant until 2030, subject to escalation.
- The Study does not monetize the reduction in noise pollution that can be realized from an electrified fleet. Similar to emissions, noise is a pollution often considered a

[6] Assuming escalated.
[7] Capital Costs for the vehicles is the electrified vehicle premium which is explained in section 3.1 Electrified Vehicle Premium.

detriment to society. Reducing noise in parking areas and residential streets can improve the lives of citizens.

- Anti-Idle Systems decrease idle time which can reduce engine wear and associated maintenance costs, especially for heavy duty trucks. The Study does not monetize the reduction in maintenance costs realized from an Anti-Idle System.
- LDVs that transition to Anti-Idle Systems because of range limitations of BEVs or lack of availability of BEVs or PHEVs are assumed to utilize Anti-Idle Systems over the entire 20-year forecast period when, in reality, these LDVs would likely transition to a BEV in later years, providing additional benefits.
- The Study does not contemplate any federal or state incentives.
- The Study assumes that MDVs and HDVs will only adopt Anti-Idle Systems over the entire 20-year forecast period. However, is it feasible that BEVs may be available for MDVs and HDVs as soon as the end of the decade, providing additional benefits.
- The Study assumes that the capital costs of the Base Program are equivalent to those of the IAP. However, because the Base Program is over a 9-year period, it is unlikely that it will realize the same execution efficiencies of the IAP, resulting in slightly higher capital costs (~10%).
- The Study does not consider the possibility that PSE&G would prioritize electrifying the more utilized (high mileage, high idle hours) vehicles in the early years, reallocating vehicles between users so that those that drive or idle more have an electrified vehicle.

# 2.0 INTRODUCTION

1898 & Co. was retained by Public Service Electric and Gas Company to perform a Cost-Benefit Analysis ("Study") for electrifying a portion of PSE&G's vehicle fleet. The purpose of the Study was to calculate the 20-year costs and benefits associated with electrifying a portion of the PSE&G vehicle fleet. The costs and benefits were developed by 1898 & Co. using data provided by PSE&G and in-house and publicly available data. 1898 & Co. has prepared cost-benefit studies for fleet electrification transitions for various fleet owners and operators including, but not limited to, utilities, municipalities, and public transit agencies. To support these studies, 1898 & Co. leverages the experience of Burns & McDonnell Engineering Company, Inc. which plans, designs, estimates, permits, procures, and constructs electric vehicle charging infrastructure.

## 2.2 Overview

PSE&G aims to decarbonize its vehicle fleet, in support of the state of New Jersey's decarbonization goals, most notably New Jersey's Energy Master Plan. PSE&G has established a goal to transition a portion of its vehicle fleet to electrified technology by 2030 and beyond. To achieve this goal, PSE&G will deploy PHEVs, BEVs, and Anti-Idle Systems across their passenger, light, medium and heavy duty vehicles and deploy the necessary infrastructure to fuel the electrified vehicles.

PSE&G is pursuing the Infrastructure Advancement Program ("IAP") – a 4-year distribution investment program to improve reliability, reduce emissions and create jobs. The IAP includes an investment in Electric Vehicle ("EV") charging infrastructure at PSE&G facilities. The EV Charging Infrastructure Program ("Program")[8] is required to enable PSE&G to convert its vehicle fleet to electrified technology, allowing PSE&G to decarbonize its fleet while still supporting day-to-day operational needs. This investment calls for the installation of more than 2,000 EV chargers and

To perform a proper cost-benefit analysis, the electrified vehicles and EV charging infrastructure must both be considered as they are dependent of one another. Without electrified vehicles, EV charging infrastructure itself cannot realize benefits associated with vehicle electrification. Conversely, EV charging infrastructure is required to adopt and deploy electrified vehicles. While the IAP is for EV charging infrastructure only, it will enable the adoption of electrified vehicles.

Thus, this Study presents the costs and benefits associated with electrifying the PSE&G vehicle fleet. Study costs include (1) acquisition costs for electrified vehicles, (2) EV charging infrastructure one-time, recurring, and replacement costs; (3) standby generation and mobile charging & battery trailer one-time and recurring costs, and (4) program management costs. Program benefits include (1) fuel and maintenance savings, (2) societal savings resulting from

[8] The EV Charging Infrastructure Program is for infrastructure only. It does not include the vehicles.

a reduction in greenhouse gases and criteria pollutants, and (3) savings from avoided future capital expenses.

## 2.3 Program Highlights

The PSE&G fleet consists of over 5,800 vehicles of various makes and models that serve different business functions. Of these vehicles, 3,251 are included in this Study[9]. The fleet vehicles were classified into Passenger, Light Duty, Medium Duty, Heavy Duty and Off-Road vehicles. Table 4 shows the vehicle categories with example vehicles, electrified solutions that may be adopted, the related charging infrastructure, and the number of vehicles by category.

Table 4: Vehicle Category Summary

| Vehicle Category | Electrified Solutions | EV Infrastructure | Number of Vehicles |
|---|---|---|---|
| **Passenger Vehicle**<br>“People Mover”<br>Class 1 & 2<br>FHWA: Light Duty<br>*(Escape Hybrid, Trax, Sonic)* | **Technology:** PHEVs, BEVs<br>**Example Models:** Ford Escape PHEV, Chevy Bolt, Ford Mustang Mach-E | **PHEV:** Level 2 charging at 6.6kW<br>**BEV:** level 2 charging at 6.6kW and Level 3 charging from 50kW up to 250kW | 807 |
| **Light Duty**<br>“Workstation”<br>Class 1 & 2<br>FHWA: Light Duty<br>*(F-150, Colorado, Transit 350)* | **Technology:** PHEVs, BEVs, Anti-Idle<br>**Example Models:** Ford F-150 Lightning, Ford E-Transit, Chevy Silverado Electric | **PHEV:** Level 2 charging at 6.6kW.<br>**BEV:** Level 2 charging at 11kW to 19.2kW and Level 3 charging up to 150kW<br>**Anti-Idle:** Level 1 charging at 3kW | 1210 |
| **Medium Duty**<br>Class 3 to 6<br>FHWA: Medium Duty<br>*(F-550, Ram 5500)* | **Technology:** Anti-Idle<br>**Example Models:** Stealth Power Systems, Viatec, Zero-RPM | **Anti-Idle:** Level 1 charging at 3kW | 716 |
| **Heavy Duty**<br>Class 7 to 8<br>FHWA: Heavy Duty<br>*(M2 106, F-750, C7500)* | **Technology:** Anti-Idle<br>**Example Models:** Stealth Power Systems, Viatec, Zero-RPM | **Anti-Idle:** Level 1 charging at 3kW | 518 |

[9] Take-home (vehicles that are parked or dwell at employees’ residences overnight) and off-road vehicles were excluded from the Study.

Three main technologies – BEV, PHEV, and Anti-Idle Systems – were considered for the purposes of electrifying PSE&G's fleet. The number of vehicles proposed to be electrified, by technology, is shown in Table 5 below.

**Table 5: Type and Count of Electrified Vehicles**

| Electrified Technology | IAP | Base Program[10] |
|---|---|---|
| PHEV | 188 | 328 |
| BEV | 1,376 | 1,105 |
| Anti-Idle | 1,687 | 1,818 |

To charge the electrified vehicles represented in Table 5, EV charging infrastructure is required at PSE&G facilities across the service territory. The number of EV chargers assumed in the Study is shown in Table 6.

**Table 6: Type and Count of EV Charging Infrastructure**

| Charger Type | Charger Quantity |
|---|---|
| Level 1 | 1,715 |
| Level 2 | 266 |
| Level 3 | 250 |

Transitioning to electrified technologies will allow PSE&G to realize operational and societal benefits. To realize these benefits, PSE&G must deploy EV charging infrastructure which is a necessary component of an electrified fleet.

- The implementation of EV charging infrastructure across PSE&G's service territory will enable PSE&G to move away from PHEVs to BEVs as technology allows, which will yield additional benefits.
- Electrified technology will reduce fuel usage, providing cost savings.
- BEVs require less maintenance than conventional vehicles, providing cost savings.
- Electrified technology provides societal benefits by reducing emissions and criteria pollutants and lowering noise pollution.
- The infrastructure investment will create additional clean energy jobs in New Jersey.

[10] The Base Program was included for reference as it represents the type and count of electrified vehicles considered in the sensitivity scenario Fewer BEVs.

## 2.4 Analysis Methodology

To perform the Study, 1898 & Co. relied on information from PSE&G to (1) develop the method of constructing the cost-benefit analysis, (2) define assumptions, and (3) incorporate operational data.

The Study focuses strictly on evaluating the incremental costs required to electrify the fleet against the estimated benefits. This Study relies on three scenarios that represent a view of the PSE&G business over the 20-year forecast period (2022 – 2041). The first scenario is a non-electrified scenario which assumes PSE&G does not implement EV charging infrastructure and continues to procure non-electrified vehicles ("Non-Electric Program"). The second scenario assumes PSE&G implements EV charging infrastructure Program as planned over a 9-year period ("Base Program") and procures electrified vehicles[11]. The third scenario assumes PSE&G implements the IAP over a 4-year period and procures electrified vehicles[12][13]. The IAP includes an EV Charging Infrastructure Program ("Program"). The Study uses all three scenarios to derive the incremental costs and benefits over the 20-year forecast period.[14] Details of the scenarios can be found in Table 7.

**Table 7: Scenario Details**

| Scenario | Vehicles | EV Charging Infrastructure | Why is this scenario required? |
|---|---|---|---|
| Non-Electric | No electrified vehicles are procured.<br><br>Vehicles are replaced on a lifecycle basis over the 20-year forecast period. | EV charging infrastructure is not required. | To establish a baseline for fuel, maintenance, and societal costs. IAP is compared to it to derive benefits. |
| Base Program | Electrified vehicles are procured.<br><br>Vehicles are replaced on a lifecycle basis over the 20-year forecast period. | EV charging infrastructure is installed over a 9-year period. | Represents PSE&G's planned EV charging infrastructure deployment to support fleet electrification. |

[11] Infrastructure would be installed over a 9-year period from 2023 - 2031. Vehicles would be replaced on a lifecycle basis which will extend beyond this 9-year period.
[12] Infrastructure would be installed over a 4-year period from 2022 - 2026. Vehicles would be replaced on a lifecycle basis which will extend beyond this 4-year period.
[13] 48-month program over 5 calendar years.
[14] The Non-Electric Program was required to establish a baseline for fuel, maintenance, and societal costs that the IAP could be compared to. The Base Program was compared to the IAP to calculate the avoided future capital expense.

| | | | |
|---|---|---|---|
| IAP | Electrified vehicles are procured.<br><br>Vehicles are replaced on a lifecycle basis over the 20-year forecast period. Vehicle replacement schedule is same as Base. | EV charging infrastructure is installed over a 4-year period. | Represents EV Charging Infrastructure Program proposed by PSE&G as part of the IAP. |

1898 & Co. included other important considerations into our analysis, including:

- An evaluation period that has a reasonable relationship to the life of the investments.
- Identifying key assumptions and evaluating how they influence results.
- Acknowledgement of the important contribution of qualitative benefits.
- Acknowledgement of the influence of legislative and market conditions supporting vehicle electrification.

The Study was constructed using nominal dollar values with a base year of 2021. An escalation factor is applied to the costs and benefits in future years. The Study was constructed by comparing the costs and benefits of the Non-Electric Program against the IAP Program for the transitioned vehicles only[15].

### 2.4.1 Persona-Based Vehicle Approach

PSE&G's vehicle fleet is comprised of a broad range of vehicles that serve different functions within different business units. To structure the Study, a persona-based vehicle approach was used to classify and categorize PSE&G's more than 5,100 on-road vehicles. Assumptions required to perform the Study (e.g., battery size, range, fuel economy, etc.) were made for each persona.

Each asset was compiled and evaluated based on vehicle type, classification, and job function. The fleet was divided into categories and subcategories. After the major and subcategories were defined for each vehicle, vehicles were also grouped by PSE&G function, Federal Highway Administration ("FHWA") vehicle weight classes, and fuel types to create unique vehicle personas. The vehicle personas were then used to identify the best transition technology for each vehicle based on the findings of the Vehicle Technology Assessment. Appendix A provides additional detail on the persona-based vehicle approach. Additional assumptions for the Study were persona-based and can be found in Appendix C.

[15] If the fleet has 100 vehicles, and, in Year 1, 10 BEVs are adopted, the cost-benefit analysis would be performed for just 10 vehicles. The remaining 90 vehicles are the same in both scenarios, thus their costs and benefits offset one another. If, in Year 2, 10 additional BEVs are adopted, the cost-benefit analysis would be performed for 20 vehicles.

### 2.4.2 Vehicle-Deployment Summary

Figure 1 depicts the proposed vehicle deployment summary on which the Study costs and benefits are based. Vehicles are deployed on a lifecycle replacement basis – it is assumed that a vehicle will be replaced once it reaches the end of its lifecycle[16].

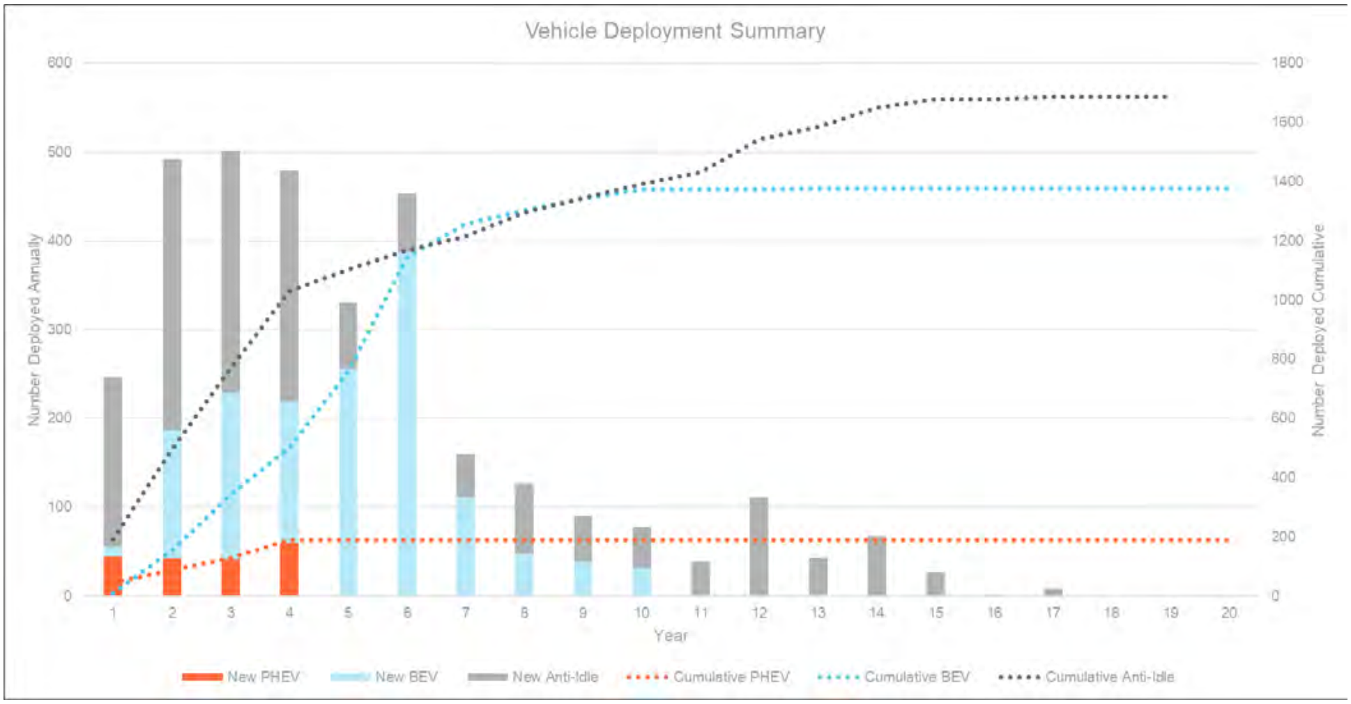


Figure 1: Proposed Vehicle Deployment Summary

## 2.5 Charger Deployment Summary

Figure 2 depicts the proposed EV charger deployment summary on which the Study costs and benefits are based[17].

[16] While no new PHEVs or BEVs are shown to be deployed in Years 11 to 20, this is not likely the case. New PHEVs and BEVs will be deployed at the end of their lifecycle; however, the Study assumes that PHEVs and BEVs will reach cost parity with convention vehicles, eliminating the need to consider incremental costs for an electrified vehicle. This is further explained in section 3.1 Electrified Vehicle Premium.

[17] Chargers may have one or more ports or connectors, allowing it to charge multiple vehicles. In the Study, Level 1 chargers are assumed to have a single port while Leve 2 and Level 3 chargers are assumed to have multiple ports.

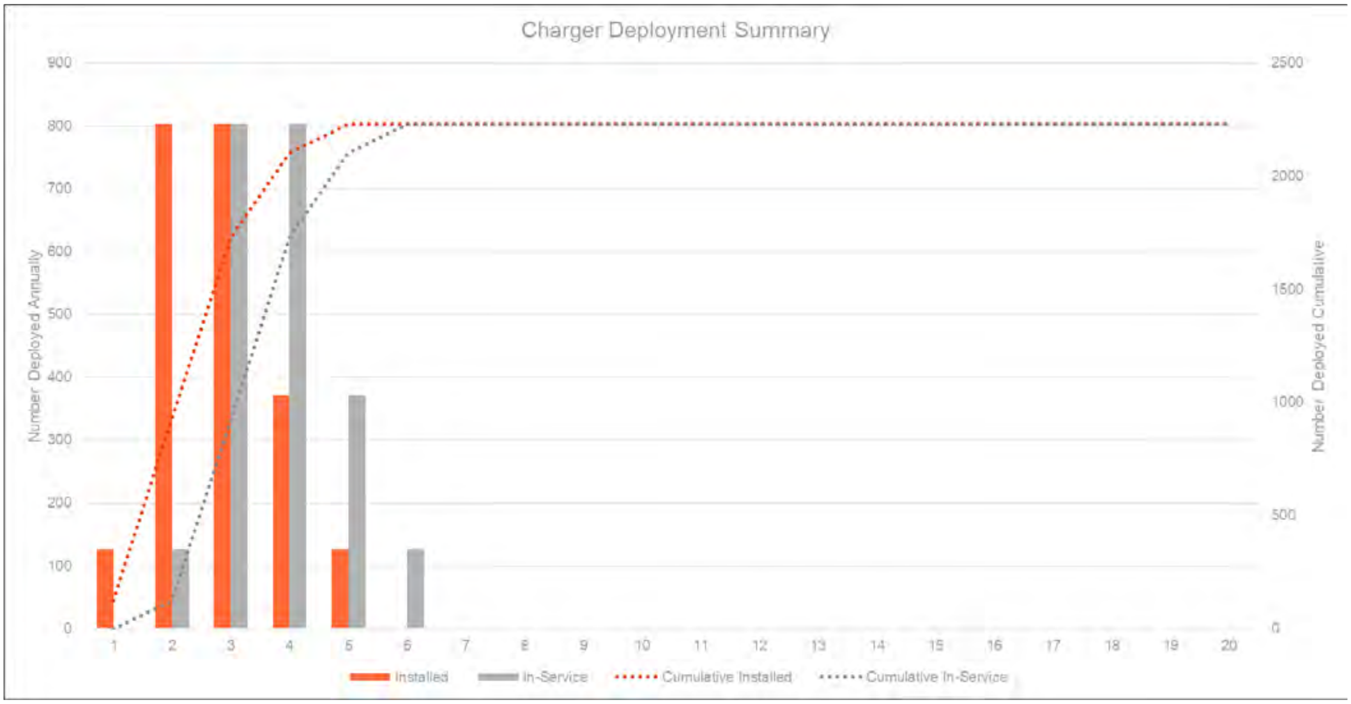


**Figure 2: Proposed Charger Deployment Summary**

## 2.6 Fleet Electrification Transition Roadmap

The Study relied significantly on PSE&G's Fleet Electrification Transition Roadmap ("Roadmap"). The Roadmap identifies what, where, and when electrified technology would be deployed and the corresponding infrastructure investments required to operate an electrified fleet. The Study relied on three key outputs from the Roadmap:

- Vehicle Personas
    - Classification and categorization of PSE&G's vehicle fleet by vehicle type, job function, weight classes, and other pertinent criteria.
- Vehicle Replacement Schedule
    - The Vehicle Replacement Schedule (also known as the Vehicle Adoption Model) identified the number of vehicles, by persona and electrification technology, that would be replaced each year.
- The EV Infrastructure & Related Costs
    - The EV Infrastructure & Related Costs identified one-time, recurring, and replacement infrastructure expenditures by year.

More detail on the approach can be found in Appendix A. Figure 3 depicts the approached used to establish the Roadmap.

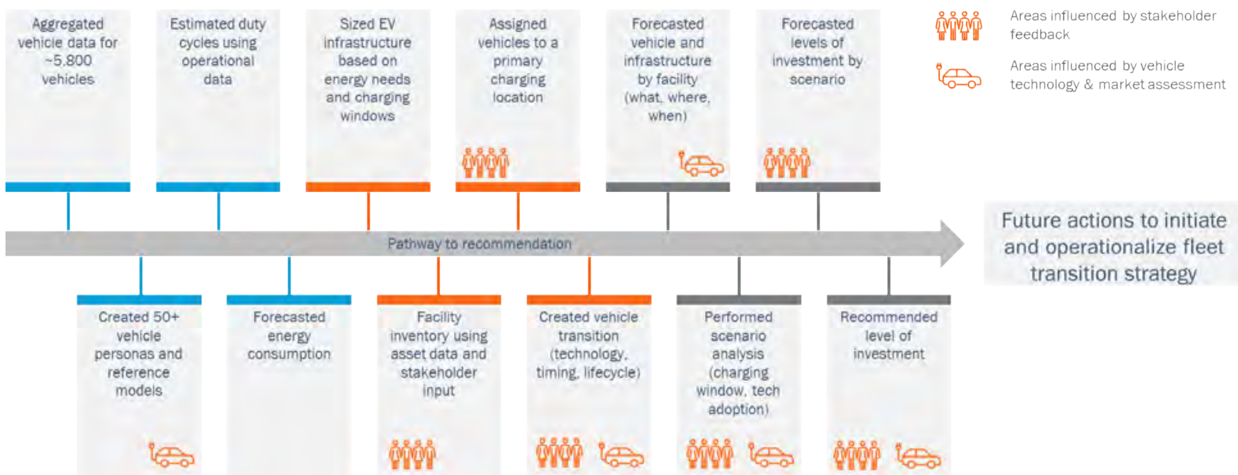


Figure 3: Summary of Approach Used to Establish Roadmap

# 3.0 PROGRAM COSTS

This section describes the costs considered in the cost-benefit analysis. The costs were categorized as follows:

- Electrified Vehicle Premium[18]
- EV Infrastructure & Related Costs

## 3.1 Electrified Vehicle Premium

Purchase prices for PHEVs and BEVs are typically higher than that of equivalent, conventional internal combustion engine ("ICE") vehicles. Additionally, Anti-Idle Systems are aftermarket systems which are installed on a vehicle by an upfitter. The electrified vehicle premium is the incremental costs required to transition the vehicle fleet to electrified technology. For PHEVs and BEVs, the electrified vehicle premium used in the Study is the additional cost above an equivalent, conventional ICE vehicle[19].

The Study relies on budgetary quotes provided by original equipment manufacturers ("OEMs") and publicly available manufacturer's suggested retail price ("MSRP"). While it is an industry expectation that prices for PHEVs and BEVs are likely to equalize with conventional vehicles as production volumes increase and battery technologies continue to mature, this Study does not forecast annual price reductions for PHEVs, BEVs, or Anti-Idle Systems. Instead, the Study assumes that price parity will be reached by the time electrified vehicles, which were deployed in the early years, are due for replacement. As such, vehicle replacement costs are not considered in the latter years of the Study. PSE&G's vehicle lifecycle varies by vehicle type and function, ranging from 8-year, 9-year, 10-year, 15-year, or 16-year with most vehicles on a 9-year, 10-year, or 16-year lifecycle. Generally, passenger vehicles and LDVs have a shorter lifecycle while MDVs and HDVs have a longer lifecycle[20].

Other important considerations:

- Study focused only on electrified vehicle premiums, as it was assumed that conventional vehicles would be procured regardless, as a part of normal vehicle fleet operations.
- Study does not consider any incentives that offset higher initial purchase price, including federal or state tax credits.

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[18] While Electrified Vehicle Premium must be included in the cost-benefit analysis, these costs are not included in the IAP. These costs are included in PSE&G's base capital spending plan.
[19] If the purchase price of a conventional small SUV is $25,000 and the purchase price of a battery electric small SUV is $32,000, then the electrified vehicle premium used in the Study was $7,000. For Anti-Idle Systems, the electrified vehicle premium was the acquisition cost (equipment and installation) of the Anti-Idle System, as this is not standard on most vehicles. For example, if the acquisition cost of the Anti-Idle System is $15,000, the electrified vehicle premium used in the Study was $15,000.
[20] A BEV LDV with a 9-year lifecycle deployed in 2022 would be replaced in 2031. By 2031, based on industry trends and projections, it is anticipated that electrified vehicles will have reached cost parity. As such, we believe that assuming no vehicle replacement costs in the latter years of the Study is a reasonable assumption.

- Study assumes that insurance and license and registration costs do not differ between ICE, PHEVs or BEVs.
- Study does not incorporate potential volume discounts for PHEVs, BEVs, or Anti-Idle Systems.
- Study assumes passenger vehicles and LDVs will transition to PHEVs, BEVs, and Anti-Idle Systems while MDVs and HDVs will transition to only Anti-Idle Systems.

## 3.2 EV Infrastructure & Related Costs

EV infrastructure and related costs includes the following:

- Program management costs (e.g., program management)
- EV charging infrastructure costs (e.g., one-time, recurring, replacement)
- Standby generation and mobile charging costs (e.g., one-time, recurring)
- Utility upgrades (e.g., one-time)

Like the electrified vehicle premium, EV infrastructure and related costs are the incremental costs required to transition the vehicle fleet to electrified technology. It includes one-time, recurring, and replacement costs.

Other important considerations:

- Study does not consider any incentives that offset infrastructure installation, including federal or state tax credits.

### 3.2.1 Program Management Costs

These are one-time costs necessary to implement the Program. This includes project management and administration, and other professional services such as engineering, procurement, environmental.

### 3.2.2 EV Charging Infrastructure Costs

EV charging infrastructure costs were estimated on a unit cost basis by type of charger and power output. For each type of charger and associated power output, a number of charging ports were assumed. For chargers assumed to have multiple ports, the unit cost was allocated evenly across the number of ports[21]. The EV charging infrastructure costs were built up on a unit cost per port basis. In the Study, it was assumed that each electrified vehicle would have a dedicated charging port.

[21] If a charging unit was assumed to connect to four (4) ports, then the total cost of the charger would be divided by four (4). That portion of the cost would be allocated to charge a vehicle.

#### 3.2.2.1 One-Time Capital Costs

One-Time EV charging infrastructure unit costs include labor, materials, equipment (engineered and miscellaneous), and construction indirects required to install a single unit, assuming programmatic deployment, not one-off installations[22].

#### 3.2.2.2 Recurring O&M Costs

Recurring EV charging infrastructure operation and maintenance unit costs include network and data costs and labor and material costs for preventative maintenance. It was assumed PSE&G would perform all preventative maintenance. Extended warranties for the EV chargers were not included.

#### 3.2.2.3 Replacement Costs

Replacement unit costs include labor, material, and equipment costs required to install a new EVSE or EV charger. While the useful life of EVSE continues to improve significantly and new EVSEs may have a useful life that extends beyond the 20-year forecast period, the Study assumes that EVSE will be replaced during the forecast period based on lifecycle assumptions for each type of charger and associated power output.

### 3.2.3 Standby Generation and Mobile Charging & Battery Costs

#### 3.2.3.1 One-Time Capital Costs

One-time standby generation (or backup power) unit costs include labor, material, equipment (engineered and miscellaneous), and construction indirect required to install a single unit. As the vehicle fleet transitions to electric, specifically to BEVs, the integration of standby generation is important to ensure uptime of the electrified vehicle fleet to support operations during times of sustained power outages. As a part of the Program, PSE&G will install standby generation at their maintenance and garage facilities. As such, the costs associated with installing standby generation have been included in the Study.

The mobile charging and battery trailer unit costs include the acquisition of engineered equipment and systems that can be deployed to locations to provide access to EV charging. These systems could be deployed to remote locations or locations without power during outages. These systems are nascent and not widely available today. However, as the vehicle fleet transitions to electric, specifically to BEVs, the integration of these systems is important to ensure uptime of the vehicle fleet to support operations. As such, the costs associated with acquiring these systems have been included in the Study.

#### 3.2.3.2 Recurring O&M Costs

Recurring standby generation and mobile charging and battery operation and maintenance unit costs include labor and material costs for preventative maintenance. It was assumed PSE&G would perform all preventative maintenance. Extended warranties were not included.

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[22] The unit costs include the EVSE, switchboard, concrete pads, concrete cuts, and repair, bollards, switchgear, transformer, panel, conduit, cable, trenching, and grounding.

### 3.2.4 Utility Upgrades

Utility upgrades are related to upgrades required to the grid at PSE&G locations and are separate from behind the meter EVSE costs. Utility upgrades include material and labor costs for installing transformers, pads, conduit, and cable to supply service across PSE&G facilities. These upgrades will be required to install EV charging at PSE&G facilities.

## 3.3 Program Costs

Table 8 shows the program cost estimates by category, inclusive of escalation. An annual escalation factor is applied to the costs.

Table 8: Program Costs by Category
($1,000s, 20-Year)

| Capital Costs | O&M Costs | Replacement Costs | Vehicle Premium Costs | Total |
|---|---|---|---|---|
| $141,977 | $16,313 | $27,672 | $77,121 | $263,083 |

Figure 4 shows the time-phased program costs. An annual escalation factor is applied to the program costs.

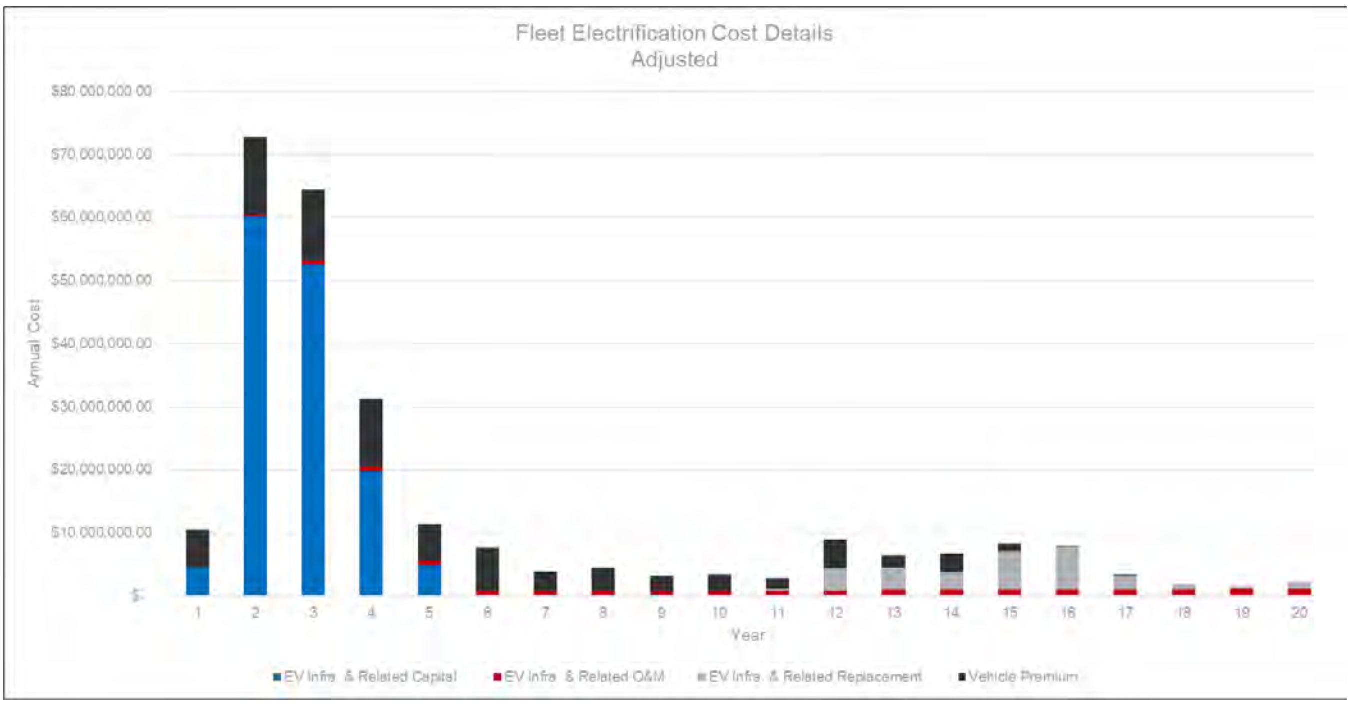


Figure 4: Time-Phased Program Costs by Category
(20-Year)

# 4.0 PROGRAM BENEFITS

This section describes the benefits considered in the cost-benefit analysis. These beneficial outcomes were categorized as follows:

- Direct Company Cost Related Benefits
- Avoided Costs within Base Capital Spending
- Societal Benefits
- Qualitative Benefits
    - E.g., alignment with goals set forth in New Jersey's Energy Master Plan

## 4.2 Direct Company Cost Related Benefits

The IAP drives operating cost savings in the form of reduced fuel and maintenance costs. Thus, these cost savings are included in the Study results as a benefit. Both fuel and maintenance costs were calculated on a per vehicle per annum basis.

Other important considerations:

- Did not include any reductions for operations and maintenance costs for existing fueling infrastructure (diesel and gasoline fueling stations) would remain unchanged during the transition as PHEVs and MDVs and HDVs still require access to diesel or gasoline.
- Did not include any avoided capital expenditures for upgrading or replacing existing fueling infrastructure (diesel and gasoline fueling stations).
- Did not include any reductions in for maintenance labor costs which could be realized as more vehicles transitions to BEVs. In the Study, it was assumed the same level of labor resources would be required to maintain vehicle fleet during transition as well as perform maintenance on new fueling infrastructure (e.g., EVSE).

### 4.2.1 Reduced Fuel Costs

PHEVs and BEVs can reduce fuel costs because of the high efficiency of electric-drive components. PHEVs and BEVs can achieve better fuel economy than that of convention vehicles. Fuel consumption is estimated for both driving and idling. By phasing out fossil fuels (gasoline or diesel) and deploying Anti-Idle Systems, fuel costs can be reduced[23].

Unit fuel costs for both driving and idling were combined with vehicle use and fuel economy to calculate annual fuel costs per vehicle. Benefits were calculated by comparing the annual fuel costs of the transitioned fleet under the Non-Electric Program and IAP scenarios.

Other important considerations:

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[23] According to the Alternative Fuels Data Center, Office of Energy Efficiency & Renewable Energy of the U.S. Department of Energy ( https://afdc.energy.gov/fuels/electricity_benefits.htmll).

- Fuel costs include costs for diesel, gasoline, and electricity.[24]
- Driving: Fuel costs estimated using fuel economy, annual mileage, and fuel cost per gallon.
- Idling: Fuel costs estimated using fuel consumption per idle hour (gallon per hour or kWh per hour), annual idle hours, and fuel cost per gallon.

### 4.2.2 Reduced Maintenance Costs

BEVs typically required less maintenance than conventional vehicles because (1) the battery, motor, and associated electronics require little to no regular maintenance, (2) there are fewer fluids that require regular maintenance, (3) brake wear is significantly reduced due to regenerative braking, and (4) there are fewer moving parts relative to a conventional gasoline or diesel engine[25].

Unit maintenance costs were developed for conventional vehicles, PHEVs, and BEVs and combined with annual vehicle mileage to calculate annual maintenance costs per vehicle[26]. Benefits were calculated by comparing the annual maintenance costs of the transitioned fleet under the Non-Electric Program and IAP scenarios.

Other important considerations[27]:

1. PHEVs: No reduction in unit maintenance costs as maintenance needs are similar to those of conventional vehicles.
2. BEVs: Reduction in unit maintenance costs ranging from 50% to 75% based on industry reports and OEM publications[28].
3. MDVs/HDVs: No reduction in maintenance costs for MDVs or HDVs as the Study considered Anti-Idle Systems. The Study did not consider potential maintenance cost reductions realized from less engine idling hours (e.g., engine overhaul or replacement).

## 4.3 Avoided Costs within Base Capital Spending

The Study identifies an avoided future capital expense related to the EV Charging Infrastructure Program and how it influences PSE&G's base capital spending plan into the future. PSE&G has estimated that it will implement the EV Charging Infrastructure Program over a 9-year period beginning in 2023. By accelerating the EV Charging Infrastructure

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[24] Fuel cost sensitivities were evaluated to demonstrate the impact an increase or decrease in fuel costs can have on the results.
[25] According to the Alternative Fuels Data Center, Office of Energy Efficiency & Renewable Energy of the U.S. Department of Energy (https://afdc.energy.gov/vehicles/electric_maintenance.html).
[26] Unit maintenance costs for BAU scenario were based on actual maintenance costs provided by PSE&G for 2019 and 2020.
[27] Based on reductions in scheduled and preventative maintenance of the powertrains and brake systems, not of the frame or body. Maintenance for upfit systems assumed to be the same for PHEVs and BEVs as conventional vehicles.
[28] Based on industry reports including Argonne National Lab recently report titled "Comprehensive Total Cost of Ownership Quantification for Vehicles with Different Size Classes and Powertrains" and City of New York publication "Reducing Maintenance Costs with Electric Vehicles."

Program, in effect customers are relieved of this specific cost burden as the costs form the basis of revenue requirement. This is an avoided cost, and therefore a benefit that is included in the cost-benefit analysis results[29].

## 4.4 Reduced Societal Costs

The Program drives societal cost savings in the form of reduced human and environmental damages from greenhouse gas emissions (primarily $CO_2$) and criteria pollutants ($NO_X$, PM10, PM2.5, VOC, $SO_X$). Thus, these cost savings are included in the Study results as a benefit. Societal benefits were calculated on a per vehicle per annum basis. Societal benefits (costs) are calculated for the vehicle only and do not include well-to-wheel emissions[30].

Emission factors for transport fuels were combined with annual vehicle use and a societal cost of carbon to calculate annual societal costs per vehicle. Benefits were calculated by comparing the annual societal costs of the transitioned fleet under the Non-Electric Program and IAP scenarios.

## 4.5 Benefits Estimate Results

Table 9 shows the benefit estimate results by category, inclusive of escalation. An annual escalation factor is applied to the benefit stream.

Table 9: Benefit Estimate Results by Category ($1,000s, 20-Year)

| | Maint. Cost Savings | Fuel Cost Savings | Avoided Future Capital Ex. | Societal Cost Savings | Total (w/ Societal) | Total (w/out Societal) |
|---|---|---|---|---|---|---|
| IAP | $32,044 | $68,878 | $90,400 | $16,890 | $208,214 | $191,324 |
| Vehicles | $13,289 | $28,565 | $37,490 | $7,005 | $86,350 | $79,345 |
| Total | $45,333 | $97,445 | $127,891 | $23,895 | $294,564 | $270,668 |

Figure 5 shows the time-phased benefit impacts, inclusive of societal benefits. An annual escalation factor is applied to the benefit stream. Direct Company Cost Related Benefits and

[29] The annual benefit in the Study is calculated by multiplying the annual base capital plan by the percent of chargers in operation. The percent of chargers in operation is calculated by dividing the cumulative number of chargers deployed by the total number of chargers to install.
[30] A Social Cost of Carbon of $50 per MT of CO2e was used. This was based on interim estimates under Executive Order 13990 published by the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. The Social Cost of Criteria Pollutants were estimated using Argonne National Lab's AFleet tool parameters for Morris County.

Societal Benefits are realized as the vehicles are transitioned. The benefits also increase over the forecast period as more vehicles are transitioned.

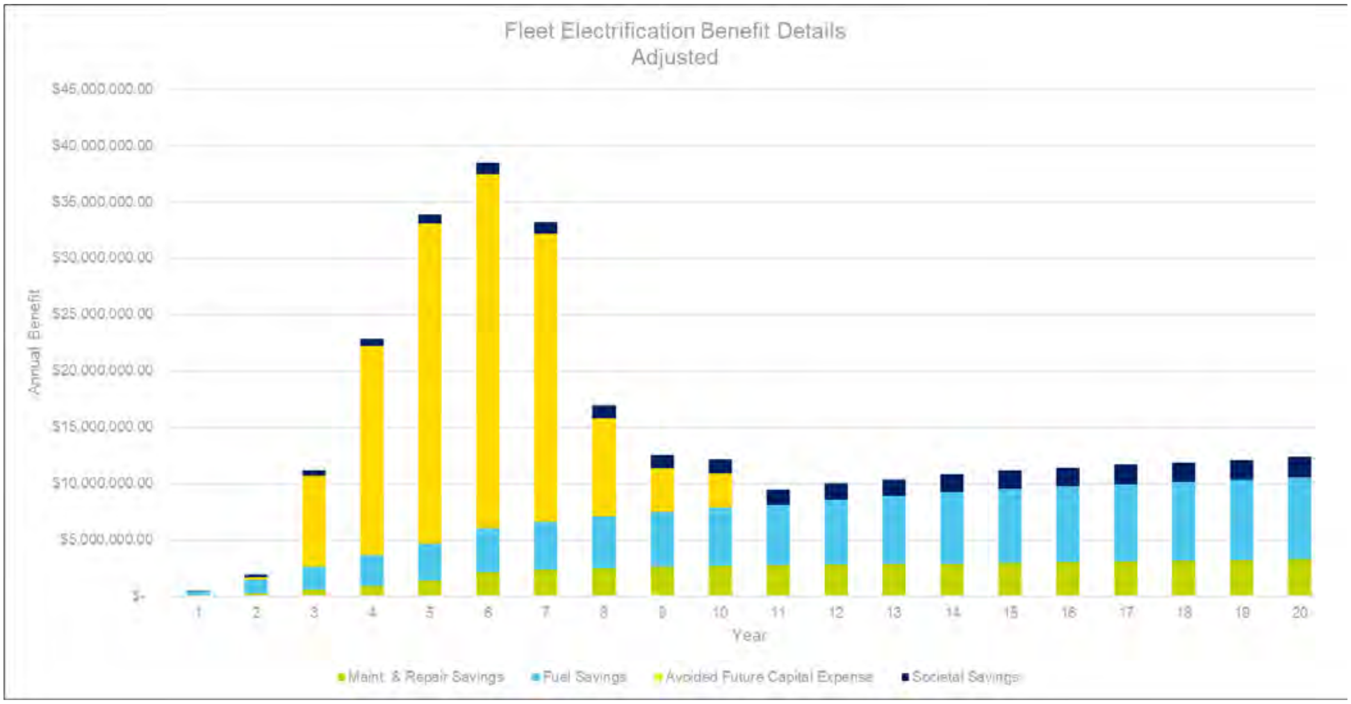


**Figure 5: Time-Phased Benefit Estimate Results by Category (20-Year)**

## 4.6 Qualitative Benefits

The above benefits do not consider the additional value added by benefits that are identified as qualitative in nature.

- Demonstrating leadership in fleet electrification by electrifying PSE&G's diverse fleet with various electrification technologies – promoting and advocating for fleet electrification in support of New Jersey Board of Public Utilities' objectives[31].
- Avoided future costs that could be incurred by not acting. There is risk associated with not initiating the fleet electrification transition or delaying until later in the decade[32].
- The Program is part of the larger IAP that aims to improve system reliability, reduce emissions, and create jobs.

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[31] New Jersey Board of Public Utilities Electric Vehicles Infrastructure Ecosystem 2021 – Medium and Heavy Duty Straw Proposal (https://www.nj.gov/bpu/pdf/publicnotice/Notice%20Medium%20Heavy%20Duty%20EV%20Straw%20Proposal.pdf)

[32] Auto OEMs have committed to an electric future. GM, for example, plans to exclusively offer electric vehicles by 2035. President Joe Biden outlined target of 50% of all new vehicles sold in 2030 would be zero-emission vehicles.

- The Program investments support the New Jersey Energy Master Plan by reducing fossil fuel-based energy consumption and emissions from the transportation sector, by supporting community energy planning and action in underserved communities, and by expanding the clean energy innovation economy[33].
- The Program investments support the New Jersey Department of Environmental Protection, the New Jersey Board of Public Utilities, and the New Jersey Economic Development Authority's Zero Emission Vehicle Initiative by helping the state progress toward its goal of registering 330,000 zero-emission vehicles by 2025[34].
- The Program investments support the state of New Jersey's commitment to the Transportation and Climate Initiative[35].

[33] State of New Jersey Energy Master Plan (https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf)
[34] New Jersey Partnership to Plug-In (https://www.nj.gov/governor/news/news/562019/20190603b.shtml)
[35] Transportation & Climate Initiative of the Northeast and Mid-Atlantic States (https://www.drivegreen.nj.gov/dg-TCI.html)

# 5.0 COST-BENEFIT ANALYSIS RESULTS

1898 & Co. estimates that the IAP will reduce PSE&G operating costs (both fuel and maintenance) and societal costs (reduction in air pollutants which contribute to smog, haze, and health problems and greenhouse gases)[36]. The estimated costs and benefits, and the resulting benefit-to-cost ratio, are presented in Table 10 and Table 11. Results have been presented with and without societal benefits.

Table 10: Cost-Benefit Analysis Results
($1,000s, NPV, 20-Year)

| Result | Costs [A] | Benefits [B] | Net Benefit (Cost) [C] = [B] - [A] | Simple Benefit Cost Factor [D] = [B] / [A] |
|---|---|---|---|---|
| **With Societal Benefits** | 194,383 | 167,535 | (26,848) | 0.86 |
| **Without Societal Benefits** | 194,383 | 156,310 | (38,073) | 0.80 |

Table 11: Cost-Benefit Analysis Results
($1,000s, Cumulative Total, 20-Year)

| Result | Costs [A] | Benefits [B] | Net Benefit (Cost) [C] = [B] - [A] | Simple Benefit Cost Factor [D] = [B] / [A] |
|---|---|---|---|---|
| **With Societal Benefits** | 263,082 | 294,564 | 31,481 | 1.12 |
| **Without Societal Benefits** | 263,082 | 270,669 | 7,587 | 1.03 |

Table 12 provides a detailed breakdown of the Study results on a cumulative total basis for the costs and benefits associated with IAP and the electrified vehicles. Benefits have been allocated to the IAP and vehicles in proportion to the cumulative total costs[37].

[36] Assuming PSE&G deploys electrified vehicles.
[37] Assuming escalated dollars.

Table 12: Detailed Breakdown of Cost-Benefit Analysis Results
($1,000s, Cumulative Total, 20-Year, With Societal Benefits)

| | Capital Costs [A] | Infrastructure O&M Costs [B] | Infrastructure Replacement Costs [C] | Total Costs [D] = [A] + [B] + [C] | Benefits [E] | Net Benefit (Cost) [F] = [E] - [D} | Simple Benefit Cost Factor [G] = [E] / [D] |
|---|---|---|---|---|---|---|---|
| IAP | 141,977 | 16,313 | 27,672 | 185,961 | 208,214 | 22,253 | 1.12 |
| Vehicles[38] | 77,121 | 0 | 0 | 77,121 | 86,349 | 9,228 | 1.12 |
| Total | 219,098 | 16,313 | 27,672 | 263,082 | 294,564 | 31,481 | 1.12 |

The cost-benefit results can be expressed in several ways. A simple comparison of cumulative costs and benefits, inclusive of escalation, reveals that the benefits exceed the costs (inclusive of societal benefits) by $31.5 million, resulting in a benefit-to-cost ratio of 1.12. If societal benefits are excluded, the simple comparison of cumulative costs and benefits, inclusive of escalaction, reveals that the benefits exceed costs by $7.6 million, resulting in a benefit-to-cost ratio of 1.03.

The net present value (NPV) of the benefit and cost impacts is negative $26.8 million with societal benefits and negative $38.1 million without societal benefits, using a discount factor of 6.48% which aligns with the weighted average cost of capital (WACC) provided by PSE&G. This results in a benefit-to-cost ratio of 0.86 with societal benefits and 0.80 without societal benefits The NPV results are as expected as transitioning to an electrified fleet requires upfront investments to realize operational and societal savings over time.

A benefit-to-cost ratio of less than 1.0 for the entire program is not uncommon for a fleet exploring the transition to electrified technology today. Fleet electrification (and even consumer vehicle electrification) requires upfront capital investment for the vehicles and necessary fueling infrastructure while the benefits of the transition are realized over time. Like other fleets, a utility fleet is not immune from the infrastructure investments required.

Figure 6 depicts the cumulative total costs and benefits, inclusive of escalation, over the 20-year forecast period.

[38] Capital Costs for the vehicles is the electrified vehicle premium which is explained in section 3.1 Electrified Vehicle Premium.

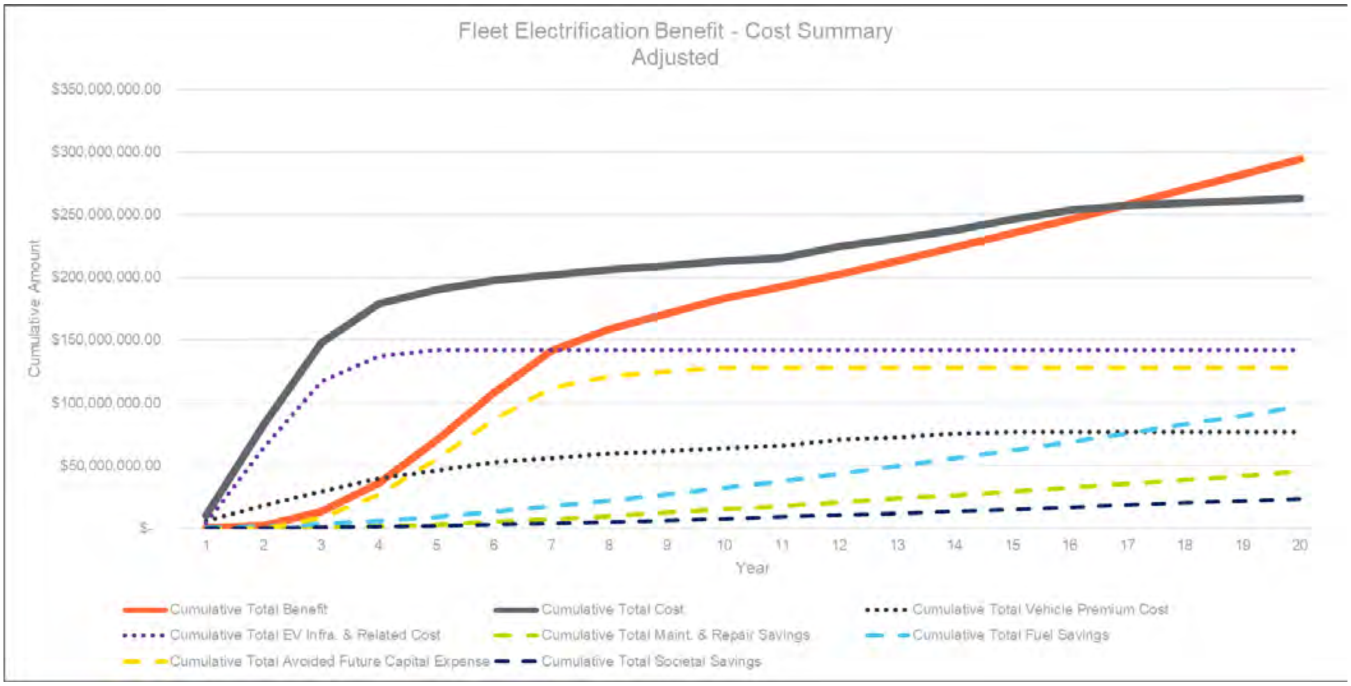



**Figure 6: Fleet Electrification Program Cumulative Costs and Benefits (20-Year)**

1898 & Co. emphasizes that the above cost-benefit analysis results are limited to those benefits that can be quantified and monetized. The results do not consider the additional value added by benefits that are identified as qualitative in nature.

In 1898 & Co.'s view, the analysis is conservative for the following reasons:

- The Study assumes that PHEV and BEV acquisition costs will not decrease over time. Instead, it assumes the acquisition costs will remain constant until 2030, subject to escalation.
- The Study does not monetize the reduction in noise pollution that can be realized from an electrified fleet. Similar to emissions, noise is a pollution often considered a detriment to society. Reducing noise in parking areas and residential streets can improve the lives of citizens.
- Anti-Idle Systems decrease idle time which can reduce engine wear and associated maintenance costs, especially for heavy duty trucks. The Study does not monetize the reduction in maintenance costs realized from an Anti-Idle System.
- LDVs that transition to Anti-Idle Systems because of range limitations of BEVs or lack of availability of BEVs or PHEVs are assumed to utilize Anti-Idle Systems over the entire 20-year forecast period when, in reality, these LDVs would likely transition to a BEV in later years, providing additional benefits.
- The Study does not contemplate any federal or state incentives.

- The Study assumes that MDVs and HDVs will only adopt Anti-Idle Systems over the entire 20-year forecast period. However, is it feasible that BEVs may be available for MDVs and HDVs as soon as the end of the decade, providing additional benefits[39].
- The Study assumes that the capital costs of the Base Program are equivalent to those of the IAP. However, because the Base Program is over a 9-year period, it is unlikely that it will realize the same execution efficiencies of the IAP, resulting in slightly higher capital costs (~10%).
- The Study does not consider the possibility that PSE&G would prioritize electrifying the more utilized (high mileage, high idle hours) vehicles in the early years, reallocating vehicles between users so that those that drive or idle more have an electrified vehicle[40].

Click here to add text.

[39] Lion Electric has announced an all-electric Class 8 bucket truck – Consolidated Edison of New York will pilot the truck in early 2022. Freightliner has announced an all-electric Class 6 truck (eM2) – the box truck will enter production in 2022. These are examples of soon to be commercially available MDVs or HDVs that could be deployed within the PSE&G fleet.
[40] Implementing this practice could reduce the overall breakeven point of the aggregated fleet as the more utilized vehicles are electrified in earlier years when the electrified vehicle premium is higher and the less utilized vehicles are electrified in later years when the electrified vehicle premium has reduced, assuming industry trends continue.

# 6.0 SENSITIVITY ANALYSIS

## 6.2 Sensitivity Scenarios

Several sensitivities have been developed to explore the range of impacts related to key input variables and assumptions. Table 13 explains the key variables that are evaluated for the purposes of sensitivity analyses.

Table 13: Sensitivity Analyses

| I.D. | Variable | Adjustment / Approach |
|---|---|---|
| Low Fuel | Decrease in fuel costs (gasoline and diesel) | Evaluate $2.0 per gallon gasoline and diesel fuel costs |
| High Fuel | Increase in fuel costs (gasoline and diesel) | Evaluate $3.50 per gallon gasoline and $3.75 per gallon diesel fuel costs |
| CapEx +10% | Increase in capital costs experienced as part of the Fleet Electrification Program | Evaluate a 10% increase in capital costs |
| CapEx -10% | Decrease in capital costs experienced as part of the Fleet Electrification Program | Evaluate a 10% decrease in capital costs |
| DR 3% | Discount rate of 3% | Evaluate 3% discount rate |
| Low Esc. | Escalation factor of 1% | Evaluate 1% escalation factor |
| High Esc. | Escalation factor of 4% | Evaluate 4% escalation factor |
| High Mileage | PSE&G drives more annually, on average, than base assumption | Evaluate high mileage scenario |
| Maint. #1 | Maintenance costs per mile do not reduce as anticipated | Evaluate maintenance costs per mile of PHEV and BEV to be 100% and 50% of ICE respectively |
| Maint. #2 | Maintenance costs per mile reduce more than anticipated | Evaluate maintenance costs per mile of PHEV and BEV to be 80% and 50% of ICE respectively |
| StandbyGen | Standby generation and mobile charging and battery systems not required | Evaluate removal of standby generation and mobile charging and battery systems costs |
| EVSE | EVSEs useful life extends beyond forecast period | Evaluate removal of EVSE replacement costs |
| LowR&C | Reduce risk and contingency | Evaluate risk and contingency of 20% |

| | | |
|---|---|---|
| **Fewer BEVs** | Fewer BEVs deployed | Evaluate fewer BEVs deployed in the transition |
| **Delayed Adopt.** | Delay in electrified vehicles | Evaluate 2-year delay in adopting and deploying electrified vehicles |
| **Reduced Idle** | Reduced idle hours | Evaluate 50% reduction in annual idle hours |

## 6.3 Sensitivity Results

The results of the sensitivity analysis are presented in Table 14 on an NPV and cumulative total basis. Results are inclusive of societal benefits.

**Table 14: Sensitivity Analysis Results ($1,000s, 20-Year)**

| I.D. | Net Benefit (Cost) [NPV] | Simple Benefit Cost Factor [NPV] | Net Benefit (Cost) [Cumulative Total] | Simple Benefit Cost Factor [Cumulative Total] |
|---|---|---|---|---|
| **Low Fuel** | (80,321) | 0.58 | (54,933) | 0.79 |
| **High Fuel** | (15,893) | 0.92 | 54,710 | 1.21 |
| **CapEx+10%** | (29,911) | 0.86 | 30,073 | 1.11 |
| **CapEx-10%** | (22,697) | 0.87 | 35,657 | 1.14 |
| **DR 3%** | (2,864) | 0.99 | 31,481 | 1.12 |
| **Low Esc.** | (31,903) | 0.83 | 18,280 | 1.07 |
| **High Esc.** | (14,325) | 0.93 | 64,123 | 1.22 |
| **High Mileage** | (19,629) | 0.90 | 46,864 | 1.18 |
| **Maint. #1** | (33,828) | 0.83 | 16,556 | 1.06 |
| **Maint. #2** | (25,813) | 0.87 | 33,546 | 1.13 |
| **StandbyGen** | (17,177) | 0.89 | 40,425 | 1.18 |
| **EVSE** | (15,976) | 0.91 | 59,154 | 1.25 |
| **LowR&C** | (20,754) | 0.88 | 34,260 | 1.15 |
| **Fewer BEVs** | (35,791) | 0.82 | 15,285 | 1.06 |
| **Delayed Adopt.** | (35,318) | 0.81 | 9,682 | 1.04 |
| **Reduced Idle** | (45,207) | 0.77 | (7,490) | 0.97 |

While the sensitivity scenarios impact the benefit-to-cost factor to varying degrees, 13 scenarios result in a benefit-to-cost factor above 1.0 on a cumulative total basis. No sensitivity scenario resulted in a benefit-to-cost factor less than 0.79 on a cumulative total basis. The Fewer BEVs scenario, which reduces the number of BEVs deployed in the early years of the forecast period, and the Delayed Adopt.[41], which assumes that the adoption and deployment of electrified vehicles is delayed by two years, still maintain a benefit-to-cost factor above 1.0 on a cumulative total basis.

The Fewer BEVs scenario represents a potentially likely scenario where PSE&G prioritizes the deployment of PHEVs and Anti-Idle Systems for passenger vehicles and LDVs in the early years (2022 – 2025) of the transition, except for compact or passenger cars which will prioritize BEVs[42]. While the Fewer BEVs scenario deploys few BEVs until after 2025, the benefit-to-cost factor is still above 1.0.

[41] The Delayed Adopt. scenario can be used to depict the impacts of (1) limited availability of electrified technology because of OEM production or supply chain issues and (2) slower adoption and deployment of electrified technology by PSE&G.
[42] This is because of (1) the need for PSE&G to build out a backbone of fueling infrastructure necessary to support and operate an electrified fleet and (2) limited availability of BEVs that meet technical and operational needs of key vehicle classes such as pickup trucks and service vans.

# 7.0 CONCLUSION

PSE&G has constructed the IAP with the objective of enabling decarbonization of their vehicle fleet, reducing operating costs and providing benefits to customers by reducing air pollutants which contribute to smog, haze and health problems, and greenhouse gases.

1898 & Co. estimates that, inclusive of escalation, the total cumulative net benefits are above the total cumulative costs by a factor of 1.12 over 20-year forecast period, assuming societal benefits are included. If societal benefits are excluded, the total cumulative benefits are above the total cumulative costs by a factor of 1.03 over a 20-year forecast period.

The NPV of the benefits and costs results in a benefit-to-cost ratio of 0.86 with societal benefits and 0.80 without societal benefits. This is expected as transitioning to an electrified vehicle fleet requires a significant upfront investment to realize steady operational and societal savings over the vehicle life.

The Study focuses on the incremental costs to transition the vehicle fleet to electrified technology and the associated benefits that are realized from that transition.

The benefit-to-cost ratios for the cumulative total, inclusive of escalation, and NPV are shown in Figure 7.


**Figure 7: Comparison of Benefit-to-Cost Ratios**

1898 & Co. describes areas where the analysis is conservative. These include: (1) PHEV and BEV acquisition costs will not decrease over time, (2) not monetizing benefits associated with a reduction in noise pollution, and (3) not monetizing benefits associated with reduced maintenance costs from Anti-Idle Systems, (4) not considering BEVs or PHEVs for vehicles that first transition to Anti-Idle Systems, (5) not considering federal or state incentives, and (6) not considering BEVs for MDVs or HDVs, (7) assuming the Base Program capital costs are equivalent to those of the IAP even though it will be deployed over a 9-year period rather than 4-year period, and (8) not considering prioritizing more utilized vehicles during the early years of the transition. .

The monetary benefit-to-cost ratio does not consider many important qualitative benefits such as (1) demonstrating leadership and commitment to electric vehicles to other fleet owner or operators, (2) avoiding future costs that could be incurred by not initiating the transition to electrified vehicles, and (3) supporting objectives of the state of New Jersey, most notably New Jersey's Energy Master Plan. These benefits, while qualitative, align with many important clean energy goals established by the state of New Jersey.

Finally, the Study evaluated sensitivities to explore the range of impacts related to key input variables and assumptions, nearly all of which still resulted in a cumulative total benefit-to-cost factor above 1.0. The Fewer BEVs and Delayed Adopt., scenarios that are potentially likely given current market conditions and supply chain issues, both resulted in cumulative total benefit-to-cost factor above 1.0.

# APPENDIX A – FLEET ELECTRIFICATION TRANSITION ROADMAP METHODOLOGY

1898 & Co. created an actionable roadmap that will help guide and inform PSE&G as they undertake a 10-year transition of legacy fleet vehicles to electrified technology. The roadmap considered Edison Electric Institute (EEI) electrification classifications and lifecycle-based vehicle replacements to develop targets for electrification by 2030. For purposes of vehicle electrification, EEI considers a vehicle electrified if it is a Battery Electric Vehicle (BEV), Plug-in Hybrid Electric Vehicle (PHEV), or utilizes Anti-Idle Job Site Work Systems to mitigate fuel consumption.

Over 5,800 vehicles were analyzed and grouped into personas based on EEI categories, vehicle types, job functions, weight classification, and fuel types.

A vehicle technology assessment was conducted that included BEVs, PHEVs and Anti-Idle Systems. A market landscape of current and future technologies including specifications and costs was compiled through research and interviews with OEMs.

Mileage data from historical odometer readings and vehicle telematics was collected and synthesized to develop the expected yearly, monthly, and daily mileage driven of each vehicle thus producing insight into vehicle duty cycle. Dwell times, locations, and expected operational duties were analyzed from provided vehicle data and through feedback from stakeholder workshops. The data was then synthetized to determine vehicle locations and expected dwell times.

A transition technology was assigned to each vehicle based on the year of replacement and the technical feasibility of the vehicle for persona. Once the transition schedule was produced charging infrastructure requirements to support the electrified vehicle was determined based on vehicle technology, daily mileage, and dwell times. Infrastructure costs were developed, and a capital expenditure forecast for the necessary EVSE to support an electrified fleet was estimated.

### Fleet Inventory Analysis

PSE&G fleet is comprised of broad range of vehicles that serve different functions within different business units. Each asset was compiled and evaluated based on vehicle type, classification, and job function. The fleet was divided into categories and subcategories setting 4 major categories as shown in Figure 8.

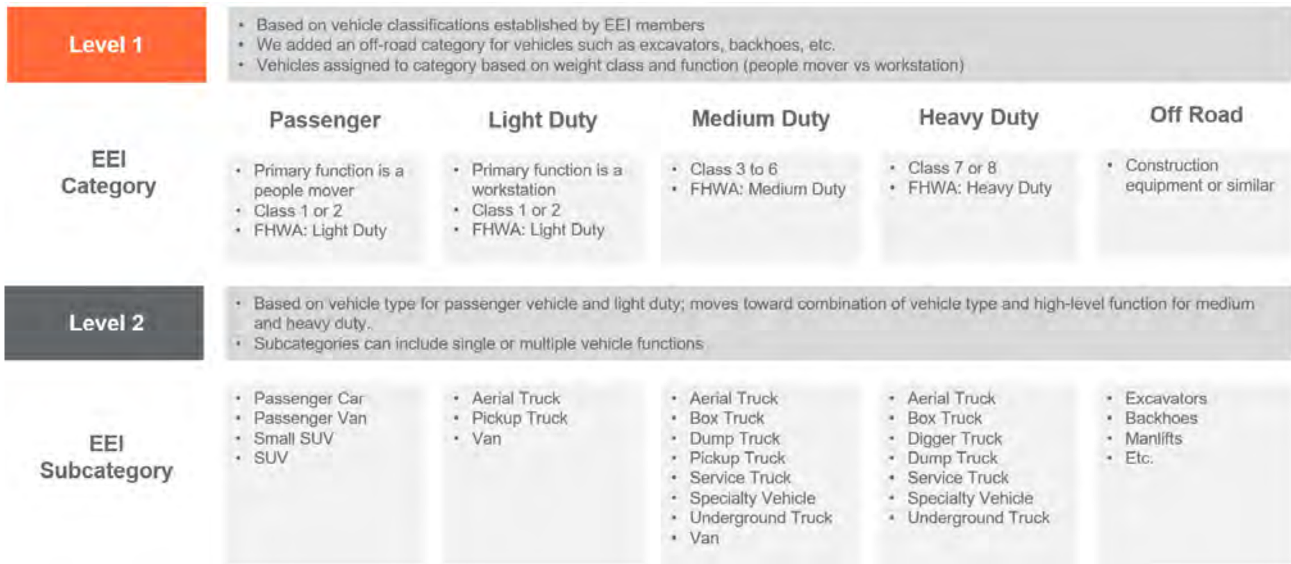



Figure 8: EEI Vehicle Categories

After the major and subcategories were defined for each vehicle, vehicles were also grouped by PSEG function, Federal Highway Administration (FHWA) vehicle weight classes, and fuel types to create unique vehicle personas. The vehicle personas were then used to identify the best transition technology for each vehicle based on the findings of the vehicle technology assessment.

### Vehicle Technology Assessment

Vehicle specification, capabilities, procurement time frames, product road maps, and costs were compiled from OEMs through primary and secondary research which included interviews with the OEM. These details informed decisions on when BEV, PHEV, or Anti-Idle Systems would be available and suitable for use by a specific vehicle persona. The approach to the vehicle technology assessment is shown in Figure 9.

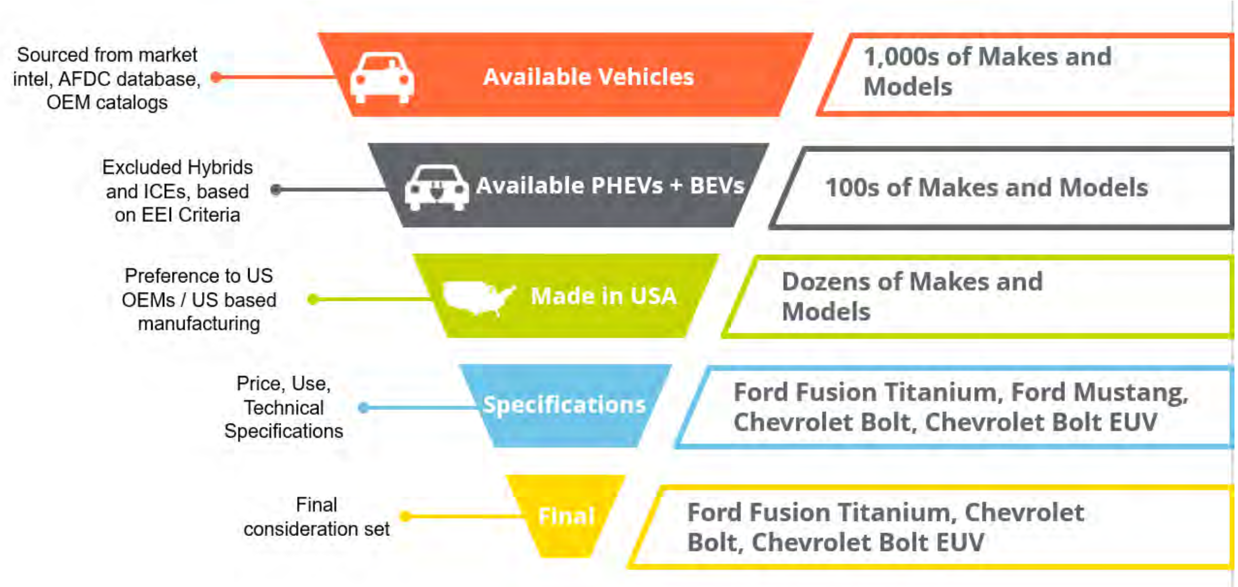



Figure 9: Vehicle Technology Assessment Methodology

### Operations Assessment

Odometer readings, vehicle telematics, and stakeholder interviews provided insight into the operations of the fleet. Yearly, monthly, and daily mileage patterns were used to determine potential energy utilization of an electrified vehicle. The energy utilization of the vehicle was used to understand which electrified technology would be most suitable for each vehicle. For example, if a vehicles driving pattern exceeded the range of a BEV, other technologies were considered for these vehicles, either PHEV or Anti-Idle Systems.

In addition to mileage patterns and energy utilization, the dwell location and times for each vehicle were identified through telematics, organizational structures, and stakeholder interviews. The dwell location and times were used to develop the necessary charging infrastructure to support the vehicle based on the best fit technology which would be either a BEV, PHEV, or Anti-Idle.

### Vehicle Electrification Transition

Using the vehicle lifecycle for replacement, vehicle persona, technology assessment and operations assessment, the transition year and technology type of BEV, PEV, or Anti-Idle Systems was assigned to each vehicle.

Different scenarios were created for the transition to account for changes in technology and to demonstrate how both less and more aggressive electrification scenarios may look, depending on the adoption of more BEV versus the other technologies. The transition scenario summary is shown in Table 15. The transition scenario was then used to estimate levels of EV charging infrastructure investment that would be required.

Table 15: Transition Scenario Summary

| Category | Base Plan | Accelerated Plan |
|---|---|---|
| **Passenger** | 2021 - 2030: BEV if technically feasible, else PHEV | 2021 - 2030: BEV if technically feasible, else PHEV |
| **Light Duty** | 2021 - 2025: PHEV if available, else Anti-Idle Systems<br><br>2026 - 2030: BEV if technically feasible, else PHEV | 2021 - 2022: PHEV if available, else Anti-Idle Systems<br><br>2023 - 2030: BEV if technically feasible, PHEV if available, else Anti-Idle Systems |
| **Medium Duty** | 2021 - 2030: Anti-Idle Systems | 2021 - 2030: Anti-Idle Systems |
| **Heavy Duty** | 2021 - 2030: Anti-Idle Systems | 2021 - 2030: Anti-Idle Systems |

## Charging Infrastructure Analysis

The approach to derive the necessary charging infrastructure is depicted in Figure 10.

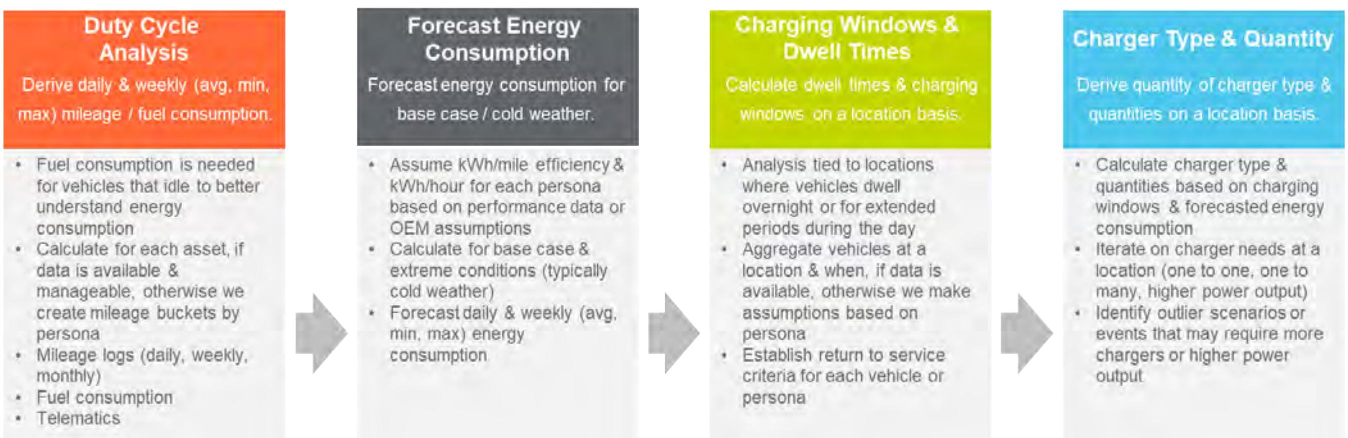



Figure 10: Approach to Derive Charging Infrastructure

Charging infrastructure was calculated based on the transition technology selected, the vehicle mileage, vehicle energy utilization, and dwell time of vehicle and dwell location. Using these parameters, the vehicle was assigned a suitable charging technology to support its energy requirements. Table 16 shows the summary of charging infrastructure that was considered in this analysis.

Charging infrastructure costs are shared between vehicles to help reduce infrastructure costs. Each vehicle is assigned a port but can share chargers which minimize the burden of infrastructure costs.

## Table 16: EV Charging Infrastructure Summary

| Charger Type | Typical Use | Input Power (KW) | Phases | Power Factor | Input Voltage (V) | Input Current (A) | Input Power (KVA) |
|---|---|---|---|---|---|---|---|
| AC1 | Anti-Idle Job Site Work Systems(1) | 3 | 1 | 1 | 120 | 25 | 3 |
| AC6.6 | LD/MD PHEVs @ PSE&G Facility | 6.6 | 1 | 1 | 208 | 32 | 6.6 |
| AC7.6 | LD PHEVs(2)/BEVs @ Home | 7.6 | 1 | 1 | 240 | 32 | 7.6 |
| AC11 | LD BEVs (overnight charging)(3) | 11 | 1 | 1 | 208 | 53 | 11 |
| AC19.2 | All BEVs (overnight charging)(3) | 19.2 | 1 | 1 | 208 | 92 | 19.2 |
| DC50 | All BEVs (overnight(3) / fast / shared(5)) | 50 | 3 | 1 | 480 | 60 | 50 |
| DC100 | BEVs (overnight(3) / fast(4) / shared(5)) | 100 | 3 | 1 | 480 | 120 | 100 |
| DC150 | BEVs (overnight(3) / fast(4) / shared(5)) | 150 | 3 | 1 | 480 | 180 | 150 |
| DC250 | MD/HD BEVs (fast(4) / shared(5)) | 250 | 3 | 1 | 480 | 301 | 250 |
| DC500 | MD/HD BEVs (fast(4) / shared(5)) | 500 | 3 | 1 | 480 | 601 | 500 |

# APPENDIX B – KEY ASSUMPTIONS TABLE

Table 17: Key Assumptions Table

| Assumption | Description | Assumed Value | Source |
|---|---|---|---|
| Discount Rate | Discount rate utilized in net present value (NPV) calculations | 6.48% | PSE&G |
| Cost Escalation | Escalation rate of equipment, materials, and consumables in the study | 2% | Estimate based on historical Consumer Price Index |
| Cost of Gasoline | Purchase cost for gasoline for the PSE&G fleet vehicles | $2.94 | U.S. EIA Petroleum & Other Liquids; https://www.eia.gov/petroleum/data.php; Central Atlantic |
| Cost of Diesel | Purchase cost for diesel for the PSE&G fleet vehicles | $3.26 | U.S. EIA Petroleum & Other Liquids; https://www.eia.gov/petroleum/data.php; Central Atlantic |
| Cost of Electricity | Purchase cost of electricity per kWh to fuel electrified fleet | $0.13 | U.S. EIA Electricity; https://www.eia.gov/electricity/data.php; Average Annual Retail Rate for PSE&G Commercial Customers |
| Level 1 Charging Infrastructure | Charging infrastructure to support charging of Anti-Idle systems; assumed install of 120V outlet | Power: 1kW<br><br>Cost: $500/Port | 1898 & Co. |
| Level 2 Charging Infrastructure | Charging infrastructure to support charging of some PHEV and BEV vehicles | Power: 6.6-19.2kW<br><br>Cost: $7000-$9000/port | 1898 & Co. |
| Level 3 Charging Infrastructure (DC Fast Charging) | Charging infrastructure to support charging of BEV vehicles | Power: 50-500kW<br><br>Cost: $20,000 to $150,000/port | 1898 & Co. |
| Cost of Electrified Vehicle Technology | Mix of BEV, PHEV, and Anti-Idle | Premium of technology varies | OEM Budgetary Quotes; 1898 & Co. estimates |
| Maintenance and Repair Cost | Cost of maintaining and repairing the PSE&G fleet; costs are evaluated on $/mi driven basis | Varies by vehicle persona (see appendix A) | PSE&G |
| Vehicle Fuel Economy | Fuel consumed by vehicle to support PSE&G work functions | Varies by vehicle class | OEM, PSE&G |
| Vehicle Mileage | Distance travelled by vehicles to support PSE&G work functions | Varies by vehicle class | PSE&G |

| | | | |
|---|---|---|---|
| Vehicle Engine Idle Time | Amount of time engine idles, used to estimate fuel consumption when engine is required to idle to support PSE&G operations | Varies by vehicle class | PSE&G; AFleet tool parameters |
| Stand by Generation | Back up generation at key PSE&G facilities that will be used to recharge fleet vehicles during grid outages | **Power:** 0.5 – 2 MW<br><br>**Cost:** $0.5 to $2M | 1898 & Co. |
| Mobile Charging | Battery trailers and mobile charging devises used for emergency or storm response to maintain operation of PSE&G electrified vehicles | Battery Trailer: $4M<br><br>Mobile Charging: $1M | OEM; 1898 & Co. |
| Diesel Emissions Factors | Emissions of Carbon Dioxide (CO2), Methane (CH4), and Nitrous Oxide (N2O) from burning diesel fuel | CO2: 10.21 kg / gal<br><br>CH4: 0.001 -0.0051 g/mile<br><br>N2O: 0.0015-0.0048 g /mile | Table 13.1 US Default CO2 Emission Factors for Transport Fuels, Climate Registry, 2018<br>Table 13.4 Default CH4 and N2O Emission Factors for Highway Vehicles by Technology Type, Diesel Light Trucks 2016<br>Table 13.4 Default CH4 and N2O Emission Factors for Highway Vehicles by Technology Type, Diesel Medium and Heavy Duty Vehicles, 2018 |
| Gasoline Emission Factors | Emissions of Carbon Dioxide (CO2), Methane (CH4), and Nitrous Oxide (N2O) from burning gasoline fuel | CO2: 8.78 kg / gal<br><br>CH4: 0.0173-0.0333 g/mile<br><br>N2O: 0.0036-0.0134 g /mile | Table 13.1 US Default CO2 Emission Factors for Transport Fuels, Climate Registry, 2018<br><br>Table 13.4 Default CH4 and N2O Emission Factors for Highway Vehicles by Technology Type, Gasoline Passenger Cars - EPA Tier 2, 2016<br><br>Table 13.4 Default CH4 and N2O Emission Factors for Highway Vehicles by Technology Type, Gasoline Light Trucks - EPA Tier 2, 2016<br>Table 13.4 Default CH4 and N2O Emission Factors for Highway Vehicles by Technology Type, Gasoline Medium and Heavy Duty Vehicles - EPA Tier 2, 2018 |

| | | | |
|---|---|---|---|
| Criteria Pollutant Emission Factors | Emissions of PM10, PM2.5, VOC, NOx, Sox for both mobile and idling | Varies g/mile by vehicle class | ANL AFLEET tool parameters |
| GHG Conversion Factors | AR5 Global Warming Potentials (GWP) to calculate C02e values | CO2 to CO2e: 1<br>CH4 to CO2e: 28<br>N2O to C02e: 235 | Intergovernmental Panel on Climate Change (IPCC) |
| Cost of Avoided CO2e emissions | Cost of avoided Metric Ton of Carbon Equivalent (MTC02e) | $50 | Interagency Working Group on Social Cost of GHGs, US Gov't |
| Costs of Criteria Pollutants | Cost of avoided Metric Ton of Criteria Pollutants | | ANL AFLEET tool parameters, Morris County |

# APPENDIX C – VEHICLE PERSONAS

| Persona | | | Vehicle Assumptions by Persona | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| EEI Category | EEI Subcategory | PSEG Function | Annual Mileage *[Miles]* | Daily Idle Time *[Hours]* | ICE Acquistion Cost *[$]* | PHEV Acquistion Cost *[$]* | BEV Acquistion Cost *[$]* | Anti-Idle Acquistion Cost *[$]* | ICE Fuel Type | ICE Fuel Economy *[MPG]* | PHEV Fuel Economy *[MPG]* | Average Efficiency *[kWh/mi]* | Idle Fuel Consumption *[gal/hr]* | Idle Fuel Consumption *[kWh/hr]* |
| Passenger Vehicle | Passenger Car | Compact Passenger Cars | 7,000.00 | 0.00 | $ 22,316.00 | $ 28,000.00 | $ 32,000.00 | $ - | Gasoline | 26.00 | 42.00 | 0.30 | 0.20 | 0.50 |
| Passenger Vehicle | Passenger Car | Standard Passenger Cars | 12,000.00 | 0.00 | $ 22,278.00 | $ 36,000.00 | $ 47,000.00 | $ - | Gasoline | 26.00 | 42.00 | 0.30 | 0.40 | 0.50 |
| Passenger Vehicle | Passenger Van | Passenger Vans | 5,000.00 | 0.00 | $ 25,195.00 | $ 35,740.00 | $ 70,000.00 | $ - | Gasoline | 18.00 | 26.00 | 0.50 | 0.40 | 0.50 |
| Passenger Vehicle | Small SUV | Small SUV | 10,200.00 | 2.00 | $ 25,027.00 | $ 33,000.00 | $ 34,000.00 | $ - | Gasoline | 26.00 | 42.00 | 0.33 | 0.40 | 0.50 |
| Passenger Vehicle | SUV | SUV | 14,640.00 | 0.00 | $ 61,848.00 | $ 85,848.00 | $ 70,000.00 | $ 15,000.00 | Gasoline | 16.00 | 36.00 | 0.66 | 0.40 | 0.50 |
| Light Duty | Aerial Truck | Van Mounted Buckets | 3,600.00 | 2.00 | $ 34,000.00 | $ 58,000.00 | $ 134,000.00 | $ 20,000.00 | Gasoline | 13.00 | 18.00 | 0.77 | 1.00 | 3.00 |
| Light Duty | Pickup Truck | Full Size Pickups | 16,560.00 | 2.00 | $ 45,805.00 | $ 69,805.00 | $ 52,500.00 | $ 20,000.00 | Gasoline | 16.00 | 22.00 | 0.56 | 0.75 | 1.00 |
| Light Duty | Pickup Truck | Small Pickups | 14,760.00 | 2.00 | $ 45,986.00 | $ 69,986.00 | $ 52,500.00 | $ 20,000.00 | Diesel | 16.00 | 22.00 | 0.46 | 0.75 | 1.00 |
| Light Duty | Van | Appliance Service Vans | 11,760.00 | 2.00 | $ 35,000.00 | $ 70,932.00 | $ 46,932.00 | $ 20,000.00 | Gasoline | 15.00 | 21.00 | 0.63 | 1.00 | 3.00 |
| Light Duty | Van | Cargo Mini-Vans | 6,000.00 | 2.00 | $ 27,400.00 | $ 62,274.00 | $ 38,274.00 | $ 20,000.00 | Gasoline | 18.00 | 26.00 | 0.58 | 1.00 | 3.00 |
| Light Duty | Van | Full Size Cargo Vans | 2,400.00 | 2.00 | $ 35,000.00 | $ 55,886.00 | $ 46,932.00 | $ 20,000.00 | Gasoline | 15.00 | 21.00 | 0.72 | 1.00 | 3.00 |
| Light Duty | Van | Hi-Cube & Cutaway Vans | 2,700.00 | 2.00 | $ 34,000.00 | $ 61,165.00 | $ 134,000.00 | $ 20,000.00 | Gasoline | 13.00 | 18.00 | 0.72 | 1.00 | 3.00 |
| Light Duty | Van | Substation Vehicles | 5,640.00 | 2.00 | $ 34,000.00 | $ 74,554.00 | $ 134,000.00 | $ 20,000.00 | Gasoline | 15.00 | 21.00 | 0.72 | 1.00 | 3.00 |
| Medium Duty | Aerial Truck | Streetlight Trucks | 9,120.00 | 4.00 | $ 50,760.00 | $ - | $ 188,760.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.60 | 0.85 | 5.00 |
| Medium Duty | Aerial Truck | Trouble Trucks | 10,320.00 | 4.00 | $ 54,260.00 | $ - | $ 192,260.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.60 | 0.85 | 5.00 |
| Medium Duty | Aerial Truck | Van Mounted Buckets | 7,200.00 | 4.00 | $ 36,355.00 | $ - | $ 141,355.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.18 | 0.85 | 5.00 |
| Medium Duty | Box Truck | Box Trucks | 3,840.00 | 4.00 | $ 51,915.00 | $ - | $ 189,915.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.00 | 0.85 | 3.00 |
| Medium Duty | Dump Truck | Dump Truck 3 Cu Yd | 4,800.00 | 4.00 | $ 54,260.00 | $ - | $ 192,260.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.50 | 0.85 | 3.00 |
| Medium Duty | Pickup Truck | Full Size Pickups | 6,300.00 | 4.00 | $ 51,856.00 | $ - | $ 189,856.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.09 | 0.85 | 5.00 |
| Medium Duty | Service Truck | Garage Service Vehicles | 4,560.00 | 4.00 | $ 51,856.00 | $ - | $ 189,856.00 | $ 30,000.00 | Diesel | 13.00 | 0.00 | 1.09 | 0.85 | 5.00 |
| Medium Duty | Service Truck | Service Trucks | 10,680.00 | 4.00 | $ 48,450.00 | $ - | $ 186,450.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.09 | 0.85 | 5.00 |
| Medium Duty | Service Truck | Substation Vehicles | 5,520.00 | 4.00 | $ 54,820.00 | $ - | $ 192,820.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.09 | 0.85 | 5.00 |
| Medium Duty | Service Truck | Utility Service Vehicles | 3,420.00 | 4.00 | $ 51,915.00 | $ - | $ 189,915.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.09 | 0.85 | 5.00 |
| Medium Duty | Speciality Vehicle | Emergency Vehicle | 1,080.00 | 4.00 | $ 36,355.00 | $ - | $ 103,355.00 | $ 30,000.00 | Diesel | 13.00 | 0.00 | 1.14 | 0.85 | 3.00 |
| Medium Duty | Speciality Vehicle | Flatbed Vehicles | 840.00 | 4.00 | $ 54,260.00 | $ - | $ 192,260.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Speciality Vehicle | Rack Vehicles | 2,400.00 | 4.00 | $ 54,260.00 | $ - | $ 192,260.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Speciality Vehicle | Refueling Vehicles | 720.00 | 4.00 | $ 50,760.00 | $ - | $ 188,760.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Speciality Vehicle | Vac Trucks | 1,140.00 | 4.00 | $ 68,770.00 | $ - | $ 206,770.00 | $ 30,000.00 | Diesel | 8.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Speciality Vehicle | Welding Vehicles | 3,780.00 | 4.00 | $ 39,340.00 | $ - | $ 177,340.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Underground Truck | Underground Vehicles | 6,360.00 | 4.00 | $ 54,820.00 | $ - | $ 192,820.00 | $ 30,000.00 | Diesel | 10.00 | 0.00 | 1.34 | 0.85 | 3.00 |
| Medium Duty | Van | Appliance Service Vans | 5,640.00 | 4.00 | $ 33,000.00 | $ - | $ 162,000.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.53 | 0.80 | 3.00 |
| Medium Duty | Van | Box Trucks | 0.00 | 4.00 | $ 34,000.00 | $ - | $ 163,000.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.53 | 0.80 | 3.00 |
| Medium Duty | Van | Hi-Cube & Cutaway Vans | 3,900.00 | 4.00 | $ 34,000.00 | $ - | $ 163,000.00 | $ 30,000.00 | Gasoline | 13.00 | 0.00 | 1.53 | 0.80 | 3.00 |
| Heavy Duty | Aerial Truck | Aerial Bucket Trucks | 6,480.00 | 4.00 | $ 90,000.00 | $ - | $ 358,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 3.26 | 1.00 | 5.00 |
| Heavy Duty | Aerial Truck | Material Handler Trucks | 5,880.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Aerial Truck | Platform Trucks | 2,700.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Aerial Truck | Trouble Trucks | 9,780.00 | 4.00 | $ 90,000.00 | $ - | $ 358,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 3.26 | 1.00 | 5.00 |
| Heavy Duty | Box Truck | Box Trucks | 1,920.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Digger Truck | Digger Derricks | 5,280.00 | 4.00 | $ 90,000.00 | $ - | $ 358,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 3.26 | 1.00 | 5.00 |
| Heavy Duty | Dump Truck | Dump Truck 3 Cu Yd | 5,880.00 | 4.00 | $ 54,260.00 | $ - | $ 195,260.00 | $ 40,000.00 | Diesel | 10.00 | 0.00 | 3.01 | 1.00 | 5.00 |
| Heavy Duty | Dump Truck | Dump Truck 5 Cu Yd | 8,280.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Service Truck | Service Trucks | 2,160.00 | 4.00 | $ 71,345.00 | $ - | $ 209,345.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.29 | 1.00 | 5.00 |
| Heavy Duty | Service Truck | Substation Vehicles | 0.00 | 4.00 | $ 54,820.00 | $ - | $ 212,320.00 | $ 40,000.00 | Diesel | 10.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Service Truck | Utility Service Vehicles | 4,320.00 | 4.00 | $ 90,000.00 | $ - | $ 358,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 3.26 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Cable Pulling Trucks | 3,540.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Crane | 1,440.00 | 4.00 | $ 1,716,000.00 | $ - | $ 1,984,000.00 | $ 40,000.00 | Diesel | 3.00 | 0.00 | 3.26 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Degasifier Trucks | 120.00 | 4.00 | $ 71,345.00 | $ - | $ 209,345.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.11 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Flatbed Vehicles | 3,600.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Rack Vehicles | 1,800.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Refueling Vehicles | 2,880.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Steamer Truck | 120.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Vac Trucks | 2,460.00 | 4.00 | $ 90,000.00 | $ - | $ 228,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.29 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Winch & Cable Reel Vehicles | 4,320.00 | 4.00 | $ 90,000.00 | $ - | $ 358,000.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 3.00 | 1.00 | 5.00 |
| Heavy Duty | Speciality Vehicle | Pipe Carrier | 9,120.00 | 4.00 | $ 90,000.00 | $ - | $ 247,500.00 | $ 40,000.00 | Diesel | 8.00 | 0.00 | 2.28 | 1.00 | 5.00 |
| Heavy Duty | Underground Truck | Underground Vehicles | 4,860.00 | 4.00 | $ 54,260.00 | $ - | $ 322,260.00 | $ 40,000.00 | Diesel | 10.00 | 0.00 | 3.00 | 1.00 | 5.00 |

# APPENDIX D – TOTAL COST FORECAST & BENEFIT ESTIMATE FORECAST

| Year | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| **Compounding Escalation** | 102% | 104% | 106% | 108% | 110% | 113% | 115% | 117% | 120% | 122% |
| **Total Costs** | | | | | | | | | | |
| **EV Infrastructure & Related (new fueling and support infrastructure)** | | | | | | | | | | |
| One-Time | $ 4,383,785.20 | $ 57,840,951.50 | $ 49,590,951.50 | $ 18,348,480.60 | $ 4,383,785.20 | $ - | $ - | $ - | $ - | $ - |
| Recurring | $ 29,417.13 | $ 291,457.38 | $ 562,997.63 | $ 682,148.63 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 |
| Replacement | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Subtotal | $ 4,413,202.33 | $ 58,132,408.88 | $ 50,153,949.13 | $ 19,030,629.23 | $ 5,095,350.95 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 |
| **Vehicle Acquisition (Acquisition cost premium for electrified options)** | | | | | | | | | | |
| BAU | $ 1,533,420.00 | $ 5,678,675.00 | $ 6,902,855.00 | $ 6,235,248.00 | $ 8,232,479.00 | $ 11,734,809.00 | $ 3,743,869.00 | $ 1,309,608.00 | $ 1,436,138.00 | $ 809,837.00 |
| EV | $ 7,361,980.00 | $ 17,476,548.00 | $ 17,509,968.00 | $ 16,103,372.00 | $ 13,422,624.00 | $ 17,824,872.00 | $ 6,411,824.00 | $ 4,426,660.00 | $ 3,410,364.00 | $ 2,868,000.00 |
| Subtotal | $ 5,828,560.00 | $ 11,797,873.00 | $ 10,607,113.00 | $ 9,868,124.00 | $ 5,190,145.00 | $ 6,090,063.00 | $ 2,667,955.00 | $ 3,117,052.00 | $ 1,974,226.00 | $ 2,058,163.00 |
| Total | $ 10,241,762.33 | $ 69,930,281.88 | $ 60,761,062.13 | $ 28,898,753.23 | $ 10,285,495.95 | $ 6,801,628.75 | $ 3,379,520.75 | $ 3,828,617.75 | $ 2,685,791.75 | $ 2,769,728.75 |
| Cumulative Total | $ 10,241,762.33 | $ 80,172,044.20 | $ 140,933,106.33 | $ 169,831,859.55 | $ 180,117,355.50 | $ 186,918,984.25 | $ 190,298,505.00 | $ 194,127,122.75 | $ 196,812,914.50 | $ 199,582,643.25 |
| Total: Adjusted for Escalation | $ 10,446,597.57 | $ 72,755,465.26 | $ 64,480,125.22 | $ 31,280,939.87 | $ 11,356,018.63 | $ 7,659,738.69 | $ 3,882,007.05 | $ 4,485,835.90 | $ 3,209,769.76 | $ 3,376,283.89 |
| Cumulative Total: Adjusted for Escalation | $ 10,446,597.57 | $ 83,202,062.83 | $ 147,682,188.05 | $ 178,963,127.92 | $ 190,319,146.55 | $ 197,978,885.24 | $ 201,860,892.29 | $ 206,346,728.19 | $ 209,556,497.96 | $ 212,932,781.85 |

| Year | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| **Compounding Escalation** | 124% | 127% | 129% | 132% | 135% | 137% | 140% | 143% | 146% | 149% |
| **Total Costs** | | | | | | | | | | |
| **EV Infrastructure & Related (new fueling and support infrastructure)** | | | | | | | | | | |
| One-Time | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Recurring | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 | $ 711,565.75 |
| Replacement | $ 163,250.00 | $ 2,736,000.00 | $ 2,742,750.00 | $ 2,153,750.00 | $ 4,580,500.00 | $ 4,979,100.00 | $ 1,517,000.00 | $ 597,650.00 | $ 370,800.00 | $ 734,500.00 |
| Subtotal | $ 874,815.75 | $ 3,447,565.75 | $ 3,454,315.75 | $ 2,865,315.75 | $ 5,292,065.75 | $ 5,690,665.75 | $ 2,228,565.75 | $ 1,309,215.75 | $ 1,082,365.75 | $ 1,446,065.75 |
| **Vehicle Acquisition (Acquisition cost premium for electrified options)** | | | | | | | | | | |
| BAU | $ - | $ - | $ 34,000.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| EV | $ 1,390,000.00 | $ 3,620,000.00 | $ 1,574,000.00 | $ 2,190,000.00 | $ 900,000.00 | $ 30,000.00 | $ 240,000.00 | $ - | $ - | $ - |
| Subtotal | $ 1,390,000.00 | $ 3,620,000.00 | $ 1,540,000.00 | $ 2,190,000.00 | $ 900,000.00 | $ 30,000.00 | $ 240,000.00 | $ - | $ - | $ - |
| Total | $ 2,264,815.75 | $ 7,067,565.75 | $ 4,994,315.75 | $ 5,055,315.75 | $ 6,192,065.75 | $ 5,720,665.75 | $ 2,468,565.75 | $ 1,309,215.75 | $ 1,082,365.75 | $ 1,446,065.75 |
| Cumulative Total | $ 201,847,459.00 | $ 208,915,024.75 | $ 213,909,340.50 | $ 218,964,656.25 | $ 225,156,722.00 | $ 230,877,387.75 | $ 233,345,953.50 | $ 234,655,169.25 | $ 235,737,535.00 | $ 237,183,600.75 |
| Total: Adjusted for Escalation | $ 2,816,013.72 | $ 8,963,382.27 | $ 6,460,679.97 | $ 6,670,381.77 | $ 8,333,705.24 | $ 7,853,248.17 | $ 3,456,588.01 | $ 1,869,882.48 | $ 1,576,802.52 | $ 2,148,777.64 |
| Cumulative Total: Adjusted for Escalation | $ 215,748,795.56 | $ 224,712,177.83 | $ 231,172,857.80 | $ 237,843,239.58 | $ 246,176,944.82 | $ 254,030,192.98 | $ 257,486,780.99 | $ 259,356,663.47 | $ 260,933,465.99 | $ 263,082,243.63 |

| **Time Value of Money** | |
|---|---|
| Discount Rate | 6.48% |
| NPV of Costs | $179,076,680.41 |
| NPV of Costs: Adjusted for Escalation | $194,382,963.31 |

| **Total Benefits** | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Maint. & Repair (Savings realized from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 116,010.50 | $ 550,907.90 | $ 1,057,754.34 | $ 1,504,106.62 | $ 2,067,531.15 | $ 2,878,347.87 | $ 3,104,304.81 | $ 3,201,065.96 | $ 3,279,243.17 | $ 3,339,506.60 |
| EV | $ 101,350.91 | $ 278,046.08 | $ 468,976.19 | $ 673,333.41 | $ 814,189.54 | $ 1,021,327.27 | $ 1,078,309.12 | $ 1,102,499.41 | $ 1,122,043.71 | $ 1,137,303.29 |
| Net Benefit | $ 14,659.60 | $ 272,861.81 | $ 588,778.15 | $ 830,773.22 | $ 1,253,341.61 | $ 1,857,020.60 | $ 2,025,995.69 | $ 2,098,566.56 | $ 2,157,199.46 | $ 2,202,203.31 |
| **Fuel (Savings realized from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 462,362.14 | $ 1,482,086.54 | $ 2,466,483.75 | $ 3,364,881.56 | $ 4,029,661.84 | $ 4,843,571.65 | $ 5,191,905.95 | $ 5,475,635.39 | $ 5,701,221.81 | $ 5,874,010.49 |
| EV | $ 94,740.10 | $ 350,523.94 | $ 610,894.25 | $ 845,548.74 | $ 1,080,458.91 | $ 1,375,470.44 | $ 1,473,272.26 | $ 1,545,703.85 | $ 1,598,774.81 | $ 1,639,886.68 |
| Net Benefit | $ 367,622.04 | $ 1,131,562.60 | $ 1,855,589.50 | $ 2,519,332.81 | $ 2,949,202.94 | $ 3,468,101.21 | $ 3,718,633.69 | $ 3,929,931.54 | $ 4,102,447.00 | $ 4,234,123.82 |
| **Avoided Future Capital Expense** | | | | | | | | | | |
| Avoided Future Capital Expense | $ - | $ 190,559.06 | $ 7,620,053.43 | $ 17,166,413.01 | $ 25,735,266.83 | $ 27,942,990.33 | $ 22,241,502.33 | $ 7,448,559.33 | $ 3,210,771.33 | $ 2,485,194.33 |
| Subtotal | $ - | $ 190,559.06 | $ 7,620,053.43 | $ 17,166,413.01 | $ 25,735,266.83 | $ 27,942,990.33 | $ 22,241,502.33 | $ 7,448,559.33 | $ 3,210,771.33 | $ 2,485,194.33 |
| **Societal (Reduction in emission related costs from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 80,484.85 | $ 261,340.62 | $ 435,578.00 | $ 595,600.52 | $ 714,933.41 | $ 861,180.38 | $ 927,033.53 | $ 978,160.90 | $ 1,020,551.32 | $ 1,053,405.61 |
| EV | $ 1,017.48 | $ 1,495.75 | $ 2,336.08 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 |
| Net Benefit | $ 79,467.37 | $ 259,844.87 | $ 433,241.92 | $ 592,134.04 | $ 711,466.93 | $ 857,713.90 | $ 923,567.06 | $ 974,694.42 | $ 1,017,084.84 | $ 1,049,939.13 |
| Total Benefit w/out Societal | $ 382,281.63 | $ 1,594,983.48 | $ 10,064,421.09 | $ 20,516,519.04 | $ 29,937,811.37 | $ 33,268,112.14 | $ 27,986,131.72 | $ 13,477,057.43 | $ 9,470,417.79 | $ 8,921,521.46 |
| Cumulative Total Benefit w/out Societal | $ 382,281.63 | $ 1,977,265.11 | $ 12,041,686.20 | $ 32,558,205.24 | $ 62,496,016.61 | $ 95,764,128.75 | $ 123,750,260.47 | $ 137,227,317.90 | $ 146,697,735.69 | $ 155,619,257.15 |
| Total Benefit w/out Societal: Adjusted for Escalation | $ 389,927.27 | $ 1,659,420.81 | $ 10,680,444.17 | $ 22,207,740.02 | $ 33,053,762.83 | $ 37,465,297.65 | $ 32,147,268.40 | $ 15,790,520.76 | $ 11,318,025.93 | $ 10,875,284.88 |
| Cumulative Total Benefit w/out Societal: Adjusted for Escalation | $ 389,927.27 | $ 2,049,348.08 | $ 12,729,792.25 | $ 34,937,532.27 | $ 67,991,295.10 | $ 105,456,592.75 | $ 137,603,861.15 | $ 153,394,381.91 | $ 164,712,407.84 | $ 175,587,692.72 |
| Total Benefit w/ Societal | $ 461,749.00 | $ 1,854,828.35 | $ 10,497,663.00 | $ 21,108,653.08 | $ 30,649,278.30 | $ 34,125,826.05 | $ 28,909,698.77 | $ 14,451,751.85 | $ 10,487,502.64 | $ 9,971,460.59 |
| Cumulative Total Benefit w/ Societal | $ 461,749.00 | $ 2,316,577.35 | $ 12,814,240.36 | $ 33,922,893.44 | $ 64,572,171.74 | $ 98,697,997.78 | $ 127,607,696.55 | $ 142,059,448.40 | $ 152,546,951.04 | $ 162,518,411.63 |
| Total Benefit w/ Societal: Adjusted for Escalation | $ 470,983.99 | $ 1,929,763.41 | $ 11,140,203.96 | $ 22,848,684.95 | $ 33,839,279.80 | $ 38,431,222.82 | $ 33,208,156.64 | $ 16,932,530.62 | $ 12,533,536.46 | $ 12,155,154.82 |
| Cumulative Total Benefit w/ Societal: Adjusted for Escalation | $ 470,983.99 | $ 2,400,747.40 | $ 13,540,951.36 | $ 36,389,636.31 | $ 70,228,916.11 | $ 108,660,138.93 | $ 141,868,295.56 | $ 158,800,826.19 | $ 171,334,362.65 | $ 183,489,517.47 |

| **Total Benefits** | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Maint. & Repair (Savings realized from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 3,339,506.60 | $ 3,339,506.60 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 | $ 3,340,281.48 |
| EV | $ 1,137,303.29 | $ 1,137,303.29 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 | $ 1,137,690.73 |
| Net Benefit | $ 2,202,203.31 | $ 2,202,203.31 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 | $ 2,202,590.75 |
| **Fuel (Savings realized from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 5,984,485.37 | $ 6,284,527.61 | $ 6,404,242.97 | $ 6,587,846.81 | $ 6,663,232.73 | $ 6,665,892.89 | $ 6,687,174.17 | $ 6,687,174.17 | $ 6,687,174.17 | $ 6,687,174.17 |
| EV | $ 1,660,728.28 | $ 1,713,518.68 | $ 1,737,756.14 | $ 1,770,079.34 | $ 1,785,928.94 | $ 1,786,552.94 | $ 1,789,548.14 | $ 1,789,548.14 | $ 1,789,548.14 | $ 1,789,548.14 |
| Net Benefit | $ 4,323,757.10 | $ 4,571,008.94 | $ 4,666,486.84 | $ 4,817,767.48 | $ 4,877,303.80 | $ 4,879,339.96 | $ 4,897,626.04 | $ 4,897,626.04 | $ 4,897,626.04 | $ 4,897,626.04 |
| **Avoided Future Capital Expense** | | | | | | | | | | |
| Avoided Future Capital Expense | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Subtotal | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Societal (Reduction in emission related costs from an electrified fleet)** | | | | | | | | | | |
| BAU | $ 1,073,546.34 | $ 1,129,239.57 | $ 1,151,554.78 | $ 1,186,112.78 | $ 1,200,387.87 | $ 1,200,903.11 | $ 1,205,024.99 | $ 1,205,024.99 | $ 1,205,024.99 | $ 1,205,024.99 |
| EV | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 | $ 3,466.48 |
| Net Benefit | $ 1,070,079.86 | $ 1,125,773.09 | $ 1,148,088.30 | $ 1,182,646.30 | $ 1,196,921.40 | $ 1,197,436.63 | $ 1,201,558.51 | $ 1,201,558.51 | $ 1,201,558.51 | $ 1,201,558.51 |
| Total Benefit w/out Societal | $ 6,525,960.41 | $ 6,773,212.25 | $ 6,869,077.59 | $ 7,020,358.23 | $ 7,079,894.55 | $ 7,081,930.71 | $ 7,100,216.79 | $ 7,100,216.79 | $ 7,100,216.79 | $ 7,100,216.79 |
| Cumulative Total Benefit w/out Societal | $ 162,145,217.57 | $ 168,918,429.82 | $ 175,787,507.41 | $ 182,807,865.64 | $ 189,887,760.19 | $ 196,969,690.90 | $ 204,069,907.69 | $ 211,170,124.48 | $ 218,270,341.26 | $ 225,370,558.05 |
| Total Benefit w/out Societal: Adjusted for Escalation | $ 8,114,211.51 | $ 8,590,070.86 | $ 8,885,884.32 | $ 9,263,213.59 | $ 9,528,605.91 | $ 9,721,973.24 | $ 9,942,017.63 | $ 10,140,857.99 | $ 10,343,675.15 | $ 10,550,548.65 |
| Cumulative Total Benefit w/out Societal: Adjusted for Escalation | $ 183,701,904.23 | $ 192,291,975.09 | $ 201,177,859.41 | $ 210,441,073.00 | $ 219,969,678.91 | $ 229,691,652.16 | $ 239,633,669.79 | $ 249,774,527.78 | $ 260,118,202.92 | $ 270,668,751.57 |
| Total Benefit w/ Societal | $ 7,596,040.27 | $ 7,898,985.34 | $ 8,017,165.89 | $ 8,203,004.53 | $ 8,276,815.95 | $ 8,279,367.34 | $ 8,301,775.30 | $ 8,301,775.30 | $ 8,301,775.30 | $ 8,301,775.30 |
| Cumulative Total Benefit w/ Societal | $ 170,114,451.90 | $ 178,013,437.24 | $ 186,030,603.13 | $ 194,233,607.66 | $ 202,510,423.60 | $ 210,789,790.94 | $ 219,091,566.24 | $ 227,393,341.54 | $ 235,695,116.84 | $ 243,996,892.14 |
| Total Benefit w/ Societal: Adjusted for Escalation | $ 9,444,721.32 | $ 10,017,823.34 | $ 10,371,058.95 | $ 10,823,690.27 | $ 11,139,504.52 | $ 11,365,797.13 | $ 11,624,489.63 | $ 11,856,979.42 | $ 12,094,119.01 | $ 12,336,001.39 |
| Cumulative Total Benefit w/ Societal: Adjusted for Escalation | $ 192,934,238.79 | $ 202,952,062.14 | $ 213,323,121.08 | $ 224,146,811.36 | $ 235,286,315.88 | $ 246,652,113.01 | $ 258,276,602.64 | $ 270,133,582.05 | $ 282,227,701.06 | $ 294,563,702.45 |

| **Time Value of Money** | |
|---|---|
| Discount Rate | 6.48% |
| NPV of Benefits w/out Societal | $133,767,983.13 |
| NPV of Benefits w/out Societal: Adjusted for Escalation | $156,309,877.13 |
| NPV of Benefits w/ Societal | $142,801,034.26 |
| NPV of Benefits w/ Societal: Adjusted for Escalation | $167,535,057.87 |

# APPENDIX E – SUMMARY DASHBOARD

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Base Case**

| Summary w/out Societal | Real Dollars | | Nominal Dollars | |
|---|---|---|---|---|
| Total 20-Year Benefit | $ | 270,668,752 | $ | 225,370,558 |
| Total 20-Year Cost | $ | 263,082,244 | $ | 237,183,601 |
| Total Net Benefit (Cost) | $ | 7,586,508 | $ | (11,813,043) |
| | | | | |
| Benefit NPV (20-Year) | $ | 156,309,877 | $ | 133,767,983 |
| Cost NPV (20-Year) | $ | 194,382,963 | $ | 179,076,680 |
| Net Benefit (Cost) NPV | $ | (38,073,086) | $ | (45,308,697) |

| Summary w/ Societal | Real Dollars | | Nominal Dollars | |
|---|---|---|---|---|
| Total 20-Year Benefit | $ | 294,563,702 | $ | 243,996,892 |
| Total 20-Year Cost | $ | 263,082,244 | $ | 237,183,601 |
| Total Net Benefit (Cost) | $ | 31,481,459 | $ | 6,813,291 |
| | | | | |
| Benefit NPV (20-Year) | $ | 167,535,058 | $ | 142,801,034 |
| Cost NPV (20-Year) | $ | 194,382,963 | $ | 179,076,680 |
| Net Benefit (Cost) NPV | $ | (26,847,905) | $ | (36,275,646) |

| Savings | Real Dollars | | Nominal Dollars | |
|---|---|---|---|---|
| Total Maint. Cost Savings | $ | 45,332,994 | $ | 35,326,533 |
| Total Fuel Cost Savings | $ | 97,445,125 | $ | 76,002,715 |
| Total Avoided Future Capital Ex. | $ | 127,890,633 | $ | 114,041,310 |
| Total Societal Cost Savings | $ | 23,894,951 | $ | 18,626,334 |

| Cost | Real Dollars | | Nominal Dollars | |
|---|---|---|---|---|
| Total EV Infra & Related Capital Cost | $ | 141,976,540 | $ | 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ | 16,312,584 | $ | 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ | 27,672,116 | $ | 20,575,300 |
| Total Vehicle Premium Cost | $ | 77,121,004 | $ | 69,109,274 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

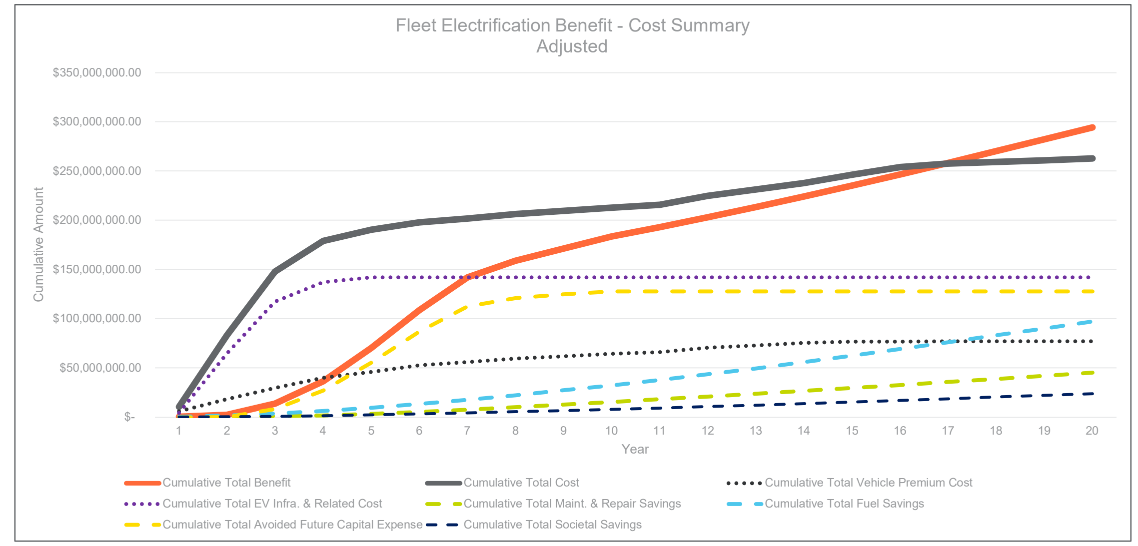
| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

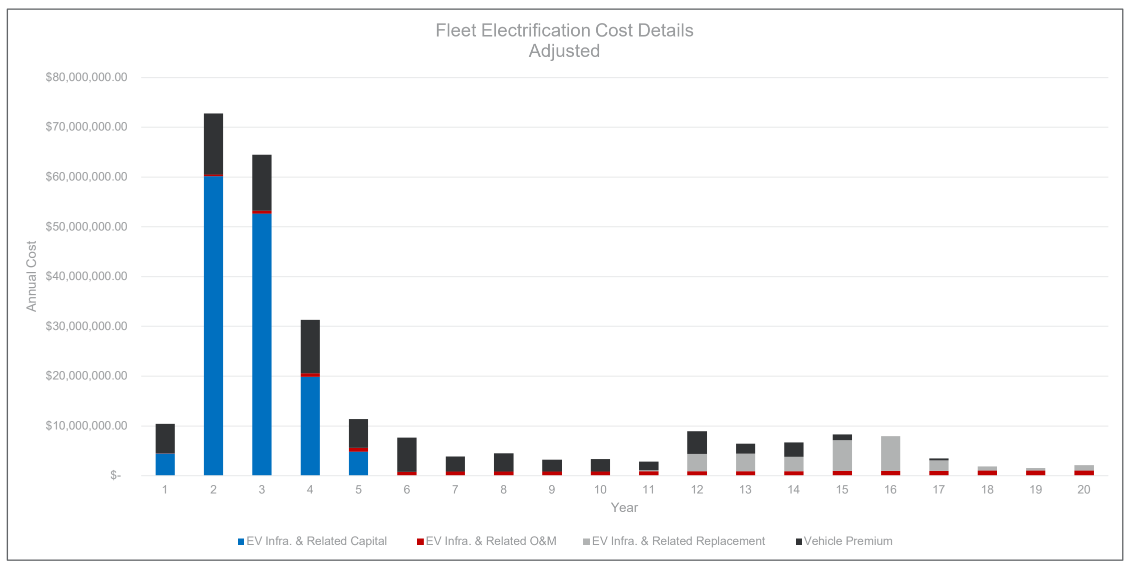
| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

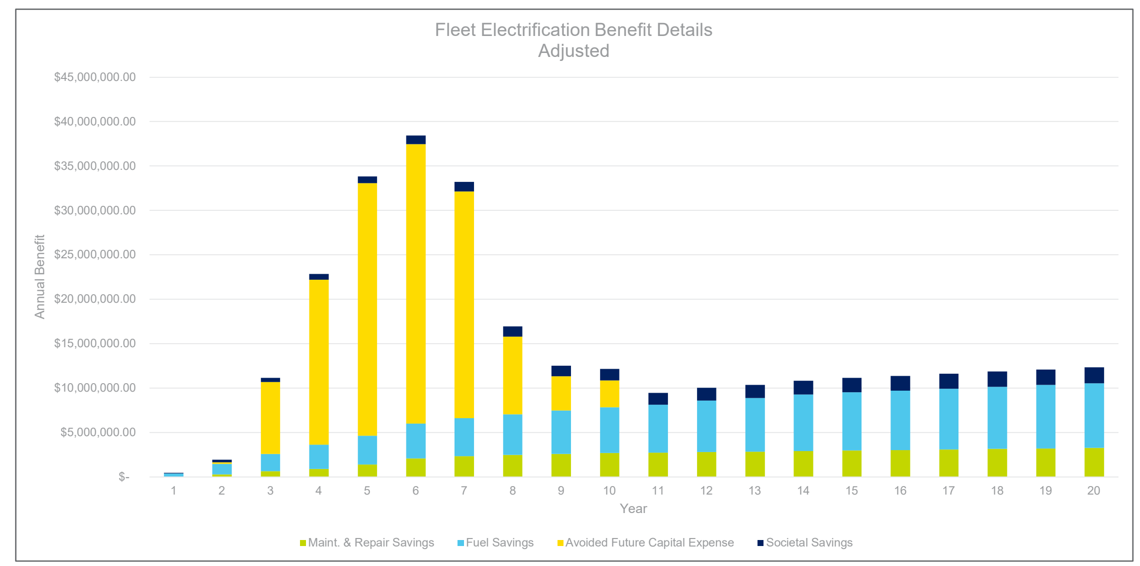
| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

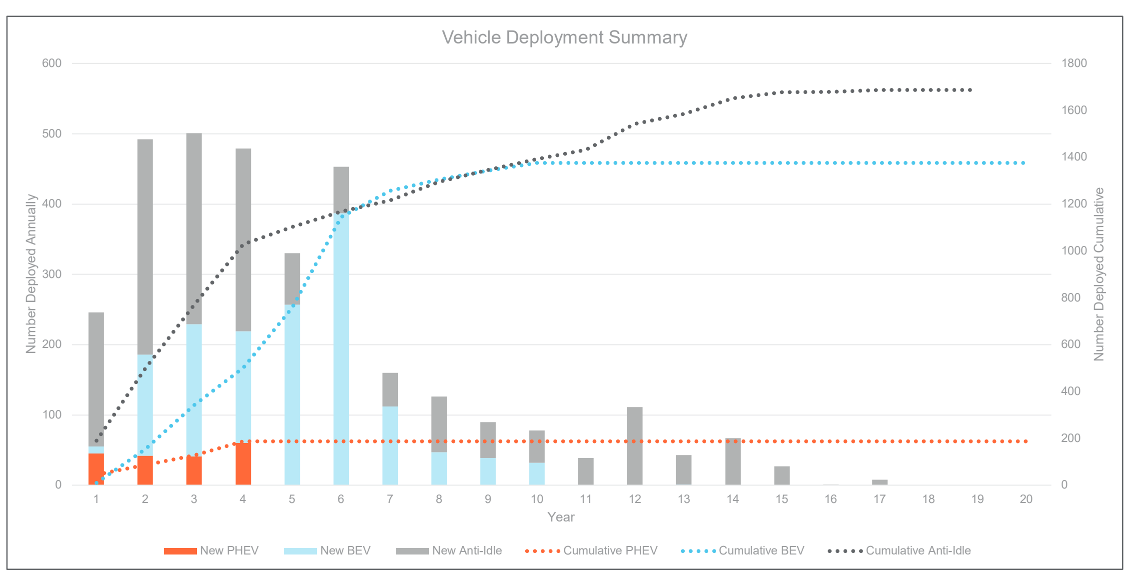
Notes

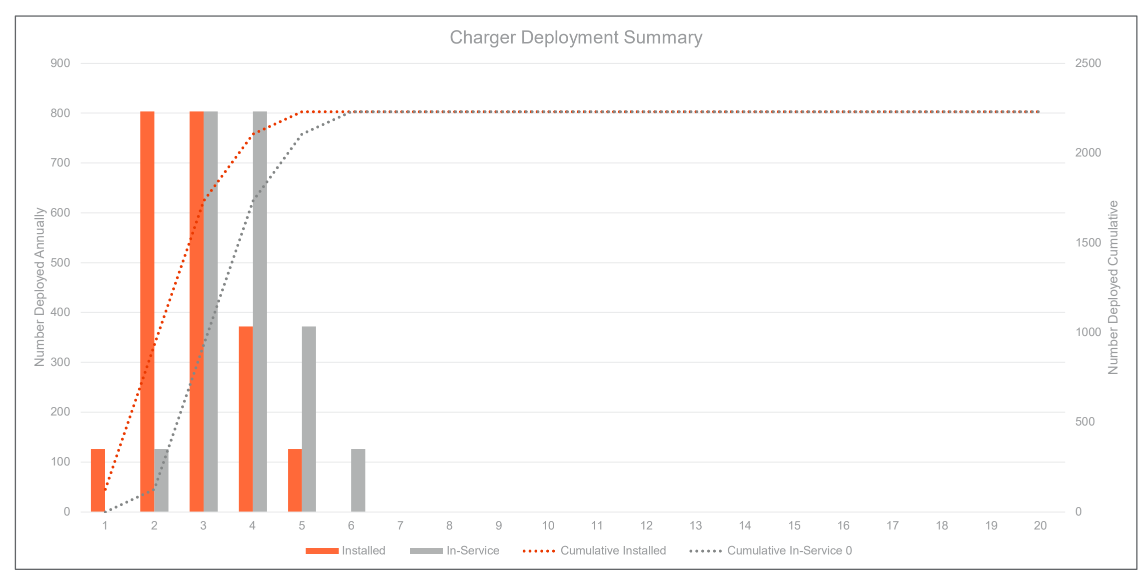
Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants



# APPENDIX F – SENSITIVITY ANALYSIS RESULTS

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **LowFuel**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 184,254,674 | $ 152,288,835 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (78,827,570) | $ (84,894,766) |
| | | |
| Benefit NPV (20-Year) | $ 100,095,004 | $ 84,835,614 |
| Cost NPV (20-Year) | $ 191,157,900 | $ 176,287,100 |
| Net Benefit (Cost) NPV | $ (91,062,896) | $ (91,451,486) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 208,149,625 | $ 170,915,169 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (54,932,619) | $ (66,268,432) |
| | | |
| Benefit NPV (20-Year) | $ 110,836,999 | $ 93,497,243 |
| Cost NPV (20-Year) | $ 191,157,900 | $ 176,287,100 |
| Net Benefit (Cost) NPV | $ (80,320,900) | $ (82,789,857) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 51,254,732.93 | $ 39,996,307.49 |
| Total Avoided Future Capital Ex. | $ 87,666,946.66 | $ 76,965,994.83 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **HighFuel**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 293,897,294 | $ 243,499,466 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 30,815,051 | $ 6,315,865 |
| | | |
| Benefit NPV (20-Year) | $ 167,265,216 | $ 142,595,056 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (27,117,747) | $ (36,481,625) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 317,792,245 | $ 262,125,800 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 54,710,002 | $ 24,942,199 |
| | | |
| Benefit NPV (20-Year) | $ 178,490,397 | $ 151,628,107 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (15,892,567) | $ (27,448,574) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 120,673,667.37 | $ 94,131,623.03 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
w/out Societal = does not include social cost of carbon
w/ Societal = includes social cost of carbon

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **CapEx +10%**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 283,457,815 | $ 236,774,689 |
| Total 20-Year Cost | $ 277,279,898 | $ 250,638,396 |
| Total Net Benefit (Cost) | $ 6,177,917 | $ (13,863,707) |
| | | |
| Benefit NPV (20-Year) | $ 165,231,628 | $ 141,747,672 |
| Cost NPV (20-Year) | $ 206,368,235 | $ 190,445,200 |
| Net Benefit (Cost) NPV | $ (41,136,606) | $ (48,697,528) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 307,352,766 | $ 255,401,023 |
| Total 20-Year Cost | $ 277,279,898 | $ 250,638,396 |
| Total Net Benefit (Cost) | $ 30,072,868 | $ 4,762,627 |
| | | |
| Benefit NPV (20-Year) | $ 176,456,809 | $ 150,780,724 |
| Cost NPV (20-Year) | $ 206,368,235 | $ 190,445,200 |
| Net Benefit (Cost) NPV | $ (29,911,426) | $ (39,664,477) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 140,679,696.13 | $ 125,445,441.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 156,174,194 | $ 148,002,749 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **CapEx -10%**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 257,879,688 | $ 213,966,427 |
| Total 20-Year Cost | $ 246,117,378 | $ 221,671,275 |
| Total Net Benefit (Cost) | $ 11,762,310 | $ (7,704,848) |
| | | |
| Benefit NPV (20-Year) | $ 147,388,126 | $ 125,788,294 |
| Cost NPV (20-Year) | $ 181,310,550 | $ 166,895,925 |
| Net Benefit (Cost) NPV | $ (33,922,423) | $ (41,107,631) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 281,774,639 | $ 232,592,761 |
| Total 20-Year Cost | $ 246,117,378 | $ 221,671,275 |
| Total Net Benefit (Cost) | $ 35,657,261 | $ 10,921,486 |
| | | |
| Benefit NPV (20-Year) | $ 158,613,307 | $ 134,821,345 |
| Cost NPV (20-Year) | $ 181,310,550 | $ 166,895,925 |
| Net Benefit (Cost) NPV | $ (22,697,243) | $ (32,074,580) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 115,101,569.56 | $ 102,637,179.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 127,778,886 | $ 121,093,159 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 24,904,904.54 | $ 18,517,770.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **DR 3%**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 270,668,752 | $ 225,370,558 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 7,586,508 | $ (11,813,043) |
| | | |
| Benefit NPV (20-Year) | $ 206,655,997 | $ 174,478,848 |
| Cost NPV (20-Year) | $ 226,055,063 | $ 206,154,884 |
| Net Benefit (Cost) NPV | $ (19,399,066) | $ (31,676,036) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 294,563,702 | $ 243,996,892 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 31,481,459 | $ 6,813,291 |
| | | |
| Benefit NPV (20-Year) | $ 223,191,024 | $ 187,560,714 |
| Cost NPV (20-Year) | $ 226,055,063 | $ 206,154,884 |
| Net Benefit (Cost) NPV | $ (2,864,039) | $ (18,594,170) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Low Esc.**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 246,790,261 | $ 225,370,558 |
| Total 20-Year Cost | $ 249,594,702 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (2,804,441) | $ (11,813,043) |
| | | |
| Benefit NPV (20-Year) | $ 144,522,464 | $ 133,767,983 |
| Cost NPV (20-Year) | $ 186,488,034 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (41,965,570) | $ (45,308,697) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 267,874,306 | $ 243,996,892 |
| Total 20-Year Cost | $ 249,594,702 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 18,279,604 | $ 6,813,291 |
| | | |
| Benefit NPV (20-Year) | $ 154,584,776 | $ 142,801,034 |
| Cost NPV (20-Year) | $ 186,488,034 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (31,903,258) | $ (36,275,646) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 39,997,866.85 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 86,005,148.86 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 120,787,244.90 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 21,084,045.19 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 138,225,689 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 14,523,445 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 23,874,179.95 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 72,971,387.63 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **High Esc.**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 327,152,106 | $ 225,370,558 |
| Total 20-Year Cost | $ 293,821,016 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 33,331,090 | $ (11,813,043) |
| | | |
| Benefit NPV (20-Year) | $ 183,480,095 | $ 133,767,983 |
| Cost NPV (20-Year) | $ 211,832,644 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (28,352,550) | $ (45,308,697) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 357,944,458 | $ 243,996,892 |
| Total 20-Year Cost | $ 293,821,016 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 64,123,442 | $ 6,813,291 |
| | | |
| Benefit NPV (20-Year) | $ 197,508,043 | $ 142,801,034 |
| Cost NPV (20-Year) | $ 211,832,644 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (14,324,602) | $ (36,275,646) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 58,396,371.16 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 125,517,352.33 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 143,238,382.84 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 30,792,351.51 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 149,701,658 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 20,671,267 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 37,059,495.10 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 86,388,596.22 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **High Mileage**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 284,368,638 | $ 236,056,292 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 21,286,394 | $ (1,127,308) |
| | | |
| Benefit NPV (20-Year) | $ 162,740,057 | $ 138,930,912 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (31,642,906) | $ (40,145,769) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 309,945,947 | $ 255,994,540 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 46,863,703 | $ 18,810,939 |
| | | |
| Benefit NPV (20-Year) | $ 174,754,205 | $ 148,597,232 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (19,628,758) | $ (30,479,449) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 53,375,098.53 | $ 41,598,144.92 |
| Total Fuel Cost Savings | $ 103,102,906.69 | $ 80,416,837.35 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 25,577,308.77 | $ 19,938,247.94 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Maint. #1**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 255,743,277 | $ 213,741,249 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (7,338,966) | $ (23,442,352) |
| | | |
| Benefit NPV (20-Year) | $ 149,329,702 | $ 128,170,507 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (45,053,262) | $ (50,906,173) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 279,638,228 | $ 232,367,583 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 16,555,984 | $ (4,816,018) |
| | | |
| Benefit NPV (20-Year) | $ 160,554,882 | $ 137,203,558 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (33,828,081) | $ (41,873,122) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 30,407,519.64 | $ 23,697,223.75 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Maint. #2**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 272,733,473 | $ 227,010,980 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 9,651,229 | $ (10,172,620) |
| | | |
| Benefit NPV (20-Year) | $ 157,344,573 | $ 134,619,560 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (37,038,390) | $ (44,457,121) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 296,628,424 | $ 245,637,314 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 33,546,180 | $ 8,453,714 |
| | | |
| Benefit NPV (20-Year) | $ 168,569,754 | $ 143,652,611 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (25,813,209) | $ (35,424,070) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 47,397,715.43 | $ 36,966,954.92 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **StandbyGen**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 235,710,138 | $ 193,661,839 |
| Total 20-Year Cost | $ 219,179,992 | $ 196,313,101 |
| Total Net Benefit (Cost) | $ 16,530,146 | $ (2,651,262) |
| | | |
| Benefit NPV (20-Year) | $ 130,627,978 | $ 110,452,174 |
| Cost NPV (20-Year) | $ 159,030,245 | $ 145,893,221 |
| Net Benefit (Cost) NPV | $ (28,402,267) | $ (35,441,047) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 259,605,089 | $ 212,288,173 |
| Total 20-Year Cost | $ 219,179,992 | $ 196,313,101 |
| Total Net Benefit (Cost) | $ 40,425,097 | $ 15,975,072 |
| | | |
| Benefit NPV (20-Year) | $ 141,853,159 | $ 119,485,226 |
| Cost NPV (20-Year) | $ 159,030,245 | $ 145,893,221 |
| Net Benefit (Cost) NPV | $ (17,177,086) | $ (26,407,996) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 92,932,019.68 | $ 82,332,590.96 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 102,319,509 | $ 97,047,954 |
| Total EV Infra. & Related O&M Cost | $ 12,067,363 | $ 9,580,573 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **EVSE**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 270,668,752 | $ 225,370,558 |
| Total 20-Year Cost | $ 235,410,127 | $ 216,608,301 |
| Total Net Benefit (Cost) | $ 35,258,624 | $ 8,762,257 |
| | | |
| Benefit NPV (20-Year) | $ 156,309,877 | $ 133,767,983 |
| Cost NPV (20-Year) | $ 183,511,539 | $ 170,954,322 |
| Net Benefit (Cost) NPV | $ (27,201,661) | $ (37,186,339) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 294,563,702 | $ 243,996,892 |
| Total 20-Year Cost | $ 235,410,127 | $ 216,608,301 |
| Total Net Benefit (Cost) | $ 59,153,575 | $ 27,388,591 |
| | | |
| Benefit NPV (20-Year) | $ 167,535,058 | $ 142,801,034 |
| Cost NPV (20-Year) | $ 183,511,539 | $ 170,954,322 |
| Net Benefit (Cost) NPV | $ (15,976,481) | $ (28,153,288) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ - | $ - |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **LowR&C**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 245,090,625 | $ 202,562,296 |
| Total 20-Year Cost | $ 234,726,000 | $ 210,310,910 |
| Total Net Benefit (Cost) | $ 10,364,625 | $ (7,748,614) |
| | | |
| Benefit NPV (20-Year) | $ 138,466,375 | $ 117,808,605 |
| Cost NPV (20-Year) | $ 170,445,096 | $ 156,370,565 |
| Net Benefit (Cost) NPV | $ (31,978,721) | $ (38,561,961) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 268,985,576 | $ 221,188,630 |
| Total 20-Year Cost | $ 234,726,000 | $ 210,310,910 |
| Total Net Benefit (Cost) | $ 34,259,576 | $ 10,877,720 |
| | | |
| Benefit NPV (20-Year) | $ 149,691,556 | $ 126,841,656 |
| Cost NPV (20-Year) | $ 170,445,096 | $ 156,370,565 |
| Net Benefit (Cost) NPV | $ (20,753,540) | $ (29,528,909) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 97,445,124.66 | $ 76,002,715.39 |
| Total Avoided Future Capital Ex. | $ 102,312,506.28 | $ 91,233,048.00 |
| Total Societal Cost Savings | $ 23,894,950.87 | $ 18,626,334.08 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 113,620,296 | $ 107,675,263 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Fewer BEVs**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 258,130,355 | $ 215,462,638 |
| Total 20-Year Cost | $ 265,891,957 | $ 239,847,348 |
| Total Net Benefit (Cost) | $ (7,761,602) | $ (24,384,710) |
| | | |
| Benefit NPV (20-Year) | $ 150,153,933 | $ 128,744,686 |
| Cost NPV (20-Year) | $ 196,766,065 | $ 181,344,942 |
| Net Benefit (Cost) NPV | $ (46,612,131) | $ (52,600,256) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 281,176,458 | $ 233,423,507 |
| Total 20-Year Cost | $ 265,891,957 | $ 239,847,348 |
| Total Net Benefit (Cost) | $ 15,284,501 | $ (6,423,841) |
| | | |
| Benefit NPV (20-Year) | $ 160,974,576 | $ 137,451,686 |
| Cost NPV (20-Year) | $ 196,766,065 | $ 181,344,942 |
| Net Benefit (Cost) NPV | $ (35,791,488) | $ (43,893,256) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 33,143,301.34 | $ 25,660,748.95 |
| Total Fuel Cost Savings | $ 97,096,420.88 | $ 75,760,578.62 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 23,046,102.79 | $ 17,960,869.27 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 79,930,717.49 | $ 71,773,021.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 328 |
| BEV | 1105 |
| Anti-Idle | 1818 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Delayed Adopt.**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 254,698,637 | $ 211,170,124 |
| Total 20-Year Cost | $ 266,197,932 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (11,499,295) | $ (26,013,476) |
| | | |
| Benefit NPV (20-Year) | $ 145,146,074 | $ 123,715,451 |
| Cost NPV (20-Year) | $ 189,810,210 | $ 173,108,543 |
| Net Benefit (Cost) NPV | $ (44,664,135) | $ (49,393,092) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 275,880,197 | $ 227,393,342 |
| Total 20-Year Cost | $ 266,197,932 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ 9,682,265 | $ (9,790,259) |
| | | |
| Benefit NPV (20-Year) | $ 154,492,629 | $ 131,059,175 |
| Cost NPV (20-Year) | $ 189,810,210 | $ 173,108,543 |
| Net Benefit (Cost) NPV | $ (35,317,581) | $ (42,049,368) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 40,420,893.82 | $ 30,921,351.16 |
| Total Fuel Cost Savings | $ 86,387,110.46 | $ 66,207,463.31 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 21,181,560.07 | $ 16,223,217.07 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 80,236,692.55 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

# Fleet Electrification 20-Year Benefit Cost Analysis

Scenario: **Reduced Idle**

| Summary w/out Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 238,620,591 | $ 200,377,053 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (24,461,653) | $ (36,806,548) |
| | | |
| Benefit NPV (20-Year) | $ 141,202,914 | $ 121,582,319 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (53,180,049) | $ (57,494,362) |

| Summary w/ Societal | Real Dollars | Nominal Dollars |
|---|---|---|
| Total 20-Year Benefit | $ 255,592,608 | $ 213,610,083 |
| Total 20-Year Cost | $ 263,082,244 | $ 237,183,601 |
| Total Net Benefit (Cost) | $ (7,489,636) | $ (23,573,517) |
| | | |
| Benefit NPV (20-Year) | $ 149,176,272 | $ 127,995,513 |
| Cost NPV (20-Year) | $ 194,382,963 | $ 179,076,680 |
| Net Benefit (Cost) NPV | $ (45,206,691) | $ (51,081,168) |

| Savings | Real Dollars | Nominal Dollars |
|---|---|---|
| Total Maint. Cost Savings | $ 45,332,994.06 | $ 35,326,532.67 |
| Total Fuel Cost Savings | $ 65,396,963.93 | $ 51,009,210.43 |
| Total Avoided Future Capital Ex. | $ 127,890,632.85 | $ 114,041,310.00 |
| Total Societal Cost Savings | $ 16,972,016.88 | $ 13,233,030.35 |

| Cost | Real Dollars | Nominal Dollars |
|---|---|---|
| Total EV Infra & Related Capital Cost | $ 141,976,540 | $ 134,547,954 |
| Total EV Infra. & Related O&M Cost | $ 16,312,584 | $ 12,951,073 |
| Total EV Infra. & Related Replace. Cost | $ 27,672,116.15 | $ 20,575,300.00 |
| Total Vehicle Premium Cost | $ 77,121,003.98 | $ 69,109,274.00 |

| Chargers Deployed | |
|---|---|
| Level 1 | 1715 |
| Level 2 | 266 |
| Level 3 | 250 |

| Vehicles Electrified by Class | |
|---|---|
| Passenger | 807 |
| Light Duty | 1210 |
| Medium Duty | 716 |
| Heavy Duty | 518 |

| Vehicles Deployed by Type | |
|---|---|
| PHEV | 188 |
| BEV | 1376 |
| Anti-Idle | 1687 |

| | |
|---|---|
| Total Vehicles in Analysis | 3251 |
| Vehicles already Electrified | 469 |
| Vehicles excluded (Take Home) | 1471 |
| Total Vehicles | 5191 |

Notes

Real Dollars = adjusted for inflation
Nominal Dollars = not adjusted for inflation
W/out Societal = does not include social cost of carbon or criterial pollutants
W/ Societal = includes social cost of carbon & criteria pollutants

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# NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

## In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Infrastructure Advancement Program

## Notice of Filing and Notice of Public Hearings

## BPU Docket No.: XXXXXXXXXX

**TAKE NOTICE** that, on November 4, 2021 Public Service Electric and Gas Company (Public Service, PSE&G, the Company) filed a Petition and supporting documentation with the New Jersey Board of Public Utilities (Board, BPU). The Company is seeking Board approval of an Infrastructure Advancement Program ("IAP" or "Program") and associated cost recovery mechanism.

PSE&G seeks Board approval to invest $708 million in IAP Electric investments and $140 million in gas infrastructure across its service territory with cost recovery based upon the Board's Infrastructure Investment Program ("IIP") rules and consistent with the recovery of electric and gas investments that have previously been approved for the Company's Energy Strong Programs. The Program proposes infrastructure investments to enhance safety, reliability, and/or resiliency, and modernize the Company's electric and gas delivery systems through twelve electric projects and one gas project.

In conjunction with the implementation of the Program, PSE&G will seek Board approval to recover the revenue increases associated with the capital investment costs of the IAP. While the Company is not seeking an increase at this time, PSE&G is seeking authority to recover a return on and return of its investments through semiannual adjustments to its IIP Charges beginning on April 1, 2024 for electric and gas. The Company estimates that the rate change for electric rates would increase rates by approximately $10.5 million and the rate change for gas rates would increase rates by approximately $3.5 million. These rate changes are only estimates at this time and are subject to change.

For illustrative purposes, the April 1, 2024 estimated IAP rate components of IIP Charges including New Jersey Sales and Use Tax (SUT) for residential Rate Schedules RS and RSG, respectively, are shown in Table #1. Tables #2 & #3 provide customers with the approximate effect of the proposed changes in the IAP component of IIP Charges relating to the Program, if approved by the Board, effective April 1, 2024 for both electric and gas, respectively. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Under the Company's proposal, a residential electric customer using 740 kilowatt-hours per month during the summer months and 6,920 kilowatt-hours on an annual basis would see an initial increase in the annual bill from $1,324.24 to $1,328.76, or $4.52 or approximately 0.34%. The approximate effect of the proposed electric IAP component of IIP Charge change on typical electric residential monthly bills, if approved by the Board, is illustrated in Table #4.

Under the Company's proposal, a residential gas heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see an initial increase in the annual bill from $580.64 to $581.78, or $1.14 or approximately 0.20%. Also, a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see an initial increase in the annual bill from $916.92 to $918.88, or $1.96 or approximately 0.21%. The approximate effect of the proposed gas IAP Component of IIP Charge change on typical gas residential monthly bills, if approved by the Board, is illustrated in Table # 5.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential electric customer using 6,920 kilowatt-hours annually would be: $4.52 or approximately 0.34% effective 4/1/2024; $2.84 or approximately 0.21% effective 10/1/2024; $2.92 or approximately 0.22% effective 4/1/2025; $15.32 or approximately 1.16% effective 4/1/2026; $2.00 or approximately 0.15% effective 10/1/2026.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential gas heating customer using 1,040 therms annually would be: $1.96 or approximately 0.21% effective 4/1/2024; $6.34 or approximately 0.69% effective 4/1/2025; $2.74 or approximately 0.30% effective 4/1/2026; and $0.40 or approximately 0.04% effective 10/1/2026.

Tables #6, #7, #8, & #9 provide customers with the estimated incremental and cumulative rate impacts of the Program to typical and class average customers for Residential, Commercial, and Industrial classes, respectively. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as a result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

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

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

Date:
Times:

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the telephonic public hearings. Members of the public are invited to participate by utilizing the Dial-In number and Access Code set forth above and may express their views on the petition. All comments will be made a part of the final record of the proceeding and will be considered by the Board.

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters, or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

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

Emailed comments may be filed with the Secretary of the Board, in PDF or Word format, to board.secretary@bpu.nj.gov.

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

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

**Table # 1**
**IAP RATE COMPONENTS OF IIP CHARGES**
**For Residential RS and RSG Customers**
**Rates if Effective April 1, 2024**

| Rate Schedule | | | IIP Charges | |
|---|---|---|---|---|
| | | | Charges in Effect October 1, 2021 Including SUT | Estimated Charges Including SUT |
| **Electric** | | | | |
| RS | | | | |
| | Service Charge | per month | $0.00 | $0.00 |
| | Distribution 0-600, June-September | $/kWh | 0.000000 | 0.001538 |
| | Distribution 0-600, October-May | $/kWh | 0.000000 | 0.000000 |
| | Distribution over 600, June-September | $/kWh | 0.000000 | 0.001538 |
| | Distribution over 600, October-May | $/kWh | 0.000000 | 0.000000 |
| **Gas** | | | | |
| RSG | Service Charge | per month | $0.00 | $0.00 |
| | Distribution Charge | $/Therm | 0.000000 | 0.001877 |
| | Off-Peak Use | $/Therm | 0.000000 | 0.000939 |
| | Basic Gas Supply Service-RSG (BGSS-RSG) | $/Therm | 0.000000 | (0.000012) |

**Table #2**
**Proposed Percentage Change in Revenue**
**By Customer Class for Electric Service**
**For Rates if Effective April 1, 2024**

| | Rate Class | Percent Change |
|---|---|---|
| Residential | RS | 0.34% |
| Residential Heating | RHS | 0.35 |
| Residential Load Management | RLM | 0.23 |
| Water Heating | WH | 0.36 |
| Water Heating Storage | WHS | 0.17 |
| Building Heating | HS | 0.11 |
| General Lighting & Power | GLP | 0.09 |
| Large Power & Lighting- Sec. | LPL-S | 0.07 |
| Large Power & Lighting- Pri. | LPL-P | 0.05 |
| High Tension-Subtr. | HTS-S | 0.06 |
| High Tension-HV | HTS-HV | 0.03 |
| Body Politic Lighting | BPL | 0.01 |
| Body Politic Lighting-POF | BPL-POF | 0.04 |
| Private Street & Area Lighting | PSAL | 0.01 |
| Overall | | 0.18 |

The percent increases noted above are based upon October 1, 2021 Delivery Rates, the applicable Basic Generation Service (BGS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

## Table # 3
## Proposed Percentage Change in Revenue by Customer Class for Gas Service For Rates if Effective April 1, 2024

| | Rate Class | Percent Change |
|---|---|---|
| Residential Service | RSG | 0.21% |
| General Service | GSG | 0.14 |
| Large Volume Service | LVG | 0.08 |
| Street Lighting Service | SLG | 0.01 |
| Firm Transportation Gas Service | TSG-F | 0.03 |
| Non-Firm Transportation Gas Service | TSG-NF | 0.04 |
| Cogeneration Interruptible Service | CIG | 0.05 |
| Contract Service | CSG | 0.05 |
| Overall | | 0.16 |

The percent increases noted above are based upon October 1, 2021 Delivery Rates, the applicable Basic Gas Supply Service (BGSS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

## Table #4
## Residential Electric Service for Rates if Effective April 1, 2024

| If Your Annual kWh Use Is: | And Your Monthly Summer kWh Use Is: | Then Your Present Monthly Summer Bill (1) Would Be: | And Your Proposed Monthly Summer Bill (2) Would Be: | Your Monthly Summer Bill Change Would Be: | And Your Monthly Summer Percent Change Would Be: |
|---|---|---|---|---|---|
| 1,732 | 185 | $39.02 | $39.31 | $0.29 | 0.74% |
| 3,464 | 370 | 73.11 | 73.68 | 0.57 | 0.78 |
| 6,920 | 740 | 143.20 | 144.33 | 1.13 | 0.79 |
| 7,800 | 803 | 155.66 | 156.89 | 1.23 | 0.79 |
| 12,500 | 1,337 | 261.37 | 263.43 | 2.06 | 0.79 |

(1) Based upon Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect October 1, 2021 and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.
(2) Same as (1) except includes the proposed change for the IAP Program.

## Table # 5
## Residential Gas Service for Rates if Effective April 1, 2024

| If Your Annual Therm Use Is: | And Your Monthly Winter Therm Use Is: | Then Your Present Monthly Winter Bill (1) Would Be: | And Your Proposed Monthly Winter Bill (2) Would Be: | Your Monthly Winter Bill Change Would Be: | And Your Monthly Winter Percent Change Would Be: |
|---|---|---|---|---|---|
| 170 | 25 | $28.28 | $28.33 | $0.05 | 0.18% |
| 340 | 50 | 47.98 | 48.07 | 0.09 | 0.19 |
| 610 | 100 | 88.24 | 88.43 | 0.19 | 0.22 |
| 1,040 | 172 | 145.59 | 145.91 | 0.32 | 0.22 |
| 1,210 | 200 | 167.86 | 168.24 | 0.38 | 0.23 |
| 1,816 | 300 | 247.48 | 248.04 | 0.56 | 0.23 |

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect October 1, 2021 and assumes that the customer receives commodity service from Public Service.
(2) Same as (1) except includes the proposed change for the IAP Program.

## Table # 6
## Residential Electric Service
## Projected Incremental Percent Change
## From Annual Bills Effective October 1, 2021

| Rate Class | Forecasted % Increase 4/1/2024 | Forecasted % Increase 10/1/2024 | Forecasted % Increase 4/1/2025 | Forecasted % Increase 4/1/2026 | Forecasted % Increase 10/1/2026 |
|---|---|---|---|---|---|
| RS | 0.34% | 0.21% | 0.22% | 1.16% | 0.15% |
| RHS | 0.35% | 0.22% | 0.23% | 1.17% | 0.16% |
| RLM | 0.23% | 0.14% | 0.15% | 0.81% | 0.11% |
| GLP | 0.09% | 0.06% | 0.06% | 0.31% | 0.04% |
| LPL-S | 0.07% | 0.04% | 0.04% | 0.23% | 0.03% |
| LPL-P | 0.05% | 0.03% | 0.03% | 0.16% | 0.02% |
| HTS-S | 0.07% | 0.04% | 0.04% | 0.25% | 0.03% |

The percent increases noted above are based upon Delivery Rates in effect October 1, 2021 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

**Table # 7**
**Electric Service**
**Projected Cumulative Percent Change**
**From Annual Bills Effective October 1, 2021**

| Rate Class | Forecasted % Increase 4/1/2024 | Forecasted % Increase 10/1/2024 | Forecasted % Increase 4/1/2025 | Forecasted % Increase 4/1/2026 | Forecasted % Increase 10/1/2026 |
|---|---|---|---|---|---|
| RS | 0.34% | 0.56% | 0.78% | 1.93% | 2.08% |
| RHS | 0.35% | 0.57% | 0.80% | 1.97% | 2.13% |
| RLM | 0.23% | 0.38% | 0.53% | 1.35% | 1.46% |
| GLP | 0.09% | 0.15% | 0.21% | 0.52% | 0.56% |
| LPL-S | 0.07% | 0.11% | 0.15% | 0.38% | 0.41% |
| LPL-P | 0.05% | 0.08% | 0.11% | 0.28% | 0.30% |
| HTS-S | 0.07% | 0.11% | 0.15% | 0.40% | 0.43% |

The percent increases noted above are based upon Delivery Rates in effect October 1, 2021 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above. The cumulative totals in Table #7 may not agree to Table #6 due to rounding.

**Table # 8**
**Gas Service**
**Projected Incremental Percent Change**
**From Annual Bills Effective October 1, 2021**

| Rate Class | Forecasted % Increase 4/1/2024 | Forecasted % Increase 4/1/2025 | Forecasted % Increase 4/1/2026 | Forecasted % Increase 10/1/2026 |
|---|---|---|---|---|
| RSG | 0.21% | 0.69% | 0.30% | 0.04% |
| GSG | 0.15% | 0.47% | 0.21% | 0.03% |
| LVG | 0.08% | 0.26% | 0.11% | 0.02% |
| TSG-F | 0.03% | 0.11% | 0.05% | 0.01% |
| TSG-NF | 0.05% | 0.17% | 0.08% | 0.01% |
| CIG | 0.06% | 0.19% | 0.09% | 0.01% |

The percent increases noted above are based upon Delivery Rates in effect October 1, 2021 and the applicable Basic Gas Supply Service (BGSS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make up to semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

**Table # 9**
**Residential Gas Service**
**Projected Cumulative Percent Change**
**From Annual Bills Effective October 1, 2021**

| Rate Class | Forecasted % Increase 4/1/2024 | Forecasted % Increase 4/1/2025 | Forecasted % Increase 4/1/2026 | Forecasted % Increase 10/1/2026 |
|---|---|---|---|---|
| RSG | 0.21% | 0.91% | 1.20% | 1.25% |
| GSG | 0.15% | 0.62% | 0.82% | 0.85% |
| LVG | 0.08% | 0.34% | 0.45% | 0.47% |
| TSG-F | 0.03% | 0.14% | 0.19% | 0.19% |
| TSG-NF | 0.05% | 0.23% | 0.30% | 0.31% |
| CIG | 0.06% | 0.25% | 0.33% | 0.34% |

The percent increases noted above are based upon Delivery Rates in effect October 1, 2021 and the applicable Basic Gas Supply Service (BGSS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make up to semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above. The cumulative totals in Table #9 may not agree to Table #8 due to rounding.

**Danielle Lopez, Esq.**
**Associate Counsel—Regulatory**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**