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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY - ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

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March 30, 2026

Cover Letter

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March 30, 2026

VIA eFILING

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v.
PECO Energy Company — Electric Division
Docket No. R-2026-3060859

Dear Secretary Homsher:

Pursuant to Section 1308 of the Pennsylvania Public Utility Code, enclosed for filing on behalf of PECO Energy Company ("PECO" or the "Company") is a Certificate of Service evidencing filing of PECO's Tariff Electric — Pa. P.U.C. No. 9 ("Tariff No. 9"), which has been uploaded to the Secretary's SharePoint site due to its size. Tariff No. 9 sets forth proposed rates designed to produce an increase in the Company's annual distribution revenue of approximately $429 million based on data for a fully projected future test year ending December 31, 2027.

CONTENTS OF THE FILING

Tariff No. 9 contains revisions in, additions to, and deletions from certain Rules and Regulations, rate schedules, and riders in the Company's currently effective tariff. Tariff No. 9 also bears an issue date of March 30, 2026, and an effective date of May 29, 2026.

Along with Tariff No. 9, the Company is filing all the supporting data required by the Pennsylvania Public Utility Commission's ("PUC" or "Commission") regulations at 52 Pa. Code §§ 53.52 — 53.53, including the written direct testimony of twelve witnesses, who are

identified in PECO Statement No. 1, the Direct Testimony of Brendan J. Taylor. A summary of the reasons for the proposed rate increase is set forth in the Company's Statement of Specific Reasons for Proposed Increase in Electric Rates.

An index of the filing is included as Attachment A to this letter.

COUNSEL OF RECORD AND SERVICE ON THE COMPANY

PECO will be represented by the following counsel in this proceeding:

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PECO's attorneys are authorized to accept service on behalf of the Company in this proceeding. PECO requests that the Commission and all parties electronically serve copies of all documents in this proceeding on its attorneys.

USE OF ALTERNATIVE METHOD OF CUSTOMER NOTIFICATION

PECO hereby advises the Commission that it has elected to use the alternative method of customer notification set forth in the Commission's regulations at 52 Pa. Code § 53.45(b)(4). Consequently, as required by that regulation, PECO will notify its customers of the proposed rate increase through bill inserts along with paid advertisements in major local newspapers. PECO also agrees to extend from 60 to 90 days the minimum period within which the filing of a complaint places the burden of proof upon the Company with respect to proposed rates, pursuant to 52 Pa. Code § 53.45(b)(4)(vi).[1]

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[1] In addition, PECO is posting the filing to its website, https://www.peco.com/mv-account/my-dashboarcVrates-tariffs/filings, and issuing a news release describing the proposed changes to local newspapers and to local radio and television stations, pursuant to 52 Pa. Code § 53.45(b)(2)-(3).

REQUEST FOR CONFIDENTIAL TREATMENT OF PROPRIETARY INFORMATION

Certain Company responses to Commission filing requirements contain information that PECO considers to be proprietary and confidential. These materials have been marked ***Confidential*** and are being included in separate electronic files submitted to the Secretary's SharePoint site.

PECO requests that the copies of the materials that have been marked ***Confidential*** be treated confidentially by the Commission, including its various Offices and Bureaus. In particular, the Company requests that the ***Confidential*** material be excluded from the Commission's public document folder and not be disclosed to the public. PECO intends to request the entry of an appropriate Protective Order from the presiding Administrative Law Judge(s) to maintain the confidentiality of such material if it is to be provided to parties in this case.

CERTIFICATE OF SERVICE

As indicated on the attached Certificate of Service, the Company has served copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate. The Company is also providing courtesy copies of the filing to the Law Bureau (David E. Screven, Chief Counsel).

Respectfully submitted,



Brendan J. Taylor
Vice President
Regulatory Policy and Strategy

Enclosures

c: Certificate of Service (w/encls.)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY – ELECTRIC DIVISION	:	

CERTIFICATE OF SERVICE

I hereby certify and affirm that I have this day served a copy of **PECO Energy Company's General Base Rate Filing for Electric Operations** on the following persons in the manner specified in accordance with the requirements of 52 Pa. Code § 1.54:

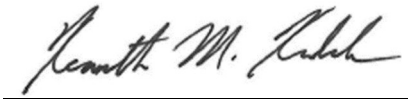
VIA OVERNIGHT MAIL

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Counsel for PECO Energy Company

Dated: March 30, 2026

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PECO ENERGY COMPANY 2026 ELECTRIC RATE CASE

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PECO Statement No. 1: Direct Testimony of Brendan J. Taylor

- **PECO Exhibit BJT-1: Regulatory Asset Rider Bill Impacts**
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PECO Statement No. 2: Direct Testimony of Jennifer Hanna

PECO Statement No. 3: Direct Testimony of Marissa E. Humphrey

- **PECO Exhibit MEH-1: PECO Energy Company Business Services Company Operations and Maintenance Costs**

PECO Statement No. 4: Direct Testimony of Michael J. Trzaska

- **PECO Exhibit MJT-1: Principal Accounting Exhibit – Fully Projected Future Test Year ending 2027**
- **PECO Exhibit MJT-2: Principal Accounting Exhibit – Future Test Year ending 2026**
- **PECO Exhibit MJT-3: Principal Accounting Exhibit – Historic Test Year ending 2025**
- **PECO Exhibit MJT-4: PECO Historical Storm Restoration Expense**

PECO Statement No. 5: Direct Testimony of John Coursey

PECO Statement No. 6: Direct Testimony of Mariana Hufford

- **PECO Exhibit MH-1: Annual Depreciation Accruals Related to Utility Plant in Service for 2025**
- **PECO Exhibit MH-2: Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2026**
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- **PECO Exhibit AEB-1 through AEB-13**

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- **PECO Exhibit JD-1: Summary of Results and Revenue Requirement by Rate Class**
- **PECO Exhibit JD-2: Total Class Allocation – Allocator Development**
- **PECO Exhibit JD-3: Revenue Requirement By Functional Classification**
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- **PECO Exhibit JAB-1: Proposed Revenue Allocation and Rates of Return by Class**
- **PECO Exhibit JAB-2: Electric Service Tariff (Blackline)**
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PECO Statement No. 10: Direct Testimony of Megan A. McDevitt

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Statement of Specific Reasons

PECO ENERGY COMPANY

STATEMENT OF SPECIFIC REASONS FOR PROPOSED INCREASE IN ELECTRIC RATES

I. Introduction

PECO Energy Company ("PECO" or the "Company") is requesting an annual overall electric rate increase of approximately $429 million. In accordance with Section 1308 of the Public Utility Code, the tariff setting forth the Company's proposed rates bears an effective date of May 29, 2026. PECO is also proposing two cost recovery mechanisms to support customer affordability, which will partially offset the proposed electric delivery increase by an $88 million revenue reduction in 2027. However, the Company anticipates that its requested increase will be suspended and investigated by the Pennsylvania Public Utility Commission (the "PUC" or the "Commission") and, therefore, the Company does not expect that new Commission-approved rates will become effective until approximately January 1, 2027.

PECO last filed for a rate increase in 2024. The principal reasons for the Company's proposed rate increase are to: (A) permit the Company to earn a fair return on the substantial investments used and useful in the Company's provision of safe and reliable electric service to customers; (B) support additional investments in utility infrastructure in accordance with the Company's Commission-approved infrastructure replacement program; (C) deploy new information technology to meet customers' expectations and drive operational improvements and efficiencies, while also working to keep rates affordable; and (D) recover higher operating expenses necessary to provide electric utility service, including increased costs of labor, contracting, and materials.

II. Reasons for the Requested Rate Increase

A. Fair return on the substantial investments used to provide safe, reliable, and resilient electric service to customers

PECO provides electric distribution service to approximately 1.7 million electric customers located throughout a 1,900-square-mile area in southeastern Pennsylvania. The Company's electric operations include thousands of miles of underground distribution cable, aerial distribution lines, and higher-voltage transmission lines. In addition, the Company operates and maintains 434 power substations. It takes considerable expertise, significant capital investment, and operations and maintenance ("O&M") activities to provide PECO's customers with safe and reliable service, as well as to ensure customers receive the experience and level of service they expect. PECO continuously strives to improve its system reliability, customer service, and service offerings to meet evolving customer expectations and needs.

In 2024, PECO reduced customer interruptions by nearly 1.1 million, with an estimated savings for customers of $495 million in avoided outages costs. In the same year, PECO operations supported 11,500 jobs and $6.9 billion in economic impact in the region. And, in 2026, despite the challenges posted by Winter Storm Fern in late January, a significant snow event in February, and more than 22 days of hazardous winds and cold temperatures, PECO delivered reliability performance well above Commission benchmarks.

Since rates were established in PECO's last rate case in 2024,[1] PECO has continued to make substantial investments in new and replacement utility plant to ensure that customers can continue to receive the safe and reliable service they have come to expect. Between January 1, 2026, and December 31, 2027 (the end of the fully projected future test year ("FPFTY") in this

[1] *PECO Energy Company General Base Rate Filing for Electric Operations*, Docket No. R-2024-3046931, filed on March 28, 2024.

filing), PECO will have invested over $2.8 billion in new and replacement electric distribution plant.

PECO's programs include a new Vegetation Strategic Reliability Improvement Initiative (the "Vegetation Strategic Initiative" or "Initiative"). This Initiative will establish a new foundation for vegetation management in targeted areas of PECO's service territory where vegetation has historically contributed to a disproportionate number of customer interruptions compared to the rest of the PECO system. By focusing enhanced, non-routine vegetation management activities in these locations and reducing vegetation to a new baseline condition, PECO will be better positioned to manage future growth more efficiently and deliver enhanced reliability. PECO also proposes a new residential battery storage program to study how residential solar systems and batteries can reduce costs for all customers by decreasing peak system load.

Even with PECO's effective control of costs below inflation, the Company's ability to make necessary, reasonable and prudent investments to continue to serve customers will be impaired without a rate increase. To mitigate the impact of a rate increase on customers' bills, PECO proposes two rate mechanisms to spread the costs of the Vegetation Strategic Initiative as well as the costs of PECO's existing Energy Efficiency & Conservation ("EE&C") program over time.

Absent a rate increase, the Company's overall rate of return at present rates is projected to be only 5.4% for the FPFTY, as shown in Schedule A-1 of PECO Exhibit MJT-1, the direct testimony of Mr. Michael J. Trzaska (PECO Statement No. 4). More importantly, the indicated return on common equity under present rates is anticipated to be only 5.94%, which is inadequate by any reasonable standard and far less than required to provide the Company with a reasonable opportunity to attract capital.

Without the requested rate relief, PECO's financial results would deteriorate even further in 2027 and thereafter. This would jeopardize the Company's ability to appropriately invest in the infrastructure needed to maintain and improve PECO's safety, reliability, and customer-service levels. A lack of rate relief would also have an adverse impact on PECO's credit-coverage ratios and negative implications with respect to maintaining the Company's current credit ratings, which would increase the Company's financing costs and, ultimately, costs to customers.

B. Support for Commission-approved infrastructure replacement

The majority of the Company's capital investments are made in coordination with the goals and requirements of PECO's Long-Term Infrastructure Improvement Plan ("LTIIP III"), which the Commission approved on December 18, 2025. In that proceeding, the Commission approved PECO's plans to spend $1.97 billion on targeted reliability projects to prevent storm-related outages, replace electric cable, and replace or retire substation equipment and small substations. These LTIIP investments are in addition to the capital spending associated with the Company's proposed rate increase but involve many of the same types of capital work. By aligning the Company's planned capital investments through the FPFTY and the Company's planned LTIIP expenditures, the Company can improve reliability and replace aging infrastructure more efficiently and at lower overall cost to customers.

C. Deployment of new information technology for grid modernization and customer service

PECO is making significant capital investments in information technology to drive operational improvements and efficiencies, reduce risk, and increase reliability. For instance, the Company is investing in its upgraded Advanced Distribution Management System to provide state-of-the-art, modernized tools to improve reliability, resiliency, and customer experience during storms; increase operational efficiency; and provide a coordinated platform for implementation

and deployment of the new operational capabilities that PECO's customers want the electric distribution system to provide. Information technology investments relating to customer operations and service include substantial improvements to the technology PECO customers use to access account and outage information; enroll in assistance and energy-saving programs; make start, stop, and move requests; receive usage data; and receive and pay bills.

D. Increased costs to provide public service

Continued investment in PECO's electric distribution system is needed to serve customers, but the cost of doing so has increased significantly. Indeed, sustained inflationary pressure has contributed to elevated interest rates, which have raised the cost of investment and led to increases in the Company's labor, contracting, and materials expense.

The Company has successfully mitigated the impact of these costs to the extent possible. PECO's projected annual O&M growth rate through the FPFTY is only 2.1% when adjusted for storms, bad debt, and pension expense (which are variable year to year and largely outside the Company's control) – nearly 20% lower than the projected 2.6% inflation increase in the Consumer Price Index over the same period. Notwithstanding PECO's effective cost-containment and management efforts, the Company continues to face significant cost increases in a variety of areas that are not within PECO's control.

In addition, even with increased efforts focused on vegetation management across PECO's system, costs associated with certain storms have resulted in higher costs for restoration and repairs, and weather events have been significantly more volatile. Such costs are very difficult to predict given the nature of storms. Therefore, PECO proposes a new Storm Reserve Account in this proceeding to enable PECO to recover its actual storm damages – neither more nor less – and ensure that customers are only paying for actual storm costs.

III. Management Performance

As set forth in the testimony accompanying this rate case filing, PECO has demonstrated superior management performance. The Company's efforts and accomplishments include:

Quality and Reliability of Service

- Outperforming the Commission's target levels for System Average Interruption Frequency Index, System Average Interruption Duration Index and Customer Average Interruption Duration Index.

- Installing new distribution system automation technology in 2024-2025 to avoid more than 2.1 million customer interruptions.

- Steady improvement in PECO's actual four-hour outage performance from 8.1% in 2021 to 6.9% in 2025, representing the Company's best performance over this period and exceeding the 2025 target of 7.1%.

Energy Efficiency and Customer Energy Savings

- Continuing PECO's award-winning Energy Efficiency and Conservation Program, now in its fifth year of its fourth phase (2021-2026) and saving PECO customers more than 1,233,900 MWh of energy in the first four years of the current program.

- As part of a settlement regarding PECO's Phase V Plan, beginning June 1, 2026, and pending Commission approval, increasing investments in comprehensive energy efficiency measures and improving coordination with external weatherization and usage reduction programs.

- Being recognized as an ENERGY STAR Partner of the Year Sustained Excellence award recipient, as well as an ENERGY STAR New Construction Market Leader Award recipient for the past five consecutive years in recognition of the Company's commitment to energy efficient new home construction.

Customer Service

- Ranking fourth out of 18 utilities in the J.D. Power East Large Region Electric Utility Residential Customer Satisfaction Study.

- Offering residential customers an electric vehicle registration rebate.

- Offering non-residential customers rebates for installing electric vehicle chargers.

- Deploying a Digital Solar Toolkit with an interactive viability map to facilitate customer solar applications and interconnections, as well as automating technical analyses for most solar applications.

Employee Safety

- Continuously improving performance and fostering a safety culture that engages the entire workforce to prevent accidents, injuries, and occupational illnesses.

Environmental Achievements

- Continuing to reduce greenhouse gas emissions from Company operations, with a reduction of approximately 59% from 2015 through 2025.

- Participating in the Edison Electric Institute's challenge to designate at least 5% of PECO's Electric Operations' annual vehicle spending for plug-in technology.

Promoting PECO's Communities and Diversity as well as Economic and Workforce Development

- In 2025, launching the Customer Relief Fund, a $10 million initiative designed to provide immediate bill assistance to limited and moderate-income households experiencing rising energy costs, and in 2026, adding an additional $2.5 million to further strengthen support to customers with the greatest need.

- Investing more than $38 million through corporate donations and employee giving campaigns (with corporate matching gifts) in hundreds of local and regional non-profit programs, organizations and institutions in Southeastern Pennsylvania that provide access to arts and culture, and support STEM education, the environment and green spaces, community vitality, workforce development, and reduction of gun violence.

- Supporting employees in volunteering nearly 26,140 hours of service across 393 nonprofit organizations.

- Along with other Exelon operating companies and the Exelon Foundation, creating a $36 million Community Equity Capital Fund to begin establishing access to capital for small businesses from under-resourced communities so that they can create more jobs, grow their companies, and reinvest in their neighborhoods and communities.

IV. Supporting Data

PECO is filing all the supporting data required by the Commission's regulations, including data for the historic test year ("HTY") ended December 31, 2025; the future test year ending December 31, 2026; and the FPFTY ending December 31, 2027. Because the Company is basing its claim principally on the level of operations for the FPFTY, the discussion that follows will address FPFTY data.

Rate Base. PECO's measures of value reflect the Company's balances of electric distribution plant on December 31, 2027, including common plant used in, and appropriately allocated to, electric distribution operations, as shown in Schedule C of PECO Exhibit MJT-1. The estimated original cost of gross plant on December 31, 2027, was developed by adding the estimated plant additions by account for 2026 and 2027 to, and subtracting the estimated plant retirements for 2026 and 2027 from, the estimated original cost of gross plant as of December 31, 2025. The estimated accumulated book reserve on December 31, 2027, was calculated in similar fashion. Specifically, the December 31, 2027 estimated accumulated depreciation was developed by: (1) adding the 2026 and 2027 estimated annual depreciation accruals to the actual accumulated depreciation by account as of January 1, 2026; (2) subtracting the estimated 2026 and 2027 plant retirements by account; and (3) adding 2026 and 2027 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The depreciated original cost of utility plant in service, cash working capital, pension asset, and materials and supplies were included in the determination of the measures of value, while accumulated deferred Federal income taxes, a 13-month average of customer advances, and a 13-month average of customer deposits were deducted from measures of value.

Operating Revenue and Expenses. The revenue and expense claims for the FPFTY have been prepared in accordance with the accepted practices of the Commission. Operating revenues at present rates were derived from budgeted revenues for PECO's electric operations for the 12 months ending December 31, 2027, and adjusted in the manner summarized on Schedule D-5 of PECO Exhibit MJT-1. Principal revenue adjustments include the removal of revenues related to portions of the Company's business that are not subject to the jurisdiction of the Commission, decreased revenues resulting from the implementation of Act 129 energy efficiency programs, the

removal of revenues billed under the surcharges (i.e., non-base rate revenue) that recover the cost of implementing the Company's energy efficiency and conservation programs pursuant to Act 129, the annualization of revenues for changes in the number of customers and the discounts provided to customers in PECO's Customer Assistance Plan, and increasing revenue to reflect a normalized annual service period containing 365.25 days.

Pro forma FPFTY operating expenses were developed from PECO's budget for electric operations for the 12 months ending December 31, 2027. Budgeted expenses were prepared based on the business activities and related cost categories of PECO's electric division (e.g., payroll, pensions, employee benefits, outside contracting costs). The expenses were distributed to the accounts identified in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts based on the expense distribution experienced by the Company during the HTY. The budget data, as distributed to FERC accounts, were annualized and/or normalized in accordance with established Commission ratemaking practices, and other appropriate adjustments were made, all of which are set forth in Schedule D of PECO Exhibit MJT-1. The necessary adjustments were made to the appropriate FERC accounts.

Annual depreciation expense for electric and common plant in service on December 31, 2027, was calculated using the remaining life method, which the Commission has previously approved for PECO's electric operations. PECO's claim for the estimated annualized depreciation accrual associated with electric plant in service on December 31, 2027, is set forth in Schedule D-17 of PECO Exhibit MJT-1 and is described by Mr. Trzaska. The manner in which PECO developed its claimed annual accrual is described in the direct testimony of Ms. Mariana Hufford (PECO Statement No. 6).

Income Taxes. Income taxes were calculated using procedures commonly accepted by the Commission. The interest expense deduction was synchronized with the Company's measures of value and claimed weighted-average cost of long-term debt. The normalization method was used to reflect the tax-book timing differences associated with the use of accelerated methods of tax depreciation to the extent permitted by the Commission and legal precedent. In addition, there are adjustments to other tax-book differences and flow-through amounts. The income tax expense claims for the FPFTY at present rate and proposed rate revenue levels are shown on PECO Exhibit MJT-1, Schedule D-18.

As is evident from the foregoing and the extensive supporting data filed by the Company, the proposed increase is just and reasonable and is the minimum increase necessary to enable the Company to earn a reasonable return on the fair value of its property that is used and useful in the public service, to maintain the integrity of its existing capital, and to attract new capital.

V. Rate Structure and Rate Design

As Mr. Joseph A. Bisti (PECO Statement No. 9) explains in his direct testimony, in developing its rate-structure proposal, the Company considered the results of a cost-of-service study performed by Ms. Jiang Ding (PECO Statement No. 8) in her direct testimony. While the cost-of-service study was used as a guide, the Company also considered the principle of gradualism that has traditionally been applied in Pennsylvania. Accordingly, the proposed rates were designed to mitigate the impact on each major rate class, to the extent practicable, while still making meaningful movement toward the system average rate of return.

PECO proposes certain changes in rate design, which include principally aligning fixed distribution/customer charges with, or closer to, customer-classified costs. Certain other changes in rate design and in the rules, regulations, and riders set forth in the Company's tariff are described in the direct testimony of Mr. Bisti and Ms. Megan A. McDevitt (PECO Statement No. 10).

VI. Cost Recovery Mechanisms to Support Customer Affordability

PECO proposes two rate mechanisms to spread the recovery of certain costs over time and help keep energy costs affordable. First, PECO is requesting to defer certain cost recovery relating to PECO's new Vegetation Strategic Initiative program for accounting and customer billing purposes. Second, PECO is requesting alternative ratemaking treatment for future costs relating to PECO's EE&C program. Both measures would mitigate the increases to customer bills and defer the recovery of costs to future rates.

With respect to the Initiative, PECO proposes a ratemaking mechanism under Section 1307 of the Public Utility Code to recover the costs of each year of the Initiative over a longer period. This approach will significantly reduce the amount customers pay in the short term, while allowing PECO to fully recover its costs over time, with a carrying charge. The details of the proposed Section 1307 mechanism are described in the direct testimony of Mr. Brendan J. Taylor (PECO Statement No. 1), and the associated tariff revisions are further described by Ms. McDevitt in her direct testimony.

In addition, PECO proposes to continue to recover its EE&C costs from all customers while also providing a credit (the "EE&C Regulatory Asset Rider") to reduce those costs in the near future. This approach would also significantly reduce the amount customers pay in the short term for the energy efficiency benefits delivered under EE&C programs, while allowing PECO to fully recover its costs over time, with a carrying charge. The details of the proposed EE&C Regulatory Asset Rider are described by Mr. Taylor in his direct testimony, and the associated tariff revisions are further described by Ms. McDevitt in her direct testimony. PECO seeks approval of the EE&C Regulatory Asset Rider under the provisions of Section 1330 of the Public Utility Code, which permits the Commission to approve alternative rate mechanisms.

VII. Conclusion

The requested increase in revenues is the minimum necessary to enable the Company to appropriately invest in the infrastructure needed to maintain and improve safety, reliability, and customer-service levels; to maintain the integrity of PECO's existing capital; to attract additional capital at reasonable costs; and to have an opportunity to achieve a fair rate of return on PECO's investment in property dedicated to public service, while keeping rates affordable. The Company's proposed revenue allocation and rate design are just, reasonable, and non-discriminatory. Accordingly, the Company's proposed rates, rules, and terms of service should be permitted to become effective as filed.

Plain Language Statement of Reasons

PLAIN LANGUAGE STATEMENT OF REASONS
FOR PECO ENERGY COMPANY'S
REQUEST TO INCREASE ELECTRIC RATES

PECO Energy Company ("PECO" or the "Company") has asked the Pennsylvania Public Utility Commission (the "PUC") for an annual overall electric rate increase of approximately $429 million. PECO is also proposing two cost recovery mechanisms to support customer affordability, which will partially offset the proposed electric delivery increase by an $88 million revenue reduction in 2027. Although the new rates are proposed to become effective on May 29, 2026, the Company expects that they will be suspended for investigation by the PUC until approximately January 1, 2027.

The main reasons PECO is asking for an increase in rates are:

- Between January 1, 2026, and December 31, 2027 (the end of the fully projected future test year in this case), PECO will have invested over $2.8 billion in additional electric distribution plant to ensure that customers can continue to receive safe and reliable electric service.

- PECO provides safe and reliable electric distribution service to 1.7 million customers and has one of the strongest reliability records among electric distribution companies in Pennsylvania. PECO last filed for an increase in electric base rates in 2024. Continued investment in PECO's electric distribution system is needed to serve customers, but the cost of doing so has increased significantly. During the last two years, inflation and interest rates have remained elevated, raising the cost of investment and increasing the Company's labor, contracting, and materials expense. The Company has actively worked to mitigate the impact of these increased costs to keep rates affordable, constraining controllable cost increases below the rate of inflation.

- Without the requested rate relief, the Company's financial results would deteriorate in 2027 and thereafter. This would jeopardize the Company's ability to appropriately invest in the infrastructure needed to maintain and improve its safety, reliability, and customer service levels. A lack of rate relief would also negatively affect PECO's ability to maintain its current credit ratings, which would increase its financing costs and, ultimately, costs to customers.

PECO is filing all the supporting data required by the PUC's regulations, as well as the written statements of 12 witnesses and numerous exhibits. The filing also includes a request for approval of two rate mechanisms to mitigate the impact of a rate increase on customers' bills and help keep energy costs affordable. First, PECO is requesting to defer certain cost recovery relating

to PECO's new Vegetation Strategic Reliability Improvement Initiative program for accounting and customer billing purposes. Second, PECO is requesting alternative ratemaking treatment for future costs relating to PECO's Energy Efficiency & Conservation program pursuant to 66 Pa. C.S. § 1330. Both measures would immediately reduce customer bills and defer the recovery of costs to future rates. All data and other information supporting PECO's rate increase have been prepared in ways that the PUC has approved in the past for PECO and other utilities.

In summary, the proposed increase in revenues is the minimum necessary to enable the Company to appropriately invest in the infrastructure needed to maintain and improve PECO's safety, reliability, and customer service levels.

Section 53.52 Filing Requirements

Q. 53.52.a-Elec

Whenever a public utility, other than a canal, turnpike, tunnel, bridge or wharf company files a tariff, revision or supplement effecting changes in the terms and conditions of service rendered or to be rendered, it shall submit to the Commission, with the tariff, revision or supplement, statements showing all of the following:

1. The specific reasons for each change.
2. The total number of the customers served by the utility.
3. A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.
4. The effect the change on the utility's customers.
5. The direct or indirect effect of the proposed change on the utility's revenue and expenses.
6. The effect of the change on the service rendered by the utility.
7. A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement about why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa. C.S. § 1308 (relating to voluntary\changes in rates).
8. Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa. C.S. § 1308.
9. Customer polls taken and other documents which indicate customer acceptance and desire for the proposed change. If the poll or other documents reveal discernible public opposition, an explanation of why the change is in the public interest shall be provided.
10. Plans the utility has for introducing or implementing the changes with respect to its ratepayers.
11. FCC, FERC or Commission orders or rulings applicable to the filing.

A. 53.52.a-Elec

1. The specific reasons for the rate changes are summarized in the Company's Statement of Reasons, which is included as part of the Company's filing, and are also discussed in the Direct Testimony of Brendan J. Taylor, PECO Statement No. 1.
2. The total number of electric customers on PECO's system as of December 31, 2025 is 1,710,217.
3. A breakdown of customers by tariff subdivision is provided below.

Rate	Customers
R	1,337,201
RH	204,769
GS	154,841
POL	2,184 (included in GS)
PD	372
HT	2,786
EP	5
SLS	257
SLE	952
SLC	14
TL	9,019
AL	1

4. Refer to PECO Statement No. 9, the Direct Testimony of Joseph A. Bisti and accompanying exhibits.
5. The proposed changes will increase total revenues to reflect the Company's revenue requirement, including increases in the Company's expenses. For details on specific changes, see the Direct Testimony of Michael J. Trzaska, PECO Statement No. 4 and accompanying exhibits.
6. No changes are expected in the service rendered by the Company. The proposed change will enable the Company to recover its costs and earn a fair return on its investment in used and useful property and, in that way, will facilitate the Company's on-going efforts to maintain and enhance its levels of safety, reliability and customer service.
7. The changes being made to rate design are discussed in the Direct Testimony of Joseph A. Bisti, PECO Statement No. 9. The Direct Testimony of Megan A. McDevitt, PECO Statement No. 10, discusses changes to Rules and Regulations, Rate Schedules,

Section 1307 surcharge mechanisms, and certain Riders that are set forth in the proposed tariff.

8. No studies were undertaken.
9. No customer polls were conducted.
10. The Company plans to implement the changes upon approval by the Commission. The methods of notification to the customers will include a press release, paid advertisements in major local newspapers, posting at PECO's Customer Solution Center, and a bill insert.
11. No FERC or Commission orders or rulings are directly applicable. To the extent that any FERC or Commission order or ruling may be relevant, it is discussed in the direct testimony submitted as part of the Company's filing.

Q. 53.52.b-Elec

Whenever a public utility, other than a canal, turnpike, tunnel, bridge, or wharf company, files a tarriff, revision or supplement, which will increase or decrease the bills to its customers, it shall submit in additon to the requirements of subsection (a), to the Commission, with the tariff, revision, or supplement, statements showing the following:

1. The specific reasons for increase or decrease.
2. The operating income statement of the utility for a 12-month period, the end of which may not be more than 120 days prior to the filing. Water and wastewater utilities with annual revenues under $100,000 and municipal corporations subject to Commission jurisdiction may provide operating income statements for a 12-month period, the end of which may not be more than 180 days prior to the filing.
3. A calculation of the number of customers, by tariff subdivision, whose bills will be increased.
4. A calculation of the total increases, in dollars, by tariff subdivision, projected to an annual basis.
5. A calculation of the number of customers, by tariff subdivision, whose bills will be decreased.
6. A calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.

A. 53.52.b-Elec

1. Refer to the Company's Statement of Reasons included with this filing.
2. Please refer to PECO Statement No. 4, the Direct Testimony of Michael J. Trzaska, and accompanying Exhibit MJT-3, Schedules B-2 through B-5.
3. Refer to PECO's response to 53.52(a)(3) for the number of customers whose bills will be increased.
4. Refer to PECO Statement No. 9, the Direct Testimony of Joseph A. Bisti, and Exhibits JAB-1 and JAB-3, for the requested information.
5. None.
6. None.

Q. 53.52.c-Elec

If a public utility files a tariff, revision or supplement which it is calculated with increase the bills of a customer or a group of customers by an amount, when projected to an annual basis, exceeding 3% of the operating revenues of the utility - subsection (b)(4) divided by the operating revenues of the utility for a 12-month period as defined in subsection (b)(2) - or which it is calculated will increase the bills 5% or more of the number of customers served by the utility - subsection (b)(3) divided by subsection (a)(2) - it shall submit to the Commission with the tariff, revision or supplement, in addition to the statements required by subsections (a) and (b), all of the following information:

1. A statement showing the utility's calculation of the rate of return or operating ratio (if the utility qualifies to use an operating ratio under § 53.54 (relating to small water and wastewater utilities)) earned in the 12-month period referred to in subsection (b)(2), and the anticipated rate of return or operating ratio to be earned when the tariff, revision or supplement becomes effective. The rate base used in this calculation shall be supported by summaries of original cost for the rate of return calculation. When an operating ratio is used in this calculation, it shall be supported by studies of margin above operation and maintenance expense plus depreciation as referred to in § 53.54(b)(2)(B).
2. A detailed balance sheet of the utility as of the close of the period referred to in subsection (b)(2).
3. A summary, by detailed plant accounts, of the book value of the property of the utility at the date of the balance sheet required by paragraph (2).
4. A statement showing the amount of the depreciation reserve, at the date of the balance sheet required by paragraph (2), applicable to the property, summarized as required by paragraph (3).
5. A statement of operating income, setting forth the operating revenues and expenses by detailed accounts for the 12-month period ending on the date of the balance sheet required by paragraph (2).
6. A brief description of a major change in the operating or financial condition of the utility occurring between the date of the balance

sheet required by paragraph (2) and the date of transmittal of the tariff, revision or supplement. As used in this paragraph, a major change is one which materially alters the operating or financial condition of the utility from that reflected in paragraphs (1) - (5).

A. 53.52.c-Elec

1. Refer to Exhibits MJT-1, MJT-2, and MTJ-3, Schedule A-1.
2. Refer to Exhibits MJT-1, MJT-2, and MTJ-3, Schedule B-1.
3. Refer to Exhibits MJT-1, MJT-2, and MTJ-3, Schedule C-2.
4. Refer to Exhibits MJT-1, MJT-2, and MJT-3, Schedule C-3.
5. Refer to Exhibits MJT-1, MJT-2, and MJT-3, Schedules B-2 to B-5.
6. There have been no major changes since the date of the balance sheet. Refer to PECO Statement No. 3, the Direct Testimony of Marissa E. Humphrey, for a discussion of the Company's financial condition.

The referenced exhibits and schedules provided in response to 53.52.c subparts 1. through 5. above are discussed in PECO Statement No. 4, the Direct Testimony of Michael J. Trzaska.

Customer Notice

peco℠
AN EXELON COMPANY

NOTICE OF PROPOSED ELECTRIC RATE CHANGES

To Our Customers:

PECO Energy Company ("PECO" or the "Company") is filing a request with the Pennsylvania Public Utility Commission (the "PUC") to increase your electric distribution rates as of May 29, 2026. This notice describes the Company's electric rate request, the PUC's role, and what actions you can take.

PECO has requested an annual overall electric distribution rate increase of approximately $429 million. PECO is also proposing to partially offset this increase by an $88 million revenue reduction, effective April 2027, that would be reflected in customer electric bills in 2027. The reduction would result from two proposed cost-recovery mechanisms including a request for approval of an EE&C Regulatory Asset Rider with a carrying charge in accordance with 66 Pa. C.S. § 1330 (relating to alternative ratemaking for utilities). If approved as filed, the two mechanisms spread certain costs over time, lowering delivery charges for customers in the near term.

If the Company's entire request is approved:

- The total monthly bill for a residential customer using 700 kWh would increase by $20.08 from $160.37 to $180.45 or by 12.5% in 2027, partially offset by $2.30 per month, or 1.3% effective April 2027, as a result of the two proposed cost recovery mechanisms.
- The total monthly bill for a commercial customer using 10,000 kWh would increase by $78.30 from $1,323.51 to $1,401.81 or by 5.9% in 2027, partially offset by $39.55 per month, or 2.8% effective April 2027, as a result of the two proposed cost recovery mechanisms.
- The total monthly bill for an industrial customer using 200,000 kWh would increase by $989.60 from $23,303.68 to $24,293.28 or by 4.2% in 2027, partially offset by $575.00 per month, or 2.4% effective April 2027, as a result of the two proposed cost recovery mechanisms.

To find out your customer class or how the requested increase may affect your electric bill, contact PECO at **1-800-494-4000**. The rates requested by the Company may be found in Electric Service Tariff No. 9. You may examine the material filed with the PUC, which explains the requested increase and the reasons for it. A copy of this material is kept at PECO's office. Upon request, the Company will send you the Statement of Specific Reasons for Proposed Increase in Electric Rates, explaining why the Company

(Over)

requested the rate increase. A copy can also be reviewed by visiting **https://www.peco.com/my-account/my-dashboard/rates-tariffs/filings**

The state agency which approves electric rates for public utilities is the PUC. The PUC will examine the requested electric rate increase and can prevent existing electric rates from changing until it investigates and/or holds hearings on the request. The Company must prove that the requested electric rates are reasonable. After examining the evidence, the PUC may grant all, some, or none of the request or may reduce existing electric rates. The PUC may change the amount of the electric rate increase or decrease requested by the utility for each customer class. As a result, the electric rate charged to you may be different than the electric rate requested by the Company and shown above.

There are three ways to challenge a Company's request to change its rates:

1. You can file a formal complaint. If you want a hearing before a judge, you must file a formal complaint. By filing a formal complaint, you assure yourself the opportunity to take part in hearings about the electric rate increase request. All complaints should be filed with the PUC before May 29, 2026. If no formal complaints are filed, the Commission may grant all, some or none of the request without holding a hearing before a judge.
2. You can send the PUC a letter telling why you object to the requested electric rate increase. Sometimes there is information in these letters that makes the PUC aware of problems with the Company's service or management. This information can be helpful when the PUC investigates the electric rate request.

Send your letter or request for a formal complaint form to the Pennsylvania Public Utility Commission, Post Office Box 3265, Harrisburg, PA 17105-3265.

3. You can be a witness at a public input hearing. Public input hearings are held if the Commission opens an investigation of the Company's electric rate increase request and if there is a large number of customers interested in the case. At these hearings you have the opportunity to present your views to the PUC judge hearing the case and the Company representatives. All testimony given "under oath" becomes part of the official electric rate case record. These hearings are normally held in the service area of the Company but may be held virtually.

For more information, call the PUC at **1-800-692-7380**. You may leave your name and address so you can be notified of any public input hearings that may be scheduled in this case.

PECO Verification

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Brendan J. Taylor, hereby declare that I am the Vice President of Regulatory Policy and Strategy of PECO Energy Company; that as such, I am authorized to make this verification on its behalf; that the facts set forth in the foregoing tariff filing are true to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa. C.S. § 4904 pertaining to false statements to authorities.



Dated: March 30, 2026

Brendan J. Taylor

PECO Exhibit 1:
PECO Electric Tariff No. 8 - Current

Supplement No. 22 to
ELECTRIC PA P.U.C NO. 8

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued January 15, 2026 **Effective March 1, 2026**

ISSUED BY: David M. Vahos – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 HOURLY– 5th Revised Page 40 - Reflects quarterly adjustments to the GSA 3/4 Hourly Procurement Class Pricing pursuant to the Order at Docket No. P-2024-3046008.

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LIST OF COMMUNITIES SERVED

PHILADELPHIA:

CITY AND COUNTY OF Philadelphia.

DELAWARE COUNTY:

CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colwyn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Haverford, Lower Chichester, Marple, Nether Providence, Radnor, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Birmingham, Chester, Concord, Edgmont, Middletown, Newtown, Thornbury, Upper Providence.

BUCKS COUNTY:

BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIPS: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, Wrightstown.

MONTGOMERY COUNTY:

BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Jenkintown, Lansdale, Narberth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Merion, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove.

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Merion, Upper Providence, Upper Salford, West Vincent, Whitemarsh, Whitpain, Worcester.

CHESTER COUNTY:

CITY: Coatesville.

BOROUGHS: Avondale, Downingtown, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, East Vincent, East Whiteland, Easttown, Elk, Franklin, Highland, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchland, Uwchland, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

YORK COUNTY:

BOROUGH: Delta.

SECOND CLASS TOWNSHIPS: Chanceford, Fawn, Lower Chanceford, Peach Bottom.

HOW TO USE LOOSE-LEAF TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page," consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No....," the second time as "Second Revised Page No....," etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example, if changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be Issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page it will be placed in the Tariff immediately following the page which it supersedes, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes Effective the page superseded should be removed from the Tariff.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

a.c. - alternating current

Advanced Meter - Advanced Meter shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Services - Advanced Meter Services shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Service Provider or AMSP - The Company or an EGS that provides Advanced Meter Services.

AEPS – Alternative Energy Portfolio Standard – statute that requires electric distribution companies and electric generation suppliers to acquire a certain percentage of their energy from alternative energy sources.

Available rate - A rate which may be obtained by a customer if the use of service conforms to the character of service contemplated in the rate, and the location is such that this service can be supplied from existing facilities of the Company.

Bad credit - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Base Rate (or rate) - The Base Rates are Rates R, R-H, RS-2, GS, PD, HT, POL, SL-S, SL-E, SL-C, TLCL, EP, and AL.

Billing demand - The calculated or measured demand after correction, if any, for power factor; except that the billing demand may be limited to a minimum figure.

Btu - British thermal unit.

Capacity charge - A charge based upon demand, either with or without power factor correction.

Competition Act - The Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and capacity provided by an Electric Generation Supplier.

Consolidated EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Consolidated EGS Billing - Billing provided by an EGS as provided for in Electric Generation Supplier Coordination Tariff.

Continuous service – Service which the Company endeavors to keep available at all times.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. For purposes of billing for an Electric Generation Supplier (as defined below), the term customer may include all meter locations for which a summary bill is provided. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules and Regulations, an EGS may act as agent for an end use customer upon written authorization to PECO Energy which may be part of the notice of EGS selection.

Customer's service extension - The facilities extending from the customer's service-receiving equipment to the Company's service supply lines.

Default Service (DS) - The provision of energy or energy and capacity by PECO Energy as Default Service Provider to customers that are: (1) not eligible to obtain Competitive Energy Supply, (2) choose not to obtain Competitive Energy Supply, (3) return to default service after having obtained Competitive Energy Supply or Competitive Default Service, or (4) who contract for Competitive Energy Supply from an EGS (as defined below) that fails to deliver such energy or energy and capacity.

Default Service Provider (DSP) – The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Demand - The maximum rate-of-use of energy during a specified time interval, expressed in kilowatts.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Direct Access - Direct Access shall have the meaning set forth in the Competition Act.

Electric Distribution Company (EDC) - Electric Distribution Company (EDC) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier (EGS) - Electric Generation Supplier (EGS) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier Coordination Tariff (or Supplier Tariff)- PECO Energy's Electric Generation Supplier Coordination Tariff, provides procedures for EGS & PECO EDC interaction to make arrangements necessary to implement Direct Access for retail customers.

Energy Supply Charge (Generation Charge) - PECO Energy's charge for energy or energy and capacity to customers that receive Default Service.

Energy charge - a charge based upon kilowatt-hours of use.

FERC - the Federal Energy Regulatory Commission.

Fixed Distribution Service Charge (Customer Charge) – A charge to recover costs caused by the presence of the customer on the system other than the costs associated with the customer's demand or energy consumption.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas Day and Sundays.

Hp, horsepower - As used herein, horsepower shall be computed as the equivalent of 750 watts.

Initial Contract Term - An initial contract term for a service location shall be 1) the customer's first Term of Contract for service to the location or 2) the first Term of Contract after the customer changes service for a location to a different Rate.

Interest Index – An annual interest rate determined by the average of one-year Treasury Bills for September, October and November of the previous year.

KV, kilovolts - 1000 volts.

KVA, kilovoltampere - Unit of measurement of rate-of-use, which determines electrical capacity, required; it is obtained by multiplying the voltage of a circuit by its amperage.

KW, kilowatt - Unit of measurement of useful power.

KWh, kilowatt-hour - Unit of measurement of energy; an amount equivalent to the use of one kilowatt for one hour.

Lumen - Unit of measurement of quantity of light.

Measured Demand - A customer's highest demand during a 30-minute time interval in a billing period.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

PaPUC or Commission - The Pennsylvania Public Utility Commission.

PECO Energy or the Company - PECO Energy Company.

Point of Delivery - The single service point at which the service-supply lines of the Company terminate and the customer's facilities for receiving the service begin.

PJM - PJM shall mean the PJM Interconnection, L.L.C.

PJM System - PJM System shall mean the transmission facilities located in the Mid-Atlantic Region that are controlled by PJM.

Power Factor - As used herein, power factor is, in a single-phase circuit, the ratio of the watts to the voltamperes, and in a polyphase circuit, is the ratio of the total watts to the vector sum of the volt-amperes in the several phases.

Principal Office – The Company's Main Office Building is located at 2301 Market Street, Philadelphia, Pa. 19103.

Property Line - The division line between land held in or for private use, and land in which the public or the Company has a right of use; or, the division line between separately owned or occupied land.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Separate EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Separate EGS Billing - Billing provided by an EGS as provided for in the Electric Generation Supplier Coordination Tariff.

Service - The distribution of energy for use by the customer, including all things done by the Company in connection with such distribution. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

- standard single-phase secondary: alternating current, 60 hertz, in accordance with Tariff Rule 2.5 (Single-Phase Up To 150 kVA:

  (a) nominally 120/240 volts, 3 wires;
  (b) nominally 120 volts, 2 wires to installations consisting of not more than two 15-ampere branch circuits;
  (c) nominally 120/208 volts, 3 wires, for residential service, where available in conjunction with standard polyphase secondary 120/208 volts, 3-phase, 4 wires.

- standard polyphase secondary; alternating current, 60 hertz. Only one service is available to a building. However, the Company will provide standard service to customer premises containing multiple buildings in accordance with Tariff Rule 2.2 (Single-Point Delivery). For purposes of determining service capacity and parallel-generating capacity limits, a building is defined as a structure, separated from other structures, or a portion of a contiguous structure separated from the remainder of the structure by approved firewalls. When demand or service voltage requires the installation of transformation equipment on the owner's premises, the transformation shall consist of a pad mounted transformer installed at a location provided by the owner and approved by the Company outside the building or a transformer bank installed inside the building in a vault located on the ground floor or one story below grade, meeting National Electrical Code requirements. The Company will not install, own or maintain any conductors inside or beneath a building nor install indoor transformation in areas supplied by or designated to be supplied at 33,000 volts or greater.
  (a) nominally 120/240 volts, 2-phase, 5 wires; only available in areas supplied by 2-phase distribution facilities located along public highways or private rights-of-way and limited to service capacities of 100 kVA or less;
  (b) nominally 240 volts, 3-phase, 3 wires; a fourth wire neutral will be extended for the supply of 120/240 volt single-phase equipment in combination with the service where neither the service capacity required nor the parallel-generating capacity required exceeds 15 kVA on any one of the phases. Where the demand to a single premises exceeds 100 kVA, transformers will be installed on the premises at a suitable location provided by the owner. The service capacity and the parallel-generating capacity are both limited to 300 kVA for transformers located inside the building and 500 kVA for transformers located outside the building.
  (c) nominally 120/208 volts, 3-phase, 4 wires, (where 3-phase distribution is available) for the exclusive supply of secondary service to a building or group of contiguous buildings occupied by one or more than one customer, with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located either inside or outside the building. When either exceeds 750 kVA for transformers located inside the building the only rate option available to the customer will be Rate HT. When either exceeds 750 kVA but remains at or below 1,500 kVA for transformers located outside of the building, the customer can request service at 277/480 volts, 3-phase 4-wires from transformers located outside of the building. Otherwise, the only rate option available to the customer will be Rate HT. When a suitable transformer location is not reasonably available on the premises and the demand does not exceed 100 kVA, service may be supplied at the Company's discretion from aerial distribution facilities located along public highways.
  (d) nominally 277/480 volts, 3-phase, 4 wires (where 3-phase distribution is available) for the exclusive supply of secondary service to a building occupied by one or more than one customer with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located inside the building and 1,500 kVA for transformers located outside the building. If either exceeds these limits the only rate option available to the customer will be Rate HT.

- standard primary - unregulated alternating current, 60 hertz, nominally 2,400 volts, 2-phase, 3 wires, or nominally 4,160 volts, 3-phase, 3 or 4 wires. Availability of these voltages is limited to those locations served at these voltages as of July 6, 1987.

- standard high tension - unregulated alternating current, 60 hertz, nominally 13,200, 33,000, 69,000, 138,000, or 230,000 volts, 3-phase, 3 or 4 wires (4-wire, 13 kV service is available in areas that have been converted to 13 kV distribution):

Where two or more such standard voltages are present in a given area, the Company will select the service voltage at which the required service can be supplied most economically. Nominally 13,200, 33,000, 69,000, 138,000 or 230,000 volts as available in the various sections of the Company's service territory for loads of such character as to require supply at one of such voltages in order not to impose unsatisfactory service conditions on the Company's supply system, or for loads of such character that supply at one of such voltages is desired both by the Company and the customer. For service at 13,200 or 33,000 volts, where the customer's demand exceeds 7,000 kW, the owner may be required to provide a suitable location on the premises for the installation of Company's transformation equipment.

The Company's charges for service, which are comprised of the Fixed Distribution Service Charge and Variable Distribution Service Charge, are non-bypassable and must be paid by any customer regardless of the voltage level at which the customer is served.

Service-supply lines - The facilities (conductors, cables, conduits, etc.) extending from the Company's facilities in the highway or other trunk line location to the facilities owned and maintained by the customer.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Summary Billing Account - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same partnership, association, corporation, or governmental agency etc. for: (1) the Company's charges for service; and/or (2) an EGS's charges for Competitive Energy Supply, as permitted by Rule 2.2.

Tariff - this Electric Service Tariff comprising the Base Rates, rules and regulations which in conjunction with Pennsylvania Public Utility Law and Pennsylvania Public Utility Commission Regulations govern the distribution of electric energy including all things done by the Company in connection with such distribution, and/or the supply of electric energy under Default Service, and other PaPUC jurisdictional services.

Variable Distribution Service Charge (Distribution Charge) - the variable supply charges for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

RULES AND REGULATIONS

1. THE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and Default Service will be provided to its customers by PECO Energy, is on file with the Commission and is posted and open to

inspection at the Principal Office of the Company. A copy of this tariff is also available on the Company's website at http://www.peco.com.

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and the recipient of service, whether service is based upon contract, agreement, accepted signed application, or otherwise, shall be subject to the terms of the Tariff. In addition, the rates therein shall apply to everyone receiving service unlawfully or otherwise, including unauthorized use as referred to in Rule 4.7 of this Tariff. A customer will receive service under the rates and riders of this tariff effective with their first scheduled billing cycle after the effective date of the tariff or as otherwise indicated in this tariff.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service supply and will be adjusted for application to service supplied during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provisions. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the supply of service under a particular Base Rate may be modified or amended only by the application of those standard riders, filed as part of this Tariff, which are specifically mentioned as applicable to that rate in the Applicability Index of Riders.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

2. SERVICE LIMITATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of electric energy of the standard characteristics available in the locality in which the premises to be served are situated. The Company does not offer to distribute and/or supply electric energy of nonstandard characteristics.

2.2 SINGLE-POINT DELIVERY The Company will provide standard distribution and/or supply through a single delivery and metering point for the total requirements at each separate premises of any person, partnership, association, or corporation, lawfully receiving service, except where, in the Company's sole judgment, special conditions warrant the installation of additional facilities. Unless otherwise stated herein, the Base Rates in this Tariff for each class of service are based upon that standard. Separate distribution and/or supply for the same customer at other points of consumption shall be separately metered and billed, except that: (1) when the Company is providing Consolidated EDC Billing, the Company will provide summary billing of its charges for and/or an EGS' charges (if requested by the EGS) for Competitive Energy Supply; and (2) when the Company is providing Separate EDC Billing, the Company will provide summary billing of its charges.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

(a) Such buildings or units are:
(1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and
(2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and
(3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

(b) There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

RULES AND REGULATIONS (continued)

(c) The transforming, receiving and distribution facilities on the customer's side of the delivery point, are:
(1) furnished, installed and maintained at the expense of the customer, and
(2) owned or leased by the customer, and
(3) operated and controlled by or at the expense of the customer.
(d) The Company is under no legal obligation of direct supply to any portion of said building or units or their appurtenances.
(e) A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in primary, secondary and/or distribution investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.
(f) All utilization equipment on the customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the building or units supplied or by the tenants of such operator whose use of electricity is dependent upon the single-point delivery and metering of service.
(g) Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the applicable Base Rate and/or riders.

2.5 SINGLE-PHASE UP TO 150 KVA. Single-phase secondary service is available for customer equipment with demand of or parallel-generation facilities having an aggregate nameplate rating up to 150 kVA. Any customer demand or generation equipment in excess of this amount will be supplied polyphase service. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

2.6 POLYPHASE LOADS AGGREGATING LESS THAN 7-1/2 HP. Polyphase service is not available for installations aggregating less than 7-1/2 horsepower, unless the excess cost of supplying polyphase rather a single-phase service is borne by the customer.

2.7 MOTORS. Service is not available to motors which do not meet the Company's standard requirements.

2.8 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Before receiving any electric service to or for new or renovated residential buildings or additions thereto, as defined by Pennsylvania Building Energy Conservation Act (BECA) as amended by Act 98 of 1985, applicants for service must provide the Company with the compliance certification copy of the Pennsylvania Department of Community Affairs (DCA) "Notice of Intent to Construct" form as processed by DCA. A compliance certification copy of "Notice of Intent to Construct" will not be required by the Company if the new or renovated residential building is located in a municipality which has elected to administer the BECA and requires that a notice of intent to construct be filed with the municipality before or at the time that application is made for a building permit and the notice has, in fact, been filed.

3. CUSTOMER INSTALLATION

3.1 INFORMATION FROM THE CUSTOMER. The Company should be advised by the customer or applicant for service, in writing, preferably on a form supplied by the Company, of premises to be equipped for service, giving exact location, and details of all current consuming devices to be installed.

The customer shall supply the Company any and all information in its possession regarding potential or actual contamination, waste or hazardous materials or other adverse environmental conditions on the customers' premises on or near where the Company facilities are to be located. The customer has a continuing obligation to provide the Company with such information relating to the premises as the customer receives it. The Company also has a continuing right to inspect the customers' premises for the purposes of performing an environmental assessment.

3.2 METER LOCATION. There shall be provided, free of expenses to the Company, at a location outdoors, unless otherwise designated by the Company or another AMSP, which the Company or another AMSP will designate in writing upon request, a suitable place for the meter or meters and any other supply, protective or control equipment of the Company or another AMSP which may be required in the provision of service. The customer shall provide access and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company's employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company's ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location shall also be situated so that the meter(s) are not concealed but shall be situated in a fashion acceptable to the Company.

3.3 POINT OF DELIVERY. The Company will designate in writing, upon request, a satisfactory point of delivery where the customer shall terminate the wiring and facilities for connection to the distribution lines of the Company. The failure to request and obtain such location may result in refusal of service pending rearrangement of customer's facilities, but the designation of a point of delivery does not constitute an agreement or obligation on the part of the Company to furnish service.

In establishing a point of delivery, the Company has the right to avoid areas known or suspected to contain contamination, waste or hazardous materials or other adverse environmental conditions. The customer will have the option of extending its own facilities to the

Company's point of service delivery.

The Company may waive this right of avoidance upon agreement by the customer or applicant to indemnify, defend, and hold harmless the Company (its successors, assigns, trustees, officers, employees and agents) from and against all actions, causes of action, claims and demands whatsoever, and from all costs, damages, expenses, losses, charges, debts and liabilities whatsoever

RULES AND REGULATIONS (continued)

(including attorney's fees), whether known or unknown, present or future, that arise from such conditions. This indemnification provision shall survive the termination or expiration of said agreement and the termination of the business relationship of the parties thereto.

3.4 SERVICE ENTRANCE EQUIPMENT. All equipment beyond the point of delivery, except the meter, shall be installed by the customer. Installation shall be in conformity with the National Electrical Code and the Company's published "Electric Service Requirements", and shall include, where necessary, an approved sealable device for mounting a meter. The meter will be supplied, owned and sealed by the Company or another AMSP.

3.5 SECONDARY SERVICE CONNECTION. (a) Wiring of any premises for connection to overhead lines must be brought outside of the building wall to a location designated or approved by the Company, at which point the house wiring must extend at least 3 feet for attachment to the Company's service-supply lines. (b) Service connections to the Company's underground facilities shall terminate on the customer's premises in an approved connection box from which customer's wiring shall extend to the other service entrance equipment.

3.6 UNDERGROUND SERVICE. Customers desiring an underground service from overhead wires must bear the excess cost incident thereto. Specifications and terms for such construction will be furnished by the Company on request.

3.7 NONSTANDARD SERVICE. The customer or applicant for service shall pay the cost of any special installation necessary to meet the unusual requirements of the customer or applicant for service, including but not limited to: (1) service at other than standard voltages, (2) service for loads that will be intermittent and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (3) service for loads that will be continuous but that will generate minimal usage, and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (4) service for loads that will require provision of closer voltage regulation than required by standard service, and (5) situations for which, in the Company's sole judgment, extenuating circumstances exist whereby the Company agrees to provide multiple services, which are not normally offered in other sections of the Tariff, to one customer located on a premises.

The customer or applicant shall pay all costs to the Company of performing environmental assessments, including, but not limited to, the cost of consultants utilized by the Company, the cost of removal and disposal of contamination, waste or hazardous materials or dealing with other adverse environmental conditions associated with either the initial installation, modification, repair, maintenance or removal of service facilities.

3.8 RELAY PROTECTION. The customer must install at the customer's own expense a reverse-phase relay of approved type on all alternating current motors for passenger and freight elevators, hoists, and cranes, and a reverse-power relay for parallel operation.

4. APPLICATION FOR SERVICE

4.1 METHOD OF APPLICATION. Customers may apply for service via the Company's website at http://www.peco.com or, in some cases, over the telephone. **(C)**

4.2 SERVICE CONTRACT. Every applicant for service may be required to sign a contract, agreement, or other form then in use by the Company, covering the special circumstances of the use of service, and shall abide by these Rules and Regulations and the standard requirements of the Company including but not limited to those in PECO's Electric Service Requirements Manual ("Blue Book") Builder's Handbook, Interconnection Guidelines and other additional requirements that PECO will provide upon request.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service: not available under a standard rate; which might affect service to other customers; which is to be delivered at a location or at a standard voltage that involves excessive cost; for bad credit; for the applicant's failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customers cannot be denied Default Service or new service for failure to pay an EGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contamination, waste or hazardous materials or other adverse environmental conditions.

4.5 ACCEPTANCE. Before the Company affirmatively accepts an application, the Company will consider the application to be "pending". When an application is accepted, it constitutes the contract between the customer and the Company, subject to the Rules and Regulations. A customer or other recipient of service also becomes contractually obliged to the Company when service is provided according to the application either with or without modification, or when the customer otherwise receives service.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

(C) Denotes Change

RULES AND REGULATIONS (continued)

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company. The use of service without notifying the Company or the AMSP and enabling them to read its meter will render the user liable for any amount due for service provided to the premises from the time of the last reading of the meter, immediately preceding the customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION. In the event the customer (or potential customer) withdraws an application for either new or modified service, the customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of providing the new or modified service.

5. CREDIT

5.1 PAYMENT OBLIGATION. For customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing, the provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff (and, for the same class of service (residential or non-residential) under the Company's Gas Service Tariff, if the customer also receives gas service at the same premises) as applicable to the location and the character of service.

The Company may, at its discretion, determine liability for a past due balance by:

1) Use of Company records that contain information previously provided to the Company;
2) Information contained on a valid mortgage, lease, deed or renter's license;
3) Use of commercially available public records databases;
4) Government and property ownership records.

5.2 PRIOR DEBTS. Service will not be furnished to former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers for which it may provide Consolidated EDC Billing or Separate EDC Billing to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers, the deposit will be equal to one-sixth of the applicant's or customer's estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule.

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RULES AND REGULATIONS (continued)

5.5 RETURN OF DEPOSIT. Deposits secured from a residential customer shall either be applied with interest to the customer's account or returned to the customer with interest in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations. In cases of discontinuance or termination of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Deposits secured from a residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 12 consecutive months. Deposits secured from a non-residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 24 consecutive months. Any residential or commercial customer /having secured the return of the deposit may be required to make another deposit in accordance with Commission statutes, regulations or Federal Bankruptcy Law if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(A) with respect to residential accounts, interest, will be computed at the simple annual rate determined by the Secretary of Revenue for interest on the underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as the Fiscal Code

(B) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent;

Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus; (2) determination of liability for a past due balance; (3) determination if a deposit is required based upon applicant's previous account history if available or through third party credit scoring of applicant. **(C)**

The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

5.8 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of this Rule 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers.

6. PRIVATE PROPERTY CONSTRUCTION

6.1 COMPANY'S SERVICE LINES. Where the Company has distribution facilities of adequate capacity on the highway or in other trunk line location adjacent to the premises to be served, it will provide, own and maintain standard service-supply lines as follows:

(a) UNDERGROUND:

Underground cable construction to a point of delivery approximately 18 inches inside the property line of the customer, except:

(1) For secondary service to new residences or new apartment buildings, underground cable construction will be extended to a meter location or connection box located at the building or buildings, as designated by the Company and in accordance with Rule 7.3.

(2) The Company will make necessary repairs to customer-owned extensions of primary and secondary underground service-supply lines for residential customers at no charge. If such customer-owned extension requires replacement, the Company will make the replacement and assume ownership of the service-supply line with the Company bearing the cost up to 200 feet in length and the customer bearing the cost for all additional length.

(b) AERIAL:

A single span of aerial open wire or cable construction to the first suitable support of the customer, nominally 100 feet inside the property line of the customer. This customer support shall establish the point of delivery for the customer. The customer's support shall be so located that the service span will be free of obstruction and adequately supported as required by the size and weight of the conductors.

6.2 SERVICE - SUPPLY ALTERATIONS. Changes related to a service-supply line or a meter owned by the Company, including the installation of protective devices or visual markers to denote safe operating distance from the Company's facilities, for the accommodation of the customer, shall be at the expense of the customer. If the alteration to the Company's facilities is temporary in nature and the materials used in that alteration can later by re-used by the Company, as for example the installation of protective "hard cover" to allow a customer, developer, or contractor to work safely in close proximity to the Company's facilities, then at the Company's discretion it may charge a refundable deposit in lieu of charging the customer for the cost of the re-usable materials.

6.3 CUSTOMER'S SERVICE EXTENSION. The customer shall provide, own, inspect and maintain the service extension from the Company's service-supply lines to the point of delivery and receiving equipment. PECO may install a Company-owned meter, transformer (which transformer may serve one or more customers), or other required equipment, of its choice, on customer-owned property or facilities; Such installation does not alter the responsibility of the customer to provide, own, inspect, and maintain the required customer service extension to which such Company-owned facilities may be attached.

6.4 METERS AND TRANSFORMERS. The Company will provide, own and maintain any meter or meters, and also the transformer or transformers (both potential and current type transformers), required in the supply of service of the current characteristics specified by the Base Rate or rider under which the service is provided, unless the customer receives Advanced Meter Services from an AMSP in that case such AMSP will install, provide, own, and/or maintain the Customer's meter or meters while the Company will continue to own the potential and current type transformers. The supply of transformers by the Company shall be limited to those required for a single standard transformation.

(C) Denotes Change

RULES AND REGULATIONS (continued)

6.5 TRAILER PARKS. Where it is established by plans, development, use or other facts that the operation of a trailer park is predominantly to provide rental locations for non-transient trailers, with not less than two nor more than four such locations, the Company, upon written application of the trailer park operator and upon the receipt of an enabling agreement and of adequate rights-of-way, will construct, own and operate within the trailer park specified aerial electric energy, the trailer park operator being liable for payment of service to trailer park tenants not contracting in writing for service in their own names. The Company's obligation to install or extend such distribution facilities within the trailer park is limited to the investment warranted by the anticipated revenue. Alterations of such distribution facilities at the request of the park operator when not for the purpose of serving additional trailer rental locations will be at the cost of the trailer park operator. A trailer park operator desiring underground distribution facilities within a trailer park consisting of less than five locations must bear the excess cost incident thereto. Specifications and terms for such underground construction will be furnished by the Company on request. In new trailer parks consisting of five or more locations, underground distribution facilities will be extended in accordance with Rule 7.3.

RULES AND REGULATIONS (continued)

7. EXTENSIONS

7.1 TRUNK LINE CONSTRUCTION. The Company will construct, own and maintain overhead or underground distribution facilities, either secondary, primary, or high tension, located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general distribution system.

7.2 LINE EXTENSIONS FOR STANDARD SERVICE.

A. DEFINITIONS. For the purposes of this rule, when capitalized herein, the below terms shall have the following meanings:

(1) Line Extension -- A single-phase or polyphase addition to the public utility electric supply line for the purpose of supplying standard service (as described under Rule 2 above, but not including Line Extensions for nonstandard service as described in Rule 3.7 above) to and connected with the customer's point of delivery which addition is so located that it cannot be supplied by means of a service line from the existing electric supply line.

(2) Contractor Cost -- The amount paid by the Company to a contractor for work performed on a Line Extension.

(3) Customer -- End use customer of the Company, or a developer.

(4) Direct Labor Cost -- The pay and expenses of the Company employees directly attributable to work performed on Line Extensions, but not including construction overheads or payroll taxes, workmen's compensation expenses or similar indirect expenses.

(5) Direct Material Cost -- The purchase price of materials used for a Line Extension, but not including related storage expenses. In computing Direct Material Costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(6) Total Construction Cost -- For single-phase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, and Direct Material Cost. For polyphase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, Direct Material Cost and allocated overheads. For projects requiring significant design work, the Company will provide a preliminary cost estimate and charge customers a non-refundable deposit of 10% of the total estimated costs to fund the detailed design work. The detailed design work cost will not be included in the Total Construction Cost of the Line Extension used to determine contribution in aid of construction ("CIAC").

(7) Capacity Adjusted Cost -- For polyphase Line Extensions, the Total Construction Cost of a Line Extension multiplied by the percentage of that Line Extension's capacity installed to serve the Customer's capacity needs.

(8) Revenue Guarantee Contribution -- The estimated Variable Distribution Service Charges, as defined in the "Definitions of Terms and Explanation of Abbreviations" Section of this tariff, to be received by the Company from the Customer for a twelve (12) month period commencing with the first month after the Line Extension is completed.

B. SINGLE-PHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a single-phase Line Extension as follows. The Company will construct a Line Extension up to 2,500 feet without a charge to the Customer. For Line Extensions over 2,500 feet, a Customer shall pay the Company a contribution in aid of construction ("CIAC") equal to the amount by which the Total Construction Cost of the Line Extension beyond 2,500 feet exceeds the Customer's Revenue Guarantee Contribution for the first three (3) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the single-phase Line Extension.

C. POLYPHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a polyphase Line Extension, as follows. A Customer must pay the Company a CIAC equal to the amount by which the Capacity Adjusted Cost of the Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the polyphase Line Extension.

D. DEVELOPERS. Prior to the construction of any Line Extension, a developer may, in lieu of paying the full CIAC, pay a minimum of 35 percent (35%) of the CIAC and, for the remaining amount, post a surety bond in a form reasonably acceptable to the Company. The unpaid portion of the CIAC is subject to interest at the then applicable prime rate and is payable no later than twelve (12) months from the date of the initial payment.

RULES AND REGULATIONS (continued)

E. SPECULATIVE LINE EXTENSIONS. A Line Extension is speculative when, in the Company's reasonable opinion there is doubt: (1) as to the continued use, or the level of use, of the new Line Extension by the Customer; or (2) as to the Company's recovery of the Total Construction Cost for a polyphase Line Extension if a Capacity Adjusted Cost is applied.

Under the first scenario of a speculative Line Extension, the Company will construct the Line Extension for a Customer, as follows: pursuant to an individual contract between the Customer and the Company, in addition to any CIAC, the Customer may be required to provide the Company a customer advance in the form of an up-front payment, or, if mutually agreed to by the Customer and the Company, a surety bond in the amount of the Customer's Revenue Guarantee Contribution used in the CIAC calculation as set forth in Part B or C above, as applicable ("Customer Advance"). If, after three (3) years for a single-phase Line Extension, or five (5) years for a polyphase Line Extension, the Customer's Variable Distribution Service Charges have met or exceeded the Customer Advance, the Company will either: (1) return the Customer Advance to the Customer if an up-front payment has been made; or (2) terminate the Customer's obligation to maintain the surety bond.

Under the second scenario of a speculative Line Extension, the Company will construct a polyphase Line Extension for a Customer, as follows: the Customer must pay the Company a CIAC equal to the amount by which the Total Construction Cost of the polyphase Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. The Customer may receive a refund of all or part of the CIAC paid if, during that five (5) year period, additional Customers have connected to the Line Extension for which the Customer paid the CIAC. The refund, if any, will be calculated based on the load of the connecting Customers.

7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS.

A. For the purposes of this rule, and in accordance with 52 Pa. Code § 57.81, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

1. Applicant For Electric Service - The developer of: a recorded plot plan consisting of five or more lots; or one or more five-unit apartment houses.
2. Developer - The party responsible for construction and providing improvements in a development; that is, streets, sidewalks, and utility-ready lots.
3. Development - A planned project which is developed by a developer/applicant for electric service set out in a recorded plot plan of five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, mobile homes, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.
4. Distribution Line - An electric supply line of untransformed voltage from which energy is delivered to one or more service lines.
5. Service Line - An electric supply line of transformed voltage from which service is delivered to the residence.
6. Subdivision - A tract of land divided by a subdivider into five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.

RULES AND REGULATIONS (continued)

B. INSTALLATION OF DISTRIBUTION AND SERVICE LINES. All distribution and service lines installed pursuant to an application for electric service within a development will be installed underground, and will be owned and maintained by the Company. Pad-mounted transformers may be installed at the option of the Company. Excavating and backfilling will be performed by the developer of the project or by such other agent as the developer may authorize. The developer or its agent may also for the purpose of reducing civil work costs, install conduit for the Company's use in installing electrical service, if the conduit and associated excavation work meets PECO's requirements. The Company will then assume ownership of such conduit. Installation of service-related facilities will be performed by the Company or by such other agent as the Company may also be installed underground, upon terms and conditions prescribed elsewhere in this tariff. The Company will not be liable for injury or damage occasioned by the willful or negligent excavation breakage, or other interference with its underground lines occasioned by anyone other than its own employees or agents.

Nothing in this section shall prohibit the Company from performing its own excavating and backfilling for greater system design flexibility. However, no charges other than those specified in Section 57.83(4) of Title 52 shall be permitted.

C. APPLICANTS FOR SERVICE. The applicant for service to a development shall conform with the following:

(1) At its own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-lighting lines and related facilities.

(2) At its own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation will consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant will follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the applicant's excavating and backfilling, such excavating and backfilling will be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse utility service until such standards and specifications are met.

(3) Request service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with any other utility sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary costs and delay.

(4) Pay to the Company any necessary and additional costs incurred by the Company as a result of the following:

a) Installation of underground facilities that deviate from the Company's underground construction standards and specifications if such deviation is requested by the applicant for electric service and is acceptable to the Company.
b) A change in the plot plan by the applicant for electric service after the Company has completed engineering for the project and/or has commenced installation of its facilities.
c) Physical characteristics such as oversized lots or lots with extreme set-back where under the Company's line extension policy contained in this tariff a change is mandated for overhead service.

(5) No charges other than those described in paragraph (4) of this subsection shall be borne by the applicant for electric service or by any other utility sharing the same trench, even if the Company elects to perform its own excavating and backfilling.

D. APPLICABILITY. The provisions of this rule will apply to all applications for service to developments, herein before defined, which are filed after the effective date of this tariff.

E. SUBDIVISIONS. Underground facilities in new residential developments are only required by Sections 57.81 through 57.87 of Title 52 when a bona fide developer exists, i.e., only when utility-ready lots are provided by the developer. A mere subdivision is not required to have underground service. However, should the lot owner or owners in a subdivision desire underground service, such service shall be provided by the Company if such lot owner or owners, at their option, either comply with Section 57.83 of title 52, or pay to the Company such charges as are contained in the Company's tariff for service not required by Title 52.

7.4 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES. All contributions in aid of construction (CIAC), customer advances or other like payments received by the Company shall constitute taxable income as defined by the Internal Revenue Service. The income taxes on such CIAC or customer advances will be segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with CIAC or customer advances will not be charged to the specific contributor of the capital.

8. RIGHTS-OF-WAY

8.1 TERM AND RENTALS. When the premises of a customer is so located that the customer can be served only by facilities extending over the property of another, the customer shall accept service for such term as is provided in a permit or other applicable agreement covering the location and the maintenance of service equipment, and shall reimburse the Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

RULES AND REGULATIONS (continued)

8.2 PROCUREMENT BY CUSTOMER. Customers applying for the construction of an extension may be required to secure to, and for, the Company, all necessary and convenient rights-of-way and to pay any associated costs.

8.3 DELAYS. Applications for service from an extension to be constructed where a right-of-way is not owned by the Company will only be accepted subject to delays incident to obtaining a satisfactory right-of-way.

9. INTRODUCTION OF SERVICE

9.1 WIRING IN PROGRESS. Service-supply lines will not be installed before the time that the customer's wiring of the premises is actually in progress.

9.2 INSPECTION. The Company reserves the right to refuse the introduction of service unless a written certificate of approval, satisfactory to the Company, has been received from a competent inspection agency authorized to perform this service in the specific locality in which service is to be provided.

9.3 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged to inspect, any installation before it begins to deliver electricity or at any later time, and reserves the right to reject any wiring or appliances not in accordance with the Company's standard requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the installation, wiring, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the customer.

9.4 DEFECTIVE INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

9.5 UNSATISFACTORY INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's equipment, or use thereof, might injuriously affect the equipment of the Company, or the Company's service to other customers.

9.6 FINAL CONNECTION. The final connection between the customer's installation and the Company's service lines shall be made by or under the supervision of a representative of the Company, except for standard single-phase secondary aerial service, in which case the customer may make the final connection in accordance with the Company's standard requirements.

9.7 NEW OR TRANSFER CUSTOMER CHARGE. When a customer's account for service is initiated or when a customer's account is transferred from one address to another address, there will be a charge of $6.00 to cover the clerical expenses incurred by the

Company. The State Tax Adjustment Clause applies to this charge.

10. COMPANY EQUIPMENT

10.1 COMPANY MAINTENANCE. The Company shall keep in repair and maintain its own property installed on the premises of the customer.

10.2 CUSTOMER'S RESPONSIBILITY. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property the customer shall pay the costs of repairs and replacement. Any changes made to the Customer’s premises after the Company completes its service and meter installation that, in the opinion of the Company, creates an unsafe condition, shall be the Customer’s responsibility to pay any costs associated with remedying the unsafe condition including, but not limited to, any required protective measures and/or relocations of Company property.

Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The customer shall protect the equipment of the Company on the premises, and shall not permit any person, except a Company employee having standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter or other apparatus of the Company located on the customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

RULES AND REGULATIONS (continued)

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. In the event of an emergency, the Company shall have the right to access customer owned facilities and equipment for the purpose of restoring electric service, for the purpose of rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities and equipment.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service from whatever cause.

10.7 POLE REMOVAL OR RELOCATION REQUESTED BY RESIDENTIAL PROPERTY OWNERS. The cost for removal or relocation of distribution line poles and their associated attachments made pursuant to the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of such work shall be borne by the property owner and shall be limited to contractor, direct labor, and direct material costs incurred less maintenance expenses avoided as a result of the pole removal or relocation. The calculation of such cost for removal or relocation shall be in accordance with the Public Utility Commission Regulations - Title 52, Section 57.27.

RULES AND REGULATIONS (continued)

10.8 RELOCATION OF COMPANY FACILITIES REQUESTED BY NON-RESIDENTIAL PROPERTY OWNERS. Except as otherwise provided by law (e.g., 66 Pa.C.S. Section 2704, et seq.), a non-residential property owner, such as a builder, developer or contractor (Owner), shall pay to the Company the costs of relocation of Company facilities or equipment, made for the accommodation of the Owner or in fulfillment of the Owner's obligation to any public authority. If the facility relocation is made to accommodate the Owner's project or in fulfillment of the Owner's obligation to any public authority, then the Owner shall be responsible to pay PECO for the relocation costs even if the relocation request is made by an entity other than the Owner. A request for relocation of Company facilities shall be in writing. The relocation cost shall include labor (including overhead), materials, storeroom expense and transportation, less the depreciated value of any equipment replaced. Where the relocation is done in conjunction with construction of a supply line to a development, the Company shall include in the relocation cost only those costs caused by the Owner's request. The Company will notify the Owner in writing of the relocation cost. Advance payment of relocation costs will be required before the Company will commence the work, except, at the sole discretion of the Company, under special circumstances.

Where the relocation relates to a development that will generate additional revenue for the Company, the Company will give the Owner an initial credit against the relocation costs in an amount not to exceed 5% of the estimated annual revenue recovered through the Company's tariffed Variable Distribution Service Charges from the portion of the development under construction at the time of the relocation request. The Company will give the Owner an additional credit against relocation costs not to exceed 5% of the estimated additional revenue recovered through the Company's tariffed Variable Distribution Service Charges realized from new load on the PECO Energy system due to buildings not under construction at the time of the initial relocation but that are under roof within a five (5) year period from the date of completion of the relocation work. Credits will be held by the Company and distributed to the owner, on a pro-rated basis, as additional loads from the development are connected to PECO Energy's distribution system. No credits will be given for loads connected after the five year period from the date of completion of the relocation work. When the relocation is done in conjunction with extension of a line in accordance with §7.2 of the Tariff, the Company will include in the credit calculation only such estimated annual revenue that exceeds the minimum revenue guarantee required by §7.2. The cost and expense of project changes which require a second relocation of the same Company facilities shall be borne solely by the party requesting the change without offset or credit.

10.9 AERIAL LINE CLEARANCE. In accordance with the requirements set forth in the National Electrical Safety Code, the Company shall have the right to trim, remove, or separate trees, vegetation or any structures therein which, in the opinion of the Company, interfere with its aerial conductors, such that they may pose a threat to public safety or to system reliability.

10.10 ADVANCED METER SERVICES PERFORMED BY AMSPs. The provisions of this Rule 10 are subject to the terms of the Electric Generation Supplier Coordination Tariff.

10.11 RECOVERY FOR PROPERTY DAMAGE. If Company equipment is damaged through the negligence or intentional act(s) of any individual(s) or entity(s), the one(s) responsible for causing the damage shall reimburse the Company for all aspects of the resulting damages. The reimbursement shall include costs related to: labor, material, transportation and tools. "Labor" shall include benefit and administrative overheads based on the Company's current standard schedule, including third party contract repairs or modifications. Additionally, "Labor" may be calculated using a "blended" or average pay rate consistent with the above referenced standards. "Materials" may include an added stores expense calculated using the above referenced standards.

11. TARIFF AND CONTRACT OPTIONS

11.1 CHOICE OF RATE. When the class of service-supply or conditions of use are such that two or more Base Rates are available, a customer shall select the Base Rate on which the customer will be billed.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist customers in selecting the most advantageous Base Rate or rate application (i.e., Base rate together with applicable riders).

11.3 RATE CHANGES. A customer may not change Base Rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above unless the Company agrees to permit the change. At any other time, a customer may change to a firm rate for which the customer qualifies upon 30 days notice to the Company. Customer ownership and obligation to maintain customer owned transformation facilities and equipment, as well as the point of delivery, will be unaffected by any Base Rate change initiated by the customer.

A customer may request that the Company modify the terms of its contract, other than the customer's Base Rate, but the Company will only allow such modification when, in the Company's sole judgment, the modification does not conflict with the Company's Tariff and is not detrimental to the Company.

The Company will not make any Base Rate change retroactive, unless, in the Company's sole judgment, the Company failed to adequately respond to a customer's request for assistance or modification at the time of such request.

RULES AND REGULATIONS (continued)

12. SERVICE CONTINUITY

12.1 LIMITATION ON LIABILITY FOR SERVICE INTERRUPTIONS AND VARIATIONS. The Company does not guarantee continuous, regular and uninterrupted supply of service. The Company may, without liability, interrupt or limit the supply of service for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public or for the purpose of preventing or limiting any actual or threatened instability or disturbance of the system. The Company is also not liable for any damages due to accident, strike, storm, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control.

In all other circumstances, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to computers and other electronic equipment and appliances, loss of business, or loss of production caused by any interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity shall in no event, unless caused by the willful and/or wanton misconduct of the Company, exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. In addition, no charge will be made to the customer for the affected service during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. A variety of protective devices and alternate power supplies that may prevent or limit such damage are available for purchase by the customer from third parties.

The Company makes no warranty as to merchantability or fitness for a particular purpose, express or implied, by operation of law or otherwise. To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company limits its liability in accordance with the previous paragraph to any Customer or third party for claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

12.2 ADDITIONAL LIMITATIONS ON LIABILITY IN CONNECTION WITH DIRECT ACCESS. Other than its duty to deliver electric energy and capacity, the Company shall have no duty or liability to a customer receiving Competitive Energy Supply arising out of or related to a contract or other relationship between such a customer and an EGS.

The Company shall implement customer selection of an EGS consistent with applicable rules of the Commission and shall have no liability to a customer receiving Competitive Energy Supply arising out of or related to switching EGSs, unless the Company is negligent in switching or failing to switch a customer.

The Company shall have no duty or liability with respect to electric energy before it is delivered by an EGS to a point of delivery on the PECO Energy distribution system. After its receipt of electric energy and capacity at the point of delivery, the Company shall have the same duty and liability for distribution service to customers receiving Competitive Energy Supply as to those receiving electric energy and capacity from the Company.

12.3 EMERGENCY LOAD CONTROL. Pursuant to order of Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever the demands for power on all or part of the Company's system exceed or threaten to exceed the capacity than actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or power pool with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system, a load emergency situation exists. In such case, the Company shall take such reasonable steps as the time available permits to bring the demands within the then-available capacity or otherwise control load. Such steps shall include but shall not be limited to reduction or interruption of service to one or more customers, in accordance with the Company's procedures for controlling load.

The Company shall establish procedures for controlling load including schedules of load shedding priorities to be followed in compliance with the foregoing paragraph, may revise such procedures from time to time, and shall revise them if so required by Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at the Company's Principle Office, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.4 EMERGENCY ENERGY CONSERVATION. Pursuant to order of the Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever events occur which are actually resulting, or in the judgment of the Company threaten to result, in a restriction of the fuel supplies available to the Company or its energy suppliers, such that the amount of electric energy which the Company is able to supply is or will be adversely affected, an emergency energy situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to conserve available fuel supplies. Such measures may include, but shall not be limited to reduction, interruption, or suspension of service to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

RULES AND REGULATIONS (continued)

The Company shall establish procedures for emergency energy conservation, including, if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

The Company may revise such procedure from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its Tariff for public inspection, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.5 NOTICE OF TROUBLE. The customer must immediately notify the Company if service is interrupted or is otherwise unsatisfactory due to defects, trouble, or accident, affecting the supply of service.

12.6 RELOCATION OF DELIVERY POINT. In the event that the Company shall be required by any public authority to place underground any portion of its mains, wires, or service-supply lines, or relocate any poles or feeders, the customer, at the customer's own expense, shall change the location of his point of delivery to a point readily accessible to the new location.

RULES AND REGULATIONS (continued)

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. Pursuant to Section 1313 of the Public Utility Code, 66 Pa. C.S. § 1313, a customer may resell Energy and Capacity and/or service provided by PECO Energy under its default service plan if: (1) the Company provides such service under a single contract at one application of an available Base Rate and for the total requirements of the premises served, and (2) the location and use of the service conforms to the availability requirements of this Tariff for provision to the customer for the customer's own account.

All residential units connected after May 10, 1980, except those dwelling units under construction or under written contract for construction as of that date must be individually metered by either the Company, the AMSP or the landlord for their basic electric service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation. The bill rendered by the reseller to any consumer shall not exceed the amount which PECO Energy would bill its own residential customers for the same quantity of service under the applicable tariffed residential rate.

The requirements for individually metered dwelling units in new construction may be waived at the sole discretion of the Company. Such waiver will only be granted when the owner can demonstrate to the Company that there are valid reasons for such waiver and that there will not be a significant impact on the consumption of an individual customer.

In accordance with the Commission's Policy Statement at Docket No. M-2017-2604382, the electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation shall not be construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Such sales are therefore not considered a resale of service as defined in this tariff rule, Rule 13.1.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned charging station, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

13.2 FLUCTUATIONS. Electric service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the customer to modify the installation and/or equip it with approved controlling devices.

13.3 TYPE OF INSTALLATIONS. Motor and other installations connected to the Company's lines must be of a type to use minimum starting current and must conform to the requirements of the Company as to wiring, character of equipment, and control devices.

13.4 UNBALANCED LOAD. The customer shall at all times take, and use, energy in such manner that the load will be balanced between phases to within nominally 10%. In the event of unbalanced polyphase loads, the Company reserves the right to require the customer to make the necessary changes at the customer's expense to correct the unsatisfactory condition, or to compute the demand used for billing purposes on the assumption that the load on each phase is equal to that on the greatest phase.

13.5 ADDITIONAL LOAD. The service connection, transformers, meters and equipment supplied by the Company for each customer, have definite capacity, and no additions to the equipment or load connected thereto will be allowed except by consent of the Company.

13.6 CHANGE OF INSTALLATION. The customer shall give immediate written notice to the Company of any proposed increase or decrease in, or change of purpose or location of, the installation.

13.7 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the customer liable for any damage to the meters or their auxiliary apparatus, or the transformers, or wires, of the Company, caused by the additional or changed installation.

14. METERING

14.1 SUPPLY OF METERS. An EGS that is also an AMSP may provide Advanced Meter Services in accordance with the Electric Generation Supplier Coordination Tariff. Otherwise, subject to Rules 14.3 and 14.9, the measurement of service for billing purposes shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment to be used for meters supplied by the Company, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes. In fulfilling its obligations with respect to metering and meter reading, and with respect to AMSPs that provide Advanced Meter Services, the Company will comply with Electric Generation Supplier Coordination Tariff.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, reactive-component meters, or other instruments, on the premises of any customer except for any customer for whom an AMSP is providing Advanced Meter Services, for the purpose of measuring the demand and/or the power factor, or for other tests of all, or any part, of the customer's load.

14.3 CUSTOMER REQUEST FOR SPECIAL METER. If a customer for whom the Company is providing either metering and meter reading wishes to replace its billing metering equipment, to the extent technically possible, the Company may offer, provide and support a selection of qualified meters and may perform installation within a reasonable amount of time and at the expense of the customer. The customer must pay for any such metering equipment based on the net incremental cost of purchasing and installing the new metering equipment as approved by the Commission. The Company will own and maintain all such new metering equipment.

RULES AND REGULATIONS (continued)

14.4 POWER FACTOR MEASUREMENT. For customers for whom the Company is providing metering and meter reading or Advanced Meter Services, the Company reserves the right to measure the power factor of the customer's load, either by test or by permanently installed instruments. For customers for whom an AMSP is providing Advanced Meter Services, the Company reserves the right to require such AMSP to measure the power factor of the load of the customer on the same basis the Company measures the power factor of customers for which the Company provides metering and meter reading or Advanced Meter Services.

14.5 REVERSE REGISTRATION. The Company may, by ratchet or other device, control its meters to prevent reverse registration.

14.6 ESTIMATED USAGE. The kilowatt-hours and billing demands to be paid for may be determined by computation instead of by measurement in the case of installations having a fixed load or demand value controlled to operate for a definite number of hours each day.

14.7 METER READING INTERVALS. The Company will read its meters in accordance with Appendix C to the Joint Petition for Full Settlement and at scheduled regular intervals of one month. Monthly customer usage will not be prorated for seasonality. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render standard bills for the recorded use of service based upon the time interval between meter readings. EGS & EDC charges shall be based on the EDC defined meter reading route schedules. Only those bills which cover a period of service of less than 26 days or more than 35 days will be prorated. The Company will reflect multiple supplier switches within a single monthly bill to ensure a customer can switch their electric service in accordance with the accelerated switching process final omitted rulemaking order that amends 52 Pa. Code, Ch. 57.172 – 57.179. See Dockets No. L-2014-2409383 and P-2014-2446292.

14.8 ESTIMATED USAGE. For customers for whom the Company provides meter reading or Advanced Meter Reading Services, the Company shall estimate the amount of service supplied to premises where access to the meter is not available or if such estimate is necessary, and to installations at remote locations when warranted by the type of installation, regularity of usage, or other circumstances. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render bills in standard form based on such estimate and so marked, for the customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential customers, an actual meter reading will be obtained at least every six months in accordance with Commission regulations.

14.9 CUSTOMER SELECTED ADVANCED METERS. A customer may request either PECO Energy or an AMSP to have an Advanced Meter installed and have Advanced Meter Services provided pursuant to Appendix C of the Joint Petition for Full Settlement and any applicable rules adopted by the Commission. For an advanced meter to be deployed in the PECO Energy service territory, it must be included in the Commission's Advanced Meter Catalog, and indicated as eligible for deployment in the PECO Energy territory.

14.10 MANUAL METER READING FEE Upon customer request, the Company will secure an in-person meter reading to confirm the accuracy of an automatic meter reading when a customer disconnects service or a new service request is received. The fee is $45 and the Company will include this fee on the customer's or applicant's bill.

15. DEMAND DETERMINATION

15.1 MEASURED DEMANDS. Measured demands may be quantified by recording or indicating instruments showing, unless otherwise specified, the greatest 30-minute rate-of-use of energy, provided that in the case of hoists, elevators, welding machine, electric furnaces, or other installations where the use of electricity is intermittent or subject to violent fluctuation the demand may be fixed by special determination.

15.2 DEMAND DETERMINATION.

(a) Special Determination. Where charges specified in this Tariff are based upon the customer's demand, it is intended that such demand shall fairly represent the customer's actual demand that the Company must stand ready to serve. In the case of installations where the customer's regular use of service in the ordinary course of the customer's business is such that measurement over a thirty-minute interval does not result in a fair or equitable measure of the customer's demand, then the demand may be estimated from the known character of use and the rating data of the equipment connected, or from special tests. The intent of this provision is that the demand so determined shall fairly represent the demand that the Company must stand ready to serve.

(b) Demand Waiver. When a customer wishes to conduct a test of equipment or process that is not part of the customer's normal operations, the customer may request that the Company waive the demand caused by that test, if that demand is the highest measured demand in the billing month. The Company will agree to such a waiver if the following conditions are met:

1. The Company's metering is of a type which allows for the determination of 30-minute demands; and
2. The customer's request is in writing, and is received by the Company at least 15 business days before the date of the commencement of the proposed test. The request must specify the nature of the test, the size of the loads to be tested and the starting and ending times; and
3. The Company determines that the tests are not a part of the customer's normal operations; and
4. The test will not last for more than twelve (12) consecutive hours; and
5. The customer has not conducted a test and received a demand waiver for a test pursuant to this rule within one year of the proposed test.

Upon receipt of a request for a demand waiver, the Company will inform the customer in writing within fifteen (15) days of receipt of the customer's request whether it will grant the proposed waive

RULES AND REGULATIONS (continued)

15.3 POWER FACTOR ADJUSTMENT.

A. Standard Power Factor Values (based on measured demands)

Measured Demands (Kw)	Standard Power Factor
0 -185	80%
186 - 2,500	90%
Over 2,500	95%

B. Adjustment to Measured Demand. When a customer's measured power factor is less than the standard power factor values above, the Company shall increase the customer's measured demand by the ratio of the standard power factor to the measured power factor. The Company will then use this adjusted demand as a basis for calculating the customer's billing demand in accordance with the applicable rate schedule.

C. Determining Measured Power Factor:

1) For customers with measured demands of 750 kW or greater in three consecutive months:

(a) Until metering equipment capable of continuous power factor measurement is installed, the Company shall determine measured power factor based C3 below.
(b) Once capable metering is installed, the Company shall continuously measure power factor.
i. The customer's measured power factor shall coincide with the customer's maximum measured demand.

ii, The Company in its sole judgment may discontinue continuous power factor measurement if: (1) the customer's measured demand is less than 750 kW for twelve consecutive months, or: (2) the Company determines that changes to the customer's load characteristics will result in that customer permanently reducing measured demand to less than 750 kW.

2) For customers with measured demands of less than 185 kW:

(a) If the Company in its sole judgment deems that that the power factor is likely to be less than this standard based on the customer's load, the Company shall determine measured power factor based on C3 below.
(b) Otherwise, the Company shall assume the customer's measured power factor to be the standard noted above

3) For all other customers, including those with measured demands between 185 kW and 750 kW, the Company shall determine measured power factor in one of the following ways:

(a) By test, at a time when the customer's load is at least two-thirds of the customer's maximum measured demand in the preceding eleven months.
(b) At the option of either the customer or the Company, by measurement as determined from meters installed by the Company, ratcheted to prevent reverse registration.
i. Customers requesting measurement of power factor shall be subject to a monthly meter charge determined in accordance with the cost of the meter installation. Such installation shall not be for less than one year.
ii. When meters are installed, the measured power factor shall be the power factor that is coincident with customer's maximum measured demand.

4) A customer that receives Advanced Meter Services from an AMSP is subject to these rules regarding determination of measured power factor.

16. METER TESTS

16.1 METER TESTS. The Company at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy.

16.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a customer or an EGS providing Competitive Energy Supply to a customer, but reserves the right to make the charge provided for in the Electric Regulations of the Pennsylvania Public Utility Commission, under conditions therein specified.

16.3 ADJUSTMENT FOR ERROR. Should any of the Company's meters become defective or fail to register correctly, the use of electricity shall be determined by a test of any such meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount registered for the preceding billing period and the amount registered during not less than one week immediately subsequent to the repairs to, or change of, the meter, taking into consideration the character of use by the customer.

16.4 RESIDENCE METER ERRORS. Meter errors in the Company's meters in residence service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

16.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests of the Company's meters as it deems necessary for the proper administration of its rates, or as are required by law.

16.6. TESTING SERVICE. The Company will, upon request by the customer, make tests of the Company's meters to supply special information regarding the customer's use of service, provided that the estimated cost of such special tests shall be paid by the customer to the Company at the Company's discretion.

RULES AND REGULATIONS (continued)

17. BILLING AND STANDARD PAYMENT OPTIONS

17.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its delivery. The customer will be billed in accordance with rule 14.7. Rate values stated for direct application to monthly billing periods will be adjusted when time elapsed between readings is substantially greater or less than a month.

17.2 BILLING OPTIONS. A customer may select one of the following three billing options as communicated to PECO by the customer's supplier: (1) Consolidated EDC Billing; (2) Consolidated EGS Billing; and (3) Separate EDC/EGS Billing, as those terms are defined herein. If a customer does not make a selection, the customer shall receive Consolidated EDC Billing. When the Company provides Consolidated EDC Billing or Separate EDC Billing, it will comply with the terms and conditions of the Electric Generation Supplier Coordination Tariff.
For customers who receive both electric and gas service from the Company, the Company will issue a bill that contains charges for both of these services.

17.3 PAYMENT.

(a) The Company's bills to customers are payable upon presentation. Payment for service received must be made on or before the due date shown on the bill. The due date shall be determined by the Company and shall be not less than twenty days from the date of transmittal of the bill for Rates R, R-H, RS-2, POL and GS (excluding Summary Billing Accounts). The due date shall be not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts. Notwithstanding the foregoing, the due date may be up to thirty days for accounts (including Summary Billing Accounts) with the United States of America, the Commonwealth of Pennsylvania, or any of their departments, political subdivisions, or instrumentalities. The Company may allow a reasonable amount of additional time for payment of bills on industrial and commercial accounts of creditworthy customers. If the due date that appears on a customer's bill falls on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not operating, the due date shall be extended to the next business day. The payment period will not be extended because of the customer's failure to receive a bill unless said failure is due to the fault of the Company. **(C)**

(b) Payment may be made at any authorized payment agency. The customer bears the risk of delivery of payment tendered on or after the date contained in any termination notice sent to the customer. **(C)**

(c) The Company may require that a customer that is not creditworthy tender payment by means of a certified, cashier's, teller's, or bank check, or by wire transfer, or in cash or other immediately available funds.

(d) A customer must pay the undisputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed, and (4) the customer nevertheless continues to dispute the same manner in bad faith.

17.4 PAYMENT PROCESSING. When the Company is providing Consolidated EDC Billing, Default Service or Separate EDC Billing, and the customer remits a partial payment to the Company, the payment will be applied as follows:

1. Any past due balances including those for prior PECO basic service charges, for prior EGS receivables purchased by the Company, for prior installment amounts on payment agreements, and also for any reconnection charges.
2. Any current charges including those for PECO basic service charges, for current EGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

17.5 LATE FEES AND COLLECTION COSTS. If payment is made at an authorized payment agency after the due date shown on the bill, a late fee will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the late fee will be added if the payment is received by the Company more than five days after the due date shown on the bill. For Rates R, R-H, RS-2, POL and GS this late fee will be 1-1/2 % per month; for all other rates the late fee will be 2% per month. The Company will not apply late fees to Final Bills as defined in Tariff Rule 20.2. If the Company files suit to collect a delinquent balance on an account (whether active or inactive) or to ensure payment of current bills, the customer will be required to pay the Company's out of pocket court costs (including filing, service, and witness fees) as ordered by the court and such costs will be added to commercial and industrial accounts. **(C)**

17.6 BUDGET BILLING.

(a) At the option of a customer receiving residential service under Rates R, R-H, RS-2, and GS, an estimated total bill for all service to be received by the customer over a twelve month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the 12th month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 17.3 and 17.5. Any such late fee will be calculated based on the lesser of budget billing arrears and actual charged arrears The Company may also arrange budget billing for creditworthy commercial and industrial customers.

(b) When the Company provides Consolidated EDC Billing, the EGS's charges will be included in the customer's Budget Billing Plan.

(C) Denotes Change

RULES AND REGULATIONS (continued)

17.7 CALCULATION OF LATE FEE. Where a late fee is applicable, the amount of the late fee to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid late fees, by the appropriate late fee rate.

17.8 TAX EXEMPTION. If a customer is tax exempt, the customer must provide a tax exempt form to PECO Energy and to its EGS, regardless of which billing option the customer chooses.

17.9 BILLING ERRORS. When the Company provides Consolidated EDC Billing, PECO Energy shall not be responsible for billing errors resulting from incorrect price information received from an EGS.

17.10 RETURNED PAYMENT CHARGE. If a check (electronic or paper) received in payment of a customer's account is returned to the Company unpaid or if upon a second attempt by the Company or its agent for payment the check is again returned unpaid, then the Company will add a returned payment charge to the customer's account in the amount of **$20.00.**

17.11 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of Rule 17, when a customer resides at a place of business or commercial establishment legitimately served pursuant to a commercial or industrial Base Rate, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to payment terms for residential customers.

18. PAYMENT TERMS & TERMINATION OF SERVICE

18.1 NON-PAYMENT TERMINATION. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations, on the portion of the past due amount attributable to the Company's charges for: (1) service, (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered to be "reasonable" hereunder

18.1.1 WINTER TERMINATIONS FOR NON-PAYMENT. Consistent with 52 PA Code §56.100, The Company will take the following steps for terminations for non-payment during the winter period, defined as December 1-March 31:

A. **Low-Income Eligibility:** The Company will use financial information provided by the Customer to determine if the Customer's income is at or below 250% of the Federal Poverty Level. The Company may elect to send to the Customer an income verification form for completion and return. The Company will also accept income verification provided by Community-Based Organizations that enter into a contract with PECO to provide such income verification services.

1. Annual income may be established using verified income information for a recent one-month (nominally 30-day) period, annualized to establish an estimated annual income.
2. The Company shall not require any customers who have established income eligibility for winter termination protections within the 12 months preceding the start of the winter period to re-certify or re-verify their income for that winter period. This Company may also use this information to determine deposit requirements, payment arrangements, and eligibility for any other income-specific program.

B. **Verified Low-Income Customers:** If the Company has received verified proof that a customer's household has income at or below 250% of the Federal Poverty Level, the Company will not pursue termination of that customer for non-payment during the winter period UNLESS (A) the Company receives Commission approval to do so via a petition filed pursuant to 52 Pa. Code §56.100(g), or (B) the customer has informed the Company after submitting this verification that the household no longer has income at or below 250% of the Federal Poverty Level.

For purposes of this section, the Company will accept the following as verified proof that the household has income at or below 250% of the Federal Poverty Level:

1. Enrollment in PECO's CAP program at any time within four years prior to the issuance of the winter termination notice;
2. Receipt of a LIHEAP grant at any time within four years prior to the issuance of the winter termination notice;
3. Receipt of a MEAF grant at any time within four years prior to the issuance of the winter termination notice;
4. Income verification provided by a CBO that has contracted with PECO to provide income verification information, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
5. Other verified documentation that the household's income is at or below 250% of the Federal Poverty Level, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
6. Receipt of verified documentation of low-income status in response to an Income Inquiry Letter, as described in Rule D.1 below.

C. **Verified Non-Low-Income Customers:** If the Company has received verified proof that a customer's household has income of greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

RULES AND REGULATIONS (continued)

D. **Customers with Non-Verified Income Levels:** For all other customers, prior to proceeding with termination for non-payment, the Company will send the customer a letter (the "Income Inquiry Letter") informing the customer that the Company does not have verified income information for the customer and that the customer is subject to termination for non-payment during the winter period.

1. If the customer responds with verified income information demonstrating that the household income is at or below 250% of the Federal Poverty Level, the Company will treat that household as Verified Low-Income for purposes of winter termination;
2. If the customer responds with verified income information demonstrating that the household income is greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.
3. If the customer fails to respond to the Income Inquiry Letter or responds without providing verified income information, the Company will attempt to contact the customer via telephone to inform the customer of their duty to provide verified income information. If contact is made and verified income information is not provided by the customer, or if contact is not made, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

18.2 PAYMENT TERMS. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the Company will in accordance with Pennsylvania Public Utility Law and applicable Pennsylvania Public Utility Commission Regulations and Orders, negotiate payment arrangements on the portion of the past due amount attributable to its charges for: (1) service (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. However, the Company will not negotiate payment arrangements on behalf of an EGS.

18.3 TERMINATION FOR CAUSE. The Company may terminate on reasonable notice if entry to the meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and Regulations and/or applicable Commission rules, including those found at Pennsylvania Public Utility Code or the Commission's regulations.

18.4 SAFETY TERMINATION. The Company may terminate without notice if the customer's installation has become hazardous or defective.

18.5 DEFECTIVE EQUIPMENT TERMINATION. The Company may terminate without notice if the customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other customers; or if a certificate of approval is refused after a re-examination of the customer's installation by a competent inspection agency authorized to perform this service in the specific locality where service is provided.

18.6 TERMINATION FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity, or tampering with the connections, the Company's meters, or other equipment of the Company.

RULES AND REGULATIONS (continued)

18.7 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the customer, the same customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs. All theft reconnections will be completed at the premise and will not be performed remotely.

	Reconnect Fees	
Electric Reconnect at the Meter	**$**	**75.00**
Electric Reconnect at Tap	**$**	**260.00**
Electric Reconnect - Underground dig	**$**	**1,650.00**
Electric with dual meters	**$**	**100.00**
Electric Remote Reconnect (one or dual meters)	**$**	**20.00**

18.8 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer's premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company's meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 18.7.

	Theft Investigation Fees
Electric Theft at Meter	**$400.00**

RULES AND REGULATIONS (continued)

19. UNFULFILLED CONTRACTS

19.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service before the expiration of a contract term will not relieve a customer from any minimum, or guaranteed, payment under any contract or rate. In the case of residential customers this Rule only applies if the customer has signed an express written contract that clearly sets forth such a term and condition of service.

19.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a customer, the Company's service is suspended, or the Company is prevented from providing service in accordance with the terms of any contract it may have entered into with the customer, the minimum charge for the unexpired portion of the initial contract term shall become due and payable immediately as liquidated damages. These liquidated damages may, at the option of the Company, be offset by estimated revenues from a succeeding customer at the same location, if such exists.

20. CANCELLATION BY CUSTOMER

20.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service from the Company must give the Company at least 7 days' written notice to that effect.

20.2 FINAL BILL. The customer is liable for service taken after notice to terminate the contract, until the meter is read and/or disconnected. The final bill for service is then due.

RULES AND REGULATIONS (continued)

21. GENERAL

21.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid to any commercial office, shall be deemed sufficient, unless the Principal Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

21.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

21.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

21.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will, in any event apply to the bill for the period during which the investigation is made.

21.5 EXCEPTIONAL CASES. The usual supply of electric service shall be subject to the provisions of this Tariff; but where special service-supply conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its supply terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

21.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and inure to the benefit of, the successors and assigns, heirs, executors and administrators of the parties thereto.

21.7 OTHER CHARGES. The Company may, if feasible, provide and charge for services, other than those provided for in this Tariff, when requested by the customer. The Company is not obligated to provide such services. The Company will, if possible, give the customer an advance written estimate of the costs to provide the service. Costs shall include, but not be limited to, materials, supplies, labor, transportation and overhead.

21.8 TAX INDEMNIFICATION. If PECO Energy becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, 66 C.S. §§ 2806(g) and 2809(c), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify PECO Energy for the amount of additional state tax liability imposed upon PECO Energy by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Reform Code of 1971 or Chapter 28 of Title 66.

22. RULES FOR DESIGNATION OF PROCUREMENT CLASS

22.1 DESIGNATION OF PROCUREMENT CLASS

a) Annually, in November the Company shall notify the customer of their procurement group class designation which shall be effective the following June 1.
b) The procurement class designation shall be used to determine the appropriate Generation Supply Adjustment to apply to the customer.
c) For non-residential customers, the procurement class shall be determined based upon the customers peak measured demand in the prior June-May period.
d) There shall be three procurement class designations. They are:
   1)Residential
   2)Small Commercial and Industrial up to and including 100 kW
   3)Large Commercial and Industrial greater than 100 kW
e) Procurement class designation shall only change once per year on the date established in rule 22.1a
f) A new customer in a new facility shall be assigned to a procurement class based upon an engineering estimate of the customer's diversified peak demand.
g) A new customer in an existing facility shall be assigned to the same procurement class as the last customer in that facility unless the new customer will use the existing facility in a substantially different manner.

RULES AND REGULATIONS (continued)

23. EGS SWITCHING

23.1 PECO Energy will accommodate requests by customers to switch EGSs on active accounts and pending active (Instant Connect) accounts in accordance with this Rule 23, Commission Order M-2014-2401085, and other applicable Commission Orders.

23.2 To switch to a new EGS, a customer must inform the new EGS. Customers that wish to switch are not required to contact PECO Energy to initiate a switch; PECO Energy will only switch a customer in accordance with Rule 23.

23.3 To enable a new EGS to complete a switch, a customer must provide to the new EGS the customer's PECO Energy Electric Choice ID number as it appears on the customer's PECO Energy monthly bill.

23.4 If a Customer contacts the Company to discontinue electric service and indicates that the Customer will be relocating outside of the Company's service territory, the Company will notify the current EGS of the Customer's discontinuance of service for the account at the Customer's location. If relocating within the Company's service territory the Company will seamlessly move the current EGS to the new location if all qualifications are met in accordance with PUC Order M-2014-2401085.

23.5 A switch to an EGS will be effective 3 business days after the enrollment request is processed, provided the enrollment request includes valid customer information as required by the controlling provisions of the Supplier Tariff. Upon receiving valid notice to switch an EGS, the Company shall notify the customer's existing EGS that such a request has been made.

23.6 If and when a customer's EGS discontinues its supply in the event of bankruptcy, loss of license, or similar occurrence, or if a Customer is dropped by its EGS for non-payment or other reason then the customer may select a new EGS. The customer will receive its energy supply from PECO Energy until the switch becomes effective.

23.7 Nothing in this Rule 23 shall be interpreted to preclude EGSs from entering into agreements for supply with a term of service of one month. EGSs may enter into agreements for longer.

23.8 The Company will send Release of Information packets to all new customers (except for customer with demands greater than 500kW), which information will provide customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2010-2183412, PECO will re-solicit its entire customer base (except for customer with demands greater than 500kW) for the purpose of opting out of disclosing information.

24. LOAD DATA EXCHANGE

24.1 PECO Energy will provide to a customer or the customer's designated EGS or authorized consultant, all available data from the meter once each calendar year for no fee. The exchange of data among PECO Energy, EGSs, and customers shall be in accordance with the Supplier Tariff and the Final Consensus Plan for Electronic Data Exchange Standards for Electric Deregulation in the Commonwealth of Pennsylvania, as approved by the Commission.

STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this tariff, a **credit value of 0.04%** will apply to all PaPUC jurisdictional distribution charges in the Base Rates and Riders, effective January 1, 2026. **(C)**

Whenever any of the tax rates used in the calculation of the surcharge are changed, or recoveries are authorized under Sections 2806, 2809 or 2810 of the Competition Act, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the change occurs and the effective date shall be ten days after filing.

In addition, if a recalculation is submitted as a result of a tax rate change (including the Revenue Neutral Reconciliation rate) the Company will thereafter file each year by December 21 annual updates or revisions with the Commission which will reflect only this tax change. These annual updates will be effective ten days after filing and will continue until such time as the effect of the change in tax rates has been included in base rates.

INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE EXPENSE (ICUS)

Purpose: The purpose of this surcharge is to refund to customers amounts of incremental COVID-19 related uncollectible accounts embedded in PECO's current rates.

Applicability: The surcharge shall be calculated to the nearest one-hundredth of a cent for billing purposes for all R and RH customers, for customers on all other rates it shall be the nearest one cent. The ICUS will become effective upon the effective date of rates for the electric distribution base rate case at Docket No. R-2024-3046931 for a period of one year. The ICUS shall be credited to each rate schedule as follows:

(C)

Rate R	$0.00000/kWh
Rate RH	$0.00000/kWh
Rate GS	$0.00/billed kW
Rate PD	$0.00/billed kW
Rate HT	$0.00/billed kW
Rate EP	$0.00/billed kW
Rate SL-E	$0.00/location
Rate SL-C	$0.00/location
Rate TLCL	$0.00/location
Rate AL	$0.00/location
Rate POL	$0.00lamp
Rate SL-S	$0.00/lamp

The Variable Distribution charges, for the above rate schedules shall include the above listed ICUS credits. For the lighting rate schedules, the applicable location or fixed distribution service charges shall include the ICUS credit.

Calculation of ICUS:

Billing Provisions: The credit was calculated by rate schedule using the following formula:

$$\textbf{ICUS} = \frac{\textbf{R(n)}}{\textbf{BU(n)}}$$

R(n) - The total amount to be refunded to customers by rate class.

BU(n) – The total estimated annual Billing Units for the rate class during the projected period when rates will be in effect.

Filing and Reconciliations: The ICUS will be reconciled at the end of the recovery period above. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharge. Such adjustments would be filed on at least 10 days' notice. The ICUS revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.

(C) Denotes Change

FIBER AFFILIATE REVENUE SURCHARGE (FARS)

Purpose: The purpose of this surcharge is to refund to customers amounts for network fees that the Company collected from former affiliates for use of its fiber network.

Applicability: The surcharge shall be calculated to the nearest one-hundredth of a cent for billing purposes for all R and RH customers, for customers on all other rates it shall be the nearest one cent. The FARS will become effective upon the effective date of rates for the electric distribution base rate case at Docket No. R-2024-3046931 for a period of one year. The FARS shall be credited to each rate schedule as follows:

Rate R	$0.00000/kWh	**(C)**
Rate RH	$0.00000/kWh	
Rate GS	$0.00/billed kW	
Rate PD	$0.00/billed kW	
Rate HT	$0.00/billed kW	
Rate EP	$0.00/billed kW	
Rate SL-E	$0.00/location	
Rate SL-C	$0.00/location	
Rate TLCL	$0.00/location	
Rate AL	$0.00/location	
Rate POL	$0.00/lamp	
Rate SL-S	$0.00/lamp	

The Variable Distribution charges, for the above rate schedules shall include the above listed FARS credits. For the lighting rate schedules, the applicable location or fixed distribution service charges shall include the FARS credit.

Calculation of FARS:

Billing Provisions: The credit was calculated by rate schedule using the following formula:

$$\textbf{FARS} = \frac{\textbf{R(n)}}{\textbf{BU(n)}}$$

R(n) - The total amount to be refunded to customers by rate class.

BU(n) – The total estimated annual Billing Units for the rate class during the projected period when rates will be in effect.

Filing and Reconciliations: The FARS will be reconciled at the end of the recovery period above. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharge. Such adjustments would be filed on at least 10 days' notice. The FARS credits and reconciliation will be subject to audit by the Commission's Bureau of Audits.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below.

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next semi-annual period beginning with the six months ended November 30, 2025**.**

The rates in this tariff shall be updated semi-annually on June 1 and December 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula:

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where;

C= The sum of the amounts paid to the full requirements suppliers providing the power for the semi-annual period, the spot market purchases for the semi-annual period, plus the cost of any other energy acquired for the semi-annual period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the component above for the semi-annual period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00035/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.10237
RH	GSA (1)	$0.10237
GS	GSA (2)	$0.09325

(C)

(C) Denotes Change

**GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)**

(C)

PD	GSA (2)	$0.09166
HT	GSA (2)	$0.08792
POL*	GSA (2)	$0.06726
SL-S*	GSA (2)	$0.06726
TLCL	GSA (2)	$0.09325
SL-E*	GSA (2)	$0.06726
AL*	GSA (2)	$0.06726
SL-C*, **	GSA (2)	$0.06726

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1 and December 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. (Customers electing this option are billed based on interval-metered consumption of usage within each TOU Pricing Period. Beginning and ending reads are not applicable TOU billing determinants.) Commencing June 1, 2025, TOU Pricing Option rates will be updated semi-annually in concurrence with the Standard GSA on June 1 and December 1 and are not prorated.

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] from June 1, 2025 through May 31, 2026 are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12,73%	14.15%	6.06-to-1	4.85-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	19.76%	20.35%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	67.51%	65.50%	1.44-to-1	1.47-to-1

Commencing with the GSA and TOU rates effective June 1, 2022, PECO may update the TOU Pricing Multipliers in the above table annually, using a rolling five years of historical PJM Day-Ahead Spot Market Pricing energy data and Reliability Pricing Model capacity pricing data for the PECO zone. PECO will **only** update the applicable TOU Pricing Multipliers if the use of such data would result in no more than a 10% change from the prior-year's TOU Pricing Multipliers. If these updates would exceed 10%, the applicable TOU Pricing Multipliers will be changed by exactly 10%.

To calculate the semi-annual TOU Pricing Option rates, the Company will first calculate the semi-annual TOU Super Off-Peak Price ("SOPP") **(C)** in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the semi-annual TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)

Current TOU Pricing Option Charges: **(C)**

TOU Rate	Peak ("PP") (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak ("SOPP") (12-6 AM all days)	Off-Peak ("OPP") (All other times)
R (GSA 1)	$0.31960	$0.05274	$0.07595
RH (GSA 1)	$0.31960	$0.05274	$0.07595
GS (GSA 2)	$0.24405	$0.05032	$0.07397
PD (GSA 2)	$0.23993	$0.04947	$0.07272
HT (GSA 2)	$0.23013	$0.04745	$0.06975

TOU Eligibility Requirements and Switching Rules:

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw.

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

$$\Sigma PJM_{DA} \text{ x usage / (1-LL)}$$

PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution

RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

$$((PJM_{AS} \text{ x Usage*}1/(1\text{-LL}) + AEPS/S_{AEPS} \text{ x Usage})$$

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_3/_4$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_3/_4$ = Procurement class 3/4 sales
WC = $0.00035/kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP
Hourly Pricing Adder* (dollars/kWh)	$0.00131	$0.00121	$0.00098	$0.00098

(C)

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

(C) Denotes Change

RECONCILIATION

Applicability: June 1, 2025 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing. **(C)**

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2024 through December 31, 2024 reconciliation period. There will be a transition reconciliation period for Procurement Classes 1 and 2 effective June 1, 2025 through November 30, 2025. The reconciliation will be based on utilizing the December 31, 2024 over/(under) balance adjusted for prior period revenues from January 2025 through May 2025. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. For Procurement Classes 1 and 2, any over/(under) recovery shall be collected after the occurrence of five months from the end of the reconciliation period. Recovery shall be over a six month period commencing June 1 and December 1. The initial six month period is June 1, 2025 through November 30, 2025. For Procurement Class 3/4 Hourly, any over/(under) recovery shall be collected after the occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2025 through August 31, 2025. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential, Class 2 – Small C&I up to and including100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class. **(C)** (C)

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest

N = Procurement class

M = Migration Rider

O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

(C) Denotes Change

RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by five months for Procurement Classes 1 and 2 and two months for Procurement Class 3/4 Hourly . For Procurement Classes 1 and 2,the GSA will be effective June 1 and December 1 commencing June 1, 2025 with over/under collection recovery occurring over the six month period beginning June 1 and December 1. For Procurement Class 3/4 Hourly, the GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2025 with over/(under) collection recovery occurring over the six month period beginning September 1 and March 1. The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits. **(C)**

(C) Denotes Change

NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE (NDCA)

The NDCA provides for the recovery of nuclear of decommissioning costs related to the Company's Ownership interest in Nuclear Generation as of 12/31/99. The NDCA shall be charged to all customers taking service under this Tariff. The adjustment shall be a cents per kWh charge calculated to the nearest one hundredth of one cent.

The Company's Ownership interest in nuclear generation as of December 31, 1999 consists of the following:

Peach Bottom 1	100%
Peach Bottom 2	42.49%
Peach Bottom 3	42.49%
Salem 1	42.59%
Salem 2	42.59%
Limerick 1	100%
Limerick 2	100%

Formula

The following formula shall be used to determine the NDCA.

$$NDCA = \frac{\text{PaPUC Authorized Decommissioning Expense Adjustment}}{\text{Total Pennsylvania Jurisdictional Sales for Calculation Year}}$$

Where:

PaPUC Authorized Decommissioning Expense Adjustment (Adjusted Annual Accrual - Base Accrual) x .95 = the Adjusted Annual Accrual in the Calculation Year less the Base Accrual. As of January 1, 2023, the NDCA shall be a credit value of ($0.0006)/kWh and will be added to the Variable Distribution Charge for all rates except for rates POL, SL-S and AL which will have a credit value of ($0.04)/location added to the Distribution Charge.

Total Pennsylvania Retail Jurisdictional Sales = total kWh sales under this Tariff for the calculation year including sales for distribution.

Calculation Year = year in which the Company proposes a change to the NDCA. To the extent a new cost study, performed every five years, indicates the Company requires an adjustment in the rate, the Company shall change the NDCA to reflect such new expense level. In calculating the annual expense, the Company shall use the sinking fund methodology.

Adjusted Annual Accrual = accrual necessary to fund the Adjusted Obligation.
Adjusted Obligation = Gross Decommissioning Obligation reduced by $50 million for ratemaking purposes.
Gross Decommissioning Obligation – The total decommissioning cost obligation as approved by the Commission as expressed in escalated future dollars.

Methodology for Calculating Expense

The base period expense shall be based upon the decommissioning costs set forth in the table below. The Company shall use a sinking fund methodology to determine the appropriate level of decommissioning expense. The assumptions shall be consistent with NRC policy and requirements.
The Base Accrual shall consist of the following levels for each unit.

Peach Bottom 1	$4,213,220
Peach Bottom 2	0
Peach Bottom 3	0
Salem 1	0
Salem 2	0
Limerick 1	0
Limerick 2	0
Total	$4,213,220

Frequency of Calculation

The annual expense shall be recalculated every five years. The Company shall adjust the NDCA to reflect the new expense level 60 days after filing the new study and the associated rate calculation with the PaPUC. The first calculation of the NDCA shall be considered to have taken place on January 1, 1998.

Completion of Decommissioning

In the event that the actual expenditures necessary to accomplish full decommissioning of the PECO Interest are less than the full balance in the funds established for such purpose, PECO shall be entitled to a release of such funds to PECO for the purpose of sharing the amount between ratepayers and shareholders. In the event that such release is granted, PECO's shareholders shall be entitled to retain: (1) the first $50 million of the net after-tax amount; and (2) 5 percent of the remaining net after-tax amount of the released funds.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for electric service in Residential Rate Schedule R and RH of this Tariff shall include a charge of $0.00287 per kWh for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below pursuant to Section 2804 (8) of the Competition Act. The USFC rate for electric service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below: (I)

COMPUTATION OF USFC.
The USFC per kWh ($0.0000), shall be computed in accordance with the formula set forth below:

$$USFC = \frac{(C+L-E-I)}{(S)}$$

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedules identified above. The amount of USFC, per kWh, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per kWh, pursuant to the formula above, the following definitions shall apply:

Reconcilable Customer Assistance Program (CAP) Costs – The difference between discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 27% offset factor.

USFC – Universal Service Fund Charge to be included in the rate for each kWh of Variable Distribution Service Charge calculated under Rate Schedules R and R-H to recover Reconcilable CAP Costs plus certain LIURP related expenditures.

C - Cost in dollars of the Reconcilable CAP Costs for the projected period.

L - Incremental LIURP related expenditures not included in base rates. This shall include expenditures for LIURP Health and Safety programming and beginning in 2025, an additional $1,000,000 increase in the annual budget of LIURP program costs.

E - The net overcollection or (undercollection) of Universal Service Fund Charges. The net overcollection or undercollection shall be determined for the most recent period, beginning with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Included in the "E" factor will be Reconcilable CAP Costs, and LIURP related expenditures.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous USFC.

I - Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period. The interest calculation will not apply to LIURP amounts.

S - projected kWh of electric service to be billed under Rate R and Rate RH (exclusive of CAP Rider) during the projected period when rates will be in effect.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.
The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective January 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

(I) Denotes Increase

PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's proposed consumer education plan. The proposed plan shall consist of the cost of the consumer education plan approved in Docket M-2008-2032274, P-2008-2062739 and R-2024-3046931.

Applicability: The surcharge shall be a per customer charge calculated to the nearest one cent, which shall be added to the fixed distribution rates for billing purposes for all customers. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is a 5.0 cent charge per month for Rates R, RH and CAP, Class 2 and 3 is a 0.0 cent per month for Rate GS and for Class 4 is 0.0 cent credit per month for Rates HT and PD with an April 1, 2025 effective date. **(C)**

Billing Provisions: The surcharge shall be calculated on an annual basis using the following formula:

$$MC(n) = \frac{(C + E + I)}{R(n)} \times \frac{1}{(1-T)}$$

C – the cost of the consumer education program includes the following:

Consumer Education Costs –The incremental cost of programs designed to educate consumers regarding the competitive market such as advertising, customer notices, informational materials cost, and any other incremental cost associated with educating consumers about the market and about available mitigation programs offered by the Company less any cost covered by the Company's Paragraph 37 Funds. Costs associated with this program shall be expensed to FERC account 910. These costs shall also include the costs of providing expanded universal service program education and outreach to low and moderate income customers to recover up to $800,000 per year commencing on January 1, 2025.

MC(n) = consumer education cost per customer for customer class n including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31

I – Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

N – Customer class where 1 = residential, 2 = C&I up to 100 kW, 3 = C&I from 100-500 kW, and 4 = C&I >500 kW

R – The total delivery service customers for the customer class for the application period where the application period shall be the 12-month period commencing annually on April 1 after the reconciliation period.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filing Schedule: The estimated surcharge shall be filed by February 1 of each year to be effective on the following April 1. The application period shall be the 12 months that start the April 1 effective date of the surcharge. The Bureau of Audits shall audit the data in the surcharge on an annual basis.

(C) Denotes Change

TRANSMISSION SERVICE CHARGE (TSC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of all transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's default service load.

Applicability: The surcharge shall be assessed to all default service customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The surcharge shall be calculated on a semi-annual basis using the formula below:

$$\mathbf{TSC(n)} = \frac{\mathbf{(C+E+I)}}{\mathbf{S(n)}} \times \frac{\mathbf{1}}{\mathbf{(1-T)}}$$

TSC(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Network Integration Transmission Service costs and Non-Firm Point to Point Transmission costs. Included in the cost to be recovered is a working capital (WC) component as defined below.

Charges assessed by PJM for network service within the PECO zone. Included in such charges are costs for the base network service charge for the zone as well as any load serving entity charges assessed to PECO under the PJM OATT that are listed in PECO's Supply Master Agreement Exhibit D as the responsibility of the Buyer. Included in the cost to be recovered is a working capital (WC) component as defined below.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $274 per mW. WC is a component of the 'C" factor

E – The estimated over or under recovery from the applicable reconciliation period.

I - interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001. This interest rate basis becomes effective with January 2016 over or under collections.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated default service sales for residential class and the street lighting class in the applicable application period. For the commercial and industrial class it shall be the estimated billed demand for the applicable application period. The application period will be the period when rates will be in effect.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Transmission Service Rate:

R= $.00787 per kilowatt hour	**(D)**
RH= $.00787 per kilowatt hour	**(D)**
Small C&I = $1.57 per billed transmission kW	**(D)**
Large C&I = $1.44 per billed transmission kW	**(D)**
Street Lighting = $.00001 per kilowatt hour	**(D)**

(D) Denotes Decrease

NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362.

Applicability: The surcharge shall be assessed to all distribution customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential, Small C&I and Street Lighting class rate schedules as described below.

For Rates PD, HT, and EP (Large C&I class), a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT. Customer's PLC will be computed to the nearest kilowatt. The NBT shall be recovered through a separate charge listed on customers' bills.

The surcharge shall be calculated on a semi-annual basis using the formula below:

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where;

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

> Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges, Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362.

E – The estimated over or under recovery from the applicable reconciliation period.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate:

R= $.00408 per kilowatt hour	**(D)**
RH= $.00408 per kilowatt hour	**(D)**
Small C&I = $0.87 per billed distribution kW	**(D)**
Large C&I = $1.08 per kW based on the PJM PLC	**(D)**
Street Lighting = $.00015 per kilowatt hour	**(D)**

(D) Denotes Decrease

PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS (EEPC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's Phase IV Energy Efficiency and Conservation Program Costs (EEPC).

Applicability: The surcharge shall be a calculated for billing purposes for all customers. The EEPC shall be charged to each rate schedule using the following units:

Phase IV **(C)**

Rates R, RS, RH:	$0.00176/kWh
Rates GS:	$0.00392/kWh
Rate SL-E,	($0.08)/location
Rate SL-C	($0.07)/location
Rate AL:	($0.02)/location
Rate TLCL:	($0.00085)/kWh
Rates HT, PD, EP:	$1.18/kW based on PJM Peak Load Contribution (PLC)

The Variable Distribution Service charges, for the residential rate schedules shall include the above listed EEPC surcharge. For the municipal lighting rate schedules, the applicable variable or fixed distribution service charges shall include the EEPC surcharge.

For Rate GS, the EEPC shall be recovered through a separate variable distribution charge listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EEPC. Customer's PLC will be computed to the nearest kilowatt. The EEPC shall be recovered through a separate variable distribution charge listed on customer bills.

Calculation of EEPC Surcharge and the Over/Under Recovery:
Billing Provisions: The surcharge and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

$$EEPC(n) = \frac{(C-E)+(SWE)}{(BU)} + \frac{(PDR)}{(1-T)} \times \frac{(1)}{}$$

C – The cost of the Energy Efficiency and Conservation Program includes: all expenditures, of the individual programs such as materials, equipment, installation, custom programs, evaluation measurement/verification, educating customers about availability to the extent not included in Consumer Education cost, not recovered through any separate recovery mechanism, and any other cost associated with implementation of the programs. Costs that relate to measures that are applicable to more than one rate class or that are shown to provide system-wide benefits, will be allocated to each class based on the ratio of class-specific projected program costs to the total projected program costs. The program costs are those approved by the PAPUC and audit costs for the Phase IV program ending May 31, 2026

E - The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

SWE – The cost in dollars of the PaPUC's Statewide Evaluator. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

PDR – The savings/costs from the portion of projected EE Peak Demand Resources (PDR) nominated into PJM's Forward Capacity Market (FCM). The Company will apply any proceeds/deficiencies from nominated PDR to the appropriate customer classes. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

BU – The total Billing Units for the applicable recovery period.

T – The current Pennsylvania gross receipts tax rate included in base rates.

n - The rate class for which the EEPC is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting
Residential - Rates R, RH
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP
Street Lighting – Rates SLE, SLC, AL, TLCL

Filings and Reconciliations: The estimated EEPC shall be filed by May 1 each year to be effective through May 31.
The first surcharge, effective June 1, 2021 will contain "C" and "E" factors calculated as follows: The "C–factor" will have two components; one including Phase III costs and the other including Phase IV costs. The Phase IV component will be set using projected costs for the 12 month period from June 1, 2021 through May 31, 2022. The Phase III component will be set using any Phase III costs from projects started prior to the end of Phase III, but not yet billed as of June 1, 2021. For the "E-factor" over/under rate will include the Phase III costs for the 10 month period from June 1, 2020 through March 31, 2021.

The second EEPC, effective June 1, 2022, will be calculated as follows: the "C-factor" will include Phase IV costs for the period June 1, 2022 through May 31, 2023 and the "E-factor" will include costs for 12 months comprising Phase III costs for the 2 months of April and May 2021 and Phase IV costs for the 10 months of June 1, 2021 through March 31, 2022. Subsequent EEPC's, effective June 1 each year will be calculated using a 12 month "C factor" for the period June 1 through May 31 and an "E factor" for the period of April 1 through March 31.

A reconciliation statement filing, in accordance with C.S. Title 66 §1307(e), will be made by April 30 of each year. The last Phase III only reconciliation statement will be for the 10 month period from June 1, 2020 through March 31, 2021. Phase IV reconciliation statements will be for the 12 month period April 1 through March 31 of each plan year. The first Phase IV reconciliation statement will cover the period April 1, 2021 through March 31, 2022 and include 2 months (April and May) of Phase III revenues and expenses and 10 months of Phase IV revenues and expenses (June through March). The EEPC mechanism is subject to annual audit review by the Bureau of Audits.

(C) Denotes Change

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a value of 0.00 % will apply consistent with the Commission Order dated October 22, 2015 at Docket No. P-2015-2471423, approving the DSIC. **(C)**

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Poles and Tower (Account 364);
Overhead conductor (Account 365) and underground conduit and conductors (Accounts 366 and 367);
Line transformers (Account 368) and substation equipment (Account 362);
Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, converters and condensers;
Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective January 1, 2016.

(C) Indicates Change

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective January 1, 2016, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between September 1, 2015 and November 30, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **[NOTE: UTILITY MAY ELECT TO INCLUDE STFT CALCULATION IN THE PTRR COMPONENT].**

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on three-month period of projected annual revenues.

[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY].

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

3. Quarterly Updates: Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, Bureau of Audits and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq*.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change or through an explanatory bill insert included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes.

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

RATE R RESIDENCE SERVICE

AVAILABILITY.
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and is served through the same meter as the dwelling unit; (g) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and requires separate metering service as a result of wiring restrictions or legal requirements.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37 1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $11.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.19

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.10276 per kWh **(I)**

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

(I) Denotes Increase

RATE RH RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $11.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.19

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.10276 per kWh for all kWh. **(I)**
WINTER MONTHS. (October through May)
$0.07923 per kWh for all kWh **(I)**

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE. The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE. Where a portion of the service provided is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS. Standard.

(I) Denotes Increase

RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option commencing September 1, 2021.

RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP.

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Commencing September 1, 2021, for default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, the Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated.

   If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

2. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period. If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

4. Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS.

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application online to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The link to the online application can be found on the Green Power Connection pages on peco.com.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

Any interconnection application in (a) Conditionally Approved or (b) Engineering Study status will expire in 6 months unless a customer-generator takes steps to (a) satisfy the conditions of the Conditional Approval or (b) pays for and moves forward with the Engineering Study. A customer-generator will be notified of the upcoming interconnection application expiration 45 calendar days ahead of the expiration date. Prior to the expiration of the 6-month period, a customer-generator may request an extension to resolve the outstanding issues surrounding their interconnection application. Upon a showing of good cause, the interconnection application expiration date will be extended up to but no more than 180 calendar days.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

RATE-GS GENERAL SERVICE

AVAILABILITY.
Service for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

Transformed service from the Company's distribution system where the company installs, owns, and maintains any transforming, switching and other receiving equipment required.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires – If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$ 24.47 for single-phase service without demand measurement, or
$ 31.20 for single-phase service with demand measurement, or
$ 74.66 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$11.50 per kW of billed demand **(I)**

($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00392per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and ¾.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.

For those customers with demand measurement the billing demand will be determined as follows:

(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
(b) For customers with measured demand or maximum demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, or (ii) 40% of the maximum contract demand.

If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge, plus the Variable Distribution Service Charge per KW of minimum billing demand as described above. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus per KW of billing demand. In addition to the above, for customers in Procurement Class ¾ charges will be assessed on PJM's reliability pricing model.

(I) Denotes Increase

RATE-GS GENERAL SERVICE (continued)

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company, non-profit rescue squad, non-profit ambulance service or a non-profit senior citizen center meeting the requirements set forth below, may, upon application, elect to have its electric service billed at any of the following rate schedules: Rate R Residential Service or Rate R-H Residential Heating Service, as appropriate for the application. The execution of an electric service contract for a minimum term of one year at the chosen rate will be required of any entity electing service pursuant to the options provided by this provision.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY. A separately metered service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of firefighting services.

NON PROFIT SENIOR CITIZEN CENTER. A separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided. The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) or the Commonwealth as a non-profit entity and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

NON-PROFIT RESCUE SQUAD. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility recognized by the Pennsylvania Emergency Management Agency (PEMA) or the Pennsylvania Department of Health as a provider of rescue services. The use of electric service at this location shall be to support the activities of the non-profit rescue squad. Any fund raising activities at this service location must be used solely to support the non-profit rescue squad operations.

NON-PROFIT AMBULANCE SERVICE. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility licensed by the Pennsylvania Department of Health as a provider of ambulance services. The use of electric service at this location shall be to support the activities of the non-profit ambulance service. Any fund raising activities at this service location must be used solely to support the non-profit ambulance service operations.

TERM OF CONTRACT.

The initial contract term shall be for at least one year.

PAYMENT TERMS.

Standard.

RATE-PD PRIMARY DISTRIBUTION POWER

AVAILABILITY.

Untransformed service from the primary supply lines of the Company's distribution system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $297.61

VARIABLE DISTRIBUTION SERVICE CHARGE:
$11.41 per kW of billing demand **(I)**
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. The 25kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, plus in the case of Procurement Class 3/4 customers, charges assessed under PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

(I) Denotes Increase

RATE-HT HIGH TENSION POWER

AVAILABILITY.
Untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $371.68

VARIABLE DISTRIBUTION SERVICE CHARGE:
$7.24 per kW of billing demand **(I)**
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.24 per kW of measured demand.
For customers supplied at 69,000 volts: $1.94 per kW of measured demand.
For customers supplied over 69,000 volts: $1.94 per kW of measured demand.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract. The 25 kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, and modify less the high voltage discount where applicable plus in the case of Procurement Class 3/4 customers, charges assessed on PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

(I) Denotes Increase

RATE EP ELECTRIC PROPULSION

AVAILABILITY.
This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances. Rate EP is also available to legacy transformed service that is receiving service pursuant to Rate EP as of January 1, 2020; Rate EP or successor rates shall remain available for such legacy transformed service until at least December 31, 2040.

CURRENT CHARACTERISTICS.
Standard sixty hertz (60 Hz) high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $1,292.35 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE:
$6.22 per kW of billing demand **(I)**
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.24 per kW.
For delivery points supplied at 69,000 volts: $1.94 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $1.94 per kW for first 100,000 kW of measured demand.

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class ¾.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company. Conjunctive billing under this section is available regardless of whether the conjunctively-billed sites take generation service from one or more generation suppliers and/or PECO default service.

(I) Denotes Increase

RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.
To any residential or commercial customer with outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rates SL-S and SL-E.

MONTHLY RATE TABLE.
A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires, and a luminaire, including lamp, reactor, and control. The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation

	PRICE PER LIGHTING UNIT DISTRIBUTION (Co.Pole)	(Cust.Pole)	
MERCURY-VAPOR LAMPS			
100 Watts (nominally 4,000 Lumens)	$20.96	$18.74	**(C)**
175 Watts (nominally 8,000 Lumens)	$28.35	$26.24	**(C)**
250 Watts (nominally 12,000 Lumens)	$34.88	$33.00	**(C)**
400 Watts (nominally 20,000 Lumens)	$44.89	$42.40	**(C)**
400 Watts Floodlight (nominally 22,000 Lumens)	$48.60	$46.11	**(C)**
SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)	
70 Watts (nominally 5,800 Lumens)	$28.75	$26.59	**(C)**
250 Watts (nominally 25,000 Lumens)	$45.52	$43.03	**(C)**
400 Watts (nominally 50,000 Lumens)	$49.75	$47.24	**(C)**
400 Watts Floodlight (nominally 50,000 Lumens)	$53.43	$50.94	**(C)**

Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps is not available as of January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

METAL HALIDE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)	
100 Watts (nominally 7,800 Lumens)	$42.64	$41.24	**(C)**
175 Watts (nominally 13,000 Lumens)	$44.72	$42.11	**(C)**
250 Watts (nominally 20,500 Lumens)	$47.28	$44.70	**(C)**
400 Watts (nominally 36,000 Lumens)	$52.62	$50.19	**(C)**
1000 Watts (nominally 110,000 Lumens)	$91.54	$89.16	**(C)**
HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)	
50 Watts (nominally 4,000 Lumens)	$28.57	$26.38	**(C)**
70 Watts (nominally 5,800 Lumens)	$32.35	$29.93	**(C)**
100 Watts (nominally 9,500 Lumens)	$34.14	$31.73	**(C)**
150 Watts (nominally 16,000 Lumens)	$37.24	$34.83	**(C)**
250 Watts (nominally 25,000 Lumens)	$43.61	$41.15	**(C)**
400 Watts (nominally 50,000 Lumens)	$52.70	$50.27	**(C)**
1,000 Watts (nominally 130,000 Lumens)	$60.62	$59.67	**(C)**
LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)	
35 Watts (nominally 3,300 Lumens)	$46.84	$44.57	**(C)**
53 Watts (nominally 5,000 Lumens)	$48.00	$45.74	**(C)**
87 Watts (nominally 8,300 Lumens)	$49.55	$47.28	**(C)**
163 Watts (nominally 15,800 Lumens)	$53.89	$51.62	**(C)**
215 Watts (nominally 20,000 Lumens)	$56.49	$54.22	**(C)**

ENERGY SUPPLY CHARGE. Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

(C) Denotes Change

RATE POL PRIVATE OUTDOOR LIGHTING (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of lamps and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, all standard service-supply lines, and all Lighting Units. The customer will install, own and maintain all poles on the customer's property and all service extensions on the customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge. Any additional investment will be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Monthly Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

(A) Location Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

Customer construction shall meet the Company's standards which are based upon the National Electrical Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work. The customer shall obtain and submit any permits or other authority requisite to the installation and operation of the Lighting Units served hereunder.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Private Outdoor Lighting installation, the Company will charge for removal or replacement of the installations and the associated poles and conductors used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

(B) Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least three years.

PAYMENT TERMS.
Standard.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
To any municipal entity for outdoor lighting of streets, highways, bridges, parks and similar places located outside the city and county of Philadelphia, including directional highway signs at locations where other outdoor lighting service is established hereunder, only if all of the distribution facilities and equipment are installed, owned, and maintained by the Company.

ANNUAL RATE TABLE
The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation.

Incandescent Filament Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution	
320 Lumens	32	$139.84	**(C)**
600 Lumens	58	$195.98	**(C)**
1,000 Lumens	103	$273.01	**(C)**
2,500 Lumens	202	$375.18	**(C)**
6,000 Lumens	448	$426.09	**(C)**
10,000 Lumens	690	$515.03	**(C)**

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution	
4,000 Lumens	115	$321.35	**(C)**
8,000 Lumens	191	$338.77	**(C)**
12,000 Lumens	275	$360.55	**(C)**
20,000 Lumens	429	$422.60	**(C)**
42,000 Lumens	768	$600.59	**(C)**
59,000 Lumens	1,090	$674.95	**(C)**

Service to the above listed Incandescent Filament Lamps and Mercury-Vapor Lamps is not available after January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken incandescent filament or mercury vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

High Pressure Sodium-Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution	
5,800 Lumens	94	$319.12	**(C)**
9,500 Lumens	131	$346.74	**(C)**
16,000 Lumens	192	$389.02	**(C)**
25,000 Lumens	294	$441.31	**(C)**
50,000 Lumens	450	$524.92	**(C)**

Light-Emitting Diode Lamps Size of Lamp (Nominal)	Billing Watts	Distribution	
3,300 Lumens	35	$562.53	**(C)**
5,000 Lumens	53	$576.51	**(C)**
8300 Lumens	87	$595.02	**(C)**
15,800 Lumens	163	$647.13	**(C)**
20,000 Lumens	215	$678.35	**(C)**

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment, Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of Lightning Units and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. The Company will install, own, and maintain its distribution facilities and equipment on the public highways to the extent warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge, with any additional investment to be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other electric distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Annual Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Annual Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

The installation cost of lighting on private property, or for contracts of less than standard term, shall be paid by the customer.

4. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Street Lighting installation, the Company will charge for removal or replacement of the installation and the associated poles and conductors used exclusively for the installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

7. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting installation shall be for at least three years.

PAYMENT TERMS.
Bills will be rendered monthly. Each month, for the purpose of prorating the price, shall be considered 1/12 of a year.

RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$7.57 per Service Location (as defined below) *	**(I)**
VARIABLE DISTRIBUTION CHARGE:	$0.02515 per kWh	

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.

* The service location charge includes an Energy Efficiency Program Surcharge ($0.08) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.

A Service Location is the Point of Delivery on the Company's secondary circuit. That connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.
2. Ownership of Utilization Facilities.

a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-E, such sale will include the supporting pole or post.

b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.

Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

c. Service to Group of Utilization Facilities:

AERIAL SUPPLY

When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

UNDERGROUND SUPPLY

When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

(I) Denotes Increase

RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES (continued)

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 11.

Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.

8. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the customer to the Company not less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

9. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

10. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

11. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

12. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

13. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to:
  a. Measurement of energy usage at the individual Utilization Facility level.
  b. Customer control of the lamp's burning hours.
  c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
  d. Ability of customer to dim the lights (LED only).

(B) Provides energy usage to the Company as described below under Data Requirements.

(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$6.41 per Service Location (as defined below)*	**(I)**
VARIABLE DISTRIBUTION CHARGE:	$0.04754 per kWh	

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.

* The service location charge includes an Energy Efficiency Program Surcharge of ($0.07) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.
The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:

8. Manufacturer-rated wattage
9. Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
10. Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.
Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.

1. Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer. If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

(I) Denotes Increase

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

2. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, Company-approved Smart Control Modules, conductors, molding and supporting insulators between the luminaires and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location. The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-C, such sale will include the supporting pole or post.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post, foundation with 90 degree pipe bend and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit. Except as provided in Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.
   c. Service to Group of Utilization Facilities:

      AERIAL SUPPLY

      When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

      UNDERGROUND SUPPLY

      When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 10.

   Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated Service Location on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations, or any replacement of the Company-approved Smart Control Module, shall be furnished by the customer to the Company not less than 30 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

10. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

11. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

12. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.
Standard single phase secondary service.

RATE TABLE.
SERVICE LOCATION CHARGE: $4.22 PER LOCATION **(I)**

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.02232 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($0.00085) per kWh
ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours. The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

SPECIAL TERMINATION RIGHTS
Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider. In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer. The customer may then, at its discretion, notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days. If the customer has not removed its facilities within 30 days, then PECO may, at its sole discretion and upon 72-hour notice, physically remove the customer facility as a means of terminating service to that facility. Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals. Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL. In addition, the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs, use of truck or other equipment, fuel costs, and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals. PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage.

TERM OF CONTRACT.
The initial contract term for each signal light installation and constant load device shall be for at least one year.

PAYMENT TERMS.
Standard.

(I) Denotes Increase

RATE BLI BORDERLINE INTERCHANGE SERVICE

AVAILABILITY.
Electric service supplied under reciprocal agreements, to neighboring electric utilities for resale in their adjacent territory at delivery points where the Company in its judgment can provide capacity in excess of the requirements of present and prospective customers in its own territory and for periods fixed by contract and terminable after the expiration of the initial term if capacity is no longer available.

CURRENT CHARACTERISTICS.
Standard primary or secondary service.

MONTHLY RATE TABLE.
For contracts newly entered on or after January 1, 2019, the Company will provide borderline interchange service under the Variable Distribution Service Charge of the appropriate Base Rate, plus an amount equal to 1% per month on the additional investment in facilities required by the Company to deliver and meter the service supplied. The appropriate Base Rate is the rate under which the Customer would be served if located within the Company's franchised service territory.

The Company will not apply this rate to contracts entered prior to January 1, 2019 unless the Company and the customer mutually agree to do so

MEASUREMENT.
The energy delivered may be metered or may be estimated from the purchaser's resales plus an agreed-upon correction to cover transformation and distribution losses.

TERM OF CONTRACT.
The initial contract term shall be for at least five years, and thereafter from year to year until terminated by 60 days' notice from either party, unless the Company and the customer mutually agree to a different term in the contract for service.

PAYMENT TERMS.
Payment of amounts billed shall be made within 15 days from date of bill.

RATE AL – ALLEY LIGHTING IN CITY OF PHILADELPHIA

APPLICABILITY. To multiple, unmetered lighting service supplied the City of Philadelphia to operate lamps and appurtenances for all night outdoor lighting of alleys and courts that are installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities. This rate shall no longer be available to new lighting installations effective January 1, 2011.

LIGHTING DISTRIBUTION SERVICE DEFINED. All night outdoor lighting of alleys and courts by lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement, removal or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.
SERVICE LOCATION CHARGE: $2.66 Per Location (as defined below)* **(I)**
*The service location charge includes an Energy Efficiency Program Surcharge of ($0.02)

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE.

PLAN OF MONTHLY BILLING.
Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION.
The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

(I) Denotes Increase

APPLICABILITY INDEX OF RIDERS

Introductory Statement

Customers under different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the Base Rate under which they are provided service. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the customer and the Company as the case may require, notwithstanding anything to the contrary contained in the Base Rate to which the rider is applied.

	Page No.	R	RH	RS	GS	PD	HT	POL	SL-S	SL-E	SL-C	EP	BLI	AL
Riders														
Capacity Reservation Rider	75-79			X	X	X	X					X		
CAP Rider	80	X	X											
Casualty	81			X	X	X	X					X		
Construction	82				X[1]	X	X					X		
Economic Development	83-84				X	X	X							
Electric Vehicle DCFC Pilot Rider (EV-FC)	85-88				X	X	X							
Emergency Energy Conservation	89						X					X		
Investment Return Guarantee	90				X	X	X							
Night Service GS	91				X									
Night Service HT	92						X					X		
Night Service PD	93					X								
Receivership Rider	94				X	X	X	X	X	X	X	X		X
Temporary Service	95	X	X	X	X	X	X							

[1]Available only to Rate GS customers with demands greater than 500kW

PILOT CAPACITY RESERVATION RIDER (CRR)

PURPOSE.
This Rider sets forth the eligibility, terms and conditions applicable to Customers who operate generation in parallel with the Company distribution system and for whom the Company needs to reserve electric capacity to serve their load when the customer's generation is offline.

This Rider also sets forth the eligibility, terms and conditions applicable to Customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion.

DEFINITIONS.
Demand and billing demand are defined in tariff sections "Definitions of Terms and Explanation of Abbreviations" and Section 15 of "Rules and Regulations".

(1) Ability to Shed Load – The capability of the customer to reduce or interrupt its total connected load as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(2) Capacity Reservation – The contracted amount of firm electrical distribution capacity, expressed in kW, reserved by the Company solely to meet the capacity requirement for which a customer has contracted under the CRR.

(3) CRR Level –

a. For customers with Parallel Generation, the portion of their Capacity Reservation equal to the contracted percentage of the Generator Nameplate Capacity of their customer-owned Parallel Generation, determined pursuant to the provisions of the section of this Rider titled "Capacity Reservation vs. CRR Level Designation."

b. For customers seeking to reserve capacity for new business growth or expansion, the portion of their Capacity Reservation for which they have contracted under the CRR for that purpose.

(4) "Failure To Shed Load" Penalty – A charge assessed to a customer with a Capacity Reservation, CRR Level, or both that were set in whole or part based upon Ability to Shed Load when that customer's generator goes offline and the customer does not shed load as agreed upon.

(5) Generator Nameplate Capacity **–** The maximum rated output of a generator under specific conditions designated by the manufacturer.

(6) Operational Flexibility in Operation of Generation – The capability of the customer to flexibly operate multiple generating facilities as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(7) Parasitic Load – The power consumed by the equipment supporting the operation of a customer's generation.

(8) Parallel Generation – Non-utility generating facility(s) approved for Parallel Operation.

(9) Parallel Operation – Occurs when a non-utility generating facility(s) interconnected with and operates while connected to PECO's distribution system, where the potential exists for electricity to flow from said generating facility(s) into PECO's electric distribution system.

(10) Uncovered Demand – The difference between the customer's CRR Level and the customer's Capacity Reservation

APPLICABILITY/AVAILABILITY.
Applicable to customers, with customer generating facilities that have generating capacity of 100 kW or greater and are first placed online, or are granted approval for Parallel Operation, after January 1, 2016. This includes but is not limited to Qualifying Facilities or Small Power Producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company's distribution system. All such customers will be supplied under the provisions of this rider, the customer's applicable Base Rate, and other applicable riders. Customers who wish to reserve available electrical capacity in excess of their present demand for new business growth or expansion may do so under this rider.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

NOTICE BEFORE COMMENCEMENT OF CRR SERVICE.

The customer shall not commence initial operation of any other source of supply in parallel with the Company's distribution lines until written permission is given by the Company for such parallel operation. Before a customer is placed on the CRR, the Company must provide written notice to the customer that includes the Capacity Reservation under the CRR and informs the customer that, upon receiving service under the CRR, capacity beyond this amount may not be available to serve the customer. The Company shall have the right to inspect the customer's installation prior to providing such written permission, and at any reasonable time thereafter in accordance with Tariff Rule 9.3.

CAPACITY RESERVATION VS. CRR LEVEL DESIGNATION.

The maximum firm capacity available to be reserved will be determined by the Company based upon its review of capacity available on its system at the time that a request for Capacity Reservation is made.

In all cases, if the requested electric capacity is not available the customer shall pay all cost to the Company of any construction necessary to meet the customer's Capacity Reservation requirement. To the extent that the requested capacity is needed for new business growth or expansion, the standard revenue test will apply when calculating the cost to be paid by the customer.
The Company must reserve capacity for a customer based upon an amount that the Company and customer agree accurately reflects the maximum demand that the Company must stand ready to serve to that customer.

For customers generating in parallel with the Company's distribution system:

For billing purposes, PECO will set the associated CRR Level as designated below:

For customers who have Generator Nameplate Capacity of greater than 100 kW but less than or equal to 5,000 kW, the CRR Level will be 60% of the Generator Nameplate Capacity.

For customers who have Generator Nameplate Capacity of greater than 5,000 kW but less than or equal to 10,000 kW, the CRR Level will be 50% of the Generator Nameplate Capacity.

Any customer, regardless of size of load or generation, may initiate negotiation as set forth below to designate the CRR at a level other than these levels.

Batteries and other electrical storage shall not be deemed to be generators for purpose of the CRR, and the nameplate capacity of storage or battery equipment shall not be included as, or treated as equivalent to, Parallel Generation for purposes of determining a customer's Capacity Reservation or CRR Level.

For customers who want to reserve capacity for new business growth or expansion, both the Capacity Reservation and the associated CRR Level will be determined by negotiation.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

NEGOTIATIONS FOR OPERATION OF CUSTOMER GENERATION.
If the CRR Level is set through negotiations for customers generating in parallel with the Company's distribution system, the following will apply:

The customer and PECO will meet to discuss customer operations. After such discussions, the customer may designate a CRR level other than as set forth above, based upon one or more of the following factors as defined above:

1. Parasitic Load: This will be subtracted from the customer's Generation Nameplate Capacity prior to determining the CRR Level.

2. Operational Flexibility in Operation of Generation: A customer with multiple generating units may commit to operate its facilities as a means of offsetting some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level

3. Ability to Shed Load: A customer may commit to shed some portion of its total connected load to offset some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level.

If PECO accepts the customer's designated Capacity Reservation and CRR Level then both amounts shall be set at the customer-designated level.

If PECO does not accept the customer's designated Capacity Reservation and or CRR Level then PECO may file a complaint with the PUC (to be referred to the Office of Mediation). Pending resolution of the complaint the Capacity Reservation and CRR Level shall be set at: as follows (subject to retrospective revision upon completion of the mediation/litigation):

- For customer designations based upon Parasitic Load, Operational Flexibility, or both, the Capacity Reservation and the CRR Level will be set at the customer-designated levels.

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- For customer designations based in whole or part on Ability to Shed Load, the Capacity Reservation and CRR Level will be set at PECO-designated levels,

PROCEDURES TO CONFIRM MODE OF CUSTOMER GENERATION OPERATION
If a customer's CRR Level is set by negotiation based upon Parasitic Load or Operational Flexibility of Generation, or both, then:

- The customer shall inform PECO in writing if its generation operations differ materially from the mode of operations used to set the CRR Level;
- The customer shall verify to PECO once each calendar year that its generator operations in the prior year did not differ materially from the mode of operations used to set the CRR Level; and
- PECO shall have the right to conduct an audit of customer operations to determine whether generator operations differed materially from the mode of operations used to set the CRR Level.

NOTICE OF OPERATION CONTRARY TO A NEGOTIATED CRR LEVEL AND RESET PROVISION.
If, in its determination, PECO believes that a customer has operated its distributed generation units in a manner contrary to the mode of operations used to set the CRR Level, PECO may issue a written violation notice to the customer.

A customer shall not be deemed to have operated its distributed generation units in a manner contrary to the mode of operation used to set its CRR Level if both of the following are true:

- The customer was required to alter its mode of operations in response to a directive from PECO or because of conditions existing on PECO's distribution system.
- The customer's actual demand does not exceed its Capacity Reservation at any time.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

PECO will rescind a violation notice if, within 30 calendar days of receiving the violation notice, a customer furnishes evidence showing that it operated its distributed generation units consistent with the mode of operations used to set the CRR during the period in question. If PECO is not satisfied that the information provided by the customer demonstrates that operated its distributed generation units consistent with the mode operations used to set the CRR Level, PECO may file a complaint with the Commission and the Commission's determination shall prevail on whether the notice of violation will be deemed to be confirmed. If a customer does not furnish such evidence within 30 calendar days of receiving the violation notice, the violation notice is confirmed.

If a customer receives two confirmed violation notices within a 24-month period; the customer's going-forward CRR for the next 12 months shall be set at levels based upon the actual operations that led to the violation notice. Thereafter, the CRR may be reset to a lower levels only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

PENALTY AND RESET FOR FAILURE TO SHED LOAD.
For customers with a Capacity Reservation CRR Level or both that were set in whole or part based upon Ability to Shed Load, the following penalty and reset provisions shall apply:

- Penalty: If the customer's generator goes offline and the customer does not shed load as agreed upon the customer will be assessed a "Failure to Shed Load" Penalty" calculated by determining the amount of load that the customer agreed to shed, but did not shed, and applying a penalty charge equal to 125% of the full demand charge in the prevailing rate to that amount of load on the first such occurrence, and 150% of the full demand charge in the prevailing rate to that amount of load for the second and subsequent occurrences, for the month in which the load shedding did not occur.

- Reset: The customer's going-forward Capacity Reservation and CRR Level for the next 12 months shall be set at a level based upon the actual operations that occurred during the failure to shed load. Alternatively, the customer can opt to pay PECO for the actual cost of the required upgrades to PECO's distribution facilities to allow the customer to use delivery service at the higher operating level during outages in accordance with PECO's line extension policy (Tariff Rule 7.2). Thereafter, these amounts may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

TEMPORARY DISCONNECTION OF CUSTOMER SERVICE.
PECO shall have the right to temporarily disconnect the customer on an emergency basis if, in PECO's opinion, the customer's failure to shed load as agreed creates a risk to PECO's distribution system or service to other customers.

BINDING LEGAL DUTY.
A CRR customer whose CRR Level is set at negotiated level based in whole or part upon the customer's representation that it has an Ability to Shed Load will be deemed to have a binding legal duty to shed such load.

RATE AND BILLING.
Subject to the Minimum Charge Provisions below, the demand charges under the customer's underlying applicable Base Rate of GS, HT, PD, and EP apply to the billing demand determined under the CRR.

Customers will be billed monthly their CRR Level plus actual electric demand and usage except as follow below:

For customers who reserve capacity due only to Parallel Generation, if such customer's actual registered demand is greater than the customer's Uncovered Demand for a given month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to such difference, but in no event will the CRR Level be less than zero.

For customers who reserve capacity for business growth or expansion, if the customer's actual registered demand in a given month includes any portion of the CRR Level contracted for expansion for that month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to said portion, but in no event will the CRR Level be less than zero.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

MINIMUM CHARGE.

Subject to the Rate And Billing provisions above the monthly minimum charge under the customer's underlying applicable Base Rate of GS, HT, PD, and EP will be calculated based on the minimum demand determined in accordance with the CRR. .
The monthly minimum demand charge for a customer reserving capacity due only to Parallel Generation will be the greater of:

1. The demand as registered by the customer's meter;
2. An amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand or
3. Any designated contract minimum.

The monthly minimum demand for a customer reserving capacity due only to new business growth or expansion will be an amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand
.
The monthly minimum customer charge will be determined by applying the minimum demand to the applicable demand charge for the Customer's underlying applicable Base Rate.

TERM OF CONTRACT.

The term of a CRR contract shall be three years for all non-negotiated CRR applications. For negotiated CRR Levels, the contract term shall be negotiated. There is no right to automatic renewal of a CRR; upon the expiration of the contract term, the Company will review available capacity on its system and, if such capacity is available, the parties will enter into a new CRR contract using the procedures set forth above.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum ($10 for non-heating customers) and will not be eligible to obtain Competitive Electric Supply or participate in budget billing. Commencing September 1, 2021 these customers will not be eligible to select the Time-Of-Use default service option.

Based on the applicable level of income and number of household members, CAP customers will receive a monthly fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2018-3005795.

CERTIFICATION/VERIFICATION.
Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in various energy education and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $10 for Residential customers or $20 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness; whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate–that is, if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

CASUALTY RIDER

AVAILABILITY/APPLICABILITY.
To service provided during a period when a customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the customer's control ("Period of Interruption").

NOTICE REQUIRED.
Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration. Written requests must be submitted to the Company within 30 calendar days after the end of the Period of interruption.

RATE IMPACT.
During Periods of Interruption, PECO Energy will not apply guarantees of revenue (power factor adjustment, minimum billing demand, and contract minimum) as contained in the customer's Contract, but will apply the actual registered demand. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

BILLS PRORATED.
Bills supplied shall be prorated, based upon the actual level of operation during the Period of Interruption.

RETURN TO NORMAL USE.
The customer shall use reasonable diligence in resuming the use of service as provided in the Contract.

TERM OF CONTRACT.
The initial contract term shall be extended for a period equal to the Period of Interruption so that the Company shall secure a working term at full connected load equal to the term of the Contract.

CONSTRUCTION RIDER

AVAILABILITY/APPLICABILITY.
To service provided during or immediately following a major construction or expansion period or during a receding load period, after the expiration of the initial contract term, while a business is in process of dissolution. A major construction or expansion period is defined as a construction or expansion project undertaken by the customer which upon completion will require an upward modification of the customer's contract limits.

RATE IMPACT.
During the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of the initial contract term, PECO Energy will not apply the following guarantees of revenue: power factor adjustment, minimum billing demand, and contract minimum. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

RIDER TERM.
The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than three successive renewals of the rider term on major construction projects. Its application during a receding load period subsequent to the completion of an initial contract term shall be for not more than one year.

TERM OF CONTRACT.
The initial contract term for service to expanding locations to which this rider is applied shall be extended for a period corresponding to the total number of months this rider is applied to the customer's bill during construction or expansion of the customer's facility.

OTHER RIDERS.
This rider, when applied to service to temporary installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

For customers taking service under PECO's Capacity Reservation Rider (CRR), the terms of the Construction Rider shall only apply to actual demand for load behind the meter that is not covered by the CRR Level, as defined within the terms and conditions of the CRR.

ECONOMIC DEVELOPMENT RIDER

AVAILABILITY/APPLICABILITY. This rider is available to customers taking distribution service under Rate HT, PD, or GS. For new services, the customer must have a projected load of at least 350 kW and must apply for the rider prior to the service being energized. For existing services, the customer must have a peak load of at least 350 kW and apply for the rider before the load growth occurs. The Company will not begin to apply the rider until at least 30 days after the customer provides to the Company written notice of its desire to be placed on the rider. Customers can qualify for this rider through provisions of either I-A, I-B; or II below. This Rider shall be available to customers regardless of whether the energy is purchased under default service rates or through an EGS.

I EMPLOYMENT & LOAD GROWTH: designed to encourage growth in all sectors of the industrial and commercial group, customers can qualify by meeting the appropriate requirements below.

A. **QUALIFICATIONS**.

1. Manufacturing Customers
   a. The New Manufacturing Customer or existing manufacturing customer files with the Company, before the effective date of the rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined below, for the Service Location. This condition is waived for Stevedoring Operations located within a Port Enterprise Development Area as defined in Title 12, Chapter 121 of the Pennsylvania Code.
   b. The existing manufacturing customer files with the Company copies of the Base Period Employment Reports as defined below, for the Service Location.
   c. For existing locations has already demonstrated a minimum 10 new jobs and a sustained increase in usage (minimum of 100 kW for at least 3 months) over the Base Period, as defined below. The Company reserves the right to request documentation to demonstrate that employment levels have been maintained over the course of eligibility for this rider.
2. Brownfield Redevelopment
   a. A new or existing customer who develops a site designated as a Brownfield Site (defined below) and demonstrates a minimum of 100 kW of new or incremental load.
3. Large Load Growth
   a. A new or existing customer who adds an additional 100MW or more of new load and adds a minimum of 10 new jobs.
4. Hydrogen Production
   a. A new or existing customer who develops on-site hydrogen production.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment, Federal Tax Adjustment Credit and Nuclear Decommissioning Cost Adjustment.

Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges.

1. Monthly Eligibility – The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.
2. A credit equivalent to 15% of the customer's Variable Distribution Service Charge ("VDC"). For New Manufacturing locations or Brownfield Redevelopment the credit will apply to all kW of the VDC. For all existing customers the credit will apply to all incremental kW of the VDC. For hydrogen producers, the credit will apply to the portion of the customer's billed kW of the VDC associated with their hydrogen production equipment nameplate.

II COMPETITIVE ALTERNATIVE: any manufacturing or non-manufacturing customer with a viable competitive alternative to service from PECO may be eligible for benefits as outlined below.

A. **QUALIFICATIONS**.

1. Provide documentation of a viable, currently available competitive alternative to service from PECO. The customer must provide a written description of the competitive alternative and any further information that the Company requires in order to document the cost and demonstrate the viability of the customer's competitive alternative, and
2. Demonstrate a sustained increase in load (1MW minimum month over month for 3 months) as measured on PECO's meter, or a demonstrated retention of at least 1MW of load and,
3. Demonstrate increasing employment of 10 jobs/MW as reported out on PA Form UC-2, or demonstrated retention of at least 10 jobs/MW of load retained for the same period as #2.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment and Nuclear Decommissioning Cost Adjustment.

1. Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges. The Company shall be the sole judge of any customer's eligibility for any rate negotiated rate reduction.
2. Any qualifying existing or new customer may qualify for a negotiated decrease in VDC charges of up to 15% to meet the customer's documented competitive alternative. The rate reduction and payment terms for service may be negotiated and specified in the applicable service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 17. Billing and Standard Payment Options of the Rules and Regulations of the Tariff shall apply. The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.

ECONOMIC DEVELOPMENT RIDER (continued)

DEFINITIONS.

1. Service Location. A single or contiguous premises having one or more delivery points for distribution service billed by the Company under a single account

2. New Manufacturing Customer. The Company has not previously provided service to the Service Location, or the service previously provided by the Company to the Service Location was not used for substantially the same type of operation or was terminated at least twelve (12) months before the customer's contractually specified effective date for service under this rider. This condition is waived for existing service locations where an entity has assumed operation of a service location from a customer which has ceased operations as a result of dissolution, so long as the formation of the entity did not occur as a result of merger, joint venture, acquisition and/or any other variation of combined business structures with the former customer at the service location. In any event, the completed application for the rider must be made within 6 months from the later of the date: (1) the customer first received service from the Company; or (2) the date the customer received its sales tax exemption certificate from the Commonwealth of Pennsylvania

3. Manufacturing Sales Tax Exemption Certificate. Pennsylvania Sales Tax Blanket Exemption Certificate filed by the customer with the Company showing the address of the Service Location and certifying that more than fifty (50) percent (on an annual basis) of the service purchased by the customer for the Service Location is exempt from sales tax because it is used in manufacturing operations, shipbuilding operations, or ship cleaning operations.

4. Employment Report. The "Employer's Report for Unemployment Compensation" (PA Form UC-2) as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania.

5. Base Period. The twelve (12) month period immediately preceding the billing month in which the customer provides the Company written notice of its desire to be placed on the rider. If the customer does not then qualify for the rider within 60 days of the written notice, then the base period will be the twelve month period immediately preceding the billing period for which this rider is first applied to the customer's bills.

6. Base Period Employment Reports. The Employment Reports for all quarterly reporting periods, as defined by 43 P.S. 753 [d], in the Base Period

7. Base Period Employees. The arithmetic mean of the number of employees each month as reported on the applicable Base Period Employment Report. An adjustment will be made to normalize Base Period Employees in quarters during which either the Casualty or Construction Rider was in effect for the Service Location.

8. Base Period Energy. The number of kilowatt-hours used by the customer for service to the Qualifying Service Location during each month of the Base Period. An adjustment will be made to normalize usage in months during which the Construction or Casualty rider was in effect.

9. Current Employment Report. The Employment Report covering the calendar month immediately following the Base Period as defined by 43 P.S. 753 [d]. The customer may submit an updated Employment Report at any time to reflect increases in Current Period Employees replacing and superseding the original report. The Company reserves the right to request an updated Employment Report at any time which may reflect increases or decreases in Current Period Employees replacing and superseding the original report.

10. Current Period Employees. The arithmetic mean of the number of employees each month as reported on the Current Employment Report.

11. Brownfield Site. Refers to real property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Requires documentation either by providing a copy of the pertinent sections of the ASTM E1903-97 Phase II Site Assessment documenting the site contamination or by providing a letter from a local, state or federal regulatory agency confirming the site is classified as a Brownfield by that agency.

TERM OF CONTRACT. This rider shall be in effect for either a period of five years provided that the customer maintains qualification for the duration of that time.

RENEWAL. A customer may renew the rider at any time in accordance with the terms and provisions of the rider as it applies to Qualifying Existing Service Locations. For renewal customers, the Base Period Energy for any month of the new Base Period shall not be less than the Base Period Energy of the corresponding month of the customer's previous Base Period. The Term of Contract for the renewal shall begin on the date on which the renewal of the rider is first applied based on the new Base Period.

TRANSFER OF OWNERSHIP. The Company will only apply the rider to the customer's bills for the term of contract. If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective July 1, 2019 through December 31, 2025)

AVAILABILITY/APPLICABILITY.
Applicable to a service that includes at least one permanently connected and publicly available (workplace fleet and public transit) Public Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to either a stand-alone metered DCFC or to a DCFC served as part of an existing service.

The pilot began on July 1, 2019 and expires on December 31, 2025.
The pilot will be modified and extended beginning on January 1, 2026 through May 31, 2029 (Docket No. R-2024-3046932).

The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Public Direct Current Fast Charger (DCFC) – A high powered, publicly available (including workplace fleet and public transit) EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered publicly available, the DCFC must be located along a public roadway corridor, at a public charging location, at a multi-dwelling unit (MDU) residential building at a public transit charging location, or at a workplace for fleet or customer charging.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system and not separately metered in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, the nameplate capacity (in kW), hourly and monthly usage (kWh), and the hourly and monthly demand (kW).

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective January 1, 2026 through May 31, 2029)

AVAILABILITY/APPLICABILITY.
Applicable to a service that is dedicated to Electric Vehicle Supply Equipment (EVSE) and includes at least one permanently connected Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to a stand-alone metered DCFC site. The Company may, at its sole discretion, apply this rider to a service that has both DCFC and other forms of EV charging so long as the combined maximum nameplate capacity rating for all DCFCs connected to the service is equal to at least 80% of the combined maximum nameplate capacity rating for all EVSE connected to the service. The Company may, at its sole discretion, apply this rider to a service that has other loads ancillary to EV charging such as signage, lighting, and communication equipment so long as the maximum combined demand of such loads does not exceed one percent of the combined maximum nameplate capacity rating for all EVSE connected to the service.

The pilot extension begins on January 1, 2026 and expires on May 31, 2029.

The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Direct Current Fast Charger (DCFC) – A high powered EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered high-powered, the DCFC must have a nameplate charging capacity of at least 50 kilowatts per charging port.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, and the nameplate capacity (in kW).

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective July 1, 2019 through December 31, 2025)

RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a fixed demand (kW) credit, initially equal to 50% of the combined maximum nameplate capacity rating for all DCFCs connected to the service, to the customer's billed distribution demand. At no time will the billing demand be less than the minimum demand applicable under the provisions of the applicable Base Rate. The Company reserves the right to reduce the demand credit based on a comparison of the customer's peak demands before and after installation of the DCFC.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal. Extended participation may be possible and could be predicated on future regulatory directives as yet to be determined.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective January 1, 2026 through May 31, 2029)

RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a variable demand (kW) credit, equal to 30% of the measured demand to the customer's billed distribution demand. For services where the minimum demand would be calculated under the applicable base as 40% of the maximum contract demand, the Company shall instead calculate minimum demand as 30% of the maximum contract demand. Otherwise, the minimum demand shall be 15 kW.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal.

EMERGENCY ENERGY CONSERVATION RIDER

AVAILABILITY/APPLICABILITY.
This rider is applicable in conjunction with Tariff Rule 12.3 relating to mandatory emergency energy conservation. It provides for modifications to the charges and practices otherwise applicable to certain customers as a result of compliance with or non-compliance with energy conservation curtailment levels as mandated by the appropriate governmental authority under emergency energy conservation conditions resulting from actual or potential shortage of fuel for electric generation. This rider is applicable to individual electric customer accounts served under Rates EP and HT, with a billing demand of 2,000 kilowatts or higher, in a recent twelve-month period prior to the emergency conservation condition. Customers designated by the procedures of Tariff Rule 12.3 and by the Pennsylvania Public Utility Commission, will be exempt from the provisions of this rider.

BASE PERIOD ENERGY USE.
The base energy use for a weekly period shall be determined by the Company for each applicable customer account based upon a consideration of the customer's actual past or current electric consumption and the customer's existing operations.

MANDATORY CURTAILMENT ENERGY USE LEVEL TARGET.
The mandatory curtailment energy use level target for each applicable customer shall be that percentage of base period energy use ordered pursuant to the emergency energy conservation procedures provided by Tariff Rule 12.3 or other percentage as a result of the order of appropriate governmental authority.

COMPLIANCE.
When the energy consumption in any weekly period during the period of mandatory curtailment exceeds the mandatory curtailment energy use level target, the customer will be deemed to be in non-compliance. Customers deemed to be in non-compliance will not receive the billing modifications as set forth in this rider. In the event of continued non-compliance, the Company, upon notice to the Commission, may discontinue service.

BILLING FOR CUSTOMERS IN COMPLIANCE.
During the period of emergency energy conservation condition, billing will be based on special meter readings made to identify the demand established and energy using during the current energy use period. Customers in compliance with conservation orders will be excused from minimum bills and historical or contract demand or ratchet provisions and will be billed instead on the basis of current consumption and demand whenever the normal calculation method would produce a greater bill. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

These customers will be individually notified of this special billing provision before the implementation of the emergency energy conservation procedure.

INVESTMENT RETURN GUARANTEE RIDER

AVAILABILITY/APPLICABILITY.
To contracts which require investment in supply facilities greater than warranted by the incremental revenue recovered through the Company's tariffed Variable Distribution Service Charges of the Base Rate under which PECO Energy provides service.

COST OF EXTENSION.
The cost of the extension of supply facilities, including the cost of the service connection, shall be set forth in each agreement for the application of this rider.

MINIMUM GUARANTEE.
The minimum monthly payment shall be the amount set forth in the rider agreement or, in the event of later increases of the customer's load, the minimum of the rate at which service is rendered, whichever minimum obligation is the greater.

CONSTRUCTION ADVANCES.
Where the service desired is of a special character or doubtful permanency, the Company will require payment of a sum equal to the cost of the extension as an advance for construction. A credit of 20% of the net amount of the customer's revenue recovered through the Company's tariffed Variable Distribution Service Charges will be allowed by the Company up to an aggregate refund of 100% of such sum, with the right to retain such portion of the advance as needed to guarantee the payment of subsequent bills.

FULFILLMENT OF CONTRACT TERM.
In the event of the discontinuance for any reason of the distribution of energy before the expiration of the term of the contract with which this rider is applied, the customer shall pay the Company immediately thereon a pro rata share of the cost of the extension for the unexpired portion of the contract term.

OWNERSHIP OF DISTRIBUTION SUPPLY FACILITIES.
The provisions of this rider shall not under any circumstances be considered as conferring upon the customer any title to, or right of property in, the distribution supply facilities.

CONTRACT TERM.
Contract terms in excess of one year may be arranged with the customer to assure the return required by the investment in distribution supply facilities.

NIGHT SERVICE GS RIDER

(The number of customers served under this rider may be limited
by the availability of the required demand meters.)

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours may be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate GS (with demand measurement), including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.
Night Service billing and metering charge: $24.56

Charge per kW of Off-Peak billing demand per month: $3.85

STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

NIGHT SERVICE HT RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rates HT or EP, including all terms and guarantees, are applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand:
$3.22 per month for Rate HT.
$2.94 per month for Rate EP.

STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

NIGHT SERVICE PD RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, trademark and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate PD, including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand per month: $4.18

STATE TAX ADJUSTMENT CLAUSEAND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand, except that, when said greatest demand during Off-Peak Hours exceeds the demand specified for Off-Peak Hours, said greatest Off-Peak demand shall be reduced by the amount of the excess in determining the Off-Peak billing demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

RECEIVERSHIP RIDER

AVAILABILITY/APPLICABILITY.
To service provided to a Receiver-Trustee for the continued operation of a property formerly under contract for its electric service requirements.

AUTHORITY FOR OPERATION.
The Receiver-Trustee shall possess the authority under appointment by Court, through an order duly entered, to operate premises recited in a contract for electric service under which the Company has been providing service.

ACCEPTANCE.
The Receiver-Trustee shall accept and adopt for the continuation of service the contract theretofore in effect, including all of its provisions, and agree to pay the Company for all charges levied during the receivership-trusteeship at the rate specified therein.

BILLING.
The Company reserves the right to render bills on a biweekly basis. To provide for biweekly billing under this rider, the provisions of the applicable rate and rider, if any, will be modified as follows:

(a) Where applicable, all references to monthly or month will be changed to biweekly or biweek.
(b) Where applicable, capacity charges will first be determined from the pricing in the monthly rate table and such sum will then be multiplied by 14/30ths (0.4667) to determine the capacity charges for the billing period.
(c) The energy charges will be determined by using the prices in the monthly rate table; however, the limit of the kilowatt-hours to be billed in each price block will be determined by multiplying the hours' use of billing demand for each price block or the kilowatt-hour limits of a given price block by 0.4667.
(d) The high voltage discount applicable to Rate HT will be determined by using the pricing in the monthly rate table and such sum will then be multiplied by 0.4667 to determine the discount for the billing period.
(e) The minimum charge will be determined on a monthly basis and such sum will then be multiplied by 0.4667 to determine the minimum charge for the billing period.
(f) A discount of 0.4% will be applied to the total bill.
(g) A bill will be rendered biweekly covering the charges for the preceding billing period and such bill shall be paid within fifteen (15) days after receipt thereof.

If the customer receives Default Service, the terms of this rider shall also apply to the Energy Supply Charge.

TERM OF CONTRACT.
The completion of the term of the contract taken over, or as terminated by the discharge of the Receiver-Trustee, or as arranged with the Receiver-Trustee for the continuation of service under the standard terms of this Tariff.

TEMPORARY SERVICE RIDER

APPLICABILITY.
To the provision of service, including builders construction service, when the Company must install temporary facilities that will be used for a limited period or for a service that is of doubtful permanency.

AVAILABILITY.
Temporary service will be provided only when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

INVESTMENT IN DISTRIBUTION FACILITIES.
The cost of the extension and removal of facilities required to furnish the temporary service under the applicable rate shall be paid by the customer, but such payment shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM.
Application of this rider to Rates R, R-H and GS shall not, for billing purposes, be considered to be for a period of less than one month.

Application of this rider to Rates PD and HT shall require payment of the minimum provisions of the contract for each month of the temporary service period, but in no case shall such period be considered, with respect to the guarantee of the monthly minimum charges, as of less duration than 6 months.

RATE IMPACT.
Billing shall be under the provisions of the applicable base rate and riders.

TERM OF CONTRACT.
Short term arrangements as agreed upon.

PECO Exhibit 2:
PECO Electric Tariff No. 9 - Proposed

ELECTRIC PA P.U.C NO. 9

SUPERCEDES ELECTRIC PA P.U.C. NO. 8 AND ALL SUPPLEMENTS THERETO

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 30, 2026 **Effective May 29, 2026**

ISSUED BY: David M. Vahos – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATION – Original Page No. 8 - Revisions to the definitions of "Standard High Tension" and "Suitable Location".

RULES AND REGULATIONS – Original Page No. 12 – Edit to definition on 3.7 NONSTANDARD SERVICE.

RULES AND REGULATIONS – Original Page No. 17 – Update to Rule 7.2.E - expand the list of acceptable securities and clarify up-front payment amount.

RULES AND REGULATIONS – Original Page No. 18 – **7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS.** Modify Rule 7.3 to allow PECO to obtain security. **7.4 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES**. Specify the application of Rule 7.4.

RULES AND REGULATIONS – Original Page No. 30 – 18.7 RECONNECTION CHARGE - Modify Rule 18.7 to waive certain reconnection fees for eligible low-income customers.

INCREMENTAL COVID-19-RELATED UNCOLLECTIBLE EXPENSE (ICUS) - page deleted.

FIBER AFFILIATE REVENUE SURCHARGE (FARS) - page deleted.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 - Original Page No. 35 – Working Capital (WC) rate updated.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 – Original Page No. 38 – Working Capital (WC) rate updated.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 42 –
Changes made to E Factor and L Factor. Offset factor updated. Methodology added within definition of "Reconcilable CAP Costs" for application of offset factor to reflect only the impacts from changes in CAP participation and PPA forgiveness baselines.

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS – Original Page No. 43 – Added new H factor.

TRANSMISSION SERVICE CHARGE – Original Page No. 44 - Working Capital (WC) rate updated.

VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER (VSRII RIDER) – Original Page No. 50 - New Rider added.

ENERGY EFFICIENCY AND CONSERVATION (EE&C) REGULATORY ASSET RIDER – Original Page No. 51 – New Rider added.

RATE R RESIDENCE SERVICE – Original Page No. 52 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE R H RESIDENTIAL HEATING SERVICE – Original Page No. 53 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE GS GENERAL SERVICE- Original Page No. 57 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability. Update to DETERMINATION OF BILLING DEMAND.

RATE PD PRIMARY-DISTRIBUTION POWER - Original Page No. 59 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE HT HIGH -TENSION POWER - Original Page No. 60 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE EP – Original Page No. 61 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE POL PRIVATE OUTDOOR LIGHTING – Original Page No. 62 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES – Original Page No. 64 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-E STREET LIGHTING CUSOMTER OWNED FACILITIES Original Page No. 66 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITES - Original Page No. 68 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE – Original Page No. 71 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE AL – Original Page No. 73 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

APPLICABILITY INDEX OF RIDERS - Original Page No. 74 – page numbers updated.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) – Deleted pages for rider rules that were prior to January 1, 2026.

NIGHT SERVICE GS RIDER - Original Page No. 89 - Distribution prices updated.

NIGHT SERVICE HT RIDER - Original Page No. 90 - Distribution prices updated.

NIGHT SERVICE PD RIDER - Original Page No. 91 - Distribution prices updated.

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LIST OF COMMUNITIES SERVED

PHILADELPHIA:

CITY AND COUNTY OF Philadelphia.

DELAWARE COUNTY:

CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colwyn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Haverford, Lower Chichester, Marple, Nether Providence, Radnor, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Birmingham, Chester, Concord, Edgmont, Middletown, Newtown, Thornbury, Upper Providence.

BUCKS COUNTY:

BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIPS: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, Wrightstown.

MONTGOMERY COUNTY:

BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Jenkintown, Lansdale, Narberth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Merion, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove.

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Merion, Upper Providence, Upper Salford, West Vincent, Whitemarsh, Whitpain, Worcester.

CHESTER COUNTY:

CITY: Coatesville.

BOROUGHS: Avondale, Downingtown, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, East Vincent, East Whiteland, Easttown, Elk, Franklin, Highland, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchland, Uwchland, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

YORK COUNTY:

BOROUGH: Delta.

SECOND CLASS TOWNSHIPS: Chanceford, Fawn, Lower Chanceford, Peach Bottom.

HOW TO USE LOOSE-LEAF TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page," consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No....," the second time as "Second Revised Page No....," etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example, if changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be Issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page it will be placed in the Tariff immediately following the page which it supersedes, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes Effective the page superseded should be removed from the Tariff.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

a.c. - alternating current

Advanced Meter - Advanced Meter shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Services - Advanced Meter Services shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Service Provider or AMSP - The Company or an EGS that provides Advanced Meter Services.

AEPS – Alternative Energy Portfolio Standard – statute that requires electric distribution companies and electric generation suppliers to acquire a certain percentage of their energy from alternative energy sources.

Available rate - A rate which may be obtained by a customer if the use of service conforms to the character of service contemplated in the rate, and the location is such that this service can be supplied from existing facilities of the Company.

Bad credit - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Base Rate (or rate) - The Base Rates are Rates R, R-H, RS-2, GS, PD, HT, POL, SL-S, SL-E, SL-C, TLCL, EP, and AL.

Billing demand - The calculated or measured demand after correction, if any, for power factor; except that the billing demand may be limited to a minimum figure.

Btu - British thermal unit.

Capacity charge - A charge based upon demand, either with or without power factor correction.

Competition Act - The Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and capacity provided by an Electric Generation Supplier.

Consolidated EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Consolidated EGS Billing - Billing provided by an EGS as provided for in Electric Generation Supplier Coordination Tariff.

Continuous service – Service which the Company endeavors to keep available at all times.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. For purposes of billing for an Electric Generation Supplier (as defined below), the term customer may include all meter locations for which a summary bill is provided. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules and Regulations, an EGS may act as agent for an end use customer upon written authorization to PECO Energy which may be part of the notice of EGS selection.

Customer's service extension - The facilities extending from the customer's service-receiving equipment to the Company's service supply lines.

Default Service (DS) - The provision of energy or energy and capacity by PECO Energy as Default Service Provider to customers that are: (1) not eligible to obtain Competitive Energy Supply, (2) choose not to obtain Competitive Energy Supply, (3) return to default service after having obtained Competitive Energy Supply or Competitive Default Service, or (4) who contract for Competitive Energy Supply from an EGS (as defined below) that fails to deliver such energy or energy and capacity.

Default Service Provider (DSP) – The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Demand - The maximum rate-of-use of energy during a specified time interval, expressed in kilowatts.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Direct Access - Direct Access shall have the meaning set forth in the Competition Act.

Electric Distribution Company (EDC) - Electric Distribution Company (EDC) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier (EGS) - Electric Generation Supplier (EGS) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier Coordination Tariff (or Supplier Tariff)- PECO Energy's Electric Generation Supplier Coordination Tariff, provides procedures for EGS & PECO EDC interaction to make arrangements necessary to implement Direct Access for retail customers.

Energy Supply Charge (Generation Charge) - PECO Energy's charge for energy or energy and capacity to customers that receive Default Service.

Energy charge - a charge based upon kilowatt-hours of use.

FERC - the Federal Energy Regulatory Commission.

Fixed Distribution Service Charge (Customer Charge) – A charge to recover costs caused by the presence of the customer on the system other than the costs associated with the customer's demand or energy consumption.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas Day and Sundays.

Hp, horsepower - As used herein, horsepower shall be computed as the equivalent of 750 watts.

Initial Contract Term - An initial contract term for a service location shall be 1) the customer's first Term of Contract for service to the location or 2) the first Term of Contract after the customer changes service for a location to a different Rate.

Interest Index – An annual interest rate determined by the average of one-year Treasury Bills for September, October and November of the previous year.

KV, kilovolts - 1000 volts.

KVA, kilovoltampere - Unit of measurement of rate-of-use, which determines electrical capacity, required; it is obtained by multiplying the voltage of a circuit by its amperage.

KW, kilowatt - Unit of measurement of useful power.

KWh, kilowatt-hour - Unit of measurement of energy; an amount equivalent to the use of one kilowatt for one hour.

Lumen - Unit of measurement of quantity of light.

Measured Demand - A customer's highest demand during a 30-minute time interval in a billing period.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

PaPUC or Commission - The Pennsylvania Public Utility Commission.

PECO Energy or the Company - PECO Energy Company.

Point of Delivery - The single service point at which the service-supply lines of the Company terminate and the customer's facilities for receiving the service begin.

PJM - PJM shall mean the PJM Interconnection, L.L.C.

PJM System - PJM System shall mean the transmission facilities located in the Mid-Atlantic Region that are controlled by PJM.

Power Factor - As used herein, power factor is, in a single-phase circuit, the ratio of the watts to the voltamperes, and in a polyphase circuit, is the ratio of the total watts to the vector sum of the volt-amperes in the several phases.

Principal Office – The Company's Main Office Building is located at 2301 Market Street, Philadelphia, Pa. 19103.

Property Line - The division line between land held in or for private use, and land in which the public or the Company has a right of use; or, the division line between separately owned or occupied land.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Separate EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Separate EGS Billing - Billing provided by an EGS as provided for in the Electric Generation Supplier Coordination Tariff.

Service - The distribution of energy for use by the customer, including all things done by the Company in connection with such distribution. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

- standard single-phase secondary: alternating current, 60 hertz, in accordance with Tariff Rule 2.5 (Single-Phase Up To 150 kVA:

  (a) nominally 120/240 volts, 3 wires;
  (b) nominally 120 volts, 2 wires to installations consisting of not more than two 15-ampere branch circuits;
  (c) nominally 120/208 volts, 3 wires, for residential service, where available in conjunction with standard polyphase secondary 120/208 volts, 3-phase, 4 wires.

- standard polyphase secondary; alternating current, 60 hertz. Only one service is available to a building. However, the Company will provide standard service to customer premises containing multiple buildings in accordance with Tariff Rule 2.2 (Single-Point Delivery). For purposes of determining service capacity and parallel-generating capacity limits, a building is defined as a structure, separated from other structures, or a portion of a contiguous structure separated from the remainder of the structure by approved firewalls. When demand or service voltage requires the installation of transformation equipment on the owner's premises, the transformation shall consist of a pad mounted transformer installed at a location provided by the owner and approved by the Company outside the building or a transformer bank installed inside the building in a vault located on the ground floor or one story below grade, meeting National Electrical Code requirements. The Company will not install, own or maintain any conductors inside or beneath a building nor install indoor transformation in areas supplied by or designated to be supplied at 33,000 volts or greater.
  (a) nominally 120/240 volts, 2-phase, 5 wires; only available in areas supplied by 2-phase distribution facilities located along public highways or private rights-of-way and limited to service capacities of 100 kVA or less;
  (b) nominally 240 volts, 3-phase, 3 wires; a fourth wire neutral will be extended for the supply of 120/240 volt single-phase equipment in combination with the service where neither the service capacity required nor the parallel-generating capacity required exceeds 15 kVA on any one of the phases. Where the demand to a single premises exceeds 100 kVA, transformers will be installed on the premises at a suitable location provided by the owner. The service capacity and the parallel-generating capacity are both limited to 300 kVA for transformers located inside the building and 500 kVA for transformers located outside the building.
  (c) nominally 120/208 volts, 3-phase, 4 wires, (where 3-phase distribution is available) for the exclusive supply of secondary service to a building or group of contiguous buildings occupied by one or more than one customer, with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located either inside or outside the building. When either exceeds 750 kVA for transformers located inside the building the only rate option available to the customer will be Rate HT. When either exceeds 750 kVA but remains at or below 1,500 kVA for transformers located outside of the building, the customer can request service at 277/480 volts, 3-phase 4-wires from transformers located outside of the building. Otherwise, the only rate option available to the customer will be Rate HT. When a suitable transformer location is not reasonably available on the premises and the demand does not exceed 100 kVA, service may be supplied at the Company's discretion from aerial distribution facilities located along public highways.
  (d) nominally 277/480 volts, 3-phase, 4 wires (where 3-phase distribution is available) for the exclusive supply of secondary service to a building occupied by one or more than one customer with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located inside the building and 1,500 kVA for transformers located outside the building. If either exceeds these limits the only rate option available to the customer will be Rate HT.

- standard primary - unregulated alternating current, 60 hertz, nominally 2,400 volts, 2-phase, 3 wires, or nominally 4,160 volts, 3-phase, 3 or 4 wires. Availability of these voltages is limited to those locations served at these voltages as of July 6, 1987.

- standard high tension - unregulated alternating current, 60 hertz, nominally 13,200, 33,000, 69,000, 138,000, 230,000 or 500,000 volts, 3-phase, 3 or 4 wires (4-wire, 13 kV service is available in areas that have been converted to 13 kV distribution):

Where two or more such standard voltages are present in a given area, the Company will select the service voltage at which the required service can be supplied most economically. Nominally 13,200, 33,000, 69,000, 138,000 ,230,000 or 500,000 volts as available in the various sections of the Company's service territory for loads of such character as to require supply at one of such voltages in order not to impose unsatisfactory service conditions on the Company's supply system, or for loads of such character that supply at one of such voltages is desired both by the Company and the customer. For service at Rate HT, where the customer's demand exceeds 7,000 kW, the customer may be required to provide a suitable property on or adjacent to their premises for the installation of Company's substation and transformation equipment.

The Company's charges for service, which are comprised of the Fixed Distribution Service Charge and Variable Distribution Service Charge, are non-bypassable and must be paid by any customer regardless of the voltage level at which the customer is served.

Service-supply lines - The facilities (conductors, cables, conduits, etc.) extending from the Company's facilities in the highway or other trunk line location to the facilities owned and maintained by the customer.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Summary Billing Account - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same partnership, association, corporation, or governmental agency etc. for: (1) the Company's charges for service; and/or (2) an EGS's charges for Competitive Energy Supply, as permitted by Rule 2.2.

Tariff - this Electric Service Tariff comprising the Base Rates, rules and regulations which in conjunction with Pennsylvania Public Utility Law and Pennsylvania Public Utility Commission Regulations govern the distribution of electric energy including all things done by the Company in connection with such distribution, and/or the supply of electric energy under Default Service, and other PaPUC jurisdictional services.

Variable Distribution Service Charge (Distribution Charge) - the variable supply charges for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

RULES AND REGULATIONS

1. THE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and Default Service will be provided to its customers by PECO Energy, is on file with the Commission and is posted and open to inspection at the Principal Office of the Company. A copy of this tariff is also available on the Company's website at http://www.peco.com.

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and the recipient of service, whether service is based upon contract, agreement, accepted signed application, or otherwise, shall be subject to the terms of the Tariff. In addition, the rates therein shall apply to everyone receiving service unlawfully or otherwise, including unauthorized use as referred to in Rule 4.7 of this Tariff. A customer will receive service under the rates and riders of this tariff effective with their first scheduled billing cycle after the effective date of the tariff or as otherwise indicated in this tariff.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service supply and will be adjusted for application to service supplied during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provisions. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the supply of service under a particular Base Rate may be modified or amended only by the application of those standard riders, filed as part of this Tariff, which are specifically mentioned as applicable to that rate in the Applicability Index of Riders.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

2. SERVICE LIMITATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of electric energy of the standard characteristics available in the locality in which the premises to be served are situated. The Company does not offer to distribute and/or supply electric energy of nonstandard characteristics.

2.2 SINGLE-POINT DELIVERY The Company will provide standard distribution and/or supply through a single delivery and metering point for the total requirements at each separate premises of any person, partnership, association, or corporation, lawfully receiving service, except where, in the Company's sole judgment, special conditions warrant the installation of additional facilities. Unless otherwise stated herein, the Base Rates in this Tariff for each class of service are based upon that standard. Separate distribution and/or supply for the same customer at other points of consumption shall be separately metered and billed, except that: (1) when the Company is providing Consolidated EDC Billing, the Company will provide summary billing of its charges for and/or an EGS' charges (if requested by the EGS) for Competitive Energy Supply; and (2) when the Company is providing Separate EDC Billing, the Company will provide summary billing of its charges.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

(a) Such buildings or units are:
(1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and
(2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and
(3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

(b) There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

RULES AND REGULATIONS (continued)

(c) The transforming, receiving and distribution facilities on the customer's side of the delivery point, are:
(1) furnished, installed and maintained at the expense of the customer, and
(2) owned or leased by the customer, and
(3) operated and controlled by or at the expense of the customer.
(d) The Company is under no legal obligation of direct supply to any portion of said building or units or their appurtenances.
(e) A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in primary, secondary and/or distribution investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.
(f) All utilization equipment on the customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the building or units supplied or by the tenants of such operator whose use of electricity is dependent upon the single-point delivery and metering of service.
(g) Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the applicable Base Rate and/or riders.

2.5 SINGLE-PHASE UP TO 150 KVA. Single-phase secondary service is available for customer equipment with demand of or parallel-generation facilities having an aggregate nameplate rating up to 150 kVA. Any customer demand or generation equipment in excess of this amount will be supplied polyphase service. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

2.6 POLYPHASE LOADS AGGREGATING LESS THAN 7-1/2 HP. Polyphase service is not available for installations aggregating less than 7-1/2 horsepower, unless the excess cost of supplying polyphase rather a single-phase service is borne by the customer.

2.7 MOTORS. Service is not available to motors which do not meet the Company's standard requirements.

2.8 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Before receiving any electric service to or for new or renovated residential buildings or additions thereto, as defined by Pennsylvania Building Energy Conservation Act (BECA) as amended by Act 98 of 1985, applicants for service must provide the Company with the compliance certification copy of the Pennsylvania Department of Community Affairs (DCA) "Notice of Intent to Construct" form as processed by DCA. A compliance certification copy of "Notice of Intent to Construct" will not be required by the Company if the new or renovated residential building is located in a municipality which has elected to administer the BECA and requires that a notice of intent to construct be filed with the municipality before or at the time that application is made for a building permit and the notice has, in fact, been filed.

3. CUSTOMER INSTALLATION

3.1 INFORMATION FROM THE CUSTOMER. The Company should be advised by the customer or applicant for service, in writing, preferably on a form supplied by the Company, of premises to be equipped for service, giving exact location, and details of all current consuming devices to be installed.

The customer shall supply the Company any and all information in its possession regarding potential or actual contamination, waste or hazardous materials or other adverse environmental conditions on the customers' premises on or near where the Company facilities are to be located. The customer has a continuing obligation to provide the Company with such information relating to the premises as the customer receives it. The Company also has a continuing right to inspect the customers' premises for the purposes of performing an environmental assessment.

3.2 METER LOCATION. There shall be provided, free of expenses to the Company, at a location outdoors, unless otherwise designated by the Company or another AMSP, which the Company or another AMSP will designate in writing upon request, a suitable place for the meter or meters and any other supply, protective or control equipment of the Company or another AMSP which may be required in the provision of service. The customer shall provide access and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company's employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company's ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location shall also be situated so that the meter(s) are not concealed but shall be situated in a fashion acceptable to the Company.

3.3 POINT OF DELIVERY. The Company will designate in writing, upon request, a satisfactory point of delivery where the customer shall terminate the wiring and facilities for connection to the distribution lines of the Company. The failure to request and obtain such location may result in refusal of service pending rearrangement of customer's facilities, but the designation of a point of delivery does not constitute an agreement or obligation on the part of the Company to furnish service.

In establishing a point of delivery, the Company has the right to avoid areas known or suspected to contain contamination, waste or hazardous materials or other adverse environmental conditions. The customer will have the option of extending its own facilities to the

Company's point of service delivery.

The Company may waive this right of avoidance upon agreement by the customer or applicant to indemnify, defend, and hold harmless the Company (its successors, assigns, trustees, officers, employees and agents) from and against all actions, causes of action, claims and demands whatsoever, and from all costs, damages, expenses, losses, charges, debts and liabilities whatsoever

RULES AND REGULATIONS (continued)

(including attorney's fees), whether known or unknown, present or future, that arise from such conditions. This indemnification provision shall survive the termination or expiration of said agreement and the termination of the business relationship of the parties thereto.

3.4 SERVICE ENTRANCE EQUIPMENT. All equipment beyond the point of delivery, except the meter, shall be installed by the customer. Installation shall be in conformity with the National Electrical Code and the Company's published "Electric Service Requirements", and shall include, where necessary, an approved sealable device for mounting a meter. The meter will be supplied, owned and sealed by the Company or another AMSP.

3.5 SECONDARY SERVICE CONNECTION. (a) Wiring of any premises for connection to overhead lines must be brought outside of the building wall to a location designated or approved by the Company, at which point the house wiring must extend at least 3 feet for attachment to the Company's service-supply lines. (b) Service connections to the Company's underground facilities shall terminate on the customer's premises in an approved connection box from which customer's wiring shall extend to the other service entrance equipment.

3.6 UNDERGROUND SERVICE. Customers desiring an underground service from overhead wires must bear the excess cost incident thereto. Specifications and terms for such construction will be furnished by the Company on request.

3.7 NONSTANDARD SERVICE. The customer or applicant for service shall pay the cost (includes related income taxes) of any special installation necessary to meet the unusual requirements of the customer or applicant for service, including but not limited to: (1) service at other than standard voltages, (2) service for loads that will be intermittent and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (3) service for loads that will be continuous but that will generate minimal usage, and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (4) service for loads that will require provision of closer voltage regulation than required by standard service, and (5) situations for which, in the Company's sole judgment, extenuating circumstances exist whereby the Company agrees to provide multiple services, which are not normally offered in other sections of the Tariff, to one customer located on a premises.

The customer or applicant shall pay all costs to the Company of performing environmental assessments, including, but not limited to, the cost of consultants utilized by the Company, the cost of removal and disposal of contamination, waste or hazardous materials or dealing with other adverse environmental conditions associated with either the initial installation, modification, repair, maintenance or removal of service facilities.

3.8 RELAY PROTECTION. The customer must install at the customer's own expense a reverse-phase relay of approved type on all alternating current motors for passenger and freight elevators, hoists, and cranes, and a reverse-power relay for parallel operation.

4. APPLICATION FOR SERVICE

4.1 METHOD OF APPLICATION. Customers may apply for service via the Company's website at http://www.peco.com or, in some cases, over the telephone.

4.2 SERVICE CONTRACT. Every applicant for service may be required to sign a contract, agreement, or other form then in use by the Company, covering the special circumstances of the use of service, and shall abide by these Rules and Regulations and the standard requirements of the Company including but not limited to those in PECO's Electric Service Requirements Manual ("Blue Book") Builder's Handbook, Interconnection Guidelines and other additional requirements that PECO will provide upon request.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service: not available under a standard rate; which might affect service to other customers; which is to be delivered at a location or at a standard voltage that involves excessive cost; for bad credit; for the applicant's failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customers cannot be denied Default Service or new service for failure to pay an EGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contamination, waste or hazardous materials or other adverse environmental conditions.

4.5 ACCEPTANCE. Before the Company affirmatively accepts an application, the Company will consider the application to be "pending". When an application is accepted, it constitutes the contract between the customer and the Company, subject to the Rules and Regulations. A customer or other recipient of service also becomes contractually obliged to the Company when service is provided according to the application either with or without modification, or when the customer otherwise receives service.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

RULES AND REGULATIONS (continued)

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company. The use of service without notifying the Company or the AMSP and enabling them to read its meter will render the user liable for any amount due for service provided to the premises from the time of the last reading of the meter, immediately preceding the customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION. In the event the customer (or potential customer) withdraws an application for either new or modified service, the customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of providing the new or modified service.

5. CREDIT

5.1 PAYMENT OBLIGATION. For customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing, the provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff (and, for the same class of service (residential or non-residential) under the Company's Gas Service Tariff, if the customer also receives gas service at the same premises) as applicable to the location and the character of service.

The Company may, at its discretion, determine liability for a past due balance by:

1) Use of Company records that contain information previously provided to the Company;
2) Information contained on a valid mortgage, lease, deed or renter's license;
3) Use of commercially available public records databases;
4) Government and property ownership records.

5.2 PRIOR DEBTS. Service will not be furnished to former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers for which it may provide Consolidated EDC Billing or Separate EDC Billing to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers, the deposit will be equal to one-sixth of the applicant's or customer's estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule.

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RULES AND REGULATIONS (continued)

5.5 RETURN OF DEPOSIT. Deposits secured from a residential customer shall either be applied with interest to the customer's account or returned to the customer with interest in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations. In cases of discontinuance or termination of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Deposits secured from a residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 12 consecutive months. Deposits secured from a non-residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 24 consecutive months. Any residential or commercial customer /having secured the return of the deposit may be required to make another deposit in accordance with Commission statutes, regulations or Federal Bankruptcy Law if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(A) with respect to residential accounts, interest, will be computed at the simple annual rate determined by the Secretary of Revenue for interest on the underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as the Fiscal Code

(B) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent;

Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus; (2) determination of liability for a past due balance; (3) determination if a deposit is required based upon applicant's previous account history if available or through third party credit scoring of applicant.

The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

5.8 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of this Rule 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers.

6. PRIVATE PROPERTY CONSTRUCTION

6.1 COMPANY'S SERVICE LINES. Where the Company has distribution facilities of adequate capacity on the highway or in other trunk line location adjacent to the premises to be served, it will provide, own and maintain standard service-supply lines as follows:

(a) UNDERGROUND:

Underground cable construction to a point of delivery approximately 18 inches inside the property line of the customer, except:

(1) For secondary service to new residences or new apartment buildings, underground cable construction will be extended to a meter location or connection box located at the building or buildings, as designated by the Company and in accordance with Rule 7.3.

(2) The Company will make necessary repairs to customer-owned extensions of primary and secondary underground service-supply lines for residential customers at no charge. If such customer-owned extension requires replacement, the Company will make the replacement and assume ownership of the service-supply line with the Company bearing the cost up to 200 feet in length and the customer bearing the cost for all additional length.

(b) AERIAL:

A single span of aerial open wire or cable construction to the first suitable support of the customer, nominally 100 feet inside the property line of the customer. This customer support shall establish the point of delivery for the customer. The customer's support shall be so located that the service span will be free of obstruction and adequately supported as required by the size and weight of the conductors.

6.2 SERVICE - SUPPLY ALTERATIONS. Changes related to a service-supply line or a meter owned by the Company, including the installation of protective devices or visual markers to denote safe operating distance from the Company's facilities, for the accommodation of the customer, shall be at the expense of the customer. If the alteration to the Company's facilities is temporary in nature and the materials used in that alteration can later by re-used by the Company, as for example the installation of protective "hard cover" to allow a customer, developer, or contractor to work safely in close proximity to the Company's facilities, then at the Company's discretion it may charge a refundable deposit in lieu of charging the customer for the cost of the re-usable materials.

6.3 CUSTOMER'S SERVICE EXTENSION. The customer shall provide, own, inspect and maintain the service extension from the Company's service-supply lines to the point of delivery and receiving equipment. PECO may install a Company-owned meter, transformer (which transformer may serve one or more customers), or other required equipment, of its choice, on customer-owned property or facilities; Such installation does not alter the responsibility of the customer to provide, own, inspect, and maintain the required customer service extension to which such Company-owned facilities may be attached.

6.4 METERS AND TRANSFORMERS. The Company will provide, own and maintain any meter or meters, and also the transformer or transformers (both potential and current type transformers), required in the supply of service of the current characteristics specified by the Base Rate or rider under which the service is provided, unless the customer receives Advanced Meter Services from an AMSP in that case such AMSP will install, provide, own, and/or maintain the Customer's meter or meters while the Company will continue to own the potential and current type transformers. The supply of transformers by the Company shall be limited to those required for a single standard transformation.

RULES AND REGULATIONS (continued)

6.5 TRAILER PARKS. Where it is established by plans, development, use or other facts that the operation of a trailer park is predominantly to provide rental locations for non-transient trailers, with not less than two nor more than four such locations, the Company, upon written application of the trailer park operator and upon the receipt of an enabling agreement and of adequate rights-of-way, will construct, own and operate within the trailer park specified aerial electric energy, the trailer park operator being liable for payment of service to trailer park tenants not contracting in writing for service in their own names. The Company's obligation to install or extend such distribution facilities within the trailer park is limited to the investment warranted by the anticipated revenue. Alterations of such distribution facilities at the request of the park operator when not for the purpose of serving additional trailer rental locations will be at the cost of the trailer park operator. A trailer park operator desiring underground distribution facilities within a trailer park consisting of less than five locations must bear the excess cost incident thereto. Specifications and terms for such underground construction will be furnished by the Company on request. In new trailer parks consisting of five or more locations, underground distribution facilities will be extended in accordance with Rule 7.3.

RULES AND REGULATIONS (continued)

7. EXTENSIONS

7.1 TRUNK LINE CONSTRUCTION. The Company will construct, own and maintain overhead or underground distribution facilities, either secondary, primary, or high tension, located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general distribution system.

7.2 LINE EXTENSIONS FOR STANDARD SERVICE.

A. DEFINITIONS. For the purposes of this rule, when capitalized herein, the below terms shall have the following meanings:

(1) Line Extension -- A single-phase or polyphase addition to the public utility electric supply line for the purpose of supplying standard service (as described under Rule 2 above, but not including Line Extensions for nonstandard service as described in Rule 3.7 above) to and connected with the customer's point of delivery which addition is so located that it cannot be supplied by means of a service line from the existing electric supply line.

(2) Contractor Cost -- The amount paid by the Company to a contractor for work performed on a Line Extension.

(3) Customer -- End use customer of the Company, or a developer.

(4) Direct Labor Cost -- The pay and expenses of the Company employees directly attributable to work performed on Line Extensions, but not including construction overheads or payroll taxes, workmen's compensation expenses or similar indirect expenses.

(5) Direct Material Cost -- The purchase price of materials used for a Line Extension, but not including related storage expenses. In computing Direct Material Costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(6) Total Construction Cost -- For single-phase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, and Direct Material Cost. For polyphase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, Direct Material Cost and allocated overheads. For projects requiring significant design work, the Company will provide a preliminary cost estimate and charge customers a non-refundable deposit of 10% of the total estimated costs to fund the detailed design work. The detailed design work cost will not be included in the Total Construction Cost of the Line Extension used to determine contribution in aid of construction ("CIAC").

(7) Capacity Adjusted Cost -- For polyphase Line Extensions, the Total Construction Cost of a Line Extension multiplied by the percentage of that Line Extension's capacity installed to serve the Customer's capacity needs.

(8) Revenue Guarantee Contribution -- The estimated Variable Distribution Service Charges, as defined in the "Definitions of Terms and Explanation of Abbreviations" Section of this tariff, to be received by the Company from the Customer for a twelve (12) month period commencing with the first month after the Line Extension is completed.

B. SINGLE-PHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a single-phase Line Extension as follows. The Company will construct a Line Extension up to 2,500 feet without a charge to the Customer. For Line Extensions over 2,500 feet, a Customer shall pay the Company a contribution in aid of construction ("CIAC") equal to the amount by which the Total Construction Cost of the Line Extension beyond 2,500 feet exceeds the Customer's Revenue Guarantee Contribution for the first three (3) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the single-phase Line Extension.

C. POLYPHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a polyphase Line Extension, as follows. A Customer must pay the Company a CIAC equal to the amount by which the Capacity Adjusted Cost of the Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the polyphase Line Extension.

D. DEVELOPERS. Prior to the construction of any Line Extension, a developer may, in lieu of paying the full CIAC, pay a minimum of 35 percent (35%) of the CIAC and, for the remaining amount, post a surety bond in a form reasonably acceptable to the Company. The unpaid portion of the CIAC is subject to interest at the then applicable prime rate and is payable no later than twelve (12) months from the date of the initial payment.

RULES AND REGULATIONS (continued)

E. SPECULATIVE LINE EXTENSIONS. A Line Extension is speculative when, in the Company's reasonable opinion there is doubt: (1) as to the continued use, or the level of use, of the new Line Extension by the Customer; or (2) as to the Company's recovery of the Total Construction Cost for a polyphase Line Extension if a Capacity Adjusted Cost is applied.

Under the first scenario of a speculative Line Extension, the Company will construct the Line Extension for a Customer, as follows: pursuant to an individual contract between the Customer and the Company, in addition to any CIAC, the Customer may be required to provide the Company a customer advance in the form of an up-front payment, or, if mutually agreed to by the Customer and the Company, a cash deposit, letter of credit, surety bond or other guarantee, satisfactory to the Company. in the amount of the lower of the Total Construction Cost or the Customer's Revenue Guarantee Contribution used in the CIAC calculation as set forth in Part B or C above, as applicable ("Customer Advance"). If, after three (3) years for a single-phase Line Extension, or five (5) years for a polyphase Line Extension, the Customer's Variable Distribution Service Charges have met or exceeded the Customer Advance, the Company will either: (1) return the Customer Advance to the Customer if an up-front payment has been made; or (2) terminate the Customer's obligation to maintain the cash deposit, letter of credit, surety bond or other guarantee,

Under the second scenario of a speculative Line Extension, the Company will construct a polyphase Line Extension for a Customer, as follows: the Customer must pay the Company a CIAC equal to the amount by which the Total Construction Cost of the polyphase Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. The Customer may receive a refund of all or part of the CIAC paid if, during that five (5) year period, additional Customers have connected to the Line Extension for which the Customer paid the CIAC. The refund, if any, will be calculated based on the load of the connecting Customers.

7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS.

A. For the purposes of this rule, and in accordance with 52 Pa. Code § 57.81, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

1. Applicant For Electric Service - The developer of: a recorded plot plan consisting of five or more lots; or one or more five-unit apartment houses.
2. Developer - The party responsible for construction and providing improvements in a development; that is, streets, sidewalks, and utility-ready lots.
3. Development - A planned project which is developed by a developer/applicant for electric service set out in a recorded plot plan of five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, mobile homes, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.
4. Distribution Line - An electric supply line of untransformed voltage from which energy is delivered to one or more service lines.
5. Service Line - An electric supply line of transformed voltage from which service is delivered to the residence.
6. Subdivision - A tract of land divided by a subdivider into five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.

RULES AND REGULATIONS (continued)

B. INSTALLATION OF DISTRIBUTION AND SERVICE LINES. All distribution and service lines installed pursuant to an application for electric service within a development will be installed underground, and will be owned and maintained by the Company. Pad-mounted transformers may be installed at the option of the Company. Excavating and backfilling will be performed by the developer of the project or by such other agent as the developer may authorize. The developer or its agent may also for the purpose of reducing civil work costs, install conduit for the Company's use in installing electrical service, if the conduit and associated excavation work meets PECO's requirements. The Company will then assume ownership of such conduit. Installation of service-related facilities will be performed by the Company or by such other agent as the Company may also be installed underground, upon terms and conditions prescribed elsewhere in this tariff. The Company will not be liable for injury or damage occasioned by the willful or negligent excavation breakage, or other interference with its underground lines occasioned by anyone other than its own employees or agents.

Nothing in this section shall prohibit the Company from performing its own excavating and backfilling for greater system design flexibility. However, no charges other than those specified in Section 57.83(4) of Title 52 shall be permitted.

C. APPLICANTS FOR SERVICE. The applicant for service to a development shall conform with the following:

(1) At its own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-lighting lines and related facilities.

(2) At its own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation will consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant will follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the applicant's excavating and backfilling, such excavating and backfilling will be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse utility service until such standards and specifications are met.

(3) Request service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with any other utility sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary costs and delay.

(4) Pay to the Company any necessary and additional costs incurred by the Company as a result of the following:

a) Installation of underground facilities that deviate from the Company's underground construction standards and specifications if such deviation is requested by the applicant for electric service and is acceptable to the Company.
b) A change in the plot plan by the applicant for electric service after the Company has completed engineering for the project and/or has commenced installation of its facilities.
c) Physical characteristics such as oversized lots or lots with extreme set-back where under the Company's line extension policy contained in this tariff a change is mandated for overhead service.
d) The Company will require developers to provide financial security in advance for all developments prior to Company installation of distribution and service lines. At the time of execution of the contract between the developer and the Company, the developer shall post a letter of credit, surety bond, or other security, satisfactory to the Company equal to 50% of the value of the Total Construction Cost as defined by the Company under Section 7.2A(6). If the developer does not fully develop the lots within five years, including, but not limited to, installing all required electric meters and flowing electricity to them, the Company reserves the right to use the security for reimbursement of all distribution and service line installation costs.

(5) No charges other than those described in paragraph (4) of this subsection shall be borne by the applicant for electric service or by any other utility sharing the same trench, even if the Company elects to perform its own excavating and backfilling.

D. APPLICABILITY. The provisions of this rule will apply to all applications for service to developments, herein before defined, which are filed after the effective date of this tariff.

E. SUBDIVISIONS. Underground facilities in new residential developments are only required by Sections 57.81 through 57.87 of Title 52 when a bona fide developer exists, i.e., only when utility-ready lots are provided by the developer. A mere subdivision is not required to have underground service. However, should the lot owner or owners in a subdivision desire underground service, such service shall be provided by the Company if such lot owner or owners, at their option, either comply with Section 57.83 of title 52, or pay to the Company such charges as are contained in the Company's tariff for service not required by Title 52.

7.4 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES. All contributions in aid of construction (CIAC), customer advances or other like payments received by the Company shall constitute taxable income as defined by the Internal Revenue Service. The income taxes on such CIAC or customer advances will be segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with CIAC or customer advances will not be charged to the specific contributor of the capital. Rule 7.4 is applicable to all CIAC or other like payments received for standard services.

8. RIGHTS-OF-WAY

8.1 TERM AND RENTALS. When the premises of a customer is so located that the customer can be served only by facilities extending over the property of another, the customer shall accept service for such term as is provided in a permit or other applicable agreement covering the location and the maintenance of service equipment, and shall reimburse the Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

RULES AND REGULATIONS (continued)

8.2 PROCUREMENT BY CUSTOMER. Customers applying for the construction of an extension may be required to secure to, and for, the Company, all necessary and convenient rights-of-way and to pay any associated costs.

8.3 DELAYS. Applications for service from an extension to be constructed where a right-of-way is not owned by the Company will only be accepted subject to delays incident to obtaining a satisfactory right-of-way.

9. INTRODUCTION OF SERVICE

9.1 WIRING IN PROGRESS. Service-supply lines will not be installed before the time that the customer's wiring of the premises is actually in progress.

9.2 INSPECTION. The Company reserves the right to refuse the introduction of service unless a written certificate of approval, satisfactory to the Company, has been received from a competent inspection agency authorized to perform this service in the specific locality in which service is to be provided.

9.3 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged to inspect, any installation before it begins to deliver electricity or at any later time, and reserves the right to reject any wiring or appliances not in accordance with the Company's standard requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the installation, wiring, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the customer.

9.4 DEFECTIVE INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

9.5 UNSATISFACTORY INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's equipment, or use thereof, might injuriously affect the equipment of the Company, or the Company's service to other customers.

9.6 FINAL CONNECTION. The final connection between the customer's installation and the Company's service lines shall be made by or under the supervision of a representative of the Company, except for standard single-phase secondary aerial service, in which case the customer may make the final connection in accordance with the Company's standard requirements.

9.7 NEW OR TRANSFER CUSTOMER CHARGE. When a customer's account for service is initiated or when a customer's account is transferred from one address to another address, there will be a charge of $6.00 to cover the clerical expenses incurred by the

Company. The State Tax Adjustment Clause applies to this charge.

10. COMPANY EQUIPMENT

10.1 COMPANY MAINTENANCE. The Company shall keep in repair and maintain its own property installed on the premises of the customer.

10.2 CUSTOMER'S RESPONSIBILITY. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property the customer shall pay the costs of repairs and replacement. Any changes made to the Customer’s premises after the Company completes its service and meter installation that, in the opinion of the Company, creates an unsafe condition, shall be the Customer’s responsibility to pay any costs associated with remedying the unsafe condition including, but not limited to, any required protective measures and/or relocations of Company property.

Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The customer shall protect the equipment of the Company on the premises, and shall not permit any person, except a Company employee having standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter or other apparatus of the Company located on the customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

RULES AND REGULATIONS (continued)

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. In the event of an emergency, the Company shall have the right to access customer owned facilities and equipment for the purpose of restoring electric service, for the purpose of rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities and equipment.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service from whatever cause.

10.7 POLE REMOVAL OR RELOCATION REQUESTED BY RESIDENTIAL PROPERTY OWNERS. The cost for removal or relocation of distribution line poles and their associated attachments made pursuant to the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of such work shall be borne by the property owner and shall be limited to contractor, direct labor, and direct material costs incurred less maintenance expenses avoided as a result of the pole removal or relocation. The calculation of such cost for removal or relocation shall be in accordance with the Public Utility Commission Regulations - Title 52, Section 57.27.

RULES AND REGULATIONS (continued)

10.8 RELOCATION OF COMPANY FACILITIES REQUESTED BY NON-RESIDENTIAL PROPERTY OWNERS. Except as otherwise provided by law (e.g., 66 Pa.C.S. Section 2704, et seq.), a non-residential property owner, such as a builder, developer or contractor (Owner), shall pay to the Company the costs of relocation of Company facilities or equipment, made for the accommodation of the Owner or in fulfillment of the Owner's obligation to any public authority. If the facility relocation is made to accommodate the Owner's project or in fulfillment of the Owner's obligation to any public authority, then the Owner shall be responsible to pay PECO for the relocation costs even if the relocation request is made by an entity other than the Owner. A request for relocation of Company facilities shall be in writing. The relocation cost shall include labor (including overhead), materials, storeroom expense and transportation, less the depreciated value of any equipment replaced. Where the relocation is done in conjunction with construction of a supply line to a development, the Company shall include in the relocation cost only those costs caused by the Owner's request. The Company will notify the Owner in writing of the relocation cost. Advance payment of relocation costs will be required before the Company will commence the work, except, at the sole discretion of the Company, under special circumstances.

Where the relocation relates to a development that will generate additional revenue for the Company, the Company will give the Owner an initial credit against the relocation costs in an amount not to exceed 5% of the estimated annual revenue recovered through the Company's tariffed Variable Distribution Service Charges from the portion of the development under construction at the time of the relocation request. The Company will give the Owner an additional credit against relocation costs not to exceed 5% of the estimated additional revenue recovered through the Company's tariffed Variable Distribution Service Charges realized from new load on the PECO Energy system due to buildings not under construction at the time of the initial relocation but that are under roof within a five (5) year period from the date of completion of the relocation work. Credits will be held by the Company and distributed to the owner, on a pro-rated basis, as additional loads from the development are connected to PECO Energy's distribution system. No credits will be given for loads connected after the five year period from the date of completion of the relocation work. When the relocation is done in conjunction with extension of a line in accordance with §7.2 of the Tariff, the Company will include in the credit calculation only such estimated annual revenue that exceeds the minimum revenue guarantee required by §7.2. The cost and expense of project changes which require a second relocation of the same Company facilities shall be borne solely by the party requesting the change without offset or credit.

10.9 AERIAL LINE CLEARANCE. In accordance with the requirements set forth in the National Electrical Safety Code, the Company shall have the right to trim, remove, or separate trees, vegetation or any structures therein which, in the opinion of the Company, interfere with its aerial conductors, such that they may pose a threat to public safety or to system reliability.

10.10 ADVANCED METER SERVICES PERFORMED BY AMSPs. The provisions of this Rule 10 are subject to the terms of the Electric Generation Supplier Coordination Tariff.

10.11 RECOVERY FOR PROPERTY DAMAGE. If Company equipment is damaged through the negligence or intentional act(s) of any individual(s) or entity(s), the one(s) responsible for causing the damage shall reimburse the Company for all aspects of the resulting damages. The reimbursement shall include costs related to: labor, material, transportation and tools. "Labor" shall include benefit and administrative overheads based on the Company's current standard schedule, including third party contract repairs or modifications. Additionally, "Labor" may be calculated using a "blended" or average pay rate consistent with the above referenced standards. "Materials" may include an added stores expense calculated using the above referenced standards.

11. TARIFF AND CONTRACT OPTIONS

11.1 CHOICE OF RATE. When the class of service-supply or conditions of use are such that two or more Base Rates are available, a customer shall select the Base Rate on which the customer will be billed.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist customers in selecting the most advantageous Base Rate or rate application (i.e., Base rate together with applicable riders).

11.3 RATE CHANGES. A customer may not change Base Rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above unless the Company agrees to permit the change. At any other time, a customer may change to a firm rate for which the customer qualifies upon 30 days notice to the Company. Customer ownership and obligation to maintain customer owned transformation facilities and equipment, as well as the point of delivery, will be unaffected by any Base Rate change initiated by the customer.

A customer may request that the Company modify the terms of its contract, other than the customer's Base Rate, but the Company will only allow such modification when, in the Company's sole judgment, the modification does not conflict with the Company's Tariff and is not detrimental to the Company.

The Company will not make any Base Rate change retroactive, unless, in the Company's sole judgment, the Company failed to adequately respond to a customer's request for assistance or modification at the time of such request.

RULES AND REGULATIONS (continued)

12. SERVICE CONTINUITY

12.1 LIMITATION ON LIABILITY FOR SERVICE INTERRUPTIONS AND VARIATIONS. The Company does not guarantee continuous, regular and uninterrupted supply of service. The Company may, without liability, interrupt or limit the supply of service for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public or for the purpose of preventing or limiting any actual or threatened instability or disturbance of the system. The Company is also not liable for any damages due to accident, strike, storm, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control.

In all other circumstances, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to computers and other electronic equipment and appliances, loss of business, or loss of production caused by any interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity shall in no event, unless caused by the willful and/or wanton misconduct of the Company, exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. In addition, no charge will be made to the customer for the affected service during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. A variety of protective devices and alternate power supplies that may prevent or limit such damage are available for purchase by the customer from third parties.

The Company makes no warranty as to merchantability or fitness for a particular purpose, express or implied, by operation of law or otherwise. To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company limits its liability in accordance with the previous paragraph to any Customer or third party for claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

12.2 ADDITIONAL LIMITATIONS ON LIABILITY IN CONNECTION WITH DIRECT ACCESS. Other than its duty to deliver electric energy and capacity, the Company shall have no duty or liability to a customer receiving Competitive Energy Supply arising out of or related to a contract or other relationship between such a customer and an EGS.

The Company shall implement customer selection of an EGS consistent with applicable rules of the Commission and shall have no liability to a customer receiving Competitive Energy Supply arising out of or related to switching EGSs, unless the Company is negligent in switching or failing to switch a customer.

The Company shall have no duty or liability with respect to electric energy before it is delivered by an EGS to a point of delivery on the PECO Energy distribution system. After its receipt of electric energy and capacity at the point of delivery, the Company shall have the same duty and liability for distribution service to customers receiving Competitive Energy Supply as to those receiving electric energy and capacity from the Company.

12.3 EMERGENCY LOAD CONTROL. Pursuant to order of Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever the demands for power on all or part of the Company's system exceed or threaten to exceed the capacity than actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or power pool with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system, a load emergency situation exists. In such case, the Company shall take such reasonable steps as the time available permits to bring the demands within the then-available capacity or otherwise control load. Such steps shall include but shall not be limited to reduction or interruption of service to one or more customers, in accordance with the Company's procedures for controlling load.

The Company shall establish procedures for controlling load including schedules of load shedding priorities to be followed in compliance with the foregoing paragraph, may revise such procedures from time to time, and shall revise them if so required by Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at the Company's Principle Office, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.4 EMERGENCY ENERGY CONSERVATION. Pursuant to order of the Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever events occur which are actually resulting, or in the judgment of the Company threaten to result, in a restriction of the fuel supplies available to the Company or its energy suppliers, such that the amount of electric energy which the Company is able to supply is or will be adversely affected, an emergency energy situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to conserve available fuel supplies. Such measures may include, but shall not be limited to reduction, interruption, or suspension of service to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

RULES AND REGULATIONS (continued)

The Company shall establish procedures for emergency energy conservation, including, if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

The Company may revise such procedure from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its Tariff for public inspection, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.5 NOTICE OF TROUBLE. The customer must immediately notify the Company if service is interrupted or is otherwise unsatisfactory due to defects, trouble, or accident, affecting the supply of service.

12.6 RELOCATION OF DELIVERY POINT. In the event that the Company shall be required by any public authority to place underground any portion of its mains, wires, or service-supply lines, or relocate any poles or feeders, the customer, at the customer's own expense, shall change the location of his point of delivery to a point readily accessible to the new location.

RULES AND REGULATIONS (continued)

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. Pursuant to Section 1313 of the Public Utility Code, 66 Pa. C.S. § 1313, a customer may resell Energy and Capacity and/or service provided by PECO Energy under its default service plan if: (1) the Company provides such service under a single contract at one application of an available Base Rate and for the total requirements of the premises served, and (2) the location and use of the service conforms to the availability requirements of this Tariff for provision to the customer for the customer's own account.

All residential units connected after May 10, 1980, except those dwelling units under construction or under written contract for construction as of that date must be individually metered by either the Company, the AMSP or the landlord for their basic electric service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation. The bill rendered by the reseller to any consumer shall not exceed the amount which PECO Energy would bill its own residential customers for the same quantity of service under the applicable tariffed residential rate.

The requirements for individually metered dwelling units in new construction may be waived at the sole discretion of the Company. Such waiver will only be granted when the owner can demonstrate to the Company that there are valid reasons for such waiver and that there will not be a significant impact on the consumption of an individual customer.

In accordance with the Commission's Policy Statement at Docket No. M-2017-2604382, the electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation shall not be construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Such sales are therefore not considered a resale of service as defined in this tariff rule, Rule 13.1.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned charging station, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

13.2 FLUCTUATIONS. Electric service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the customer to modify the installation and/or equip it with approved controlling devices.

13.3 TYPE OF INSTALLATIONS. Motor and other installations connected to the Company's lines must be of a type to use minimum starting current and must conform to the requirements of the Company as to wiring, character of equipment, and control devices.

13.4 UNBALANCED LOAD. The customer shall at all times take, and use, energy in such manner that the load will be balanced between phases to within nominally 10%. In the event of unbalanced polyphase loads, the Company reserves the right to require the customer to make the necessary changes at the customer's expense to correct the unsatisfactory condition, or to compute the demand used for billing purposes on the assumption that the load on each phase is equal to that on the greatest phase.

13.5 ADDITIONAL LOAD. The service connection, transformers, meters and equipment supplied by the Company for each customer, have definite capacity, and no additions to the equipment or load connected thereto will be allowed except by consent of the Company.

13.6 CHANGE OF INSTALLATION. The customer shall give immediate written notice to the Company of any proposed increase or decrease in, or change of purpose or location of, the installation.

13.7 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the customer liable for any damage to the meters or their auxiliary apparatus, or the transformers, or wires, of the Company, caused by the additional or changed installation.

14. METERING

14.1 SUPPLY OF METERS. An EGS that is also an AMSP may provide Advanced Meter Services in accordance with the Electric Generation Supplier Coordination Tariff. Otherwise, subject to Rules 14.3 and 14.9, the measurement of service for billing purposes shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment to be used for meters supplied by the Company, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes. In fulfilling its obligations with respect to metering and meter reading, and with respect to AMSPs that provide Advanced Meter Services, the Company will comply with Electric Generation Supplier Coordination Tariff.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, reactive-component meters, or other instruments, on the premises of any customer except for any customer for whom an AMSP is providing Advanced Meter Services, for the purpose of measuring the demand and/or the power factor, or for other tests of all, or any part, of the customer's load.

14.3 CUSTOMER REQUEST FOR SPECIAL METER. If a customer for whom the Company is providing either metering and meter reading wishes to replace its billing metering equipment, to the extent technically possible, the Company may offer, provide and support a selection of qualified meters and may perform installation within a reasonable amount of time and at the expense of the customer. The customer must pay for any such metering equipment based on the net incremental cost of purchasing and installing the new metering equipment as approved by the Commission. The Company will own and maintain all such new metering equipment.

RULES AND REGULATIONS (continued)

14.4 POWER FACTOR MEASUREMENT. For customers for whom the Company is providing metering and meter reading or Advanced Meter Services, the Company reserves the right to measure the power factor of the customer's load, either by test or by permanently installed instruments. For customers for whom an AMSP is providing Advanced Meter Services, the Company reserves the right to require such AMSP to measure the power factor of the load of the customer on the same basis the Company measures the power factor of customers for which the Company provides metering and meter reading or Advanced Meter Services.

14.5 REVERSE REGISTRATION. The Company may, by ratchet or other device, control its meters to prevent reverse registration.

14.6 ESTIMATED USAGE. The kilowatt-hours and billing demands to be paid for may be determined by computation instead of by measurement in the case of installations having a fixed load or demand value controlled to operate for a definite number of hours each day.

14.7 METER READING INTERVALS. The Company will read its meters in accordance with Appendix C to the Joint Petition for Full Settlement and at scheduled regular intervals of one month. Monthly customer usage will not be prorated for seasonality. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render standard bills for the recorded use of service based upon the time interval between meter readings. EGS & EDC charges shall be based on the EDC defined meter reading route schedules. Only those bills which cover a period of service of less than 26 days or more than 35 days will be prorated. The Company will reflect multiple supplier switches within a single monthly bill to ensure a customer can switch their electric service in accordance with the accelerated switching process final omitted rulemaking order that amends 52 Pa. Code, Ch. 57.172 – 57.179. See Dockets No. L-2014-2409383 and P-2014-2446292.

14.8 ESTIMATED USAGE. For customers for whom the Company provides meter reading or Advanced Meter Reading Services, the Company shall estimate the amount of service supplied to premises where access to the meter is not available or if such estimate is necessary, and to installations at remote locations when warranted by the type of installation, regularity of usage, or other circumstances. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render bills in standard form based on such estimate and so marked, for the customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential customers, an actual meter reading will be obtained at least every six months in accordance with Commission regulations.

14.9 CUSTOMER SELECTED ADVANCED METERS. A customer may request either PECO Energy or an AMSP to have an Advanced Meter installed and have Advanced Meter Services provided pursuant to Appendix C of the Joint Petition for Full Settlement and any applicable rules adopted by the Commission. For an advanced meter to be deployed in the PECO Energy service territory, it must be included in the Commission's Advanced Meter Catalog, and indicated as eligible for deployment in the PECO Energy territory.

14.10 MANUAL METER READING FEE Upon customer request, the Company will secure an in-person meter reading to confirm the accuracy of an automatic meter reading when a customer disconnects service or a new service request is received. The fee is $45 and the Company will include this fee on the customer's or applicant's bill.

15. DEMAND DETERMINATION

15.1 MEASURED DEMANDS. Measured demands may be quantified by recording or indicating instruments showing, unless otherwise specified, the greatest 30-minute rate-of-use of energy, provided that in the case of hoists, elevators, welding machine, electric furnaces, or other installations where the use of electricity is intermittent or subject to violent fluctuation the demand may be fixed by special determination.

15.2 DEMAND DETERMINATION.

(a) Special Determination. Where charges specified in this Tariff are based upon the customer's demand, it is intended that such demand shall fairly represent the customer's actual demand that the Company must stand ready to serve. In the case of installations where the customer's regular use of service in the ordinary course of the customer's business is such that measurement over a thirty-minute interval does not result in a fair or equitable measure of the customer's demand, then the demand may be estimated from the known character of use and the rating data of the equipment connected, or from special tests. The intent of this provision is that the demand so determined shall fairly represent the demand that the Company must stand ready to serve.

(b) Demand Waiver. When a customer wishes to conduct a test of equipment or process that is not part of the customer's normal operations, the customer may request that the Company waive the demand caused by that test, if that demand is the highest measured demand in the billing month. The Company will agree to such a waiver if the following conditions are met:

1. The Company's metering is of a type which allows for the determination of 30-minute demands; and
2. The customer's request is in writing, and is received by the Company at least 15 business days before the date of the commencement of the proposed test. The request must specify the nature of the test, the size of the loads to be tested and the starting and ending times; and
3. The Company determines that the tests are not a part of the customer's normal operations; and
4. The test will not last for more than twelve (12) consecutive hours; and
5. The customer has not conducted a test and received a demand waiver for a test pursuant to this rule within one year of the proposed test.

Upon receipt of a request for a demand waiver, the Company will inform the customer in writing within fifteen (15) days of receipt of the customer's request whether it will grant the proposed waive

RULES AND REGULATIONS (continued)

15.3 POWER FACTOR ADJUSTMENT.

A. Standard Power Factor Values (based on measured demands)

Measured Demands (Kw)	Standard Power Factor
0 -185	80%
186 - 2,500	90%
Over 2,500	95%

B. Adjustment to Measured Demand. When a customer's measured power factor is less than the standard power factor values above, the Company shall increase the customer's measured demand by the ratio of the standard power factor to the measured power factor. The Company will then use this adjusted demand as a basis for calculating the customer's billing demand in accordance with the applicable rate schedule.

C. Determining Measured Power Factor:

1) For customers with measured demands of 750 kW or greater in three consecutive months:

   (a) Until metering equipment capable of continuous power factor measurement is installed, the Company shall determine measured power factor based C3 below.
   (b) Once capable metering is installed, the Company shall continuously measure power factor.
      i. The customer's measured power factor shall coincide with the customer's maximum measured demand.

      ii, The Company in its sole judgment may discontinue continuous power factor measurement if: (1) the customer's measured demand is less than 750 kW for twelve consecutive months, or: (2) the Company determines that changes to the customer's load characteristics will result in that customer permanently reducing measured demand to less than 750 kW.

2) For customers with measured demands of less than 185 kW:

   (a) If the Company in its sole judgment deems that that the power factor is likely to be less than this standard based on the customer's load, the Company shall determine measured power factor based on C3 below.
   (b) Otherwise, the Company shall assume the customer's measured power factor to be the standard noted above

3) For all other customers, including those with measured demands between 185 kW and 750 kW, the Company shall determine measured power factor in one of the following ways:

   (a) By test, at a time when the customer's load is at least two-thirds of the customer's maximum measured demand in the preceding eleven months.
   (b) At the option of either the customer or the Company, by measurement as determined from meters installed by the Company, ratcheted to prevent reverse registration.
      i. Customers requesting measurement of power factor shall be subject to a monthly meter charge determined in accordance with the cost of the meter installation. Such installation shall not be for less than one year.
      ii. When meters are installed, the measured power factor shall be the power factor that is coincident with customer's maximum measured demand.

4) A customer that receives Advanced Meter Services from an AMSP is subject to these rules regarding determination of measured power factor.

16. METER TESTS

16.1 METER TESTS. The Company at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy.

16.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a customer or an EGS providing Competitive Energy Supply to a customer, but reserves the right to make the charge provided for in the Electric Regulations of the Pennsylvania Public Utility Commission, under conditions therein specified.

16.3 ADJUSTMENT FOR ERROR. Should any of the Company's meters become defective or fail to register correctly, the use of electricity shall be determined by a test of any such meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount registered for the preceding billing period and the amount registered during not less than one week immediately subsequent to the repairs to, or change of, the meter, taking into consideration the character of use by the customer.

16.4 RESIDENCE METER ERRORS. Meter errors in the Company's meters in residence service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

16.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests of the Company's meters as it deems necessary for the proper administration of its rates, or as are required by law.

16.6. TESTING SERVICE. The Company will, upon request by the customer, make tests of the Company's meters to supply special information regarding the customer's use of service, provided that the estimated cost of such special tests shall be paid by the customer to the Company at the Company's discretion.

RULES AND REGULATIONS (continued)

17. BILLING AND STANDARD PAYMENT OPTIONS

17.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its delivery. The customer will be billed in accordance with rule 14.7. Rate values stated for direct application to monthly billing periods will be adjusted when time elapsed between readings is substantially greater or less than a month.

17.2 BILLING OPTIONS. A customer may select one of the following three billing options as communicated to PECO by the customer's supplier: (1) Consolidated EDC Billing; (2) Consolidated EGS Billing; and (3) Separate EDC/EGS Billing, as those terms are defined herein. If a customer does not make a selection, the customer shall receive Consolidated EDC Billing. When the Company provides Consolidated EDC Billing or Separate EDC Billing, it will comply with the terms and conditions of the Electric Generation Supplier Coordination Tariff. For customers who receive both electric and gas service from the Company, the Company will issue a bill that contains charges for both of these services.

17.3 PAYMENT.

(a) The Company's bills to customers are payable upon presentation. Payment for service received must be made on or before the due date shown on the bill. The due date shall be determined by the Company and shall be not less than twenty days from the date of transmittal of the bill for Rates R, R-H, RS-2, POL and GS (excluding Summary Billing Accounts). The due date shall be not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts. Notwithstanding the foregoing, the due date may be up to thirty days for accounts (including Summary Billing Accounts) with the United States of America, the Commonwealth of Pennsylvania, or any of their departments, political subdivisions, or instrumentalities. The Company may allow a reasonable amount of additional time for payment of bills on industrial and commercial accounts of creditworthy customers. If the due date that appears on a customer's bill falls on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not operating, the due date shall be extended to the next business day. The payment period will not be extended because of the customer's failure to receive a bill unless said failure is due to the fault of the Company.

(b) Payment may be made at any authorized payment agency. The customer bears the risk of delivery of payment tendered on or after the date contained in any termination notice sent to the customer.

(c) The Company may require that a customer that is not creditworthy tender payment by means of a certified, cashier's, teller's, or bank check, or by wire transfer, or in cash or other immediately available funds.

(d) A customer must pay the undisputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed, and (4) the customer nevertheless continues to dispute the same manner in bad faith.

17.4 PAYMENT PROCESSING. When the Company is providing Consolidated EDC Billing, Default Service or Separate EDC Billing, and the customer remits a partial payment to the Company, the payment will be applied as follows:

1. Any past due balances including those for prior PECO basic service charges, for prior EGS receivables purchased by the Company, for prior installment amounts on payment agreements, and also for any reconnection charges.
2. Any current charges including those for PECO basic service charges, for current EGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

17.5 LATE FEES AND COLLECTION COSTS. If payment is made at an authorized payment agency after the due date shown on the bill, a late fee will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the late fee will be added if the payment is received by the Company more than five days after the due date shown on the bill. For Rates R, R-H, RS-2, POL and GS this late fee will be 1-1/2 % per month; for all other rates the late fee will be 2% per month. The Company will not apply late fees to Final Bills as defined in Tariff Rule 20.2. If the Company files suit to collect a delinquent balance on an account (whether active or inactive) or to ensure payment of current bills, the customer will be required to pay the Company's out of pocket court costs (including filing, service, and witness fees) as ordered by the court and such costs will be added to commercial and industrial accounts.

17.6 BUDGET BILLING.

(a) At the option of a customer receiving residential service under Rates R, R-H, RS-2, and GS, an estimated total bill for all service to be received by the customer over a twelve month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the 12th month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 17.3 and 17.5. Any such late fee will be calculated based on the lesser of budget billing arrears and actual charged arrears The Company may also arrange budget billing for creditworthy commercial and industrial customers.

(b) When the Company provides Consolidated EDC Billing, the EGS's charges will be included in the customer's Budget Billing Plan.

RULES AND REGULATIONS (continued)

17.7 CALCULATION OF LATE FEE. Where a late fee is applicable, the amount of the late fee to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid late fees, by the appropriate late fee rate.

17.8 TAX EXEMPTION. If a customer is tax exempt, the customer must provide a tax exempt form to PECO Energy and to its EGS, regardless of which billing option the customer chooses.

17.9 BILLING ERRORS. When the Company provides Consolidated EDC Billing, PECO Energy shall not be responsible for billing errors resulting from incorrect price information received from an EGS.

17.10 RETURNED PAYMENT CHARGE. If a check (electronic or paper) received in payment of a customer's account is returned to the Company unpaid or if upon a second attempt by the Company or its agent for payment the check is again returned unpaid, then the Company will add a returned payment charge to the customer's account in the amount of **$20.00.**

17.11 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of Rule 17, when a customer resides at a place of business or commercial establishment legitimately served pursuant to a commercial or industrial Base Rate, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to payment terms for residential customers.

18. PAYMENT TERMS & TERMINATION OF SERVICE

18.1 NON-PAYMENT TERMINATION. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations, on the portion of the past due amount attributable to the Company's charges for: (1) service, (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered to be "reasonable" hereunder

18.1.1 WINTER TERMINATIONS FOR NON-PAYMENT. Consistent with 52 PA Code §56.100, The Company will take the following steps for terminations for non-payment during the winter period, defined as December 1-March 31:

A. **Low-Income Eligibility:** The Company will use financial information provided by the Customer to determine if the Customer's income is at or below 250% of the Federal Poverty Level. The Company may elect to send to the Customer an income verification form for completion and return. The Company will also accept income verification provided by Community-Based Organizations that enter into a contract with PECO to provide such income verification services.

1. Annual income may be established using verified income information for a recent one-month (nominally 30-day) period, annualized to establish an estimated annual income.
2. The Company shall not require any customers who have established income eligibility for winter termination protections within the 12 months preceding the start of the winter period to re-certify or re-verify their income for that winter period. This Company may also use this information to determine deposit requirements, payment arrangements, and eligibility for any other income-specific program.

B. **Verified Low-Income Customers:** If the Company has received verified proof that a customer's household has income at or below 250% of the Federal Poverty Level, the Company will not pursue termination of that customer for non-payment during the winter period UNLESS (A) the Company receives Commission approval to do so via a petition filed pursuant to 52 Pa. Code §56.100(g), or (B) the customer has informed the Company after submitting this verification that the household no longer has income at or below 250% of the Federal Poverty Level.

For purposes of this section, the Company will accept the following as verified proof that the household has income at or below 250% of the Federal Poverty Level:

1. Enrollment in PECO's CAP program at any time within four years prior to the issuance of the winter termination notice;
2. Receipt of a LIHEAP grant at any time within four years prior to the issuance of the winter termination notice;
3. Receipt of a MEAF grant at any time within four years prior to the issuance of the winter termination notice;
4. Income verification provided by a CBO that has contracted with PECO to provide income verification information, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
5. Other verified documentation that the household's income is at or below 250% of the Federal Poverty Level, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
6. Receipt of verified documentation of low-income status in response to an Income Inquiry Letter, as described in Rule D.1 below.

C. **Verified Non-Low-Income Customers:** If the Company has received verified proof that a customer's household has income of greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

RULES AND REGULATIONS (continued)

D. **Customers with Non-Verified Income Levels:** For all other customers, prior to proceeding with termination for non-payment, the Company will send the customer a letter (the "Income Inquiry Letter") informing the customer that the Company does not have verified income information for the customer and that the customer is subject to termination for non-payment during the winter period.

1. If the customer responds with verified income information demonstrating that the household income is at or below 250% of the Federal Poverty Level, the Company will treat that household as Verified Low-Income for purposes of winter termination;
2. If the customer responds with verified income information demonstrating that the household income is greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.
3. If the customer fails to respond to the Income Inquiry Letter or responds without providing verified income information, the Company will attempt to contact the customer via telephone to inform the customer of their duty to provide verified income information. If contact is made and verified income information is not provided by the customer, or if contact is not made, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

18.2 PAYMENT TERMS. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the Company will in accordance with Pennsylvania Public Utility Law and applicable Pennsylvania Public Utility Commission Regulations and Orders, negotiate payment arrangements on the portion of the past due amount attributable to its charges for: (1) service (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. However, the Company will not negotiate payment arrangements on behalf of an EGS.

18.3 TERMINATION FOR CAUSE. The Company may terminate on reasonable notice if entry to the meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and Regulations and/or applicable Commission rules, including those found at Pennsylvania Public Utility Code or the Commission's regulations.

18.4 SAFETY TERMINATION. The Company may terminate without notice if the customer's installation has become hazardous or defective.

18.5 DEFECTIVE EQUIPMENT TERMINATION. The Company may terminate without notice if the customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other customers; or if a certificate of approval is refused after a re-examination of the customer's installation by a competent inspection agency authorized to perform this service in the specific locality where service is provided.

18.6 TERMINATION FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity, or tampering with the connections, the Company's meters, or other equipment of the Company.

RULES AND REGULATIONS (continued)

18.7 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the customer, the same customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs. All theft reconnections will be completed at the premise and will not be performed remotely.

	Reconnect Fees	
Electric Reconnect at the Meter	**$**	**75.00**
Electric Reconnect at Tap	**$**	**260.00**
Electric Reconnect - Underground dig	**$**	**1,650.00**
Electric with dual meters	**$**	**100.00**
Electric Remote Reconnect (one or dual meters)	**$**	**20.00**

Beginning April 2028, the Company will waive the Electric Remote Reconnect (one or dual meters) fee ($20.00 per reconnection) for all customers who were disconnected due to nonpayment and who have demonstrated annual household gross income at or below 150% of the Federal Poverty Level through one or more of the following means : (1) provided verified financial information (i.e., proof of income documentation) in the last two years; and/or (2) currently enrolled in the Customer Assistance Program (“CAP”); and/or (3) received a Low-Income Home Energy Assistance Program (“LIHEAP”) grant in the last two years.

18.8 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer’s premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company’s meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 18.7.

	Theft Investigation Fees
Electric Theft at Meter	**$400.00**

RULES AND REGULATIONS (continued)

19. UNFULFILLED CONTRACTS

19.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service before the expiration of a contract term will not relieve a customer from any minimum, or guaranteed, payment under any contract or rate. In the case of residential customers this Rule only applies if the customer has signed an express written contract that clearly sets forth such a term and condition of service.

19.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a customer, the Company's service is suspended, or the Company is prevented from providing service in accordance with the terms of any contract it may have entered into with the customer, the minimum charge for the unexpired portion of the initial contract term shall become due and payable immediately as liquidated damages. These liquidated damages may, at the option of the Company, be offset by estimated revenues from a succeeding customer at the same location, if such exists.

20. CANCELLATION BY CUSTOMER

20.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service from the Company must give the Company at least 7 days' written notice to that effect.

20.2 FINAL BILL. The customer is liable for service taken after notice to terminate the contract, until the meter is read and/or disconnected. The final bill for service is then due.

RULES AND REGULATIONS (continued)

21. GENERAL

21.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid to any commercial office, shall be deemed sufficient, unless the Principal Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

21.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

21.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

21.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will, in any event apply to the bill for the period during which the investigation is made.

21.5 EXCEPTIONAL CASES. The usual supply of electric service shall be subject to the provisions of this Tariff; but where special service-supply conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its supply terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

21.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and inure to the benefit of, the successors and assigns, heirs, executors and administrators of the parties thereto.

21.7 OTHER CHARGES. The Company may, if feasible, provide and charge for services, other than those provided for in this Tariff, when requested by the customer. The Company is not obligated to provide such services. The Company will, if possible, give the customer an advance written estimate of the costs to provide the service. Costs shall include, but not be limited to, materials, supplies, labor, transportation and overhead.

21.8 TAX INDEMNIFICATION. If PECO Energy becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, 66 C.S. §§ 2806(g) and 2809(c), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify PECO Energy for the amount of additional state tax liability imposed upon PECO Energy by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Reform Code of 1971 or Chapter 28 of Title 66.

22. RULES FOR DESIGNATION OF PROCUREMENT CLASS

22.1 DESIGNATION OF PROCUREMENT CLASS

a) Annually, in November the Company shall notify the customer of their procurement group class designation which shall be effective the following June 1.
b) The procurement class designation shall be used to determine the appropriate Generation Supply Adjustment to apply to the customer.
c) For non-residential customers, the procurement class shall be determined based upon the customers peak measured demand in the prior June-May period.
d) There shall be three procurement class designations. They are:
   1)Residential
   2)Small Commercial and Industrial up to and including 100 kW
   3)Large Commercial and Industrial greater than 100 kW
e) Procurement class designation shall only change once per year on the date established in rule 22.1a
f) A new customer in a new facility shall be assigned to a procurement class based upon an engineering estimate of the customer's diversified peak demand.
g) A new customer in an existing facility shall be assigned to the same procurement class as the last customer in that facility unless the new customer will use the existing facility in a substantially different manner.

RULES AND REGULATIONS (continued)

23. EGS SWITCHING

23.1 PECO Energy will accommodate requests by customers to switch EGSs on active accounts and pending active (Instant Connect) accounts in accordance with this Rule 23, Commission Order M-2014-2401085, and other applicable Commission Orders.

23.2 To switch to a new EGS, a customer must inform the new EGS. Customers that wish to switch are not required to contact PECO Energy to initiate a switch; PECO Energy will only switch a customer in accordance with Rule 23.

23.3 To enable a new EGS to complete a switch, a customer must provide to the new EGS the customer's PECO Energy Electric Choice ID number as it appears on the customer's PECO Energy monthly bill.

23.4 If a Customer contacts the Company to discontinue electric service and indicates that the Customer will be relocating outside of the Company's service territory, the Company will notify the current EGS of the Customer's discontinuance of service for the account at the Customer's location. If relocating within the Company's service territory the Company will seamlessly move the current EGS to the new location if all qualifications are met in accordance with PUC Order M-2014-2401085.

23.5 A switch to an EGS will be effective 3 business days after the enrollment request is processed, provided the enrollment request includes valid customer information as required by the controlling provisions of the Supplier Tariff. Upon receiving valid notice to switch an EGS, the Company shall notify the customer's existing EGS that such a request has been made.

23.6 If and when a customer's EGS discontinues its supply in the event of bankruptcy, loss of license, or similar occurrence, or if a Customer is dropped by its EGS for non-payment or other reason then the customer may select a new EGS. The customer will receive its energy supply from PECO Energy until the switch becomes effective.

23.7 Nothing in this Rule 23 shall be interpreted to preclude EGSs from entering into agreements for supply with a term of service of one month. EGSs may enter into agreements for longer.

23.8 The Company will send Release of Information packets to all new customers (except for customer with demands greater than 500kW), which information will provide customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2010-2183412, PECO will re-solicit its entire customer base (except for customer with demands greater than 500kW) for the purpose of opting out of disclosing information.

24. LOAD DATA EXCHANGE

24.1 PECO Energy will provide to a customer or the customer's designated EGS or authorized consultant, all available data from the meter once each calendar year for no fee. The exchange of data among PECO Energy, EGSs, and customers shall be in accordance with the Supplier Tariff and the Final Consensus Plan for Electronic Data Exchange Standards for Electric Deregulation in the Commonwealth of Pennsylvania, as approved by the Commission.

STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this tariff, a credit value of 0.04% will apply to all PaPUC jurisdictional distribution charges in the Base Rates and Riders, effective January 1, 2026.
6
Whenever any of the tax rates used in the calculation of the surcharge are changed, or recoveries are authorized under Sections 2806, 2809 or 2810 of the Competition Act, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the change occurs and the effective date shall be ten days after filing.

In addition, if a recalculation is submitted as a result of a tax rate change (including the Revenue Neutral Reconciliation rate) the Company will thereafter file each year by December 21 annual updates or revisions with the Commission which will reflect only this tax change. These annual updates will be effective ten days after filing and will continue until such time as the effect of the change in tax rates has been included in base rates.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below.

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next semi-annual period beginning with the six months ended November 30, 2025**.**

The rates in this tariff shall be updated semi-annually on June 1 and December 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula:

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where;

C= The sum of the amounts paid to the full requirements suppliers providing the power for the semi-annual period, the spot market purchases for the semi-annual period, plus the cost of any other energy acquired for the semi-annual period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the component above for the semi-annual period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00069/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.10237
RH	GSA (1)	$0.10237
GS	GSA (2)	$0.09325

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

PD	GSA (2)	$0.09166
HT	GSA (2)	$0.08792
POL*	GSA (2)	$0.06726
SL-S*	GSA (2)	$0.06726
TLCL	GSA (2)	$0.09325
SL-E*	GSA (2)	$0.06726
AL*	GSA (2)	$0.06726
SL-C*, **	GSA (2)	$0.06726

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1 and December 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. (Customers electing this option are billed based on interval-metered consumption of usage within each TOU Pricing Period. Beginning and ending reads are not applicable TOU billing determinants.) Commencing June 1, 2025, TOU Pricing Option rates will be updated semi-annually in concurrence with the Standard GSA on June 1 and December 1 and are not prorated.

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] from June 1, 2025 through May 31, 2026 are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12,73%	14.15%	6.06-to-1	4.85-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	19.76%	20.35%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	67.51%	65.50%	1.44-to-1	1.47-to-1

Commencing with the GSA and TOU rates effective June 1, 2022, PECO may update the TOU Pricing Multipliers in the above table annually, using a rolling five years of historical PJM Day-Ahead Spot Market Pricing energy data and Reliability Pricing Model capacity pricing data for the PECO zone. PECO will **only** update the applicable TOU Pricing Multipliers if the use of such data would result in no more than a 10% change from the prior-year's TOU Pricing Multipliers. If these updates would exceed 10%, the applicable TOU Pricing Multipliers will be changed by exactly 10%.

To calculate the semi-annual TOU Pricing Option rates, the Company will first calculate the semi-annual TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the semi-annual TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

Current TOU Pricing Option Charges:

TOU Rate	Peak ("PP") (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak ("SOPP") (12-6 AM all days)	Off-Peak ("OPP") (All other times)
R (GSA 1)	$0.31960	$0.05274	$0.07595
RH (GSA 1)	$0.31960	$0.05274	$0.07595
GS (GSA 2)	$0.24405	$0.05032	$0.07397
PD (GSA 2)	$0.23993	$0.04947	$0.07272
HT (GSA 2)	$0.23013	$0.04745	$0.06975

TOU Eligibility Requirements and Switching Rules:

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4
LOADS GREATER THAN 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw.

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

ΣPJM_{DA} x usage / (1-LL)
PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution

RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

$((PJM_{AS}$ x Usage*1/(1-LL) + $AEPS/S_{AEPS}$ x Usage)

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_3/_4$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_3/_4$ = Procurement class 3/4 sales
WC = $0.00069/kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP
Hourly Pricing Adder* (dollars/kWh)	$0.00131	$0.00121	$0.00098	$0.00098

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

RECONCILIATION

Applicability: June 1, 2025 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing.

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2024 through December 31, 2024 reconciliation period. There will be a transition reconciliation period for Procurement Classes 1 and 2 effective June 1, 2025 through November 30, 2025. The reconciliation will be based on utilizing the December 31, 2024 over/(under) balance adjusted for prior period revenues from January (C) 2025 through May 2025. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. For Procurement Classes 1 and 2, any over/(under) recovery shall be collected after the occurrence of five months from the end of the reconciliation period. Recovery shall be over a six month period commencing June 1 and December 1. The initial six month period is June 1, 2025 through November 30, 2025. For Procrement Class 3/4 Hourly, any over/(under) recovery shall be collected after the occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2025 through August 31, 2025. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 –Residential, Class 2 – Small C&I up to and including100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest

N = Procurement class

M = Migration Rider

O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by five months for Procurement Classes 1 and 2 and two months for Procurement Class 3/4 Hourly . For Procurement Classes 1 and 2,the GSA will be effective June 1 and December 1 commencing June 1, 2025 with over/under collection recovery occurring over the six month period beginning June 1 and December 1. For Procurement Class 3/4 Hourly, the GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2025 with over/(under) collection recovery occurring over the six month period beginning September 1 and March 1. The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE (NDCA)

The NDCA provides for the recovery of nuclear of decommissioning costs related to the Company's Ownership interest in Nuclear Generation as of 12/31/99. The NDCA shall be charged to all customers taking service under this Tariff. The adjustment shall be a cents per kWh charge calculated to the nearest one hundredth of one cent.

The Company's Ownership interest in nuclear generation as of December 31, 1999 consists of the following:

Peach Bottom 1	100%
Peach Bottom 2	42.49%
Peach Bottom 3	42.49%
Salem 1	42.59%
Salem 2	42.59%
Limerick 1	100%
Limerick 2	100%

Formula

The following formula shall be used to determine the NDCA.

$$NDCA = \frac{\text{PaPUC Authorized Decommissioning Expense Adjustment}}{\text{Total Pennsylvania Jurisdictional Sales for Calculation Year}}$$

Where:

PaPUC Authorized Decommissioning Expense Adjustment (Adjusted Annual Accrual - Base Accrual) x .95 = the Adjusted Annual Accrual in the Calculation Year less the Base Accrual. As of January 1, 2023, the NDCA shall be a credit value of ($0.0006)/kWh and will be added to the Variable Distribution Charge for all rates except for rates POL, SL-S and AL which will have a credit value of ($0.04)/location added to the Distribution Charge.

Total Pennsylvania Retail Jurisdictional Sales = total kWh sales under this Tariff for the calculation year including sales for distribution.

Calculation Year = year in which the Company proposes a change to the NDCA. To the extent a new cost study, performed every five years, indicates the Company requires an adjustment in the rate, the Company shall change the NDCA to reflect such new expense level. In calculating the annual expense, the Company shall use the sinking fund methodology.

Adjusted Annual Accrual = accrual necessary to fund the Adjusted Obligation.
Adjusted Obligation = Gross Decommissioning Obligation reduced by $50 million for ratemaking purposes.
Gross Decommissioning Obligation – The total decommissioning cost obligation as approved by the Commission as expressed in escalated future dollars.

Methodology for Calculating Expense

The base period expense shall be based upon the decommissioning costs set forth in the table below. The Company shall use a sinking fund methodology to determine the appropriate level of decommissioning expense. The assumptions shall be consistent with NRC policy and requirements.
The Base Accrual shall consist of the following levels for each unit.

Peach Bottom 1	$4,213,220
Peach Bottom 2	0
Peach Bottom 3	0
Salem 1	0
Salem 2	0
Limerick 1	0
Limerick 2	0
Total	$4,213,220

Frequency of Calculation

The annual expense shall be recalculated every five years. The Company shall adjust the NDCA to reflect the new expense level 60 days after filing the new study and the associated rate calculation with the PaPUC. The first calculation of the NDCA shall be considered to have taken place on January 1, 1998.

Completion of Decommissioning

In the event that the actual expenditures necessary to accomplish full decommissioning of the PECO Interest are less than the full balance in the funds established for such purpose, PECO shall be entitled to a release of such funds to PECO for the purpose of sharing the amount between ratepayers and shareholders. In the event that such release is granted, PECO's shareholders shall be entitled to retain: (1) the first $50 million of the net after-tax amount; and (2) 5 percent of the remaining net after-tax amount of the released funds.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for electric service in Residential Rate Schedule R and RH of this Tariff shall include a charge of $0.00287 per kWh for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below pursuant to Section 2804 (8) of the Competition Act. The USFC rate for electric service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below:

COMPUTATION OF USFC.
The USFC per kWh ($0.0000), shall be computed in accordance with the formula set forth below:

$$USFC = \frac{(C+L-E-I)}{(S)}$$

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedules identified above. The amount of USFC, per kWh, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per kWh, pursuant to the formula above, the following definitions shall apply:

Reconcilable Customer Assistance Program (CAP) Costs – The difference between (A) the sum of discounts provided to CAP customers (CAP revenue shortfalls) and forgiven Pre-Program Arrearages recovered through base rates, and; (B) the sum of actual total CAP discounts and actual forgiven Pre-Program Arrearages, net of an offset factor applied on a monthly basis as follows:

1. PECO will compare the actual month-end CAP participation level to the baseline CAP participation level most recently approved by the Commission within a Company distribution rate case proceeding to determine the CAP participation above or below the baseline for that month. (The Company's current baseline CAP participation level is 145,721 participants, approved under Docket Number R-2026-3060859.)
2. PECO will calculate the actual average CAP discount per customer for that month, dividing the actual amount of discounts by the actual month-end CAP participation level.
3. PECO will multiply the results of Items 1 and 2 above together to obtain the portion of the offset basis related to CAP discounts above or below the approved baseline.
4. PECO will compare the actual month-end Pre-Program Arrearage forgiven to one-twelfth of the baseline Pre-Program Arrearage level most recently approved by the Commission within a Company distribution rate case proceeding to determine the Pre-Program Arrearage forgiven above or below the baseline for that month. (The Company's current baseline Pre-Program Arrearage Forgiveness level is $17,845,130, approved under Docket Number R-2026-3060859.) The result will be the portion of the offset basis related to Pre-Program Arrearage forgiveness.
5. PECO will calculate the monthly offset by applying the offset factor percentage most recently approved by the Commission within a Company distribution rate case proceeding to the sum of Items 3 and 4 above. (The Company's current offset factor percentage is 11.9%, approved under Docket Number R-2026-3060859.)

USFC – Universal Service Fund Charge to be included in the rate for each kWh of Variable Distribution Service Charge calculated under Rate Schedules R and R-H to recover Reconcilable CAP Costs plus certain LIURP related expenditures.

C - Cost in dollars of the Reconcilable CAP Costs for the projected period.

L - Incremental LIURP related expenditures not included in base rates. This shall include an additional $500,000 increase expenditures for LIURP Health and Safety program and up to $200,000 expenditures for De Facto Heating program beginning in 2027 in the annual budget of LIURP program costs.

E - The net overcollection or (undercollection) of Universal Service Fund Charges. The net overcollection or undercollection shall be determined for the most recent period, beginning with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Included in the "E" factor will be Reconcilable CAP Costs, and LIURP related expenditures. Included in the E factor calculation is the reconciliation of Pre-Program Arrearages, effective January 1, 2027.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous USFC.

I - Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period. The interest calculation will not apply to LIURP amounts.

S - projected kWh of electric service to be billed under Rate R and Rate RH (exclusive of CAP Rider) during the projected period when rates will be in effect.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.
The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective January 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's proposed consumer education plan. The proposed plan shall consist of the cost of the consumer education plan approved in Docket M-2008-2032274, P-2008-2062739 and R-2024-3046931.

Applicability: The surcharge shall be a per customer charge calculated to the nearest one cent, which shall be added to the fixed distribution rates for billing purposes for all customers. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is a 5.0 cent charge per month for Rates R, RH and CAP, Class 2 and 3 is a 0.0 cent per month for Rate GS and for Class 4 is 0.0 cent credit per month for Rates HT and PD with an April 1, 2025 effective date.

Billing Provisions: The surcharge shall be calculated on an annual basis using the following formula:

$$MC(n) = \frac{(C+E+I-H)}{R(n)} \times \frac{1}{(1-T)}$$

C – the cost of the consumer education program includes the following:

Consumer Education Costs –The incremental cost of programs designed to educate consumers regarding the competitive market such as advertising, customer notices, informational materials cost, and any other incremental cost associated with educating consumers about the market and about available mitigation programs offered by the Company less any cost covered by the Company's Paragraph 37 Funds. Costs associated with this program shall be expensed to FERC account 910. These costs shall also include the costs of providing expanded universal service program education and outreach to low and moderate income customers to recover up to $800,000 per year commencing on January 1, 2025.

MC(n) = consumer education cost per customer for customer class n including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31

I – Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

H – The value of revenue share commissions received by the Company for the customer class from a home services provider with which the Company has entered into a commercial arrangement for marketing of the home services provider's services to the Company's customers. Commissions will be allocated between the Company's Electric and Gas divisions in proportion to the customer counts in the customer class.

n – Customer class where 1 = residential, 2 = C&I up to 100 kW, 3 = C&I from 100-500 kW, and 4 = C&I >500 kW

R – The total delivery service customers for the customer class for the application period where the application period shall be the 12-month period commencing annually on April 1 after the reconciliation period.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filing Schedule: The estimated surcharge shall be filed by February 1 of each year to be effective on the following April 1. The application period shall be the 12 months that start the April 1 effective date of the surcharge. The Bureau of Audits shall audit the data in the surcharge on an annual basis.

TRANSMISSION SERVICE CHARGE (TSC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of all transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's default service load.

Applicability: The surcharge shall be assessed to all default service customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The surcharge shall be calculated on a semi-annual basis using the formula below:

$$\mathbf{TSC(n)} = \frac{\mathbf{(C+E+I)}}{\mathbf{S(n)}} \times \frac{\mathbf{1}}{\mathbf{(1-T)}}$$

TSC(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Network Integration Transmission Service costs and Non-Firm Point to Point Transmission costs. Included in the cost to be recovered is a working capital (WC) component as defined below.

Charges assessed by PJM for network service within the PECO zone. Included in such charges are costs for the base network service charge for the zone as well as any load serving entity charges assessed to PECO under the PJM OATT that are listed in PECO's Supply Master Agreement Exhibit D as the responsibility of the Buyer. Included in the cost to be recovered is a working capital (WC) component as defined below.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $311 per mW. WC is a component of the 'C" factor

E – The estimated over or under recovery from the applicable reconciliation period.

I - interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001. This interest rate basis becomes effective with January 2016 over or under collections.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated default service sales for residential class and the street lighting class in the applicable application period. For the commercial and industrial class it shall be the estimated billed demand for the applicable application period. The application period will be the period when rates will be in effect.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Transmission Service Rate:

R= $.00787 per kilowatt hour
RH= $.00787 per kilowatt hour
Small C&I = $1.57 per billed transmission kW
Large C&I = $1.44 per billed transmission kW
Street Lighting = $.00001 per kilowatt hour

NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362.

Applicability: The surcharge shall be assessed to all distribution customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential, Small C&I and Street Lighting class rate schedules as described below.

For Rates PD, HT, and EP (Large C&I class), a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT. Customer's PLC will be computed to the nearest kilowatt. The NBT shall be recovered through a separate charge listed on customers' bills.

The surcharge shall be calculated on a semi-annual basis using the formula below:

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where;

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

> Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges, Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362.

E – The estimated over or under recovery from the applicable reconciliation period.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate:

R= $.00408 per kilowatt hour
RH= $.00408 per kilowatt hour
Small C&I = $0.87 per billed distribution kW
Large C&I = $1.08 per kW based on the PJM PLC
Street Lighting = $.00015 per kilowatt hour

PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS (EEPC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's Phase IV Energy Efficiency and Conservation Program Costs (EEPC).

Applicability: The surcharge shall be a calculated for billing purposes for all customers. The EEPC shall be charged to each rate schedule using the following units:

Phase IV

Rates R, RS, RH:	$0.00176/kWh
Rates GS:	$0.00392/kWh
Rate SL-E,	($0.08)/location
Rate SL-C	($0.07)/location
Rate AL:	($0.02)/location
Rate TLCL:	($0.00085)/kWh
Rates HT, PD, EP:	$1.18/kW based on PJM Peak Load Contribution (PLC)

The Variable Distribution Service charges, for the residential rate schedules shall include the above listed EEPC surcharge. For the municipal lighting rate schedules, the applicable variable or fixed distribution service charges shall include the EEPC surcharge.

For Rate GS, the EEPC shall be recovered through a separate variable distribution charge listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EEPC. Customer's PLC will be computed to the nearest kilowatt. The EEPC shall be recovered through a separate variable distribution charge listed on customer bills.

Calculation of EEPC Surcharge and the Over/Under Recovery:
Billing Provisions: The surcharge and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

$$EEPC(n) = \frac{(C-E)+(SWE)}{(BU)} + \frac{(PDR)}{(1-T)} \times (1)$$

C – The cost of the Energy Efficiency and Conservation Program includes: all expenditures, of the individual programs such as materials, equipment, installation, custom programs, evaluation measurement/verification, educating customers about availability to the extent not included in Consumer Education cost, not recovered through any separate recovery mechanism, and any other cost associated with implementation of the programs. Costs that relate to measures that are applicable to more than one rate class or that are shown to provide system-wide benefits, will be allocated to each class based on the ratio of class-specific projected program costs to the total projected program costs. The program costs are those approved by the PAPUC and audit costs for the Phase IV program ending May 31, 2026

E - The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

SWE – The cost in dollars of the PaPUC's Statewide Evaluator. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

PDR – The savings/costs from the portion of projected EE Peak Demand Resources (PDR) nominated into PJM's Forward Capacity Market (FCM). The Company will apply any proceeds/deficiencies from nominated PDR to the appropriate customer classes. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

BU – The total Billing Units for the applicable recovery period.

T – The current Pennsylvania gross receipts tax rate included in base rates.

n - The rate class for which the EEPC is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting
Residential - Rates R, RH
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP
Street Lighting – Rates SLE, SLC, AL, TLCL

Filings and Reconciliations: The estimated EEPC shall be filed by May 1 each year to be effective through May 31.
The first surcharge, effective June 1, 2021 will contain "C" and "E" factors calculated as follows: The "C–factor" will have two components; one including Phase III costs and the other including Phase IV costs. The Phase IV component will be set using projected costs for the 12 month period from June 1, 2021 through May 31, 2022. The Phase III component will be set using any Phase III costs from projects started prior to the end of Phase III, but not yet billed as of June 1, 2021. For the "E-factor" over/under rate will include the Phase III costs for the 10 month period from June 1, 2020 through March 31, 2021.

The second EEPC, effective June 1, 2022, will be calculated as follows: the "C-factor" will include Phase IV costs for the period June 1, 2022 through May 31, 2023 and the "E-factor" will include costs for 12 months comprising Phase III costs for the 2 months of April and May 2021 and Phase IV costs for the 10 months of June 1, 2021 through March 31, 2022. Subsequent EEPC's, effective June 1 each year will be calculated using a 12 month "C factor" for the period June 1 through May 31 and an "E factor" for the period of April 1 through March 31.

A reconciliation statement filing, in accordance with C.S. Title 66 §1307(e), will be made by April 30 of each year. The last Phase III only reconciliation statement will be for the 10 month period from June 1, 2020 through March 31, 2021. Phase IV reconciliation statements will be for the 12 month period April 1 through March 31 of each plan year. The first Phase IV reconciliation statement will cover the period April 1, 2021 through March 31, 2022 and include 2 months (April and May) of Phase III revenues and expenses and 10 months of Phase IV revenues and expenses (June through March). The EEPC mechanism is subject to annual audit review by the Bureau of Audits.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a value of 0.00 % will apply consistent with the Commission Order dated October 22, 2015 at Docket No. P-2015-2471423, approving the DSIC.

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Poles and Tower (Account 364);
Overhead conductor (Account 365) and underground conduit and conductors (Accounts 366 and 367);
Line transformers (Account 368) and substation equipment (Account 362);
Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, converters and condensers;
Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective January 1, 2016.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective January 1, 2016, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between September 1, 2015 and November 30, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **[NOTE: UTILITY MAY ELECT TO INCLUDE STFT CALCULATION IN THE PTRR COMPONENT].**

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on three-month period of projected annual revenues.

[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY].

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

3. Quarterly Updates: Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, Bureau of Audits and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq.*) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change or through an explanatory bill insert included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes.

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER (VSRII RIDER)

Purpose: The purpose of this rider with annual credits or charges is to extend the costs recovery of the Company's annual Vegetation Strategic Reliability Improvement Initiative to improve system reliability from one (1) year to ten (10) years in order to enhance customer affordability.

Applicability: The VSRII Rider shall be calculated to the nearest one-thousandth of a cent for billing purposes for all R and RH customers. For customers on all other rates, it shall be the nearest one cent. The VSRII Rider will become effective April 1, 2027 upon the Pennsylvania Public Utility Commission's approval at Docket No. R-2026-3060859. Subsequent rates will become effective January 1. The VSRII Rider will be based on a ten-year amortization of annual costs to enhance customer affordability. Revenues on the deferred balance of annual cost will include a return and associated taxes. Each year's original deferred revenue will be offset against annual cost.

The VSRII Rider shall be applied to each rate schedule as follows:

Rate R: ($0.00102)/kWh
Rate RH: ($0.00106)/kWh
Rate GS: ($0.15)/billed kW
Rate PD: ($0.29)/billed kW
Rate HT: ($0.08)/billed kW
Rate EP: ($0.14)/billed kW
Rate SL-E: ($0.07)/location
Rate SL-C: ($0.06)/location
Rate TLCL: ($0.04)/location
Rate AL: ($0.02)/location
Rate POL: ($0.40)/lamp
Rate SL-S: ($3.04)/lamp

The Variable Distribution charges for the above rates shall include the above listed VSRII Rider. For the lighting rate schedules, the applicable location or lamp charges shall include the VSRII Rider.

Calculation of VSRII Rider and the Over/Under Recovery Billing Provisions:

Billing Provisions: The VSRII Rider and over/under recovery shall be calculated by rate schedule using the following formula:

Credits or Charges = (C(n) + RET(n) – DR(n) - E(n)) / BU(n) / (1 - T(n))

C(n) – The cumulative annual VSRII costs to be recovered from customers by rate class for the applicable year based on a ten year amortization of annual VSRII cost.

RET(n) – Revenue requirements for return on the unrecovered deferred revenue from customers and associated taxes based on average balance during the year. For the return calculation, PECO will use the equity return rate for electric utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities. The capitalization structure and the effective cost of debt will be based on the Company's actual capitalization structure and the effective cost of debt during the year.

DR(n) – Original deferred revenue for each annual VSRII costs recovery, prior to application of the ten year amortization.

E(n) – The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

BU(n) – The total estimated annual billing units for the rate class during the projected period when rates will be in effect.

T(n) – Pennsylvania Gross Receipts Tax rate

n – Applicable rate classifications

Filing and Reconciliations: The VSRII Rider will be calculated and reconciled annually for each year of the program. The credits or charges will be calculated to be effective from January 1 to December 31 of the next projected year and filed with the Pennsylvania Public Utility Commission ten (10) days prior to the effective date. The reconciliation will be filed by February 28 for the previous year, January 1 through December 31. The initial nine month rate effective period is April 1, 2027 through December 31, 2027 and will reflect twelve months of costs and credits for the twelve months ended December 31, 2027. The initial reconciliation period will be April 1, 2027 through December 31, 2027. Subsequently, the rate effective period will be January 1 through December 31 each year with annual reconciliation of data from January 1 through December 31 of the previous year. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection for refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery. Such adjustments would be filed on at least 10 days' notice. The VSRII Rider and associated reconciliation will be subject to audit by the Pennsylvania Public Utility Commission's Bureau of Audits.

ENERGY EFFICIENCY AND CONSERVATION (EE&C) REGULATORY ASSET RIDER

Purpose: The purpose of this rider with annual credits or charges is to extend the recovery the Company's annual expenditures associated with the Company's Energy Efficiency and Conservation (EE&C) from one (1) year to ten (10) years in order to enhance customer affordability.

Applicability: The annual credits or charges shall be calculated for billing purposes for customers. The EE&C credits or charges shall be applied to each rate schedule using the following units:

Rates R, RH: ($0.00227)/kWh
Rates GS: ($0.00358)/kWh
Rate SL-E: ($0.15)/location
Rate SL-C: ($0.13)/location
Rate AL: ($0.05)/location
Rates HT, PD, EP: ($1.07)/kW based on PJM Peak Load Contribution (PLC)

Rates will become effective April 1, 2027 upon the Pennsylvania Public Utility Commission's approval at Docket No. R-2026-3060859. Subsequent rates will become effective January 1. Credits or charges will be based on a ten-year amortization of annual costs to enhance customer affordability. Revenues on the deferred balance will include a return and associated taxes. Each year's original deferred revenue will be offset against annual cost.

The Variable Distribution Service charges, for the residential rate schedules, shall include the above listed EE&C Regulatory Asset Rider. For the municipal lighting rate schedules, the applicable location or lamp charges shall include the EE&C Regulatory Asset Rider.

For Rate GS, the EE&C Regulatory Asset Rider shall be applied through a separate variable distribution credits or charges listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EE&C Regulatory Asset Rider. Customer's PLC will be computed to the nearest kilowatt. The EE&C Regulatory Asset credits or charges shall be returned or recovered through a separate variable distribution charge listed on customer bills.

Calculation of EE&C Regulatory Asset Rider and the Over/Under Recovery Billing Provisions:

The EE&C Regulatory Asset Rider and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

Credits or Charges = (C(n) + RET(n) – DR(n) - E(n)) / BU(n) / (1 -T(n))

C(n) – The cumulative annual EE&C costs to be recovered from customers by rate class for the applicable year based on a ten year amortization of annual EE&C costs.

RET(n) – Revenue requirements for return on the unrecovered deferred revenue from customers and associated taxes based on average balance during the year. For the return calculation, PECO will use the equity return rate for electric utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities. The capitalization structure and the effective cost of debt will be based on the Company's actual capitalization structure and the effective cost of debt during the year.

DR(n) – Original deferred revenue for each annual EE&C costs recovery, prior to application of the ten year amortization.

E(n) – The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

BU(n) – The total estimated annual billing units for the rate class during the projected period when rates will be in effect.

T(n) – Pennsylvania gross receipts tax rate.

n – The rate class for which the EE&C is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting

Residential – Rates R, RH
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP
Street Lighting – Rates SLE, SLC and AL

Filing and Reconciliations: The EE&C Regulatory Asset Rider will be calculated and reconciled annually for each year of the program. The credits or charges will be calculated to be effective from January 1 to December 31 of the next projected year and filed with the Pennsylvania Public Utility Commission ten (10) days prior to effective date. The reconciliation will be filed by February 28 for the previous year, January 1 through December 31. The initial nine month rate effective period is April 1, 2027 through December 31, 2027 and will reflect twelve months of costs and credits for the twelve months ended December 31, 2027. The initial reconciliation period will be April 1, 2027 through December 31, 2027. Subsequently, the rate effective period will be January 1 through December 31 each year with annual reconciliation of data from January 1 through December 31 of the previous year. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection for refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery. Such adjustments would be filed on at least 10 days' notice. The EE&C Regulatory Asset Rider and associated reconciliation will be subject to audit by the Pennsylvania Public Utility Commission's Bureau of Audits.

RATE R RESIDENCE SERVICE

AVAILABILITY.
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and is served through the same meter as the dwelling unit; (g) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and requires separate metering service as a result of wiring restrictions or legal requirements.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37 1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $15.05
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.92

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.12610 per kWh

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

RATE RH RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $15.05
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.92

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.12610 per kWh for all kWh.
WINTER MONTHS. (October through May)
$0.10123 per kWh for all kWh

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE. The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE. Where a portion of the service provided is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS. Standard.

RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option commencing September 1, 2021.

RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP.

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Commencing September 1, 2021, for default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, the Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated.

   If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

2. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period. If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

4. Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS.

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application online to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The link to the online application can be found on the Green Power Connection pages on peco.com.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

Any interconnection application in (a) Conditionally Approved or (b) Engineering Study status will expire in 6 months unless a customer-generator takes steps to (a) satisfy the conditions of the Conditional Approval or (b) pays for and moves forward with the Engineering Study. A customer-generator will be notified of the upcoming interconnection application expiration 45 calendar days ahead of the expiration date. Prior to the expiration of the 6-month period, a customer-generator may request an extension to resolve the outstanding issues surrounding their interconnection application. Upon a showing of good cause, the interconnection application expiration date will be extended up to but no more than 180 calendar days.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

RATE-GS GENERAL SERVICE

AVAILABILITY.
Service for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

Transformed service from the Company's distribution system where the company installs, owns, and maintains any transforming, switching and other receiving equipment required.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires – If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$ 27.28 for single-phase service without demand measurement, or
$ 34.78 for single-phase service with demand measurement, or
$ 83.23 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$14.49 per kW of billed demand

($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00392 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and ¾.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COSTA DJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILTIY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.

For those customers with demand measurement the billing demand will be determined as follows:

(a) For customers with measured demand or maximum contract demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, or (ii) 40% of the maximum contract demand.
(b) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.

If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge, plus the Variable Distribution Service Charge per KW of minimum billing demand as described above. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus per KW of billing demand. In addition to the above, for customers in Procurement Class ¾ charges will be assessed on PJM's reliability pricing model.

RATE-GS GENERAL SERVICE (continued)

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company, non-profit rescue squad, non-profit ambulance service or a non-profit senior citizen center meeting the requirements set forth below, may, upon application, elect to have its electric service billed at any of the following rate schedules: Rate R Residential Service or Rate R-H Residential Heating Service, as appropriate for the application. The execution of an electric service contract for a minimum term of one year at the chosen rate will be required of any entity electing service pursuant to the options provided by this provision.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY. A separately metered service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of firefighting services.

NON PROFIT SENIOR CITIZEN CENTER. A separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided. The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) or the Commonwealth as a non-profit entity and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

NON-PROFIT RESCUE SQUAD. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility recognized by the Pennsylvania Emergency Management Agency (PEMA) or the Pennsylvania Department of Health as a provider of rescue services. The use of electric service at this location shall be to support the activities of the non-profit rescue squad. Any fund raising activities at this service location must be used solely to support the non-profit rescue squad operations.

NON-PROFIT AMBULANCE SERVICE. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility licensed by the Pennsylvania Department of Health as a provider of ambulance services. The use of electric service at this location shall be to support the activities of the non-profit ambulance service. Any fund raising activities at this service location must be used solely to support the non-profit ambulance service operations.

TERM OF CONTRACT.

The initial contract term shall be for at least one year.

PAYMENT TERMS.

Standard.

RATE-PD PRIMARY DISTRIBUTION POWER

AVAILABILITY.

Untransformed service from the primary supply lines of the Company's distribution system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $297.61

VARIABLE DISTRIBUTION SERVICE CHARGE:
$14.37 per kW of billing demand
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. The 25kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, plus in the case of Procurement Class 3/4 customers, charges assessed under PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

RATE-HT HIGH TENSION POWER

AVAILABILITY.
Untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $371.68

VARIABLE DISTRIBUTION SERVICE CHARGE:
$9.22 per kW of billing demand
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.31 per kW of measured demand.
For customers supplied at 69,000 volts: $2.47 per kW of measured demand.
For customers supplied over 69,000 volts: $2.47 per kW of measured demand.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract. The 25 kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, and modify less the high voltage discount where applicable plus in the case of Procurement Class 3/4 customers, charges assessed on PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

RATE EP ELECTRIC PROPULSION

AVAILABILITY.
This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances. Rate EP is also available to legacy transformed service that is receiving service pursuant to Rate EP as of January 1, 2020; Rate EP or successor rates shall remain available for such legacy transformed service until at least December 31, 2040.

CURRENT CHARACTERISTICS.
Standard sixty hertz (60 Hz) high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $1,292.35 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE:
$9.27 per kW of billing demand
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.36 per kW.
For delivery points supplied at 69,000 volts: $2.89 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $2.89 per kW for first 100,000 kW of measured demand.

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class ¾.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company. Conjunctive billing under this section is available regardless of whether the conjunctively-billed sites take generation service from one or more generation suppliers and/or PECO default service.

RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.
To any residential or commercial customer with outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rates SL-S and SL-E.

MONTHLY RATE TABLE.
A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires, and a luminaire, including lamp, reactor, and control. The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation

MERCURY-VAPOR LAMPS	PRICE PER LIGHTING UNIT DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 4,000 Lumens)	$22.46	$20.08
175 Watts (nominally 8,000 Lumens)	$30.37	$28.11
250 Watts (nominally 12,000 Lumens)	$37.37	$35.35
400 Watts (nominally 20,000 Lumens)	$48.09	$45.42
400 Watts Floodlight (nominally 22,000 Lumens)	$52.07	$49.40

SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
70 Watts (nominally 5,800 Lumens)	$30.80	$28.49
250 Watts (nominally 25,000 Lumens)	$48.77	$46.10
400 Watts (nominally 50,000 Lumens)	$53.30	$50.61
400 Watts Floodlight (nominally 50,000 Lumens)	$57.24	$54.57

Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps is not available as of January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

METAL HALIDE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 7,800 Lumens)	$45.68	$44.18
175 Watts (nominally 13,000 Lumens)	$47.91	$45.11
250 Watts (nominally 20,500 Lumens)	$50.65	$47.89
400 Watts (nominally 36,000 Lumens)	$56.37	$53.77
1000 Watts (nominally 110,000 Lumens)	$98.07	$95.52

HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
50 Watts (nominally 4,000 Lumens)	$30.61	$28.26
70 Watts (nominally 5,800 Lumens)	$34.66	$32.07
100 Watts (nominally 9,500 Lumens)	$36.58	$33.99
150 Watts (nominally 16,000 Lumens)	$39.90	$37.32
250 Watts (nominally 25,000 Lumens)	$46.72	$44.09
400 Watts (nominally 50,000 Lumens)	$56.46	$53.86
1,000 Watts (nominally 130,000 Lumens)	$64.94	$63.93

LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
35 Watts (nominally 3,300 Lumens)	$50.18	$47.75
53 Watts (nominally 5,000 Lumens)	$51.42	$49.00
87 Watts (nominally 8,300 Lumens)	$53.08	$50.65
163 Watts (nominally 15,800 Lumens)	$57.73	$55.30
215 Watts (nominally 20,000 Lumens)	$60.52	$58.09

ENERGY SUPPLY CHARGE. Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

RATE POL PRIVATE OUTDOOR LIGHTING (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of lamps and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, all standard service-supply lines, and all Lighting Units. The customer will install, own and maintain all poles on the customer's property and all service extensions on the customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge. Any additional investment will be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Monthly Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

(A) Location Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

Customer construction shall meet the Company's standards which are based upon the National Electrical Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work. The customer shall obtain and submit any permits or other authority requisite to the installation and operation of the Lighting Units served hereunder.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Private Outdoor Lighting installation, the Company will charge for removal or replacement of the installations and the associated poles and conductors used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

(B) Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least three years.

PAYMENT TERMS.
Standard.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
To any municipal entity for outdoor lighting of streets, highways, bridges, parks and similar places located outside the city and county of Philadelphia, including directional highway signs at locations where other outdoor lighting service is established hereunder, only if all of the distribution facilities and equipment are installed, owned, and maintained by the Company.

ANNUAL RATE TABLE
The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation.

Incandescent Filament Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
320 Lumens	32	$149.81
600 Lumens	58	$209.95
1,000 Lumens	103	$292.47
2,500 Lumens	202	$401.92
6,000 Lumens	448	$456.46
10,000 Lumens	690	$551.74

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
4,000 Lumens	115	$344.25
8,000 Lumens	191	$362.92
12,000 Lumens	275	$386.25
20,000 Lumens	429	$452.72
42,000 Lumens	768	$643.39
59,000 Lumens	1,090	$723.05

Service to the above listed Incandescent Filament Lamps and Mercury-Vapor Lamps is not available after January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken incandescent filament or mercury vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

High Pressure Sodium-Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
5,800 Lumens	94	$341.87
9,500 Lumens	131	$371.45
16,000 Lumens	192	$416.75
25,000 Lumens	294	$472.76
50,000 Lumens	450	$562.33

Light-Emitting Diode Lamps Size of Lamp (Nominal)	Billing Watts	Distribution
3,300 Lumens	35	$602.62
5,000 Lumens	53	$617.60
8300 Lumens	87	$637.43
15,800 Lumens	163	$693.25
20,000 Lumens	215	$726.70

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment, Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of Lightning Units and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. The Company will install, own, and maintain its distribution facilities and equipment on the public highways to the extent warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge, with any additional investment to be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other electric distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Annual Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Annual Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

The installation cost of lighting on private property, or for contracts of less than standard term, shall be paid by the customer.

4. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Street Lighting installation, the Company will charge for removal or replacement of the installation and the associated poles and conductors used exclusively for the installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

7. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting installation shall be for at least three years.

PAYMENT TERMS.
Bills will be rendered monthly. Each month, for the purpose of prorating the price, shall be considered 1/12 of a year.

RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$8.26 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE:	$0.02693 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.

* The service location charge includes an Energy Efficiency Program Surcharge ($0.08) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.

A Service Location is the Point of Delivery on the Company's secondary circuit. That connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.
2. Ownership of Utilization Facilities.

a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.

The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-E, such sale will include the supporting pole or post.

b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.

Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

c. Service to Group of Utilization Facilities:

AERIAL SUPPLY

When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

UNDERGROUND SUPPLY

When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3 .Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES (continued)

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 11.

Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.

8. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the customer to the Company not less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

9. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

10. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

11. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

12. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

13. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to:
  a. Measurement of energy usage at the individual Utilization Facility level.
  b. Customer control of the lamp's burning hours.
  c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
  d. Ability of customer to dim the lights (LED only).

(B) Provides energy usage to the Company as described below under Data Requirements.

(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $6.99 per Service Location (as defined below)*
VARIABLE DISTRIBUTION CHARGE: $0.05092 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.
* The service location charge includes an Energy Efficiency Program Surcharge of ($0.07) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.
The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:

8. Manufacturer-rated wattage
9. Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
10. Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.
Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.

1. Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer. If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

2. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, Company-approved Smart Control Modules, conductors, molding and supporting insulators between the luminaires and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location. The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-C, such sale will include the supporting pole or post.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post, foundation with 90 degree pipe bend and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit. Except as provided in Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.
   c. Service to Group of Utilization Facilities:

      AERIAL SUPPLY

      When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

      UNDERGROUND SUPPLY

      When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 10.

   Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated Service Location on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations, or any replacement of the Company-approved Smart Control Module, shall be furnished by the customer to the Company not less than 30 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

10. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

11. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

12. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.
Standard single phase secondary service.

RATE TABLE.
SERVICE LOCATION CHARGE: $4.60 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.02396 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($0.00085) per kWh
ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours. The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

SPECIAL TERMINATION RIGHTS
Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider. In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer. The customer may then, at its discretion, notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days. If the customer has not removed its facilities within 30 days, then PECO may, at its sole discretion and upon 72-hour notice, physically remove the customer facility as a means of terminating service to that facility. Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals. Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL. In addition, the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs, use of truck or other equipment, fuel costs, and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals. PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage.

TERM OF CONTRACT.
The initial contract term for each signal light installation and constant load device shall be for at least one year.

PAYMENT TERMS.
Standard.

RATE BLI BORDERLINE INTERCHANGE SERVICE

AVAILABILITY.
Electric service supplied under reciprocal agreements, to neighboring electric utilities for resale in their adjacent territory at delivery points where the Company in its judgment can provide capacity in excess of the requirements of present and prospective customers in its own territory and for periods fixed by contract and terminable after the expiration of the initial term if capacity is no longer available.

CURRENT CHARACTERISTICS.
Standard primary or secondary service.

MONTHLY RATE TABLE.
For contracts newly entered on or after January 1, 2019, the Company will provide borderline interchange service under the Variable Distribution Service Charge of the appropriate Base Rate, plus an amount equal to 1% per month on the additional investment in facilities required by the Company to deliver and meter the service supplied. The appropriate Base Rate is the rate under which the Customer would be served if located within the Company's franchised service territory.

The Company will not apply this rate to contracts entered prior to January 1, 2019 unless the Company and the customer mutually agree to do so

MEASUREMENT.
The energy delivered may be metered or may be estimated from the purchaser's resales plus an agreed-upon correction to cover transformation and distribution losses.

TERM OF CONTRACT.
The initial contract term shall be for at least five years, and thereafter from year to year until terminated by 60 days' notice from either party, unless the Company and the customer mutually agree to a different term in the contract for service.

PAYMENT TERMS.
Payment of amounts billed shall be made within 15 days from date of bill.

RATE AL – ALLEY LIGHTING IN CITY OF PHILADELPHIA

APPLICABILITY. To multiple, unmetered lighting service supplied the City of Philadelphia to operate lamps and appurtenances for all night outdoor lighting of alleys and courts that are installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities. This rate shall no longer be available to new lighting installations effective January 1, 2011.

LIGHTING DISTRIBUTION SERVICE DEFINED. All night outdoor lighting of alleys and courts by lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement, removal or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.
SERVICE LOCATION CHARGE: $2.90 Per Location (as defined below)*
*The service location charge includes an Energy Efficiency Program Surcharge of ($0.02)

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE.

PLAN OF MONTHLY BILLING.
Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION.
The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

APPLICABILITY INDEX OF RIDERS

Introductory Statement

Customers under different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the Base Rate under which they are provided service. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the customer and the Company as the case may require, notwithstanding anything to the contrary contained in the Base Rate to which the rider is applied.

	Page No.	R	RH	RS	GS	PD	HT	POL	SL-S	SL-E	SL-C	EP	BLI	AL
Riders														
Capacity Reservation Rider	75-79			X	X	X	X					X		
CAP Rider	80	X	X											
Casualty	81			X	X	X	X					X		
Construction	82				X[1]	X	X					X		
Economic Development	83-84				X	X	X							
Electric Vehicle DCFC Pilot Rider (EV-FC)	85-86				X	X	X							
Emergency Energy Conservation	87						X					X		
Investment Return Guarantee	88				X	X	X							
Night Service GS	89				X									
Night Service HT	90						X					X		
Night Service PD	91					X								
Receivership Rider	92				X	X	X	X	X	X	X	X		X
Temporary Service	93	X	X	X	X	X	X							

[1]Available only to Rate GS customers with demands greater than 500kW

PILOT CAPACITY RESERVATION RIDER (CRR)

PURPOSE.
This Rider sets forth the eligibility, terms and conditions applicable to Customers who operate generation in parallel with the Company distribution system and for whom the Company needs to reserve electric capacity to serve their load when the customer's generation is offline.

This Rider also sets forth the eligibility, terms and conditions applicable to Customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion.

DEFINITIONS.
Demand and billing demand are defined in tariff sections "Definitions of Terms and Explanation of Abbreviations" and Section 15 of "Rules and Regulations".

(1) Ability to Shed Load – The capability of the customer to reduce or interrupt its total connected load as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(2) Capacity Reservation – The contracted amount of firm electrical distribution capacity, expressed in kW, reserved by the Company solely to meet the capacity requirement for which a customer has contracted under the CRR.

(3) CRR Level –

a. For customers with Parallel Generation, the portion of their Capacity Reservation equal to the contracted percentage of the Generator Nameplate Capacity of their customer-owned Parallel Generation, determined pursuant to the provisions of the section of this Rider titled "Capacity Reservation vs. CRR Level Designation."

b. For customers seeking to reserve capacity for new business growth or expansion, the portion of their Capacity Reservation for which they have contracted under the CRR for that purpose.

(4) "Failure To Shed Load" Penalty – A charge assessed to a customer with a Capacity Reservation, CRR Level, or both that were set in whole or part based upon Ability to Shed Load when that customer's generator goes offline and the customer does not shed load as agreed upon.

(5) Generator Nameplate Capacity **–** The maximum rated output of a generator under specific conditions designated by the manufacturer.

(6) Operational Flexibility in Operation of Generation – The capability of the customer to flexibly operate multiple generating facilities as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(7) Parasitic Load – The power consumed by the equipment supporting the operation of a customer's generation.

(8) Parallel Generation – Non-utility generating facility(s) approved for Parallel Operation.

(9) Parallel Operation – Occurs when a non-utility generating facility(s) interconnected with and operates while connected to PECO's distribution system, where the potential exists for electricity to flow from said generating facility(s) into PECO's electric distribution system.

(10) Uncovered Demand – The difference between the customer's CRR Level and the customer's Capacity Reservation

APPLICABILITY/AVAILABILITY.
Applicable to customers, with customer generating facilities that have generating capacity of 100 kW or greater and are first placed online, or are granted approval for Parallel Operation, after January 1, 2016. This includes but is not limited to Qualifying Facilities or Small Power Producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company's distribution system. All such customers will be supplied under the provisions of this rider, the customer's applicable Base Rate, and other applicable riders. Customers who wish to reserve available electrical capacity in excess of their present demand for new business growth or expansion may do so under this rider.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

NOTICE BEFORE COMMENCEMENT OF CRR SERVICE.

The customer shall not commence initial operation of any other source of supply in parallel with the Company's distribution lines until written permission is given by the Company for such parallel operation. Before a customer is placed on the CRR, the Company must provide written notice to the customer that includes the Capacity Reservation under the CRR and informs the customer that, upon receiving service under the CRR, capacity beyond this amount may not be available to serve the customer. The Company shall have the right to inspect the customer's installation prior to providing such written permission, and at any reasonable time thereafter in accordance with Tariff Rule 9.3.

CAPACITY RESERVATION VS. CRR LEVEL DESIGNATION.

The maximum firm capacity available to be reserved will be determined by the Company based upon its review of capacity available on its system at the time that a request for Capacity Reservation is made.

In all cases, if the requested electric capacity is not available the customer shall pay all cost to the Company of any construction necessary to meet the customer's Capacity Reservation requirement. To the extent that the requested capacity is needed for new business growth or expansion, the standard revenue test will apply when calculating the cost to be paid by the customer.
The Company must reserve capacity for a customer based upon an amount that the Company and customer agree accurately reflects the maximum demand that the Company must stand ready to serve to that customer.

For customers generating in parallel with the Company's distribution system:

For billing purposes, PECO will set the associated CRR Level as designated below:

For customers who have Generator Nameplate Capacity of greater than 100 kW but less than or equal to 5,000 kW, the CRR Level will be 60% of the Generator Nameplate Capacity.

For customers who have Generator Nameplate Capacity of greater than 5,000 kW but less than or equal to 10,000 kW, the CRR Level will be 50% of the Generator Nameplate Capacity.

Any customer, regardless of size of load or generation, may initiate negotiation as set forth below to designate the CRR at a level other than these levels.

Batteries and other electrical storage shall not be deemed to be generators for purpose of the CRR, and the nameplate capacity of storage or battery equipment shall not be included as, or treated as equivalent to, Parallel Generation for purposes of determining a customer's Capacity Reservation or CRR Level.

For customers who want to reserve capacity for new business growth or expansion, both the Capacity Reservation and the associated CRR Level will be determined by negotiation.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

NEGOTIATIONS FOR OPERATION OF CUSTOMER GENERATION.
If the CRR Level is set through negotiations for customers generating in parallel with the Company's distribution system, the following will apply:

The customer and PECO will meet to discuss customer operations. After such discussions, the customer may designate a CRR level other than as set forth above, based upon one or more of the following factors as defined above:

1. Parasitic Load: This will be subtracted from the customer's Generation Nameplate Capacity prior to determining the CRR Level.

2. Operational Flexibility in Operation of Generation: A customer with multiple generating units may commit to operate its facilities as a means of offsetting some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level

3. Ability to Shed Load: A customer may commit to shed some portion of its total connected load to offset some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level.

If PECO accepts the customer's designated Capacity Reservation and CRR Level then both amounts shall be set at the customer-designated level.

If PECO does not accept the customer's designated Capacity Reservation and or CRR Level then PECO may file a complaint with the PUC (to be referred to the Office of Mediation). Pending resolution of the complaint the Capacity Reservation and CRR Level shall be set at: as follows (subject to retrospective revision upon completion of the mediation/litigation):

- For customer designations based upon Parasitic Load, Operational Flexibility, or both, the Capacity Reservation and the CRR Level will be set at the customer-designated levels.

,

- For customer designations based in whole or part on Ability to Shed Load, the Capacity Reservation and CRR Level will be set at PECO-designated levels,

PROCEDURES TO CONFIRM MODE OF CUSTOMER GENERATION OPERATION
If a customer's CRR Level is set by negotiation based upon Parasitic Load or Operational Flexibility of Generation, or both, then:

- The customer shall inform PECO in writing if its generation operations differ materially from the mode of operations used to set the CRR Level;
- The customer shall verify to PECO once each calendar year that its generator operations in the prior year did not differ materially from the mode of operations used to set the CRR Level; and
- PECO shall have the right to conduct an audit of customer operations to determine whether generator operations differed materially from the mode of operations used to set the CRR Level.

NOTICE OF OPERATION CONTRARY TO A NEGOTIATED CRR LEVEL AND RESET PROVISION.
If, in its determination, PECO believes that a customer has operated its distributed generation units in a manner contrary to the mode of operations used to set the CRR Level, PECO may issue a written violation notice to the customer.

A customer shall not be deemed to have operated its distributed generation units in a manner contrary to the mode of operation used to set its CRR Level if both of the following are true:

- The customer was required to alter its mode of operations in response to a directive from PECO or because of conditions existing on PECO's distribution system.
- The customer's actual demand does not exceed its Capacity Reservation at any time.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

PECO will rescind a violation notice if, within 30 calendar days of receiving the violation notice, a customer furnishes evidence showing that it operated its distributed generation units consistent with the mode of operations used to set the CRR during the period in question. If PECO is not satisfied that the information provided by the customer demonstrates that operated its distributed generation units consistent with the mode operations used to set the CRR Level, PECO may file a complaint with the Commission and the Commission's determination shall prevail on whether the notice of violation will be deemed to be confirmed. If a customer does not furnish such evidence within 30 calendar days of receiving the violation notice, the violation notice is confirmed.

If a customer receives two confirmed violation notices within a 24-month period; the customer's going-forward CRR for the next 12 months shall be set at levels based upon the actual operations that led to the violation notice. Thereafter, the CRR may be reset to a lower levels only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

PENALTY AND RESET FOR FAILURE TO SHED LOAD.
For customers with a Capacity Reservation CRR Level or both that were set in whole or part based upon Ability to Shed Load, the following penalty and reset provisions shall apply:

- Penalty: If the customer's generator goes offline and the customer does not shed load as agreed upon the customer will be assessed a "Failure to Shed Load" Penalty" calculated by determining the amount of load that the customer agreed to shed, but did not shed, and applying a penalty charge equal to 125% of the full demand charge in the prevailing rate to that amount of load on the first such occurrence, and 150% of the full demand charge in the prevailing rate to that amount of load for the second and subsequent occurrences, for the month in which the load shedding did not occur.

- Reset: The customer's going-forward Capacity Reservation and CRR Level for the next 12 months shall be set at a level based upon the actual operations that occurred during the failure to shed load. Alternatively, the customer can opt to pay PECO for the actual cost of the required upgrades to PECO's distribution facilities to allow the customer to use delivery service at the higher operating level during outages in accordance with PECO's line extension policy (Tariff Rule 7.2). Thereafter, these amounts may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

TEMPORARY DISCONNECTION OF CUSTOMER SERVICE.
PECO shall have the right to temporarily disconnect the customer on an emergency basis if, in PECO's opinion, the customer's failure to shed load as agreed creates a risk to PECO's distribution system or service to other customers.

BINDING LEGAL DUTY.
A CRR customer whose CRR Level is set at negotiated level based in whole or part upon the customer's representation that it has an Ability to Shed Load will be deemed to have a binding legal duty to shed such load.

RATE AND BILLING.
Subject to the Minimum Charge Provisions below, the demand charges under the customer's underlying applicable Base Rate of GS, HT, PD, and EP apply to the billing demand determined under the CRR.

Customers will be billed monthly their CRR Level plus actual electric demand and usage except as follow below:

For customers who reserve capacity due only to Parallel Generation, if such customer's actual registered demand is greater than the customer's Uncovered Demand for a given month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to such difference, but in no event will the CRR Level be less than zero.

For customers who reserve capacity for business growth or expansion, if the customer's actual registered demand in a given month includes any portion of the CRR Level contracted for expansion for that month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to said portion, but in no event will the CRR Level be less than zero.

PILOT CAPACITY RESERVATION RIDER (CRR) continued

MINIMUM CHARGE.

Subject to the Rate And Billing provisions above the monthly minimum charge under the customer's underlying applicable Base Rate of GS, HT, PD, and EP will be calculated based on the minimum demand determined in accordance with the CRR. .
The monthly minimum demand charge for a customer reserving capacity due only to Parallel Generation will be the greater of:

1. The demand as registered by the customer's meter;
2. An amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand or
3. Any designated contract minimum.

The monthly minimum demand for a customer reserving capacity due only to new business growth or expansion will be an amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand
.
The monthly minimum customer charge will be determined by applying the minimum demand to the applicable demand charge for the Customer's underlying applicable Base Rate.

TERM OF CONTRACT.

The term of a CRR contract shall be three years for all non-negotiated CRR applications. For negotiated CRR Levels, the contract term shall be negotiated. There is no right to automatic renewal of a CRR; upon the expiration of the contract term, the Company will review available capacity on its system and, if such capacity is available, the parties will enter into a new CRR contract using the procedures set forth above.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum ($10 for non-heating customers) and will not be eligible to obtain Competitive Electric Supply or participate in budget billing. Commencing September 1, 2021 these customers will not be eligible to select the Time-Of-Use default service option.

Based on the applicable level of income and number of household members, CAP customers will receive a monthly fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2018-3005795.

CERTIFICATION/VERIFICATION.
Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in various energy education and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $10 for Residential customers or $20 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness; whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate–that is, if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

CASUALTY RIDER

AVAILABILITY/APPLICABILITY.
To service provided during a period when a customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the customer's control ("Period of Interruption").

NOTICE REQUIRED.
Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration. Written requests must be submitted to the Company within 30 calendar days after the end of the Period of interruption.

RATE IMPACT.
During Periods of Interruption, PECO Energy will not apply guarantees of revenue (power factor adjustment, minimum billing demand, and contract minimum) as contained in the customer's Contract, but will apply the actual registered demand. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

BILLS PRORATED.
Bills supplied shall be prorated, based upon the actual level of operation during the Period of Interruption.

RETURN TO NORMAL USE.
The customer shall use reasonable diligence in resuming the use of service as provided in the Contract.

TERM OF CONTRACT.
The initial contract term shall be extended for a period equal to the Period of Interruption so that the Company shall secure a working term at full connected load equal to the term of the Contract.

CONSTRUCTION RIDER

AVAILABILITY/APPLICABILITY.
To service provided during or immediately following a major construction or expansion period or during a receding load period, after the expiration of the initial contract term, while a business is in process of dissolution. A major construction or expansion period is defined as a construction or expansion project undertaken by the customer which upon completion will require an upward modification of the customer's contract limits.

RATE IMPACT.
During the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of the initial contract term, PECO Energy will not apply the following guarantees of revenue: power factor adjustment, minimum billing demand, and contract minimum. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

RIDER TERM.
The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than three successive renewals of the rider term on major construction projects. Its application during a receding load period subsequent to the completion of an initial contract term shall be for not more than one year.

TERM OF CONTRACT.
The initial contract term for service to expanding locations to which this rider is applied shall be extended for a period corresponding to the total number of months this rider is applied to the customer's bill during construction or expansion of the customer's facility.

OTHER RIDERS.
This rider, when applied to service to temporary installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

For customers taking service under PECO's Capacity Reservation Rider (CRR), the terms of the Construction Rider shall only apply to actual demand for load behind the meter that is not covered by the CRR Level, as defined within the terms and conditions of the CRR.

ECONOMIC DEVELOPMENT RIDER

AVAILABILITY/APPLICABILITY. This rider is available to customers taking distribution service under Rate HT, PD, or GS. For new services, the customer must have a projected load of at least 350 kW and must apply for the rider prior to the service being energized. For existing services, the customer must have a peak load of at least 350 kW and apply for the rider before the load growth occurs. The Company will not begin to apply the rider until at least 30 days after the customer provides to the Company written notice of its desire to be placed on the rider. Customers can qualify for this rider through provisions of either I-A, I-B; or II below. This Rider shall be available to customers regardless of whether the energy is purchased under default service rates or through an EGS.

I EMPLOYMENT & LOAD GROWTH: designed to encourage growth in all sectors of the industrial and commercial group, customers can qualify by meeting the appropriate requirements below.

A. **QUALIFICATIONS**.

1. Manufacturing Customers
   a. The New Manufacturing Customer or existing manufacturing customer files with the Company, before the effective date of the rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined below, for the Service Location. This condition is waived for Stevedoring Operations located within a Port Enterprise Development Area as defined in Title 12, Chapter 121 of the Pennsylvania Code.
   b. The existing manufacturing customer files with the Company copies of the Base Period Employment Reports as defined below, for the Service Location.
   c. For existing locations has already demonstrated a minimum 10 new jobs and a sustained increase in usage (minimum of 100 kW for at least 3 months) over the Base Period, as defined below. The Company reserves the right to request documentation to demonstrate that employment levels have been maintained over the course of eligibility for this rider.
2. Brownfield Redevelopment
   a. A new or existing customer who develops a site designated as a Brownfield Site (defined below) and demonstrates a minimum of 100 kW of new or incremental load.
3. Large Load Growth
   a. A new or existing customer who adds an additional 100MW or more of new load and adds a minimum of 10 new jobs.
4. Hydrogen Production
   a. A new or existing customer who develops on-site hydrogen production.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment, Federal Tax Adjustment Credit and Nuclear Decommissioning Cost Adjustment.

Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges.

1. Monthly Eligibility – The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.
2. A credit equivalent to 15% of the customer's Variable Distribution Service Charge ("VDC"). For New Manufacturing locations or Brownfield Redevelopment the credit will apply to all kW of the VDC. For all existing customers the credit will apply to all incremental kW of the VDC. For hydrogen producers, the credit will apply to the portion of the customer's billed kW of the VDC associated with their hydrogen production equipment nameplate.

II COMPETITIVE ALTERNATIVE: any manufacturing or non-manufacturing customer with a viable competitive alternative to service from PECO may be eligible for benefits as outlined below.

A. **QUALIFICATIONS**.

1. Provide documentation of a viable, currently available competitive alternative to service from PECO. The customer must provide a written description of the competitive alternative and any further information that the Company requires in order to document the cost and demonstrate the viability of the customer's competitive alternative, and
2. Demonstrate a sustained increase in load (1MW minimum month over month for 3 months) as measured on PECO's meter, or a demonstrated retention of at least 1MW of load and,
3. Demonstrate increasing employment of 10 jobs/MW as reported out on PA Form UC-2, or demonstrated retention of at least 10 jobs/MW of load retained for the same period as #2.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment and Nuclear Decommissioning Cost Adjustment.

1. Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges. The Company shall be the sole judge of any customer's eligibility for any rate negotiated rate reduction.
2. Any qualifying existing or new customer may qualify for a negotiated decrease in VDC charges of up to 15% to meet the customer's documented competitive alternative. The rate reduction and payment terms for service may be negotiated and specified in the applicable service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 17. Billing and Standard Payment Options of the Rules and Regulations of the Tariff shall apply. The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.

ECONOMIC DEVELOPMENT RIDER (continued)

DEFINITIONS.

1. Service Location. A single or contiguous premises having one or more delivery points for distribution service billed by the Company under a single account

2. New Manufacturing Customer. The Company has not previously provided service to the Service Location, or the service previously provided by the Company to the Service Location was not used for substantially the same type of operation or was terminated at least twelve (12) months before the customer's contractually specified effective date for service under this rider. This condition is waived for existing service locations where an entity has assumed operation of a service location from a customer which has ceased operations as a result of dissolution, so long as the formation of the entity did not occur as a result of merger, joint venture, acquisition and/or any other variation of combined business structures with the former customer at the service location. In any event, the completed application for the rider must be made within 6 months from the later of the date: (1) the customer first received service from the Company; or (2) the date the customer received its sales tax exemption certificate from the Commonwealth of Pennsylvania

3. Manufacturing Sales Tax Exemption Certificate. Pennsylvania Sales Tax Blanket Exemption Certificate filed by the customer with the Company showing the address of the Service Location and certifying that more than fifty (50) percent (on an annual basis) of the service purchased by the customer for the Service Location is exempt from sales tax because it is used in manufacturing operations, shipbuilding operations, or ship cleaning operations.

4. Employment Report. The "Employer's Report for Unemployment Compensation" (PA Form UC-2) as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania.

5. Base Period. The twelve (12) month period immediately preceding the billing month in which the customer provides the Company written notice of its desire to be placed on the rider. If the customer does not then qualify for the rider within 60 days of the written notice, then the base period will be the twelve month period immediately preceding the billing period for which this rider is first applied to the customer’s bills.

6. Base Period Employment Reports. The Employment Reports for all quarterly reporting periods, as defined by 43 P.S. 753 [d], in the Base Period

7. Base Period Employees. The arithmetic mean of the number of employees each month as reported on the applicable Base Period Employment Report. An adjustment will be made to normalize Base Period Employees in quarters during which either the Casualty or Construction Rider was in effect for the Service Location.

8. Base Period Energy. The number of kilowatt-hours used by the customer for service to the Qualifying Service Location during each month of the Base Period. An adjustment will be made to normalize usage in months during which the Construction or Casualty rider was in effect.

9. Current Employment Report. The Employment Report covering the calendar month immediately following the Base Period as defined by 43 P.S. 753 [d]. The customer may submit an updated Employment Report at any time to reflect increases in Current Period Employees replacing and superseding the original report. The Company reserves the right to request an updated Employment Report at any time which may reflect increases or decreases in Current Period Employees replacing and superseding the original report.

10. Current Period Employees. The arithmetic mean of the number of employees each month as reported on the Current Employment Report.

11. Brownfield Site. Refers to real property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Requires documentation either by providing a copy of the pertinent sections of the ASTM E1903-97 Phase II Site Assessment documenting the site contamination or by providing a letter from a local, state or federal regulatory agency confirming the site is classified as a Brownfield by that agency.

TERM OF CONTRACT. This rider shall be in effect for either a period of five years provided that the customer maintains qualification for the duration of that time.

RENEWAL. A customer may renew the rider at any time in accordance with the terms and provisions of the rider as it applies to Qualifying Existing Service Locations. For renewal customers, the Base Period Energy for any month of the new Base Period shall not be less than the Base Period Energy of the corresponding month of the customer's previous Base Period. The Term of Contract for the renewal shall begin on the date on which the renewal of the rider is first applied based on the new Base Period.

TRANSFER OF OWNERSHIP. The Company will only apply the rider to the customer's bills for the term of contract. If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective January 1, 2026 through May 31, 2029)

AVAILABILITY/APPLICABILITY.
Applicable to a service that is dedicated to Electric Vehicle Supply Equipment (EVSE) and includes at least one permanently connected Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to a stand-alone metered DCFC site. The Company may, at its sole discretion, apply this rider to a service that has both DCFC and other forms of EV charging so long as the combined maximum nameplate capacity rating for all DCFCs connected to the service is equal to at least 80% of the combined maximum nameplate capacity rating for all EVSE connected to the service. The Company may, at its sole discretion, apply this rider to a service that has other loads ancillary to EV charging such as signage, lighting, and communication equipment so long as the maximum combined demand of such loads does not exceed one percent of the combined maximum nameplate capacity rating for all EVSE connected to the service.

The pilot extension begins on January 1, 2026 and expires on May 31, 2029.

The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Direct Current Fast Charger (DCFC) – A high powered EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered high-powered, the DCFC must have a nameplate charging capacity of at least 50 kilowatts per charging port.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, and the nameplate capacity (in kW).

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective January 1, 2026 through May 31, 2029)

RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a variable demand (kW) credit, equal to 30% of the measured demand to the customer's billed distribution demand. For services where the minimum demand would be calculated under the applicable base as 40% of the maximum contract demand, the Company shall instead calculate minimum demand as 30% of the maximum contract demand. Otherwise, the minimum demand shall be 15 kW.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal.

EMERGENCY ENERGY CONSERVATION RIDER

AVAILABILITY/APPLICABILITY.
This rider is applicable in conjunction with Tariff Rule 12.3 relating to mandatory emergency energy conservation. It provides for modifications to the charges and practices otherwise applicable to certain customers as a result of compliance with or non-compliance with energy conservation curtailment levels as mandated by the appropriate governmental authority under emergency energy conservation conditions resulting from actual or potential shortage of fuel for electric generation. This rider is applicable to individual electric customer accounts served under Rates EP and HT, with a billing demand of 2,000 kilowatts or higher, in a recent twelve-month period prior to the emergency conservation condition. Customers designated by the procedures of Tariff Rule 12.3 and by the Pennsylvania Public Utility Commission, will be exempt from the provisions of this rider.

BASE PERIOD ENERGY USE.
The base energy use for a weekly period shall be determined by the Company for each applicable customer account based upon a consideration of the customer's actual past or current electric consumption and the customer's existing operations.

MANDATORY CURTAILMENT ENERGY USE LEVEL TARGET.
The mandatory curtailment energy use level target for each applicable customer shall be that percentage of base period energy use ordered pursuant to the emergency energy conservation procedures provided by Tariff Rule 12.3 or other percentage as a result of the order of appropriate governmental authority.

COMPLIANCE.
When the energy consumption in any weekly period during the period of mandatory curtailment exceeds the mandatory curtailment energy use level target, the customer will be deemed to be in non-compliance. Customers deemed to be in non-compliance will not receive the billing modifications as set forth in this rider. In the event of continued non-compliance, the Company, upon notice to the Commission, may discontinue service.

BILLING FOR CUSTOMERS IN COMPLIANCE.
During the period of emergency energy conservation condition, billing will be based on special meter readings made to identify the demand established and energy using during the current energy use period. Customers in compliance with conservation orders will be excused from minimum bills and historical or contract demand or ratchet provisions and will be billed instead on the basis of current consumption and demand whenever the normal calculation method would produce a greater bill. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

These customers will be individually notified of this special billing provision before the implementation of the emergency energy conservation procedure.

INVESTMENT RETURN GUARANTEE RIDER

AVAILABILITY/APPLICABILITY.
To contracts which require investment in supply facilities greater than warranted by the incremental revenue recovered through the Company's tariffed Variable Distribution Service Charges of the Base Rate under which PECO Energy provides service.

COST OF EXTENSION.
The cost of the extension of supply facilities, including the cost of the service connection, shall be set forth in each agreement for the application of this rider.

MINIMUM GUARANTEE.
The minimum monthly payment shall be the amount set forth in the rider agreement or, in the event of later increases of the customer's load, the minimum of the rate at which service is rendered, whichever minimum obligation is the greater.

CONSTRUCTION ADVANCES.
Where the service desired is of a special character or doubtful permanency, the Company will require payment of a sum equal to the cost of the extension as an advance for construction. A credit of 20% of the net amount of the customer's revenue recovered through the Company's tariffed Variable Distribution Service Charges will be allowed by the Company up to an aggregate refund of 100% of such sum, with the right to retain such portion of the advance as needed to guarantee the payment of subsequent bills.

FULFILLMENT OF CONTRACT TERM.
In the event of the discontinuance for any reason of the distribution of energy before the expiration of the term of the contract with which this rider is applied, the customer shall pay the Company immediately thereon a pro rata share of the cost of the extension for the unexpired portion of the contract term.

OWNERSHIP OF DISTRIBUTION SUPPLY FACILITIES.
The provisions of this rider shall not under any circumstances be considered as conferring upon the customer any title to, or right of property in, the distribution supply facilities.

CONTRACT TERM.
Contract terms in excess of one year may be arranged with the customer to assure the return required by the investment in distribution supply facilities.

NIGHT SERVICE GS RIDER

(The number of customers served under this rider may be limited by the availability of the required demand meters.)

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours may be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate GS (with demand measurement), including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.
Night Service billing and metering charge: $27.38

Charge per kW of Off-Peak billing demand per month: $4.93

STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

NIGHT SERVICE HT RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rates HT or EP, including all terms and guarantees, are applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand:
$4.10 per month for Rate HT.
$4.38 per month for Rate EP.

STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

NIGHT SERVICE PD RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, trademark and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate PD, including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand per month: $5.26

STATE TAX ADJUSTMENT CLAUSEAND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand, except that, when said greatest demand during Off-Peak Hours exceeds the demand specified for Off-Peak Hours, said greatest Off-Peak demand shall be reduced by the amount of the excess in determining the Off-Peak billing demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

RECEIVERSHIP RIDER

AVAILABILITY/APPLICABILITY.
To service provided to a Receiver-Trustee for the continued operation of a property formerly under contract for its electric service requirements.

AUTHORITY FOR OPERATION.
The Receiver-Trustee shall possess the authority under appointment by Court, through an order duly entered, to operate premises recited in a contract for electric service under which the Company has been providing service.

ACCEPTANCE.
The Receiver-Trustee shall accept and adopt for the continuation of service the contract theretofore in effect, including all of its provisions, and agree to pay the Company for all charges levied during the receivership-trusteeship at the rate specified therein.

BILLING.
The Company reserves the right to render bills on a biweekly basis. To provide for biweekly billing under this rider, the provisions of the applicable rate and rider, if any, will be modified as follows:

(a) Where applicable, all references to monthly or month will be changed to biweekly or biweek.
(b) Where applicable, capacity charges will first be determined from the pricing in the monthly rate table and such sum will then be multiplied by 14/30ths (0.4667) to determine the capacity charges for the billing period.
(c) The energy charges will be determined by using the prices in the monthly rate table; however, the limit of the kilowatt-hours to be billed in each price block will be determined by multiplying the hours' use of billing demand for each price block or the kilowatt-hour limits of a given price block by 0.4667.
(d) The high voltage discount applicable to Rate HT will be determined by using the pricing in the monthly rate table and such sum will then be multiplied by 0.4667 to determine the discount for the billing period.
(e) The minimum charge will be determined on a monthly basis and such sum will then be multiplied by 0.4667 to determine the minimum charge for the billing period.
(f) A discount of 0.4% will be applied to the total bill.
(g) A bill will be rendered biweekly covering the charges for the preceding billing period and such bill shall be paid within fifteen (15) days after receipt thereof.

If the customer receives Default Service, the terms of this rider shall also apply to the Energy Supply Charge.

TERM OF CONTRACT.
The completion of the term of the contract taken over, or as terminated by the discharge of the Receiver-Trustee, or as arranged with the Receiver-Trustee for the continuation of service under the standard terms of this Tariff.

TEMPORARY SERVICE RIDER

APPLICABILITY.
To the provision of service, including builders construction service, when the Company must install temporary facilities that will be used for a limited period or for a service that is of doubtful permanency.

AVAILABILITY.
Temporary service will be provided only when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

INVESTMENT IN DISTRIBUTION FACILITIES.
The cost of the extension and removal of facilities required to furnish the temporary service under the applicable rate shall be paid by the customer, but such payment shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM.
Application of this rider to Rates R, R-H and GS shall not, for billing purposes, be considered to be for a period of less than one month.

Application of this rider to Rates PD and HT shall require payment of the minimum provisions of the contract for each month of the temporary service period, but in no case shall such period be considered, with respect to the guarantee of the monthly minimum charges, as of less duration than 6 months.

RATE IMPACT.
Billing shall be under the provisions of the applicable base rate and riders.

TERM OF CONTRACT.
Short term arrangements as agreed upon.

PECO Statement No. 1:
Direct Testimony of Brendan J. Taylor

PECO ENERGY COMPANY
STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: BRENDAN J. TAYLOR

SUBJECT: OVERVIEW OF RATE FILING; INTRODUCTION OF WITNESSES; CUSTOMER SERVICE OPERATIONS, PROGRAMS AND AFFORDABILITY; FULFILLMENT OF 2024 JOINT PETITION FOR SETTLEMENT COMMITMENTS; ECONOMIC DEVELOPMENT, WORKFORCE DEVELOPMENT, AND COMMUNITY ENGAGEMENT; MANAGEMENT PERFORMANCE

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
BRENDAN J. TAYLOR

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Brendan J. Taylor. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company as Vice President of Regulatory Policy and Strategy. My duties and responsibilities include regulatory strategy and policy, energy efficiency and energy acquisition for gas and electric activities at PECO.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Business Administration from the University of Delaware and a Master of Business Administration from Villanova University. During the past 19 years, I have held numerous positions within PECO and its parent, Exelon Corporation. Before becoming Vice President of Regulatory Policy and Strategy of PECO, I served as Director of Operations Analysis and Strategy at Pepco Holdings Inc. and was previously the Director of Finance at Pepco Holdings Inc. Prior to those roles, I held various positions of increasing responsibility in Exelon Finance. Prior to Exelon, I worked for a subsidiary of PNC Bank for four years as a Financial Analyst.

4. Q. What are the purposes of your testimony?

A. The purposes of my direct testimony are to (1) provide an overview of this rate filing and explain the factors that require increased investment to keep our electric utility infrastructure reliable; (2) introduce the witnesses who will present testimony in support of PECO's case-in-chief; (3) discuss PECO's customer service operations and programs intended to help ensure rates are affordable and assist customers in saving energy and using new energy technologies; (4) discuss PECO's fulfillment of the commitments made by the Company as part of the settlement approved by the Pennsylvania Public Utility Commission (the "Commission") in PECO's 2024 electric base rate proceeding; (5) describe PECO's community work and support for economic and workforce development; and (6) address PECO's overall management performance in relation to the factors identified in Section 523 of the Public Utility Code.

II. OVERVIEW OF RATE FILING

5. Q. Please summarize the relief that PECO is requesting through this rate filing.

A. PECO has requested an annual overall electric rate increase of approximately $429 million. As required by the Public Utility Code, PECO's proposed tariff has been filed on 60 days' notice and, therefore, bears an effective date of May 29, 2026. However, we recognize that our filing will likely be suspended and investigated.

6. Q. Why is PECO requesting a rate increase at this time?

A. Our customers rely on us to deliver the electricity they need to work, learn and live. PECO provides safe and reliable electric distribution service to 1.7 million customers, and we have one of the strongest reliability records among electric distribution companies in the Commonwealth. In 2024, PECO reduced customer interruptions by nearly 1.1 million, with an estimated savings for customers of $495 million in avoided outages costs. In the same year, our operations supported 11,500 jobs and $6.9 billion in economic impact in our region. And in 2026, despite the challenges posed by Winter Storm Fern in late January, a significant snow event in February, and more than 22 days of hazardous winds and cold temperatures, we delivered reliability performance well above Commission benchmarks.

We are committed to enhancing safety and reliability for our customers through new investments while supporting new business growth, managing increased storm activity, and integrating new technologies. We carefully align our operational, regulatory and financial plans to improve reliability, safety and service offerings and meet the evolving expectations and needs of our customers. In order to meet those expectations and needs, we will invest $2.8 billion in additional electric distribution plant between January 1, 2026 and December 31, 2027.

This capital investment is necessary to continue to maintain and improve the reliability results we have achieved, including reducing the duration of outages and number of customers experiencing multiple

interruptions. Our programs include a new Vegetation Strategic Reliability Improvement Initiative (the "Vegetation Strategic Initiative" or "Initiative") to establish a new foundation for vegetation management in targeted areas of PECO's service territory where vegetation is a leading and persistent cause of customer interruptions compared to the rest of the PECO system. By focusing enhanced, non-routine vegetation management activities in these locations and reducing vegetation to a new baseline condition, PECO will be better positioned to manage future growth more efficiently and deliver enhanced reliability. We are also proposing a new residential battery storage program to study how residential solar systems and batteries can reduce costs for all customers by reducing peak system load.

Even with effectively managing increases in controllable costs below the rate of inflation, our ability to make necessary, reasonable and prudent investments to continue to serve our customers will be impaired without a rate increase. In order to mitigate the impact of a rate increase on our customers' bills, PECO is proposing two rate mechanisms to spread the cost of the Vegetation Initiative as well as the costs of our existing energy efficiency programs over time, which I will discuss later in my testimony. And PECO will continue its robust portfolio of programs for our most vulnerable customers, which include an extensive Customer Assistance Program ("CAP") and our $12.5 million Customer Relief Fund as well as a comprehensive suite of energy efficiency programs designed to help customers save both energy and money.

Despite our commitment to affordable rates and our partnering with the Commonwealth and other stakeholders to expand customer assistance and energy efficiency, we understand that customers are increasingly paying more for energy costs that do not directly reflect local distribution investments or improvements in service quality due to constrained regional energy supply and capacity market pressures that are outside PECO's control. That is why we will also continue to be an active advocate for customers at the federal and state levels and with PJM Interconnection, L.L.C. to help keep energy costs lower and deliver tangible reliability and customer service benefits.

7. Q. Please provide an overview of the significant capital investments planned through December 31, 2027.

A. As discussed in detail in the testimony of PECO witness Jennifer Hanna, Vice President of Electric Operations (PECO Statement No. 2), the Company's capital investments are focused on corrective maintenance, system performance, capacity expansion, facility relocation, new business, and information technology ("IT"). The investments go through a thorough review and approval as part of the Company's capital investment process, with the majority made in coordination with the goals and requirements of PECO's Long-Term Infrastructure Improvement Plan. Additionally, and as discussed in Ms. Hanna's testimony, safety is a foundational element of PECO's capital investment strategy, with investments in equipment replacement, system hardening, facility upgrades, and physical and cybersecurity measures

supporting the highest standards of safety for employees, customers, and the electric system while enabling safe and reliable operations.

8. Q. What has PECO done to control expenses?

A. As in past years, we have continued to carefully manage our operations and maintenance ("O&M") expenses. As discussed by PECO Chief Financial Officer Marissa Humphrey in PECO Statement No. 3, PECO projects that its compound annual growth rate in O&M expense (when adjusted for storm, bad debt, and pension expense, which are variable year to year and largely outside the Company's control) beginning in January 2026 through the end of the FPFTY will be 2.1%. This is nearly 20% lower than the projected average inflation rate of 2.6% over the same period. Nevertheless, as PECO witness Marissa Humphrey explains, we continue to face cost increases in a variety of areas that are not within our control, including elevated inflation that increases borrowing costs.

As described by PECO witness Hanna, we are focused on reduction of outages through vegetation management across our system, but recent storms have resulted in higher costs for restoration and repairs. Such costs are very difficult to predict given the nature of storms, and we are proposing a new Storm Reserve Account in this proceeding to recover actual storm damages – neither more nor less – to ensure that customers are only paying for storm costs incurred. This account is described by Company witness Michael J. Trzaska, Principal Regulatory and Rates Specialist, in PECO Statement No. 4.

9. Q. How have the Company's increased expenditures impacted its rate of return in invested capital?

A. Without an increase in revenues, PECO's electric operations are projected to produce an overall return on investment capital of 5.40% and a return on common equity of 5.94% during the 12 months ending December 31, 2027. As explained by Ms. Ann E. Bulkley in PECO Statement No. 7, such levels of return are inadequate under any reasonable standard and below the rates of return generally afforded to public utilities. Absent a rate increase, the erosion in PECO's projected returns will impair the Company's ability to make all of the reasonable and prudent investments in electric distribution infrastructure that are necessary to maintain and enhance the provision of safe and reliable electric distribution service to its customers. Inadequate returns would also negatively impact PECO's credit-coverage ratios and its ability to maintain its investment-grade credit ratings, thereby increasing the Company's financing costs, and ultimately the cost to customers, as further explained by Ms. Humphrey.

10. Q. Please identify the witnesses providing direct testimony on behalf of PECO in this proceeding.

A. In addition to myself, the following witnesses will be responsible for presenting PECO's case-in-chief:

Jennifer Hanna (PECO Statement No. 2) is Vice President of Electric Operations and oversees the daily operations of PECO's electric distribution system. Ms. Hanna explains the responsibilities of the Electric Operations

department and details our focus on capital investments to improve system reliability as well as our safety, security and environmental programs.

Marissa Humphrey (PECO Statement No. 3) is Senior Vice President, Chief Financial Officer and Treasurer of PECO. Ms. Humphrey discusses PECO's efforts to minimize customer costs and bills and provides an overview of PECO's principal accounting exhibits; discusses PECO's budgeting process; describes the services that PECO receives from affiliated entities and the estimated cost of those services during the FPFTY; and discusses the impacts of the Corporate Alternative Minimum Tax.

Michael J. Trzaska (PECO Statement No. 4) is a Principal Regulatory and Rates Specialist at PECO. Mr. Trzaska sponsors PECO Exhibits MJT-1, MJT-2, and MJT-3, which set forth PECO's revenue requirement for the FPFTY ending December 31, 2027, the future test year ("FTY") ending December 31, 2026, and the historic test year ("HTY") ended December 31, 2025, respectively. He supports PECO's rate base, revenue, operating expense and tax claims, as well as the Company's proposed Storm Reserve Account.

John Coursey (PECO Statement No. 5) is a Load Forecast Analysis Manager at Exelon. Mr. Coursey describes the development and results of PECO's electric sales forecast.

Mariana Hufford (PECO Statement No. 6) is Director of Accounting at Exelon. Ms. Hufford describes PECO's accounting processes, supports the assignment and allocation of common costs between PECO's electric and gas operations, and explains the development of the depreciated original cost of the

Company's utility plant in service and its claim for annual depreciation expense.

Ann E. Bulkley (PECO Statement No. 7) is a Principal at The Brattle Group. Ms. Bulkley presents testimony concerning the rate of return that PECO should be afforded an opportunity to earn on its rate base. She supports PECO's claimed capital structure ratios, its embedded costs of debt, and its requested equity allowance.

Jiang Ding (PECO Statement No. 8) is a Principal Regulatory and Rates Specialist at PECO. Ms. Ding presents an unbundled, fully allocated customer class cost of service study ("COSS").

Joseph A. Bisti (PECO Statement No. 9) is a Manager of Rate Analysts at PECO. Mr. Bisti presents PECO's proposed tariff rates and explains how the results of Ms. Ding's COSS, as well as the consideration of other factors, were utilized in the rate design process to develop PECO's proposed new rates.

Megan A. McDevitt (PECO Statement No. 10) is Senior Manager, Strategic Initiatives, at PECO. Ms. McDevitt discusses proposed changes and clarifications to PECO's electric service tariff.

Steven J. DeMott (PECO Statement No. 11) is Senior Manager, Strategic Planning, at PECO. He discusses PECO's proposal for a residential battery energy storage system pilot.

Jacqueline F. Golden (PECO Statement No. 12) is Director of Customer Financial Operations at PECO. Ms. Golden discusses PECO's current universal service assistance programs, PECO's proposal for the Low Income Usage

Reduction Program ("LIURP"), PECO's De Facto heating program, and PECO's proposal for LIURP Health and Safety ("H&S") program, certain customer service issues, the Company's reconnection fee waiver proposal, and information on PECO's electric rate case settlement commitment regarding payment processing fees.

III. CUSTOMER SERVICE OPERATIONS, PROGRAMS AND AFFORDABILITY

11. Q. What steps has PECO taken in recent years to enhance the quality of the customer service it provides?

A. Our customers expect customer service programs to be available on-line, comprehensive, and dynamic. PECO's mobile application and its website, www.peco.com, have many features that make it easier for a customer to sign up or move service, monitor usage, report an outage, receive outage updates, and enroll in electronic billing, automatic payments, or budget billing.

On average, the Company sends over 32 million notifications and confirmations to our customers on a yearly basis. As of the end of 2025, PECO now has 1.3 million customers enrolled in "MyAccounts" (approximately 74.3% of customers), which is an increase from 1.15 million (approximately 64% of customers) as of the end of 2023 and directly reduces our customer operations costs.

In order to help protect our customers, in 2024, we sent five educational email campaigns to customers regarding payment scams. These emails were sent to more than 5.7 million email addresses with an average open rate of 45%. In 2025, we sent six educational email campaigns to customers regarding

payment scams. These emails were sent to more than 6.8 million email addresses with an average open rate of 48%. The emails reminded customers how to keep their personal, financial, and account information safe and what to look for from potential scammers.

PECO has a variety of other processes, features, and capabilities, including a multifactor authentication process to improve customer account security. This two-step verification is applied to all new customers, and 65.1% of existing customers are now enrolled.

We also provide customers with an "Assistance Finder" feature to aid customers with determining their eligibility to participate in programs providing energy or financial assistance, including energy efficiency programs. Since implementation in May 2023, nearly 30,000 customers have leveraged the Assistance Finder to receive personalized recommendations and application instructions for programs such as Deferred Payment Arrangements, Budget Billing, Due Date Extensions, and the CAP.

12. Q. What do the results of customer surveys indicate about the Company's customer satisfaction?

A. The Company uses a research firm, Escalent, that conducts surveys with customers about their experiences with the Company based on drivers that measure customer satisfaction. According to an analysis of Escalent's survey results for 2025, the Company's top drivers of satisfaction included reliability, customer service performance, and safety.

Customer Operations also evaluates Escalent's measurement of call center satisfaction, as well as the results of customer satisfaction surveys, to monitor and continuously improve the Company's interactions with customers when they contact the call center.

The customer survey results indicate that PECO customers have high levels of customer satisfaction across the various key drivers. At year-end 2025, PECO Residential customer satisfaction was at 84%, with 91% of customers satisfied with PECO's reliability and 81% of customers stating that they believed it was easy to do business with PECO.

PECO also uses the J.D. Power Electric Utility Residential Customer Satisfaction Study to assess its performance. In the 2025 J.D. Power Electric Utility Residential Customer Satisfaction Study, PECO's Overall Customer Satisfaction score was in the first quartile, with PECO ranking 4th out of 18 companies in the East Large Region. PECO ended the year with above-average scores for safety and reliability, problem resolution, ease, digital channel, people, cost, trust, and information provided.

13. Q. How does the Company plan to continue improvement in customer satisfaction?

A. PECO recognizes its responsibilities to customers and is investing in maintaining and improving how the Company provides premier customer service and how it interfaces with customers. Customer Operations has focused on improving customer service through incorporating Generative Artificial Intelligence ("AI") into continuous improvement training of PECO's Customer

Service Representatives, as well as incorporating more customer-requested features into the Company's web portal, My Account, and mobile apps.

One example of a new feature is PECO's recently implemented Service Installations and Upgrade Portal ("SIUP") that makes it easier for customers to request new or upgraded service by guiding them through a simpler, more accurate process. SIUP simplifies the customer request process by automatically determining the appropriate work scope and routing service requests to the correct backend workflows, reducing application errors, potential rework, and delays. The SIUP provides enhanced visibility, notifications, and self-service capabilities for customers and reduces follow-up inquiries and administrative overhead, allowing employees to focus on critical infrastructure work. The systems are agile and allow future enhancements to improve efficiency and added features for customers.

Another example of using technology to enhance customer experience is through PECO's Planned Outage Notification ("PON") system, which keeps customers informed when a planned outage is scheduled or when work is needed to safely restore power. Customers receive clear, timely, and personalized notifications that explain what to expect, including proactive alerts, updates, and notices if work is canceled or rescheduled. Information is delivered through the customer's preferred communication channels, helping customers plan ahead and stay informed with consistent, easy-to-understand messaging.

14. Q. Has the Company, since its last rate case, addressed the customer service and other issues described in the Statement of Chairman DeFrank on March 12, 2026 in Docket No. D-2025-3053971?

A. Yes. The Company's efforts to address customer service issues are addressed in the testimony of Ms. Golden. Ms. Hanna describes the Company's efforts to manage employee overtime.

15. Q. Please describe PECO's leadership in the area of energy efficiency customer programs.

A. Now in the fifth year of the fourth phase (Phase IV, 2021-2026) of its Energy Efficiency & Conservation ("EE&C") Program, PECO's Ways to Save offerings continue to provide meaningful customer savings and comprehensive energy solutions for residential, non-residential, and low-income customers. During the first four years of the current EE&C Program phase, PECO helped customers save more than 1,233,900 MWh, including approximately 88,880 MWh of savings by low-income customers. The Company continues to develop innovative programs, including an Act 129 Health and Safety Pilot for low-income customers resulting in $500,000 of health and safety services to facilitate $1,300,000 in energy efficiency work being completed at no cost for these customers.

PECO has gained consistent annual recognition for its excellence in program delivery with ENERGY STAR's Partner of the Year Sustained Excellence Award for promoting a vast array of ENERGY STAR certified products to residential and commercial customers. Additionally, PECO

received ENERGY STAR's New Construction Market Leader Award for the past five years in a row for our commitment to energy efficient new home construction.

Recently, PECO reached a settlement with all parties in proceedings for approval of PECO's Phase V (2026-2031) EE&C Plan. As agreed to in the settlement, the Company will make increased investments in comprehensive energy efficiency measures, improve coordination with external weatherization and usage reduction programs, and continue to provide diverse opportunities for low-income, residential, commercial, and industrial customers to save energy and reduce energy costs. The settlement was unanimously approved by the Commission on March 26, 2026.

16. Q. Has PECO deployed advanced metering infrastructure ("AMI") meters in accordance with Act 129?

A. Yes. Under Act 129, PECO has deployed nearly 1.8 million electric AMI meters at customer premises. PECO's meter reading systems have consistently maintained strong performance (99.82%) since 2016.

Consistent with previous years, customers are increasingly taking advantage of AMI meter capabilities. For 2025, PECO customers with AMI meters utilized the interactive "My Usage" tool on the Company's website more than 150,000 times for detailed information on their energy usage. The remote connect and disconnect function of AMI meters has significantly improved customer-requested connect and disconnect services as well as credit-related disconnect and restoration. In 2025, 95% of customer-requested connects and

disconnects were completed remotely, and 98.5% of credit-related disconnects were completed remotely. This translates to an estimated 463,000 truck rolls avoided in 2025.

Deploying AMI technology across the Company's service territory has also enabled PECO to reduce restoration times during major storms. Improved AMI-based storm restoration efforts have avoided over 12,800 truck rolls during the past year (2025). For example, we expanded our distribution automation devices from an installed base of 400 in 2017 to over 4,525 to facilitate automatic and remote re-routing of power during outages to enhance performance and improve reliability. In 2025, PECO issued nearly 486,800 remote commands to distribution equipment to limit human contact with high-voltage equipment and reduce restoration times, with a 95% success rate. Real-time remote monitoring of distribution switches allows PECO to proactively identify failing distribution equipment and make repairs before it impacts electric service to customers. In addition, remote monitoring of over 860 capacitors has reduced field inspection cycles from every year to every four years. These devices also enhance the Company's ability to manage the communication system by allowing PECO to dedicate channels for unrestricted use during reliability events.

17. Q. Has PECO undertaken any programs to facilitate the installation of distributed solar generation and other distributed generation ("DG") technologies?

A. Yes. The Company has implemented a range of initiatives to streamline interconnection processes, improve transparency, and enhance the overall experience for solar and other DG customers. These efforts are led by PECO's Green Power Connect ("GPC") department, which is currently staffed by 20 dedicated employees focused on supporting customers and developers seeking to interconnect to the grid.

PECO established a solar collaborative in 2016, the first of its kind in the region, and it continues today with participation from solar developers, environmental organizations, public officials, utilities, and competitive electric suppliers. Most recently, PECO convened the collaborative in February 2026 to provide education on existing process improvements and to gather stakeholder feedback. In addition, the GPC team conducts monthly webinars with customers and developers in Approved to Install status to provide guidance on the interconnection process and solar billing.

PECO also provides customers with planning and transparency tools, including its Digital Solar Toolkit and interactive viability map, which help customers understand whether their location can support solar or other distributed generation and whether system upgrades may be required. These tools continue to provide meaningful upfront information that helps reduce avoidable delays. In February 2026, PECO further enhanced transparency for

developers by launching a distributed energy resources Capacity Queue tool that shows how many applications and how much capacity are ahead of customer projects across the PECO territory.

From a technical standpoint, PECO continues to use automated technical analysis for the majority of Level 1 and smaller Level 2 solar applications. This approach has proven effective in reducing manual reviews and shortening interconnection timelines. PECO is also updating its technical interconnection requirements to better align with current technologies and industry standards. One external-facing interconnection document has been updated, and work is ongoing to update a second document.

Finally, PECO has improved the customer experience by enabling electronic application payments through its interconnection platform and by assigning a single point of contact through a Senior Interconnection Specialist role. Collectively, these initiatives reduce administrative and technical friction, avoid unnecessary reviews and upgrade costs, improve field productivity, and support reliable, cost-effective integration of distributed energy resources.

18. Q. Is the Company proposing any new programs relating to distributed generation?

A. Yes, PECO is proposing a Battery Energy Storage System ("BESS") Leasing Pilot ("BESS Leasing Pilot"). As further described in the Testimony of Steven J. DeMott in PECO Statement No. 11, PECO is proposing a pilot program that will offer discounted leases on home batteries for up to 200 residential customers who previously installed rooftop solar systems without an energy

storage component. Through the pilot program, the Company aims to understand whether and how it can best engage residential customers with installed solar systems and batteries to shift daily peak load to non-peak times. Resource adequacy challenges during times of peak load affect reliability and affordability of electric service for all customers. PECO will use the installed capacity of the batteries in the pilot to reduce demand during peak periods, thereby reducing costs for all customers, including non-participating customers.

19. Q. Does PECO offer or administer programs to support the Company's low-income customers?

A. Yes. As described in the testimony of Jacqueline F. Golden in PECO Statement No. 12, PECO has a portfolio of universal service assistance programs designed to support low-income customers in maintaining affordable service, including the CAP, LIURP, Customer Assistance Referral and Evaluation Service ("CARES"), and Matching Energy Assistance Fund ("MEAF"), in addition to its support of Low-Income Home Energy Assistance Program ("LIHEAP").

20. Q. Does the Company propose enhancements to these programs to support customer affordability?

A. Yes, as further described by Ms. Golden, PECO is proposing to make the LIURP De Facto Heating pilot program approved in the Company's 2016-2018 Universal Service and Energy Conservation Plan ("USECP") a permanent component of LIURP. The program facilitates additional energy reduction and financial support benefits for our most vulnerable customers. PECO is also proposing to increase the budget for its LIURP H&S program.

21. Q. Is the Company proposing any changes to how costs are recovered to support customer affordability?

A. Yes, PECO is proposing two rate mechanisms to spread the recovery of certain costs over time and help keep energy costs affordable. First, PECO is requesting to defer certain cost recovery relating to PECO's new Vegetation Strategic Initiative program for accounting and customer billing purposes. Second, PECO is requesting alternative ratemaking treatment for future costs relating to PECO's EE&C program. Both measures would immediately reduce customer bills and defer the recovery of costs to future rates.

22. Q, What are the projected costs of the Vegetation Strategic Initiative?

A. Projected costs for the Initiative vary by year, but as described by PECO witness Hanna, total program costs are estimated to be approximately $130 million over the eight-year duration of the Initiative, or roughly $16 million per year on average for all PECO customers. Consistent with the treatment of other vegetation management costs, PECO proposes to recover the annual costs of the Initiative through base rates, using the projected costs reflected in the FPFTY in this proceeding.

23. Q. How does PECO's proposal mitigate impacts to customers' bills in the near term?

A. Recovery of the Initiative's annual costs entirely through base rates in the year incurred would not, by itself, reduce customer bills. To provide immediate near-term bill relief, PECO is proposing a creative ratemaking mechanism

under Section 1307 of the Public Utility Code to recover the costs of each year of the Initiative over a longer period.

Under this proposal, beginning in 2027, the annual $16 million program costs during the eight years of the Initiative would be recovered over a ten-year period, rather than entirely in the year incurred. This approach significantly reduces the amount customers pay in the short term, while allowing PECO to fully recover its costs over time, with a carrying charge.

24. Q. Please explain how the proposed Section 1307 mechanism works.

A. The proposed Section 1307 mechanism does not change the recovery of the Initiative's annual costs through base rates based on projected FPFTY amounts. Instead, it will operate as an additional step to mitigate near-term customer bill impacts, as customers realize the immediate benefits of the Initiative.

Each year, the Company would (1) credit customers for the Initiative costs recovered through base rates, with the credited amount recorded on PECO's books as a regulatory asset, and (2) recover that regulatory asset from customers over a ten-year amortization period, with a carrying charge applied to the unrecovered balance. This process would repeat for each year of Initiative costs.

For example, in 2027—the first year of the Initiative—program costs are projected to be approximately $17.6 million, with a corresponding base rate recovery of $18.7 million inclusive of gross receipts tax. Under the proposed Section 1307 mechanism, PECO would first credit customers the full $18.7 million to offset the base rate charge. That credited amount would then be

recovered over ten years, resulting in an annual Section 1307 recovery of approximately $1.87 million in 2027, plus a carrying charge calculated annually based on the average unrecovered balance.

As a result, the net cost to customers in 2027 would be approximately $2.7 million, rather than the full $18.7 million otherwise recovered through base rates, with the remaining balance deferred as a regulatory asset for recovery in future years. Similar deferrals and amortizations would be recorded for each of the remaining seven years of the Initiative (2028-2034). Over time, as deferred amounts and carrying charges are recovered, annual customer charges would increase but remain below the full annual program cost until later years of the recovery period.

The details of the proposed Section 1307 mechanism and the associated tariff revisions are further described by PECO witness McDevitt in PECO Statement No. 10.

25. Q. Have you estimated the annual net impact of the proposal on total customer bills?

A. Yes. Under the proposed mechanism, customers would experience a substantial reduction in bill impacts in the early years of the Initiative. In 2027, the first year of the program, customers would see a reduction of approximately $16.0 million compared to the cost of full, contemporaneous recovery. Similar bill reductions would continue during the initial years of the Initiative as each year's costs are deferred and recovered over a longer period.

Over time, as additional years of costs are incurred, deferred, and amortized, and carrying charges are applied, annual customer credits would gradually decline and transition to net charges. Across the full recovery period, customers would pay the same costs of the program with only the additional carrying charges, to receive materially lower bill impacts in the near term.

The proposed Section 1307 mechanism meaningfully improves near-term customer affordability while supporting enhanced reliability benefits. I have attached a table that shows the estimated annual Initiative costs and the resulting net impact on customer bills under the proposed Section 1307 surcharge as PECO Exhibit BJT-1 to my testimony.

26. Q. Has the Commission approved comparable mechanisms for any other Pennsylvania utilities?

A. I am advised by counsel that the Commission has regularly approved the deferral of utility expenses that are extraordinary and non-recurring for future recovery. Typically, these regulatory assets are related to extraordinary storms, but the Commission has also approved regulatory assets associated with other unanticipated utility costs. Here, these costs are for a one-time, non-recurring program to address significant vegetation growth in PECO's service territory. The actual costs would remain subject to examination for prudence and reasonableness in future rate proceedings. This proposal for a new Section 1307 mechanism is to spread the cost recovery relating to the initiative over time in order to create a near-term net customer bill reduction to support customer affordability.

27. Q. Please describe the Company's proposed mechanism relating to EE&C costs.

A. Act 129 of 2008 provides that an electric distribution company is entitled to recover the annual costs of its EE&C plan mandated by Act 129 up to 2% of its annual electric distribution revenues as of December 31, 2006. For PECO, that amount is $85,477,166 per year, or $427,385,828 over the five years of PECO's Phase V plan beginning on June 1, 2026. These costs are recovered through PECO's Variable Distribution Charge on residential customer bills and the Energy Efficiency Charge for other customers.

Similar to our proposal for recovery of costs associated with the Vegetation Strategic Initiative, PECO proposes to continue to recover EE&C costs from all customers while also providing a credit (the "EE&C Regulatory Asset Rider") to reduce those costs in the near future.

28. Q. How will the proposed EE&C Regulatory Asset Rider operate to reduce customers' bills in the near term?

A. Under this proposal, beginning in 2027, the annual program costs of $84 million per year during the five years of PECO's Phase V plan and costs for subsequent phases of the EE&C program would be recovered over a ten-year period, rather than entirely in the year incurred. This approach would also significantly reduce the amount customers pay in the short term for the energy efficiency benefits delivered under Phase V, while allowing PECO to fully recover its costs over time, with a carrying charge.

29. Q. Please explain how the proposed EE&C Regulatory Asset Rider will work.

A. The proposed EE&C Regulatory Asset Rider does not change the recovery of PECO's EE&C costs. Instead, it will operate as an additional step to mitigate near-term customer bill impacts as customers realize the immediate benefits of energy efficiency projects.

Each year, the Company would (1) credit customers for the entirety of the EE&C charge paid by customers, with the credited amount recorded on PECO's books as a regulatory asset, and (2) recover that regulatory asset from customers over a ten-year amortization period, with a carrying charge applied to the unrecovered balance. This process would repeat for each year of EE&C costs after the rates in this proceeding become effective.

For example, in 2027, EE&C costs to be recovered are approximately $84 million, inclusive of Pennsylvania's Gross Receipts Tax. Under the proposed mechanism, PECO would credit customers the full $84 million to offset the EE&C charge. That credited amount would then be recovered over ten years, resulting in an annual recovery of approximately $12 million in 2027, including a carrying charge calculated annually based on the average unrecovered balance.

As a result, the net cost to customers in 2027 would be approximately $12 million, rather than the full $84 million otherwise recovered under PECO's tariff for Phase V costs, with the remaining balance deferred as a regulatory asset for recovery in future years. Similar deferrals and amortizations would be recorded for each of the future years of EE&C programs.

The details of the proposed Regulatory Asset Rider and the associated tariff revisions are further described by PECO witness McDevitt in PECO Statement No. 10.

30. Q. Have you estimated the annual net impact of the proposal on total customer bills?

A. Yes. Under the proposed mechanism, customers would experience a substantial reduction in bill impacts in the early years of the Initiative. In 2027, the first year of the program, customers would see a reduction of approximately $72.1 million compared to the cost of full, contemporaneous recovery of Plan V costs. Similar bill reductions would continue as each year's costs are deferred and recovered over a longer period.

Over time, as additional years of costs are incurred, deferred, and amortized, and carrying charges are applied, annual customer credits would gradually decline and transition to net charges. Across the full recovery period, customers would pay the same EE&C costs with only the additional carrying charges, to receive materially lower bill impacts in the near term.

I have attached a table that shows the estimated annual EE&C Regulatory Asset Rider costs and the resulting net impact on customer bills under the proposed Section 1307 surcharge as PECO Exhibit BJT-2 to my testimony.

31. Q. Is PECO asking for the Commission to approve the EE&C Regulatory Asset Rider on the same basis as the Vegetation Initiative regulatory asset?

A. No. Under Act 129, the costs of EE&C programs are generally required to be recovered from customers on a full and current basis, and PECO will continue to charge customers the full EE&C charge. PECO is seeking approval of the EE&C Regulatory Asset Rider under the provisions of Section 1330 of the Public Utility Code, which permits the Commission to approve alternative rate mechanisms.

32. Q. Does the proposed EE&C mechanism align with the Statement of Policy for alternative ratemaking mechanisms adopted by the Commission?

A. Yes. Attached to my testimony as PECO Exhibit BJT-3 are the Company's responses to each consideration identified in the Statement of Policy.

33. Q. Is PECO taking other actions to assist customers with energy-related costs?

A. Yes, PECO is considering offering a home services program, similar to programs offered by other utilities in Pennsylvania, under which customers would be able to obtain maintenance plans from a third party for a variety of home repairs to protect themselves from large repair bills. While PECO has not yet introduced such a program for customers, PECO is proposing a tariff change that would flow all revenues PECO receives from any such program to customers. PECO witness McDevitt also discusses the tariff change necessary to arrange for such payments to customers in the future.

34. Q. In its Customer Assistance Program Policy Statement, the Commission states that "[i]n rate cases, parties may raise the issue of recovery of CAP costs, whether specifically or as part of universal service program costs in general, from all ratepayer classes. No rate class should be considered routinely exempt from CAP and other universal service obligations."[1] Did PECO consider making such a proposal in these proceedings?

A. Yes. We do believe it is appropriate to raise the issue in accordance with the Policy Statement and in the spirit of considering creative solutions to address customer affordability. However, I note that the Commission rejected such a proposal by the Office of Consumer Advocate and the Coalition for Affordable Utility Services and Energy Efficiency in our 2020 gas rate proceeding. While PECO is not making a proposal to shift universal service program cost recovery from residential customers in this proceeding, we propose that the Commission should initiate a collaborative to explore alternative mechanisms for recovery of universal service costs given the increasing costs of universal service programs. PECO believes that this is an issue that should be addressed not in a single utility proceeding but through a Commission-sponsored process in which utilities, advocates, stakeholder groups and customers throughout the Commonwealth can participate.

[1] 52 Pa. Code § 69.266.

IV. FULFILLMENT OF 2024 JOINT PETITION FOR SETTLEMENT RATE CASE COMMITMENTS

35. Q. In the Joint Petition for Settlement of Rate Investigation that the Commission approved in PECO's last electric base rate proceeding at Docket No. R-2024-3046931 ("2024 Settlement" or "Settlement"), PECO agreed to report on various expenditures. Please describe each reporting requirement and PECO's compliance with this commitment.

A. First, PECO agreed to provide the Commission's Bureau of Technical Utility Services, the Commission's Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate, and the Office of Small Business Advocate with an update on its electric division's actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2024. Second, the Company agreed to provide a similar update on or before April 1, 2026, to include actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2025. Finally, PECO agreed, in its next base rate proceeding, to prepare a comparison of its actual expenses and rate base additions for the 12 months ended December 31, 2025, to its projections in the 2024 electric base rate proceeding. PECO met each of these reporting commitments. PECO witness Humphrey describes the Company's 2025 actual expenditures further in her testimony.

36. Q. Please summarize PECO's compliance with other commitments in the Settlement directly affecting rates, customer programs, assistance to low-income customers, and clean energy interconnection.

A. ***Customer Assistance Programs (Settlement paragraphs 28-41).***

PECO has participated in the Department of Human Services ("DHS") data-sharing program and has used the data provided through the DHS program to automatically recertify current CAP customers. Additionally, PECO met with its Universal Services Advisory Committee ("USAC") on February 11, 2026, to develop a new procedure for obtaining informed consent for LIHEAP data sharing participants who want to enroll in PECO's CAP that does not require completing a new CAP application. PECO filed a revised Universal Service Energy Conservation Plan to outline the new process on March 12, 2026. An additional collaborative will occur in 2026 and recommendations will be provided by October 1, 2026. PECO also added health usage rider exemption language to CAP communications to assist customers with a serious illness or injury that require electric service above the maximum CAP credit limit.

With respect to PECO's LIURP, PECO has met all settlement commitments, including increasing the annual budget and providing information on how the Company targets CAP customers approaching their maximum credit for LIURP services and providing related customer statistics on the number of customers who reach their maximum CAP credit and who have been offered a LIURP audit at USAC meetings. CAP and LIURP data has

also been shared with the City of Philadelphia on a quarterly basis. Additionally, PECO has begun to track and report annually to the USAC the number of LIURP jobs deferred due to health and safety issues or other circumstances.

Regarding MEAF, PECO made a compliance filing as part of its USECP to reflect amendments in maximum grant amounts and balance requirements to receive a MEAF grant. PECO also imposed data collection requirements on MEAF agencies and began reporting at quarterly USAC meetings statistics regarding the number of MEAF applications submitted, approved and denied by county, reasons for denials, and average processing time. PECO improved oversight of MEAF agencies in order to ensure appropriate termination holds on applicable accounts where MEAF applications have been approved. PECO also updated its website regarding additional information around the MEAF process and required documentation.

In addition, PECO fulfilled its commitments related to speech analytics software, usage of low-income status in the billing system to establish payment arrangements, review of inclusion of additional language in its ten-day termination notices around CAP, and provision of CAP and Universal Service information to Cold Weather Survey participants. Information regarding Rate RH was provided to those who were identified as eligible under the Cold Weather Survey. PECO also fulfilled commitments related to service reconnection at reduced restoration amounts and CAP enrollment of eligible low-income customers who were previously terminated. Further, PECO has

begun to hold semi-annual meetings with the City of Philadelphia and Philadelphia Energy Authority ("PEA") regarding expanded outreach opportunities in low-income areas and language access improvements.

Customer Service and Consumer Protection (Settlement paragraphs 42-52).

PECO investigated material issues with call handling identified in the 2022 Audit Report and filed a report on its investigation. PECO also reviewed, and will continue to review quarterly, accounts where security deposits were previously collected from confirmed low-income customers, then either refunded or applied, as appropriate. PECO also implemented changes to the security deposit letter regarding eligibility for a waiver. The Company also conducted an assessment to ensure Environmental Justice communities were not disproportionately impacted by service termination or security deposit requests and continued its Limited English Proficiency stakeholder meetings.

With respect to the determination of Residential Heating Type, PECO met its commitment to increase customer awareness of Rate RH at the time of opening of a new account and when performing a LIURP audit. The Company has convened a collaborative to discuss Rate RH availability and applicability.

Related to payment processing, in this filing, PECO has provided information regarding residential payments by debit and credit card and has provided information explaining why the Company has not made a proposal to eliminate payment processing fees, as discussed by PECO witness Golden in PECO Statement No. 12. PECO continues to negotiate lower payment processing fees with third-party vendors.

PECO has established annual meetings with the City of Philadelphia to review certain project types planned within the next three to five years and has also established a municipal customer "mailbox" to notify PECO when municipalities submit applications for interconnections and incentives. Additionally, PECO created a tracking document for open customer service and billing issues from the City of Philadelphia and has also created a knowledge book to assist the City of Philadelphia with understanding PECO's internal processes and procedures. Further, PECO instituted semi-annual meetings with the City of Philadelphia to review account management, billing, and strategic plans and initiatives.

Electric Vehicle ("EV") Programs (Settlement paragraphs 53-55).

The Company continued its EV Charging Pilot, which extends through May 31, 2029, in accordance with Settlement provisions relating to demand credit calculations. PECO also met its commitment to treat certain City-related agencies as separate customers and has been working with the City of Philadelphia to provide information regarding potential projects to serve load without a line extension. Beginning in 2027, PECO will work with stakeholders through its transportation electrification collaborative working group to evaluate the current Electric Vehicle Fast Charging Pilot Rider and determine plans for a potential successor rider.

Assistance with Non-company clean energy and conservation programs (Settlement paragraphs 56-61).

PECO has established annual meetings with PEA to assist in development of an outreach plan for low- and moderate-income customers eligible for PEA's Solar for All Program. PECO also now refunds or waives engineering study fees from Solar for All customers in various circumstances consistent with the Settlement. In addition, PECO has engaged in discussions with PEA regarding its Built to Last Program and has taken referrals from Built to Last for possible participation in the PECO program. The Company has also met with PEA to discuss opportunities to coordinate PEA programs and LIURP. Lastly, related to greenhouse gas emission, PECO has provided the City of Philadelphia and PEA with documented progress in reducing such greenhouse emissions.

Interconnection Costs (Settlement paragraph 62).

The Company has collaborated with the City of Philadelphia, PEA, the Office of Consumer Advocate, the Office of Small Business Advocate, Pennsylvania Industrial Energy Users Group, Tenant Union Representative Network and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania to assess approaches to achieve a more equitable distribution of utility construction costs to interconnect distributed energy resources. Consistent with the terms of the commitment, PECO convened a collaborative meeting of the stakeholders in May 2025, and at the request of the City of Philadelphia and PEA, a follow-up discussion in December 2025, where the

City of Philadelphia and PEA presented the outline of potential alternative DER cost assignment methodologies to stakeholders. While no consensus was reached at the December meeting, PECO agreed to develop an internal study of interconnection cost assignment data. The components of the proposed study were provided to stakeholders for review and feedback.

V. ECONOMIC DEVELOPMENT, WORKFORCE DEVELOPMENT, AND COMMUNITY ENGAGEMENT

37. Q. Please describe PECO's efforts to support economic development and the communities in which the Company provides service.

A. PECO has a dedicated Economic Development Team that works cooperatively with local, regional, and state economic development officials, as well as commercial and industrial real-estate professionals, to assist businesses that are considering locating or expanding in southeastern Pennsylvania. For example, the team provides information on electric and gas availability and prices to companies, developers, and consultants as key inputs to location decisions. The team also works with developers on electric and gas infrastructure strategies for large development sites.

Since the beginning of 2024, PECO has experienced a sharp increase in large-load requests from developers looking to build data centers. These capacity requests are expected to have a significant and positive impact on jobs and tax revenue in many communities in PECO's service territory. As PECO is determining how to build out the network to support these requests, the Company is simultaneously developing protections (such as credit

requirements) to ensure these large-load customers are paying their fair share of the costs for the required infrastructure improvements.

In 2025, PECO's efforts to drive economic growth and job creation across southeastern Pennsylvania were recognized for the 15th time by *Site Selection Magazine*, "an award-winning magazine recognized as the leading publication in corporate real estate, facility planning, location analysis and foreign direct investment." In 2025 alone, PECO helped secure 15 new commercial projects that are collectively set to add 7,429 jobs at their facilities and more than $21.3 billion in local investment.

Additionally, as I discussed earlier, PECO makes significant capital and infrastructure investments in its service territory every year that create and maintain thousands of jobs in the region. The Company regularly hosts an Aerial Line School, Underground Splicing School, and Energy Technician School to develop a hiring pool for electric operations personnel. In 2024 and 2025, the Company held two Schools each for Aerial, Underground, and Energy Technician, hiring 111 graduating individuals. The Company intends to host another School for each discipline in 2026 and 2027 and has plans to hire the same amount of individuals.

38. Q. Are there other ways in which PECO and its employees support their communities?

A. Yes. In 2025, PECO advanced its role as an anchor institution by aligning Corporate Community Impact ("CCI") activities with core objectives related to customer affordability, community resilience, and workforce readiness.

Through coordinated, enterprise-wide efforts, PECO delivered initiatives designed to expand access to energy assistance, strengthen community infrastructure, and support development of a skilled workforce across its service territory. These initiatives were structured to produce measurable outcomes and to complement the Company's broader operational and regulatory priorities.

One of PECO's primary focuses in 2025 was maintaining energy affordability for customers experiencing financial hardship. PECO expanded direct customer outreach to increase awareness of, and access to, available assistance programs by delivering information and support through community-based locations and digital channels. During the year, PECO conducted 349 outreach events, resulting in approximately 25,000 customer touchpoints and exceeding established outreach targets. In addition, PECO hosted 38 Virtual Assistance Sessions that provided individualized support with eligibility determination, applications, and documentation. These sessions assisted 1,824 customers live, with an additional 1,075 customers supported through follow-up engagement. These efforts contributed to increased participation in key affordability programs. Enrollment in CAP reached approximately 137,000 customers at the end of 2025, an increase of 12% from year-end 2024.

Participation in the Gift of Energy program also increased materially, with contributions rising 108% and providing more than $42,000 in direct bill credits supporting 182 customers facing short-term hardship. PECO further supported effective delivery of assistance by collaborating with 23

Neighborhood Energy Centers to ensure accurate, up-to-date guidance for customers seeking help. In addition, in its role as Pennsylvania's state lead for LIHEAP outreach, PECO supported the delivery of $17.28 million in LIHEAP bill assistance during Fiscal Year 2024–2025, including $2.42 million in supplemental grants.

Further, in 2025, PECO expanded its affordability strategy with the launch of the Customer Relief Fund ("CRF"), a $10 million initiative designed to provide immediate bill assistance to limited- and moderate-income households experiencing rising energy costs. The CRF became available on August 4, 2025, and is administered in partnership with the United Way of Greater Philadelphia and Southern New Jersey. The CRF is designed to support customers who may not qualify for traditional assistance programs and was integrated with PECO's existing portfolio of affordability offerings, including CAP, LIHEAP, and MEAF.

Building on the strong foundation of the original CRF, PECO launched CRF 2.0 on March 2, 2026, adding an additional $2.5 million to further strengthen support for households facing rising energy costs. Also administered in partnership with the United Way of Greater Philadelphia and Southern New Jersey, this expanded phase continues PECO's commitment to reaching our most vulnerable customers by focusing on those whose household incomes at or below 150% of the Federal Poverty Level.

In addition to affordability initiatives, PECO invested in programs that support neighborhood stability, environmental resilience, and community

wellbeing. Through the Green Region Open Space Program, PECO awarded more than $200,000 in grants during the program's 20th year to support community-led improvements of local open spaces. PECO also provided $150,000 in grants through the Powering the Arts program to nonprofit organizations that promote community connection and revitalization. In partnership with the Pennsylvania Horticultural Society, PECO supported the planting, sorting, and distribution of more than 1,000 trees to improve air quality, mitigate heat island effects, and assist with stormwater management within its service territory. PECO employees further supported these efforts through volunteerism, contributing 26,140 hours of service across 393 nonprofit organizations—from preparing thousands of meals at MANNA on Thanksgiving morning, to installing free smoke alarms with the Red Cross, to Love Your Park clean-ups and back-to-school drives.

PECO also invested in initiatives designed to strengthen nonprofit governance and long-term community capacity. In 2025, PECO launched its first 3C (Community, Connection, Commitment) leadership cohort, engaging 38 employees from across the Company to promote service, partnership, and learning. PECO also expanded participation in nonprofit board service by offering quarterly governance training in partnership with La Salle University, resulting in 14 employees joining boards focused on housing, education, and community development.

Workforce development also remained a key focus for PECO in 2025, with initiatives designed to establish clear pathways into family-sustaining

careers in the utility sector. PECO hosted its seventh Infrastructure Academy, engaging more than 160 participants in hands-on demonstrations, testing preparation, and structured interviews. Since the Academy's inception in 2020, more than 70 participants have been hired into PECO roles. PECO also launched Helper Pre-Apprenticeship Cohort 4 with 16 participants, many referred through community partners, to accelerate readiness for critical operational roles. Additional investments included a regional high school internship program, a Junior Infrastructure Academy serving 80 students, and multiple STEM engagement initiatives. PECO further supported education access by awarding 70 scholarships during Academic Year 2024–2025 and initiating 22 additional scholarships for Academic Year 2025–2026 at colleges, universities, and community colleges.

PECO's community investments are structured as strategic partnerships that complement the Company's operational objectives and regulatory obligations. Taken together, these initiatives support improved customer stability, strengthened community infrastructure, and development of a qualified workforce necessary to maintain and modernize PECO's electric distribution system.

Since 2021, PECO's corporate contributions and employee giving campaigns (including corporate matching gifts) have invested more than $38 million dollars in hundreds of local and regional non-profit programs, organizations, and institutions that provide access to arts and culture, and support STEM education, the environment and green spaces, community

vitality, workforce development, and reduction of gun violence. And PECO, along with other Exelon operating companies and the Exelon Foundation, created a $36 million Community Equity Capital Fund to begin establishing access to capital for small businesses from under-resourced communities so that they can create more jobs, grow their companies, and reinvest in their neighborhoods and communities. Notably, in 2023, PECO was named a recipient of The Civic 50 Greater Philadelphia Award by Philadelphia Foundation, in partnership with Points of Light, for superior corporate citizenship in utilizing the Company's time, skills, and resources to drive social impact within the Company and the communities PECO serves.

PECO has been recognized with several awards for its community engagement and workforce development including the OIC of Philadelphia's Workforce Partner Award, which was awarded during the 60th Anniversary Gala, Partners in Philanthropy Award from the *Philadelphia Business Journal* (in partnership with Beyond Literacy), CEWD Community Partner Impact Award - (national organization), PECO Innovation Award Trailblazer - (Junior Infrastructure Academy), and the City of Philadelphia's Employer of Choice Award.

PECO will continue to focus on removing barriers to access, strengthening partnerships, and investing in initiatives that support safe, reliable, and resilient electric service for customers across its service territory.

VI. MANAGEMENT PERFORMANCE

39. Q. Mr. Taylor, is PECO requesting an enhanced return on equity based on its management performance?

A. No. PECO is not seeking an enhanced return on equity tied to management performance, although our results reflect disciplined, effective management focused on reliability, customer value, and cost control.

VII. CONCLUSION

40. Q. Does that complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Brendan J. Taylor, hereby state that I am a Vice President of Regulatory Policy & Strategy for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 1 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.



Dated: March 30, 2026

Brendan J. Taylor

PECO Exhibit BJT-1:
Regulatory Asset Rider Bill Impacts

Impact of Regulatory Asset Treatment for Vegetation Strategic Reliability Improvement Initiative (in $ Million)

Year	Annual Initiative Costs	Current Method - Customer Bill	Proposed Method - Customer Bill	Bill (Reduction) / Increase	% (Reduction) / Increase
2027	$ 18	$ 19	$ 3	$ (16)	-86%
2028	16	17	6	(11)	-66%
2029	21	22	9	(12)	-57%
2030	21	22	13	(9)	-41%
2031	14	15	15	1	6%
2032	14	15	17	3	19%
2033	14	15	19	4	31%
2034	14	15	21	6	42%
2035	-	-	20	20	0%
2036	-	-	19	19	0%
2037	-	-	16	16	0%
2038	-	-	13	13	0%
2039	-	-	10	10	0%
2040	-	-	7	7	0%
2041	-	-	5	5	0%
2042	-	-	3	3	0%
2043	-	-	2	2	0%
6-yr Total	103	109	64	(45)	-42%
10-yr Total	130	138	142	4	3%
17-yr Total	130	138	197	59	43%

PECO Exhibit BJT-2:
Energy Efficiency & Conservation (EE&C)
Regulatory Asset Rider Bill Impacts

Impact of Regulatory Asset Treatment for Energy Efficiency & Conservation Programs (in $ Million)

Year	Annual Initiative Costs	Current Method - Customer Bill	Proposed Method - Customer Bill	Bill (Reduction) / Increase	% (Reduction) / Increase
2027	$ 79	$ 84	$ 12	$ (72)	-86%
2028	91	97	29	(68)	-70%
2029	98	104	47	(57)	-55%
2030	83	89	62	(27)	-30%
2031	88	94	76	(18)	-19%
2032	88	94	89	(4)	-5%
2033	88	94	102	8	9%
2034	88	94	113	20	21%
2035	88	94	124	30	33%
2036	88	94	134	40	43%
2037	88	94	135	41	44%
2038	88	94	134	41	43%
2039	88	94	133	40	42%
2040	88	94	134	40	43%
2041	88	94	134	40	43%
2042	88	94	134	40	43%
2043	88	94	134	40	43%
6-yr Total	528	561	315	(246)	-44%
10-yr Total	880	935	788	(148)	-16%
17-yr Total	1,496	1,590	1,724	134	8%

PECO Exhibit BJT-3:
Energy Efficiency & Conservation (EE&C)
Regulatory Asset Rider Rate Considerations

PECO EXHIBIT BJT-3

Distribution Rate Considerations – EE&C Regulatory Asset Rider

Each rate consideration identified in the Commission's Distribution Rates – Statement of Policy (52 Pa. Code § 69.3302) is listed below along with the relevant effect the proposed EE&C Regulatory Asset Rider has on each rate consideration:

1. Please explain how the EE&C Regulatory Asset Rider and rate design align revenues with cost causation principles as to both fixed and variable costs.

PECO's proposed EE&C Regulatory Asset Rider is designed to mitigate annual EE&C costs on customer bills by spreading the annual costs of PECO's Act 129 Energy Efficiency and Conservation Plan ("EE&C Plan") by customer class over a 10-year period. The EE&C Regulatory Asset Rider will reduce customer bills in the first six years of its implementation while maintaining the current method of utilizing variable rates to refund and collect program costs from customers.

2. Please explain how the EE&C Regulatory Asset Rider and rate design impact the fixed utility's capacity utilization.

PECO's proposed EE&C Regulatory Asset Rider and rate design will have no identifiable impact on capacity utilization.

3. Please explain whether the EE&C Regulatory Asset Rider and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

PECO's proposed EE&C Regulatory Asset Rider and rate design will use each customer's actual consumption to calculate the amount of credits and charges.

4. Please explain how the EE&C Regulatory Asset Rider and rate design limit or eliminate interclass and intraclass cost shifting.

As PECO's proposed EE&C Regulatory Asset Rider and rate design will apply based on the actual EE&C Plan spending by customer class, it will limit or eliminate the potential for interclass or intraclass cost shifting.

5. Please explain how the EE&C Regulatory Asset Rider limits or eliminates disincentives for the promotion of efficiency programs.

The EE&C Regulatory Asset Rider is not intended to have any impact on the promotion of energy efficiency programs as the EE&C Regulatory Asset Rider does not change a customer's actual consumption for billing purposes.

6. Please explain how the EE&C Regulatory Asset Rider impacts customer incentives to employ efficiency measures and distributed energy resources.

The EE&C Regulatory Asset Rider is not intended to have any impact on incentives to employ efficiency measures and distributed energy resources. A reduction in a customer's usage resulting from any efficiency measures or distributed energy resources will continue to reduce a customer's overall bill.

7. Please explain how the EE&C Regulatory Asset Rider impacts low-income customers and supports consumer assistance programs.

Customers served under the Company's current customer assistance program ("CAP") receive bill discounts based on household size and income level. The EE&C credit

amount, like other bill components, would be subject to the percentage of income payment plan without any disproportionate impact on low-income customers.

8. Please explain how the EE&C Regulatory Asset Rider impacts customer rate stability principles.

PECO's proposed EE&C Regulatory Asset Rider is designed to achieve the effect of mitigating annual EE&C Plan costs by customer class over a 10-year period. This EE&C Regulatory Asset Rider will create a customer bill reduction in the first six years of its implementation.

9. Please explain how weather impacts utility revenue under the proposed EE&C Regulatory Asset Rider.

Weather does not impact utility revenue under the proposed EE&C Regulatory Asset Rider.

10. Please explain how the proposed EE&C Regulatory Asset Rider impacts the frequency of rate case filings and affects regulatory lag.

The proposed EE&C Regulatory Asset Rider is a reconcilable mechanism and will not impact the frequency of rate case filings or affect regulatory lag.

11. Please explain if the proposed EE&C Regulatory Asset Rider interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9)

(relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

The Company's proposed EE&C Regulatory Asset Rider will be an additional independent variable distribution service charges on customer bills. The calculated credits or charges shall be subject to the State Tax Adjustment Surcharge and Distribution System Improvement Charge.

12. Please explain whether the proposed EE&C Regulatory Asset Rider includes appropriate consumer protections.

PECO's proposed EE&C Regulatory Asset Rider is designed to achieve the effect of spreading annual EE&C Plan costs by customer class over a 10-year period. The EE&C Regulatory Asset Rider will reduce customer bills in the first six years of its implementation. The proposed mechanism is a reconcilable item, which will be updated to ensure timely credits and charges to customers. This mechanism will also be subject to audit by the Commission as with other 1307 mechanisms.

13. Please explain whether the proposed EE&C Regulatory Asset Rider is understandable to customers.

PECO's proposed EE&C Regulatory Asset Rider is a 1307 mechanism and is not a new concept to customers in Pennsylvania or the broader regulated utility industry. Similar mechanisms have been successfully implemented by other Pennsylvania electric and natural gas distribution companies and by utilities in other jurisdictions across the country. PECO will also provide appropriate notice to customers related to price change.

14. Please explain how the proposed EE&C Regulatory Asset Rider will support improvements in the Company's reliability.

The proposed EE&C Regulatory Asset Rider is intended to provide customers with near-term bill reductions and will not impact the Company's reliability.

PECO Statement No. 2:
Direct Testimony of Jennifer Hanna

PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY –
ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: JENNIFER HANNA

SUBJECTS: PECO'S ELECTRIC OPERATIONS; PECO'S CAPITAL INVESTMENTS; SYSTEM RELIABILITY; AND SAFETY, SECURITY, ENVIRONMENTAL PROGRAMS

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
JENNIFER HANNA

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Jennifer Hanna. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Vice President of Electric Operations. In that capacity, I oversee the operations of PECO's electric distribution system. These operations include distribution system operations, construction and maintenance, engineering and design, fleet, new business, and business planning and support. These functions, in turn, are staffed by approximately 1,195 craft, professional and support employees.

3. Q. Please summarize your prior professional experience.

A. During the past 23 years, I have held numerous positions within PECO and its parent company Exelon Corporation. Before becoming Vice President, Electric Operations at PECO, I served as Vice President, Projects and Contracts at PECO. In this role, I oversaw a multi-billion-dollar capital project execution over a five-year long-range plan, including the construction of substations, natural gas, and distribution facilities aimed to modernize and increase the reliability and resiliency of the grid. Prior to that, I served as Director of the Philadelphia Region in Electric

Operations in addition to various leadership roles in Engineering, Transmission Development, Corporate and Renewable Development at PECO and Exelon.

4. Q. What is your educational background?

A. I earned my Bachelor of Science degree in electrical and computer engineering from Temple University. Additionally, I earned my Master of Business Administration from Villanova University.

5. Q. What is the purpose of your direct testimony?

A. The several purposes of my direct testimony are to: (1) generally describe PECO's electric distribution operations; (2) explain PECO's capital investment process; (3) describe various measures by PECO to ensure system reliability, including PECO's new Vegetation Strategic Reliability Initiative; (4) describe PECO's initiatives increasing productivity and efficiencies and how such efforts benefit our customers; and (5) describe measures taken by the Company with respect to safety, security, and its environmental impact.

II. DESCRIPTION OF PECO'S ELECTRIC OPERATIONS

6. Q. Please provide an overview of PECO's electric distribution operations.

A. PECO is the largest combined electric and natural gas utility in Pennsylvania. In addition to the approximately 1.7 million electric customers we serve, PECO provides natural gas service to over half a million customers. PECO's electric service region is located throughout a 2,100 square-mile area in southeastern Pennsylvania. The Company's electric service territory comprises all or portions of Bucks, Chester, Delaware, Montgomery, Philadelphia, and York Counties and includes a total population served of approximately 4.2 million people.

7. Q. What services does PECO offer its electric customers?

A. PECO provides electric distribution services and electric generation supply to both new and existing residential and commercial customers in Southeastern Pennsylvania. PECO makes available electric distribution service and electric generation supply on an unbundled basis. In addition to those customers who have exercised their option to procure their own electric generation supply service and pay PECO for delivery (i.e., distribution) service only, the Company, as the default service provider, procures and delivers power to the homes or places of business of residential, commercial, and industrial customers not receiving service from an electric generation supplier ("EGS") or who return to default service after being served by an EGS that becomes unable or unwilling to serve its customers.

8. Q. How does the type of electric customers PECO serves break down by major customer classification?

A. As of December 31, 2025, we served approximately 1.5 million residential customers, 154,841 small commercial and industrial ("C&I") customers, and 3,158 large C&I customers.

9. Q. What are the major assets and facilities that PECO utilizes to provide electric service to its customers?

A. To provide electric service to its customers, PECO operates and maintains approximately 10,000 miles of underground distribution cable, approximately 13,000 linear circuit miles of aerial distribution lines, and approximately 1,054 miles of higher-voltage transmission lines. In addition, we operate and maintain 434 power substations. Generally speaking, this infrastructure is a mix of reliable

older and newer facilities and equipment. Consequently, a high level of expertise in a variety of areas, as well as significant capital investment, are required to maintain and operate all of PECO's plant and equipment and to provide the service, reliability, and advanced electric grid capabilities that our customers expect.

III. PECO'S CAPITAL INVESTMENTS

10. Q. How does PECO determine its annual capital investment requirements?

A. PECO's capital investment plan begins with a detailed budgeting and long-range plan development process. A key goal of that process is to integrate and align capital investments with PECO's strategic operational goals and regulatory and financial plans. The mix of capital investment needs can change from year to year and is the product of a variety of factors, including trends in the housing market, emergent operational constraints, local municipality workloads, and most importantly, the condition of existing facilities.

Projects requiring a capital investment of over $1.5 million ("Major Projects") are subject to an additional, rigorous committee review process which includes senior management control of project scope and contract strategy. The primary goals of the process are to ensure that:

(1) the technical merits of each Major Project are balanced with the economic and customer benefits and goals of the Company;

(2) Major Projects are properly researched, developed, planned, reviewed, and authorized by senior management before significant resources are committed or expended; and

(3) decision points for consideration and approval of any additional funds are established as the details of Major Projects evolve.

All of these capital investment processes work together to ensure that PECO's investments fully support safety, reliability, customer affordability, and customer service goals as well as achieve optimal operational efficiency.

11. Q. How does PECO's annual capital investment process impact jobs in its electric service territory?

A. PECO invests significant capital in maintaining existing and developing new electric distribution infrastructure that not only supports thousands of jobs in the region but also creates new jobs each year. The Company regularly hosts an Aerial Line School, Underground Splicing School, and Energy Technician School to develop a hiring pool for electric operations personnel. In 2024 and 2025, the Company held two Schools each for Aerial, Underground, and Energy Technician, hiring 111 graduating individuals. The Company intends to host another School for each discipline in 2026 and 2027 and has plans to hire the same number of individuals.

12. Q. What are PECO's primary categories of capital investment?

A. Our capital investment requirements are evaluated on a functional level and are placed primarily into categories of corrective maintenance, system performance, capacity expansion, facility relocation, new business, and information technology ("IT").

Corrective maintenance is work in support of maintaining the existing electric distribution infrastructure, such as replacing or upgrading utility poles, reclosers, cable and/or wire. These projects can be identified as a result of patrols,

inspections performed, or storms and outage causing events (e.g., pole hits, tree limbs, etc.).

System performance projects are risk modeled and evaluated to prioritize the projects for replacements. These projects are ranked based on certain criteria, including but not limited to age, failure rates, customer complaints, cost to replace versus cost to repair, condition of infrastructure, and environmental factors. Of particular note are system reliability and resiliency improvements under the Company's Customers Experiencing Multiple Interruptions ("CEMI"), Aerial Infrastructure Resiliency ("AIR"), and Underground Cable Replacement programs that all target replacement of infrastructure with higher risk profiles based on field observations and a review of performance metrics (for example, replacing underground cable with underground cable in conduit for much longer operational life). From 2024-2025, PECO worked to meet its second Electric Long Term Infrastructure Improvement Plan ("LTIIP") and baseline commitments. In 2026-2027, PECO is continuing its focus on improved reliability through the third Electric LTIIP ("LTIIP III") and baseline plans.

Capacity expansion projects relieve capacity constrained areas, which allows for the addition of new customers and increases the ability of those feeders to handle the interconnection of additional customer-owned solar facilities. From 2024-2025, PECO completed multi-year projects to retire the last vintage 2.4 kV two-phase building substations, with conversion to 13 kV. This facilitates new customer connections and energization of the new Civic Gas Insulated Switchgear ("GIS") transmission/distribution substation, greatly expanding capacity for the

highly active University City area of Philadelphia and enabling the retirement of the Schuylkill Tunnel. The project involves relocating and upgrading infrastructure to ensure safe, reliable service to University City, home to critical hospitals and institutions.

The retirement of the Schuylkill Tunnel facilities is necessary given the current conditions of the Schuylkill Tunnel which are undesirable and continue to cause extreme deterioration of the infrastructure making it challenging to maintain the aging facilities. Maintenance on the deteriorating Schuylkill Tunnel and infrastructure has become increasingly difficult to manage in a timely manner, and cables are well past their life expectancy. Relocating the facilities out of the Schuylkill Tunnel and upgrading the infrastructure will provide safe and efficient access to maintain the system.

In 2024 and 2025, PECO continued design and construction work supporting public improvement projects for PECO's Facility Relocation program. Facility relocation projects move electric facilities away from conflicting township and state road improvements. These projects included PennDOT improvements along the I-95 corridor and State Route 3010–Market Street Bridge within Philadelphia County; Montgomery County's rehabilitation of Ridge Pike; and in Delaware County, PECO continues to coordinate with PennDOT on the road widening of SR 322–Conchester Highway.

In 2026-2027, PECO is seeing increased new business demand driven by residential and commercial development and a growing volume of customer requests associated with anticipated large load projects. In some cases, these

customers initially request smaller, interim or "bridging" levels of service to support phased development, construction activity, or early operations, which still represent meaningful additions to the distribution system. Additionally, PECO is evaluating the significant number of requests that constitute substantial new load and may be served from either the distribution or transmission system depending on engineering study results. PECO evaluates each request to determine the appropriate point of service and required infrastructure upgrades.

While the majority of full data center buildouts are expected to occur beyond 2027 and are not yet reflected in this rate case, the increased volume of near term, customer-driven requests is placing incremental capacity demands on the distribution system that are appropriately addressed through the investments reflected here. Our existing customers whose operations are expanding (e.g., warehouses) also need a variety of infrastructure upgrades, and we are addressing rising demand for electric vehicle charging stations at businesses.

13. Q. Please describe PECO's IT investments.

A. PECO invests in its IT systems to support safe, reliable, and efficient operation of the electric distribution system. These investments help employees monitor the system, respond to outages, plan work, and protect critical infrastructure. The company's capital projects drive operational improvements and efficiencies, reduce risk, increase reliability, and strengthen cybersecurity.

In 2024 and 2025, PECO modernized several systems by retiring older platforms, streamlining outage reporting functions, and updating the software and

hardware that support real-time system monitoring. These updates reduce operational risk and extend the life of the tools that employee operators rely on.

For example, the Advanced Distribution Management System ("ADMS") Release 1 established the foundational capabilities of the ADMS platform by implementing Supervisory Control and Data Acquisition ("SCADA") functionality. This release introduced real-time device monitoring, giving system operators live visibility into the status and condition of field devices such as breakers, switches, and sensors. These capabilities improve situational awareness and support faster operational decision-making. ADMS Release 1 also enables secure remote control of field devices, allowing operators to isolate faults and perform switching activities without manual intervention, improving both safety and restoration response times.

PECO also enhanced its mapping systems so that digital maps more accurately reflect the equipment in the field. By using its Geographic Information System ("GIS") as the central source for the electric network model, PECO ensures consistent and accurate information for operations and other applications. Additionally, PECO consolidated data sources into the GIS application, creating one System of Record to maintain. This allows the company to streamline design processes, lower maintenance overhead, and will enable automating creation and maintenance of various diagrams that are manually drawn today.

PECO also continued its multiyear Work Asset and Supply ("WA&S") initiative. Once placed in service, WA&S will replace the legacy system known as Asset Suite 8 which currently supports critical business processes, including work

management, supply chain, and accounts payable functions. The replacement platform will improve PECO's asset management programs through end-to-end process design, which will improve PECO insight into work status, updated data models accommodating new asset types, ownership models, and technical integration and performance. WA&S will enable several other initiatives, including enhanced digital tools, process optimization and automation of basic manual tasks and data analytics capabilities, intuitive solutions for customers and stakeholders, self-service options, and fully integrated workflow. Enterprise Asset Management ("EAM") also connects with GIS, OneMDS (Exelon's unified mobile dispatch and mobile mapping platform used to digitize, schedule, dispatch, and manage fieldwork across all Exelon utilities), as well as customer platforms.

Through 2026–2027, PECO will continue improving these platforms. This includes upgrading the tools used to safely direct field work, consolidating older outage management systems into a single updated platform, and enhancing operator efficiency by improving how these systems work together. These upgrades help operators evaluate conditions quickly and respond to customers more effectively.

The Company is also investing in upgrades to its ADMS for Release 2, which will replace Outage Management System ("OMS"), Switch Order Management ("SOM"), and Distribution Management System ("DMS") capabilities within a single, standardized platform. Release 2 will provide tools for outage prediction using analytics and sensor data, improved trouble call management that correlates customer reports with network conditions, and automated outage reporting and notifications to customers and internal

stakeholders. It will also enhance planned outage coordination to reduce customer impact, deliver storm management functionality to support large-scale events through better resource allocation and restoration tracking, and standardize switch order management to ensure safe, correctly sequenced switching activities. Together, these capabilities will enable a geographically based, integrated view of the distribution network across OMS, DMS, SOM, and SCADA, supporting more efficient, coordinated, and resilient system operations.

PECO will also strengthen its outage reporting and analytics capabilities through Outage Reporting and Analytics ("ORA") Release 2. These enhancements will improve the reliability of systems that share outage information across PECO's applications, ensuring accurate data during major outage events and continued availability of critical reporting systems when they are needed most.

The ORA platform provides reporting functionalities for end users and provides data feeds related to outages. This initiative aims to shift the source systems of the ORA platform from existing outage and reliability sources (including OMS) to the ADMS. This project is necessary to create a new design for, and development of, the ORA engine so that it encompasses source system ingestion, data transformation, data modeling, data consumption, and data visualization to support operational, reliability, and self-service reporting capabilities, as well as integrations for current and new consumption channels.

14. Q. How do capital investments in distribution system infrastructure relate to PECO's LTIIP?

A. The majority of our capital investments are made in coordination with the goals and requirements of PECO's LTIIP III, which the Pennsylvania Public Utility Commission (the "Commission") approved on December 18, 2025. In that proceeding, the Commission approved PECO's plans to spend $1.97 billion on targeted reliability projects to prevent storm-related outages, replace electric cable, and replace or retire substation equipment and small substations. These LTIIP investments are in addition to the capital spending associated with the Company's proposed rate increase but involve many of the same types of capital work. These investments, in the aggregate, are necessary to meet improvement targets. For example, as reflected in PECO's Commission-approved LTIIP, PECO's long-term goal for its CEMI programs is a 25% reduction in the frequency of interruptions for the improved areas and circuits by 2031. By aligning our "baseline" capital investments discussed in this proceeding and our planned LTIIP expenditures, we are able to improve reliability and replace aging infrastructure more efficiently and therefore at a lower overall cost to customers.

15. Q. Is PECO investing in technology to support its grid investments?

A. Yes, we are investing in a number of innovative technologies that enhance our ability to identify critical areas for investment. For example, we are deploying aerial drone technologies for construction planning and design, storm damage assessment, post-construction audits, transmission line patrols, and other construction-related activities. Drones are being integrated into programmatic data

collection, included in updated procedures across the company, and are used to gain situational awareness in hard-to-access areas during various electric operations.

PECO is actively investing in grid modernization and reliability improvements through a variety of initiatives. Our automation efforts include the continued installation of underground automatic transfer switches. These devices enhance reliability by automatically rerouting power during supply interruptions, helping customers remain energized. They also provide system visibility, which supports reductions in both System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI"). Additionally, PECO monitors the performance of previously installed switches and is piloting new underground switches to further strengthen the reliability of our grid. The results of those investments are shown in the consistent reliability that we are able to deliver. Out of the eleven electric distribution companies ("EDCs") in Pennsylvania, PECO is one of only two EDCs that has consistently achieved its SAIFI benchmark in all rolling 12-month quarters for the past seven calendar years (2018 through 2025). In addition, PECO was one of only three of the eleven Pennsylvania EDCs to achieve the Commission's standards for reliability across all categories for both year-end and three-year averages (for the rolling 12 months ending Dec 31, 2024)[1].

We are also investigating the use of various other line sensors, including downed wire sensors for detecting energized fallen conductors and underground sensors that assist in fault location and provide valuable field condition insights.

[1] *See* 2024 Pennsylvania Electric Reliability Report, Pa. Pub. Util. Comm'n (August 2025) available at 24_-electric-reliability-report_final.pdf.

These technologies have significant potential to minimize the duration of customer interruptions when outages occur.

16. Q. Please describe, in broad terms, the types of plant additions that PECO expects to place in service during the course of the FTY and FPFTY.

A. PECO's FPFTY and FTY plant additions are itemized by functional area and by FERC account in PECO Statement No. 4, the direct testimony of Mr. Trzaska, Exhibits MJT-1(Schedule C-2) and MJT-2, for the FPFTY and FTY, respectively.

In summary, our 2026 capital budget calls for approximately $1.2 billion of plant additions in new distribution facilities, including the portions allocated to distribution from general and common plant additions. For 2027, we have budgeted approximately $1.4 billion of plant additions in new distribution facilities, including the portions allocated to distribution from general and common plant.

17. Q. In your opinion, is all of the plant that PECO has included in its rate base claim needed in order to provide safe and reliable electric service?

A. Yes, it is. The assets included in PECO's rate base are, or by the end of the FPFTY will be, in service and used by PECO to provide safe and reliable electric service to customers.

IV. SYSTEM RELIABILITY

18. Q. What steps has PECO taken in recent years to ensure system reliability?

A. Each year, PECO invests heavily in its electric system to increase reliability and to enhance the quality of the service it provides. Nationally, our system is in the first quartile when benchmarked against similar utilities in the electric power industry, and our performance under Pennsylvania's reliability metrics is consistently amongst the strongest in the Commonwealth. The needs and expectations of our

customers for reliable electric service are evolving as more individuals, businesses, and communities plan for and manage hybrid work arrangements and increasingly use electric vehicles and other technologies that are dependent upon a reliable, resilient, and flexible electric distribution grid that is always on, 24 hours a day, seven days a week.

In order to identify, develop, and prioritize reliability-related investment in electric infrastructure, the Company uses a risk-based approach. PECO's risk analysis reflects the accepted definition of risk as the product of probability and impact, where "probability" is the likelihood that an event may occur, and "impact" is a measure of the adverse consequences such an occurrence would create.

In conjunction with a risk-based approach, PECO continues to adapt reliability efforts to match evolving customer expectations. We focus on traditional reliability metrics, such as SAIFI, CAIDI, and System Average Interruption Duration Index ("SAIDI"), as well as additional measures such as CEMI and geographical areas. This additional focus facilitates targeting our investments to areas that may be experiencing outage issues that are not captured under traditional metrics linked to "average" numbers of interruptions or outage duration.

PECO's focus and continued investment have proven to be effective. PECO began 2026 with strong reliability performance, achieving stronger-than-benchmark performance despite the challenges posed by Winter Storm Fern in late January, a significant snow event in late February, and 22 days of hazard winds and cold temperatures. In February of this year, PECO achieved a SAIFI benchmark that was 10,500 customer interruptions better than target, and a SAIDI that was 8.9,

which is 0.1 minutes better than target. This early-year performance reflects sustained investments in vegetation management and system improvements which benefit customers through lack of disruption of service.

In recent years, PECO performed many targeted system enhancements to continue its strong electric reliability performance. Highlights of our reliability-related investments and work include the following activities:

CEMI Area Infrastructure.[2] We focused our distribution system infrastructure investments on areas and circuits where customers experienced a higher number of sustained interruptions, and our investments resulted in an average reduction of 35% in the frequency of interruptions for those customers since the investments have gone in-service through 2025. The CEMI Areas program has demonstrated measurable and sustained effectiveness in reducing outage events for customers experiencing chronic reliability issues across the Delaware and Chester County Region. As of December 31, 2025, projects delivered in this area under the program reduced total outage events from 796 pre-implementation to 335 post-implementation across 29 completed projects. When normalized for time, CEMI Areas projects reduced outage event frequency by approximately 29% compared to the 60-month pre-implementation baseline. These results confirm that the program is delivering tangible reliability improvements in the areas most vulnerable to repeat and prolonged interruptions.

[2] CEMI is an index that tracks the number of customers that have experienced more than a specific number of interruptions in a given period. PECO has established a threshold of four interruptions per year to establish "multiple interruptions" for CEMI purposes.

Over the past five years, PECO has delivered consistent and measurable improvements in system reliability as a direct result of strategic capital investments made following the Company's prior rate case. These investments have proven effective in reducing both the frequency and duration of customer interruptions, thereby lowering the overall cost of service to customers. PECO's actual four-hour outage value improved from 8.1% in 2021 to 6.9% in 2025, representing the Company's strongest performance over this period and exceeding the 2025 performance target of 7.1%. The sustained improvement in these outcomes demonstrates that PECO's capital investments are being effectively converted into tangible reliability benefits for customers, reinforcing the prudence of prior infrastructure spending and the Company's continued commitment to delivering safe, reliable, and cost-effective electric service.

Retirements and Conversions. PECO retired several large substations and converted surrounding distribution facilities with their transformers to operate at higher (13 kV or 34 kV) voltages to reduce losses, improve voltage regulation, and facilitate more interconnection of customer-owned solar facilities. Retirements during the 2024-2025 period included 40-unit substations and one building substation.

Replacement of Underground Cable and Poles. In 2024 and 2025, PECO replaced over 614 miles of underground residential development ("URD") cable and 80 miles of mainstem cable that had exhibited a rising trend of failure rates, resulting in reduced customer interruptions. We also replaced approximately 10,000 poles with modern equipment designed to withstand higher winds and

snow/ice loading under the AIR Targeted Assets Program. The strength of these new installations will improve reliability in normal weather conditions and provide enhanced resistance to storm-related damages. As PECO facilities become newer and more resilient, the number and duration of customer outages due to equipment failure are expected to be reduced considerably.

Increased Distribution System Automation. We continued to identify circuits throughout PECO's service territory as candidates for priority reliability improvements and installation of reclosers, sectionalizers, and distribution automation to pinpoint problems and quickly restore service. In 2024 and 2025, PECO installed 258 of these devices, upgraded 673 devices and avoided an estimated 2.1 million customer interruptions over that period. Our integration of smart technology, combined with information from advanced metering infrastructure meters, communication infrastructure, and the Company's upgraded geographic information and distribution management systems, improves situational awareness, operations, safety, and communication outreach during outages.

Vegetation Management. PECO utilizes a four-year cycle for vegetation-related preventative maintenance work on more than 13,000 linear circuit miles of aerial distribution lines, which ensures frequent inspection and control of vegetation that could cause outages. This helps to significantly reduce the amount of outages caused by tree-in-growth, vines, and bamboo. Our distribution vegetation management programs are operated in conjunction with data-driven corrective maintenance and inspection programs that focus on enhanced vegetation clearance to improve reliability, as well as the removal of dead and declining trees

to improve performance in areas where multiple tree-related interruptions have occurred (especially in storms). PECO implemented additional vegetation management programs to aggressively address selected circuit segments with poor performance attributable to vegetation. These multi-year programs address problematic areas with enhanced trimming standards to significantly reduce the amount of overhanging canopy and also enhanced design applications such as aerial cables, tree wire, and armless construction with associated vegetation management. In 2024 and 2025, PECO addressed 78 selected circuit segments with poor performance attributed to vegetation. Overall, these projects were effective, and customers experienced fewer interruptions due to vegetation.

19. Q. Ms. Hanna, please describe PECO's reliability performance since its last base rate proceeding.

A. Our customers are experiencing the benefits of the reliability and performance improvements we continue to achieve since our last rate case. As a result of the Company's investments, including the projects I described above, PECO outperformed the Commission's target levels for SAIFI and SAIDI. Additionally, as I have noted, PECO continues to rank in the top quartile when compared to our electric industry peers across the country on SAIFI, SAIDI, and CAIDI.

PECO's SAIFI for the two-year (2024-2025) period was 0.79 interruptions, compared to the Commission benchmark of 1.23 and the three-year standard of 1.35 interruptions. Over this period, PECO's average number of service interruptions increased by 3%, from 0.78 interruptions in 2024 to 0.81 interruptions in 2025. This slight uptick is driven primarily by weather-related factors, which

remain the most significant external influence on system reliability. In 2024 and 2025, PECO experienced a comparable overall number of storm events, but customer impacts were driven by a relatively small number of high severity storms. Over that time period, PECO encountered six Extreme storms, four Very Large storms, and eleven Large storms. While these storms represented a minority of total events, Extreme storms—those exceeding 1,000 sustained primary events—accounted for a disproportionate share of customer interruptions and the longest restoration durations, particularly in the early hours of restoration.

During 2025, the region experienced more frequent and more severe weather events and several days of unfavorable weather conditions that did not meet the formal classification of a "major storm event" but still had a material impact on the electric distribution system. Despite the slight increase in service interruptions, PECO's continued investments in targeting CEMI customers and large-scale vegetation trimming programs have significantly strengthened overall system reliability. These improvements helped offset what could have been a much more substantial impact from the year's challenging weather patterns, demonstrating the resilience and effectiveness of the system enhancements already in place. This experience underscores the importance of continued investment in resiliency capital programs, including system hardening, automation, and operational improvements, which reduce the number of customers impacted per outage and improve restoration during severe events.

For SAIDI, PECO's 2024-2025 two-year average was 79 minutes, compared to the benchmark of 138 minutes and the three-year standard of 167

minutes. Notably, PECO's SAIDI performance improved significantly in recent years, with SAIDI dropping from 164 minutes in 2021 to 82 minutes in 2025 – a 50% reduction. When benchmarked with our industry peers, PECO's SAIDI performance also ranks in the top quartile.

The Commission also measures PECO's CAIDI. This three-year performance standard only allows a deviation of 10% from the reliability index benchmark. The 2024-2025 two-year average restoration time for PECO customers who lost power was 99 minutes (2024-2025) compared to the benchmark of 112 minutes and the three-year standard of 123 minutes. We are continuing to actively improve, with a favorable CAIDI performance in 2025 of 102 minutes. As with SAIFI and SAIDI, PECO's CAIDI continues to rank in the top quartile of our industry peers.

20. Q. Does PECO have a commitment to continue to maintain and enhance reliability?

A. Absolutely. Over the next two years (2026-2027), PECO will continue to focus on storm hardening and resiliency and plans to invest approximately $1.57 billion to improve the reliability of its electric distribution system. These strategic investments will help prevent customer outages, modernize the electric grid, and reduce the impact of extreme weather on PECO's electric infrastructure. The Company's reliability improvement programs in 2026 and 2027 will include:

Storm Hardening and System Enhancement. PECO will continue to replace aging equipment and upgrade facilities to the latest construction standards for improved distribution system reliability and resiliency to storms. As PECO's

equipment continues to age, the risk of customer outages increases. Therefore, it is important to proactively replace and upgrade aging equipment where possible to reduce the frequency of these outages. These upgrades will take place under the AIR, Building & Unit Substation Retirements, and CEMI programs. Between 2026 and 2027, PECO plans to replace about 10,000 poles under AIR Targeted Assets as well as complete a minimum of nine AIR Areas projects, two building substation retirements, 50 unit substation retirements, and 40 CEMI Areas projects. PECO plans to install approximately 650 reclosers in 2026 and 2027 comprised of 300 new devices, 100 modifications to existing devices to enable new functionality, and 250 whole device upgrades to newer models that enable future technologies.

Underground Cable. PECO is currently piloting two selective undergrounding projects planned for 2026 in-servicing. These pilots are associated with the Company's Worst Performing Vegetation Sections Program, where PECO has identified areas where adequate vegetation management is not able to be performed, and undergrounding will eliminate customer outages caused by vegetation.

Additionally, between 2026 and 2027, PECO will replace at least 80 additional miles of mainstem cable and over 530 miles of URD cable and will upgrade associated equipment to the latest construction standards, including looping any radial URD cable. PECO's proactive replacement of aged cable and looping will also reduce the outage frequency and duration of customers fed from this underground cable.

AIR. PECO will replace aerial infrastructure to proactively address those facilities that are vulnerable to failures caused by age-related degradation, normal environmental exposure, and ordinary wear and tear – factors that also increase the probability of storm-related damage. For example, the Company will install insulated aerial wire arranged in a special configuration to better withstand tree contact. PECO has already completed some installations in areas with dense tree coverage in an effort to strengthen its system against storms, increase reliability, and reduce customer outages from aerial equipment failures. In addition, between 2026 and 2027, PECO will replace approximately 10,000 poles under the AIR Targeted Assets Program that were installed at least 50 years ago.

PECO's Top Priority Circuit Program. PECO analyzes and completes reliability enhancements on at least 5% of the system's worst performing circuits on an annual basis. Improvements include installing reclosers for distribution automation, identifying and repairing issues through visual thermographic inspections, increasing vegetation management activities, installing and upgrading fuses, and replacing cable and other equipment. This program focuses on monitoring approximately 114 different circuits each year to capture risks to PECO's facilities as well as opportunities to minimize or prevent a potential customer outage before it occurs.

Targeted CEMI Areas. PECO will continue to address CEMI areas by reinforcing circuits with construction that can better withstand tree contact and storms, as well as adding automated switching flexibility. In 2026 and 2027, PECO

plans to complete a total of 40 CEMI Areas projects. These investments are expected to reduce the frequency and duration of interruptions for those customers.

Distribution Automation. PECO will continue to expand the deployment of distribution automation equipment across its electric distribution system through 2027 to further improve reliability and reduce the impact of outages on customers. This work includes the continued application of automated reclosers, fault-interrupting devices, capacitors, voltage regulators, underground switches, load centers, and system monitoring and sensing technologies. Together, these assets enable the system to detect faults, isolate affected sections, and restore service automatically or remotely, reducing both the number of customers interrupted and the duration of outages when events occur. Distribution automation also enhances system visibility and operational control, allowing field crews to be deployed more efficiently and focused on the highest impact work. By continuing this deployment through 2027, PECO builds on the proven effectiveness of prior capital investments, converting customer-funded resources into durable infrastructure improvements that strengthen system resilience, improve reliability performance, and help reduce long-term costs for customers.

Substation Retirements. In 2026 and 2027, PECO plans to retire an additional 50 unit substations and three building substations that are experiencing an increasing failure rate (i.e., those constructed forty or more years ago) and will upgrade all downstream low-voltage supply facilities to operate at higher voltages consistent with modern modes of operation. The higher risk impact of unit and building substations is due to the relatively large numbers of customers served from

each substation that would experience an outage if a failure or malfunction were to occur. These retirement programs are designed to address PECO facilities that are aging, that contain obsolete (and, therefore, hard to repair or replace) components, and that are showing signs of degradation due to ordinary environmental exposure and ongoing use.

From 2026 to 2030, PECO plans to retire at least 125 unit substations and five building substations between the baseline and LTIIP plan. Nearly all of PECO's existing building substations that supply power to downstream facilities serving thousands of customers were constructed over 50 years ago and contain obsolete equipment. These retirements will enhance system resiliency, and the associated upgrades to the downstream facilities will support the adoption of clean energy resources in PECO's service area.

Targeted Vegetation Management. PECO will address areas with poor reliability performance due to vegetation interference by implementing enhanced trimming standards to remediate the overhanging tree canopy and by removing trees that are at greatest risk of impacting the Company's distribution facilities. Aggressively managing the overhanging canopy will reduce the amount of outage events caused by broken tree limbs, which is a leading cause of vegetation-related outage events. Extensive investment in priority tree removals is also extremely important given the fact that broken tree trunks and uprooted trees are another leading cause of vegetation-related outages. In addition, the impact of the emerald ash borer on ash trees in the PECO service territory continues to affect PECO's service reliability, and PECO will continue to invest in the removal of ash trees.

Furthermore, PECO intends to expand its focus on remediating the overhanging canopy and removing priority trees through the Vegetation Strategic Reliability Improvement Initiative ("Vegetation Strategic Initiative"). PECO will also continue to reinforce circuits with construction that can better withstand tree contact in certain prioritized locations. PECO will build on the success to date of its vegetation management programs and focus on the circuit segments identified as "worst performing" to maximize the value of the associated capital investment.

21. Q. Please describe PECO's Vegetation Strategic Reliability Improvement Initiative in greater detail.

A. In 2025, the company began to expand the scope of vegetation work by remediating the overhanging canopy and removing additional priority trees in select densely vegetated areas where customers have experienced multiple tree-related interruptions. PECO focused investment on circuit segments with a history of elevated CEMI exposure, producing clear and immediate reliability benefits. For example, vegetation mitigation on the Linfield Unit in Chester County addressed three consecutive years of more than four interruptions affecting 356 customers, resulting in zero vegetation-related interruptions following completion. Similar results were achieved on Manor 002, also in Chester County, where 392 customers with three years of frequent interruptions experienced no post-completion vegetation-related outages. In Bucks County, targeted work on Buckingham 342

addressed two years of repeated interruptions affecting 605 customers, likewise, resulting in zero vegetation-related interruptions after completion.

The additional work performed in 2025 has proven effective in reducing the number of customers experiencing repeat outage events caused by broken tree limbs and broken tree trunks in the majority of the corresponding circuit sections. While completing this vegetation work, PECO has identified additional areas within its service territory that require extraordinary, one-time, vegetation management activities in order to improve system reliability. As a result, PECO intends to expand this program into the Vegetation Strategic Initiative in 2027 and beyond to address more locations impacted by repeat vegetation related outages.

This enhanced scope of work, which is a one-time program in addition to the traditional maintenance programs, is required due to the extensive volume of mature trees and associated dense canopy overhanging PECO's facilities through a significant portion of the service territory. As a result of this work, customers will experience significantly fewer outages caused by trees. Once the enhanced scope of work is complete, PECO plans to continue with ongoing routine maintenance practices in those areas to minimize risk of regrowth and we will continue to reassess canopy conditions to determine if any further enhanced scoping is required at other locations throughout the PECO territory.

Given the nature of the work, costs over the eight-year period of the Initiative will vary year-by-year. We estimate total costs for the Initiative to be approximately $130 million over the estimated eight-year duration of the initiative, or roughly $16 million per year on average for all PECO customers. Mr. Taylor

(in PECO Statement No. 1) and Ms. McDevitt (in PECO Statement No. 10) discuss PECO's proposal for recovery of the costs of the Initiative.

V. CUSTOMER SERVICE AND OPERATIONS INITIATIVES

22. Q. How does the Company enable the continued integration of solar and electric vehicles in the territory?

A. PECO provides multiple resources to enable the continued integration of solar and electric vehicles in the territory. There is a dedicated team**,** Green Power Connect ("GPC"), to allow the Company to efficiently integrate solar generation and electric vehicle charging while maintaining reliability and controlling costs for customers. By using a centralized digital platform with defined review and engineering timelines, GPC improves workforce productivity and ensures that field work and infrastructure upgrades are performed only when necessary. This disciplined approach directs customer-funded investments toward durable system improvements, accelerates customer energization, and reduces future corrective costs, ultimately benefiting all customers.

Additionally, PECO's capacity expansion projects relieve capacity constrained areas, which allows for the addition of new customers and increases the ability of those feeders to handle the interconnection of additional customer-owned solar facilities.

To further facilitate solar applications and solar interconnections, PECO created a Digital Solar Toolkit with an interactive viability map. With this toolkit, customers can see if their home or area can support solar or other distributed generation resources or if any system upgrades would be necessary. From a technical standpoint, PECO has automated the technical analysis for a majority of

Level 1 and smaller Level 2 solar applications by incorporating data analytics and machine learning techniques into the review process. This approach has proven effective in reducing manual reviews and shortening interconnection timelines. PECO is also updating its technical interconnection requirements to better align with current technologies and industry standards.

PECO has taken several additional steps to improve interconnection efficiency and customer experience while controlling costs. Online application payments through the Connect the Grid portal have reduced administrative delays, and a new Senior Interconnection Specialist role provides customers and developers with a single point of contact. Updated interconnection standards, approval of a customer-owned meter collar, and a pilot of advanced inverter settings further reduce unnecessary reviews, field work, and upgrade costs. Together, these actions improve field productivity, accelerate customer interconnections, and ensure customer-funded investments are used efficiently to support reliable, cost-effective system integration. PECO has also created a process where customers can request high-level DER queue information for a given site prior to submitting an application.

23. Q. How does the Company work to ensure minimizing customer impact on a day to day basis?

A. PECO understands customers rely on electricity as they work, learn, and live, and PECO leverages multiple solutions to minimize customer impact while utility business is conducted. The Company has focused on multiple initiatives to improve communication with customers and enhance productivity, including the following:

New Business Customer Service Installations and Upgrade Portal ("SIUP"): PECO's newly implemented SIUP is an online application and project dashboard for two-way communication and file sharing between PECO and customers. The SIUP began operating in March 2026 and works in tandem with PECO's internal project management system, Intellio.

SIUP simplifies the customer request process by automatically determining the appropriate work scope and routing service requests to the correct backend workflows, reducing application errors, potential rework, and delays. The SIUP provides enhanced visibility, notifications, and self-service capabilities for customers, reduces follow-up inquiries and administrative overhead, allowing employees to focus on critical infrastructure work. The systems are agile and allow future enhancements to improve efficiency and added features for customers.

PON System: The Planned Outage Notification ("PON") is a system used to notify electric customers of a planned outage. It also can be used in situations where a crew needs to operate switches to quickly make an area safe for work to restore power. The benefits to using the Electric PON process include a single user interface for PON information, with consolidated outage information in one easy-to-use portal to automate the creation and distribution of timely notices to customers. Customer benefits of Electric PONs include personalized notifications, timely updates, proactive alerts, cancellation and rescheduling alerts, and customer-friendly messaging. The communication channels include letter (U.S. mail service), email, SMS, push (PECO notification cell phone application), and voice (phone call).

Insource Work: As part of PECO's ongoing focus on cost discipline and operational efficiency, the Company has identified opportunities to reduce contractor spending by strategically bringing work back in-house where it can be performed more efficiently by Company employees. By shifting appropriate work from external contractors to internal field resources and actively monitoring contractor usage, PECO can reduce overall contractor expenditures while maintaining service quality and reliability. This approach improves productivity, enhances accountability, and allows customer-funded resources to be deployed more effectively, resulting in lower operating costs and greater long-term value for customers.

Condition Based Maintenance Initiatives: The Company is advancing Condition Based Maintenance initiatives that modernize asset management practices while improving field productivity and the efficient use of funding. Historically, it was common practice for utilities to inspect and replace assets using a time-based schedule, but now, through the advances in technology and efficiencies, we are able to use a condition-based maintenance inspection to focus resources where needed. Additionally, the Company continues to deploy new equipment to collect data to refine the inspection intervals. For example, the Company is leading an obsolescence project to replace approximately 1,000 switch capacitors and install SCADA capabilities, allowing inspection intervals to be extended from annual cycles to once every four years without compromising safety or system performance. This shift reduces unnecessary field inspections and enables more effective deployment of field crews. In addition, the Company

implemented a process to opportunistically inspect cable-only manholes during planned field activities, improving asset condition awareness without requiring additional site visits. Together, these initiatives reduce labor intensity, enhance data driven maintenance decisions, and allow operating resources to be redirected toward higher value infrastructure work, resulting in improved system reliability and better long-term cost outcomes for customers.

Storm Restoration Response: In response to an increasing frequency of extreme weather events, PECO has strengthened its storm response capabilities by improving how mutual assistance crews are managed, integrated, and deployed in the field. PECO implemented standardized crew rosters to improve visibility into resource assignments and enable more efficient management of mutual assistance crews during restoration efforts. Onboarding processes were streamlined, including proactively providing PECO's safety manual to external crews, who previously worked on PECO's system, ensuring safe and clear expectations and improved response during restoration activities. Dedicated Crew Leads were established to provide on-site coordination and address day-to-day execution needs, improving productivity and reducing delays in the field. In addition, the Damage Assessor role was expanded to confirm outage readiness, material requirements, tree involvement, and the need for specialized resources prior to dispatch, helping ensure crews are sent to the right work with the right equipment. These operational improvements are particularly critical as the number of extreme storms has increased in recent years, rising from none in 2022 to multiple events annually in 2024 and 2025.

VI. SAFETY, SECURITY, AND ENVIRONMENTAL PROGRAMS

24. Q. With overtime currently above a Commission-recommended 15%, what steps is PECO taking to manage this trend, and how is the Company monitoring overtime hours to prevent employee fatigue?

A. PECO Electric Operations continues to evaluate and implement alternatives identified through the Commission's Management Efficiency Investigation ("MEI") follow-up review to improve overtime performance while maintaining safe and reliable operations. Collectively, these actions reflect PECO's commitment to a strong safety culture while ensuring that, during storm events and outage conditions, crews are appropriately staffed and supported to restore service as safely and as quickly as possible, minimizing outage duration and impacts to customers.

Electric Operations actively utilizes overtime analytics, including departmental overtime Key Performance Indicators that are reviewed through the monthly Overtime Cost Management report, to monitor trends and identify opportunities for improvement. In parallel, PECO is enhancing its fatigue management practices by updating its Fatigue Report procedures to strengthen knowledge and understanding of the impacts of overtime on employee safety and performance. The updated procedures include a requirement that conversations between frontline supervisors and employees who exceed established work thresholds are documented, and a tracking mechanism to ensure accountability and employee awareness of available resources.

25. Q. What is PECO's record with respect to the safety of its employees?

A. Maintaining the highest standards for workplace safety is a top priority for the Company. A critical component of safety culture involves protecting our employees from serious injuries and fatalities ("SIFs"). Serious injuries are defined by the Edison Electric Institute ("EEI") SIF Criteria. An HSIF is a high energy event with no direct controls utilized that resulted in an employee's serious injury or fatality. To that end, PECO uses energy-based safety clarifications to mitigate incidents with high energy that increase the potential for SIFs to improve the effectiveness and efficiency of hazard recognition, prioritization, and control across the organization. Utilizing our Safety Classification Learning Model, employees are able to identify high energy sources that could lead to serious injuries and put direct or limited controls in place to reduce or eliminate the exposure to the high energy hazard.

In 2026 and beyond, PECO will strive to continuously improve performance and foster a safety culture that engages the entire workforce to prevent accidents, injuries, and occupational illnesses. In 2026, PECO will distribute a new Energy Based Safety Field Guide for employees to use as an aid in identifying the high energy hazards on their job site. Frontline leaders are now performing energy-based observations to reinforce the Energy Based Safety mindset as well.

In addition, PECO participates in a coordinated effort with its sister utilities across Exelon through a program called Safety Best Practices ("SBP"). This program ensures that all Exelon operating companies leverage their diverse

experiences to stay focused on performing work as safely as possible and providing consistent, high-quality support to drive safe operations across the enterprise.

For 2026, PECO has a target of completing five Safety Best Practices initiatives.

Three initiatives continuing from 2025 include:

- Roadside Safety, which aims to evaluate and implement Work Area Protection solutions beyond minimum requirements to help ensure the health and safety of employees and contractors while working in roadways.

- Crew Leader Training Academy, which will be an enhanced initial training program to ensure crew leaders and Foremen have the safety leadership knowledge and skills to perform effectively in their roles.

- SIF Leadership Prevention Guide, which is a guide that educates the leaders of today and tomorrow on Exelon's SIF Prevention Playbook to continue to advance safety as Exelon's core value.

Two new initiatives will also launch in 2026:

- The Confined and Enclosed Spaces program is in stage 1 of an SBP where we are looking to have one combined protocol for all Exelon Operating Companies ("OPCOs") at the conclusion of the SBP. The current process is in compliance with all applicable regulatory agencies, but there is an opportunity to streamline our processes and equipment throughout the OPCOs.

- Job Brief Quality, which will align criteria of what is required on a job brief across Exelon.

These efforts ensure PECO continues to learn from partners across Exelon and the broader industry, strengthening our processes and further enhancing PECO safety culture.

PECO maintains a collaborative culture that listens to employee safety concerns and receives feedback through its Line-Led Teams. PECO's employee safety focus is on the following core areas: Hazard Recognition, Safe Driving, Ergonomics, and Slips/Trips/Falls. The Company's open environment affords all

of its employees the opportunity to raise awareness and collaborate with PECO on innovative solutions to promote employee safety in these safety areas.

26. Q. What actions is the Company taking regarding physical security and cybersecurity?

A. The ever-evolving threat landscape is of concern to our entire industry. In response, PECO has made significant investments in physical security as part of two separate programs. In 2015, PECO initiated the Facility Enhancement Program ("FEP") to enhance the physical security for operationally critical electric and gas assets. Additionally, in 2020, PECO began its Office and Support Facilities ("O&SF") program to enhance the physical security at offices and operation service centers. Both FEP and the O&SF program were designed to reduce unauthorized access to personnel, equipment, systems, and materials utilizing an in-depth defense strategy. Both programs use a risk-based approach and tiering methodologies that analyze the criticality of each type of asset (Electric, Gas, and Office & Support Facilities) to prioritize investment. PECO tiers our assets based on factors such as, but not limited to, system impact, customer count, critical customers served, and feeder number. While the tier dictates the protections implemented at each site, the protections are designed for the threats within the service territory that PECO operates.

Both FEP and O&SF programs have proven effective in mitigating threats to PECO's infrastructure, including protection of our employees, assets and community. We continue to review our standards and industry best practices, making appropriate modifications, as necessary. Since 2024, PECO has

successfully commissioned 15 additional site improvements through the FEP and O&SF programs. The FEP program is scheduled to complete physical security enhancements at an additional 24 Electric and Gas assets by the end of 2027. The O&SF program will run through 2030 with enhancements scheduled at 20 additional Offices and Support Facilities.

In 2017, PECO expanded its resiliency efforts with the purchases of critical supplies and redundant equipment to facilitate timely system restoration following disruptions by natural or man-made events. Resiliency supplies and equipment are stored at separate facilities, strategically located, to restore service and minimize impacts to the over 1.7 million electric and gas customers throughout Southeastern Pennsylvania.

In implementing these security programs, we continue to forge strong partnerships among policymakers and regulators at the local, state, regional, and federal levels, customers, and utilities so that actionable information and intelligence can be shared, and best practices to defend against the changing threat landscape can continue to be identified to protect assets in a reliable and resilient manner. PECO annually participates in readiness drills/exercises, such as North American Electric Reliability Cooperation's ("NERC") GridEx, to ensure we are prepared for potential threats. These types of exercises, which prioritize readiness and resiliency, encompass countless hours of planning and execution by dozens of PECO/Exelon personnel. PECO Security maintains partnerships and conducts trainings with local law enforcement/first responders on the criticality of response and safety issues when responding.

PECO Security and Exelon Corporate Security maintain partnerships with local law enforcement and intelligence groups, including, but not limited to, the Electricity Information Sharing and Analysis Center, Delaware Valley Intelligence Center, and the PA Criminal Intelligence Center. Finally, PECO is an active participant in "Black Sky" exercises to test Pennsylvania's ability to respond to a large-scale disruption of power and utility services. The Black Sky initiative is coordinated by the Commission, the Governor's Office of Homeland Security, and the Pennsylvania Emergency Management Agency. Through 2024 and 2025, PECO Security launched their Active Assailant Demonstration training platform. This demonstration is a live, scenario-based training to give employees and contractors the knowledge, skills, and information needed to keep them safe in the event of an active assailant incident. As we move through 2026, PECO Security will continue to provide the training, giving all employees and contractors an opportunity to experience the scenarios and apply the skills and information to keep people safe in our dynamic work environments.

In addition to the Company's IT investments, PECO has implemented an extensive defense-in-depth cybersecurity program that has cyber and physical security controls that are aligned to the National Institute of Standards & Technology Cyber Security Framework and other industry standards to identify, detect, defend, and respond to cybersecurity threats in order to protect PECO's critical infrastructure. These controls are certified annually. The cybersecurity plan is managed by a centralized security team, Exelon's Corporate and Information Security Services, who has 24x7 operations to monitor and respond to

any potential risk to Company assets. In addition, PECO maintains a NERC CIP Compliance program for Bulk Electric System Assets and is also currently undergoing a significant Operational Technology ("OT") Security Controls program as a part of a multi-year effort to implement a consistent set of security practices across our OT and supporting networks for the Exelon utilities. In accordance with this program, we properly identify and categorize OT assets and are developing an associated inventory of OT assets currently on our systems. The Company has implemented procedures to identify and mitigate specific cyber threat vulnerabilities to our OT assets and has implemented security measures to protect our systems from external threats via third-party connections.

27. Q. Ms. Hanna, please describe PECO's energy efficiency and environmental efforts regarding its own land, buildings, and emissions.

A. PECO's commitment to energy efficiency and environmental stewardship is also integrated in the Company's daily operations. PECO has established an environmental management system based on standards set forth in International Organization for Standardization 14001, which supports the development of performance-improvement goals and targets. Exelon, PECO's parent company, was recognized for its sustainability leadership for the 19th consecutive year and has been named to the Dow Jones Sustainability North America Index for its carbon reduction efforts, investments in innovative technology, and local philanthropy. With respect to land quality, PECO has obtained Conservation Certification from the Wildlife Habitat Council, powered by Tandem Global, the National Wildlife

Federation, and the North American Pollinator Partnership Campaign for 20 sites (166 acres).

PECO is also focused on being a low-carbon company. From 2015-2025, PECO reduced its greenhouse gas emissions by approximately 59% through infrastructure investments such as the replacement of first-generation sulfur hexafluoride (SF6)-filled electrical breakers and replacement of cast iron/bare steel gas piping. PECO's greenhouse gas reduction program is in alignment with the 2018 Pennsylvania Climate Action Plan goal of a 26% reduction in greenhouse gas emissions by 2025. The Company has achieved this goal, and as of 2025, PECO has reduced its greenhouse gas emissions by approximately 50% from 2018. PECO is seeking to exceed this goal with our 2030 Path to Clean initiative, which aims to reduce Exelon's operational emissions by 50% from 2015 levels by 2030. The Path to Clean initiatives include the modernization of gas infrastructure via pipe replacements, the implementation of programs to reduce SF6 leaks in electrical equipment and the piloting of SF6 alternatives in electrical equipment, continued focus on energy efficiency/conservation in buildings/facilities and the electrification of vehicles to reduce fuel consumption. The Company's investments in natural gas infrastructure and technologies to reduce distribution system leaks are critical to achieving this goal. In addition, we have now implemented a new technology known as ZEVAC (for Zero Emissions Vacuum and Compression). Typically, when a natural gas distribution utility replaces an outmoded main, residual gas is released into the atmosphere. Through ZEVAC,

PECO teams can vacuum the residual gas from the outmoded main and inject it directly into an active main and thereby reduce related emissions by nearly 100%.

PECO also continues to maintain one of the largest urban green roofs in Pennsylvania (approximately one acre) built on an existing building at its headquarters in Philadelphia certified by Pollinator Partnership as an important pollinator habitat. Waste recycling also continues to be a focus at PECO, with recycling increasing from 94% (2016) to 98% (2025).

In 2025, PECO donated 900 trees to customers via the Arbor Day Foundation's Energy-Saving Trees program and has donated nearly 7,000 trees in the last six years. An additional 200 trees were provided directly to PECO customers under a newly developed Fall Yard Tree Giveaway. In 2025, PECO awarded Green Region grants totaling $206,300, including a bonus round of $50,000 in celebration of the program's 20th anniversary to enhance green space throughout the service area in partnership with Natural Lands Trust. The Arbor Day Foundation also recognized PECO for the sixth year with Tree Line USA certification for the Company's Energy-Saving Trees program and its commitment to proper tree pruning, tree planting, and education in its service area. To facilitate this effort and as part of its "ReLeaf" initiative, the Company awarded $200,000 to the PA Horticultural Society ("PHS"), which supported the PHS in planting an additional 12,972 trees across PECO's service territory in 2024 and 2025. In addition, PECO partners with the Philadelphia Zoo and the Elmwood Park Zoo to donate "browse," which are leafy tree branches removed as part of the Company's vegetation management program, to provide supplemental nutrition and

engagement opportunities for the animals. We provided approximately 15,000 pounds of browse with this program in 2024 to 2025 and over 56,000 pounds of browse since the program began in 2017.

Finally, as part of PECO's habitat protection efforts, the Company developed a comprehensive avian protection plan to reduce bird mortalities associated with power line interactions. This plan addresses the removal and relocation of protected species nests and provides employee training on avian management. PECO has completed an avian environmental risk assessment of its service territory to identify important bird nesting and roosting areas. Distribution circuits in these areas were evaluated for avian-safe equipment, and the devices were added where needed. Also, as part of proactive measures to protect bald eagles, an inventory of bald eagle nest sites was established, and all distribution circuits within a quarter mile of the active nests were inspected to make sure that avian-safe equipment was present. Retrofits were also made in areas needing avian-safe equipment. Those distribution circuits that experienced repeated avian mortalities have been evaluated in a similar fashion, and remedial measures will be taken if needed. From 2022 to 2025, avian interactions (both collisions and electrocutions) for bird species protected by the U.S. Fish and Wildlife Migratory Bird Treaty Act decreased by 50%.

28. Q. Please describe the Company's efforts to support the use of alternative fuel vehicles and related technologies.

A. PECO participates in the Edison Electric Institute's challenge to designate at least 5% of its Electric Operations' annual vehicle spending for plug-in technology.

PECO operates its own fleet of 1,522 hybrid, electric, flex fuel, and biodiesel vehicles including 69 plug-in hybrid trucks, 62 battery electric vehicles, and 160 Job Energy Management system worksite electrification plug-in aerial trucks. Additionally, PECO has onboarded three fully electric heavy duty bucket vehicles. PECO continues to utilize telematics technology to drive performance and efficiencies. The Company also encourages sustainable practices with employees by providing over 127 EV charging stations, rebate programs, and bike racks at most Company locations.

PECO currently offers residential customers an EV registration rebate. The Company also offers rebates to qualifying non-residential customers for installing Level 2 EV chargers and DC fast chargers (the "EV Charging Pilot") as well as a special pilot rider (the "EV-FC Pilot Rider") for the installation of direct current fast chargers to support the build out of EV infrastructure in Pennsylvania.

VII. CONCLUSION

29. Q. Does that complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Jennifer Hanna, hereby state that I am a Vice President of Electric Operations for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 2 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Jennifer Hanna

PECO Statement No. 3:
Direct Testimony of Marissa E. Humphrey

PECO ENERGY COMPANY
STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: EFFORTS TO CONTROL CUSTOMER COSTS AND MITIGATE IMPACTS TO CUSTOMER BILLS; OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS; EXELON BUSINESS SERVICES COMPANY; AND THE CORPORATE ALTERNATIVE MINIMUM TAX

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
MARISSA HUMPHREY

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Marissa Humphrey. My business address is 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President, Chief Financial Officer and Treasurer. In that capacity, I am responsible for PECO's financial function, including budgeting, long-range financial planning, financial analysis and reporting, project evaluation, and financings. In addition, I have oversight and coordination responsibilities for PECO's accounting, tax, treasury, investor relations, and risk management activities, and I monitor the Company's financial performance to ensure that PECO complies with its financial internal controls and management discipline.

3. Q. Please briefly describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in Biology from Brown University and a Master of Business Administration from Duke University Fuqua School of Business. I joined Constellation Energy in 2007, working in Corporate Finance, and have advanced through a number of positions at Constellation, Baltimore Gas & Electric ("BGE"), Exelon Business Services Company ("EBSC"), Pepco Holdings ("PHI"), and PECO. Prior to and following the 2012 merger of Exelon and Constellation, I

was named Director of Financial Planning & Analysis ("FP&A") at BGE. Beginning in 2014, I served as the Exelon Project Management Officer for the Exelon/PHI merger and, upon the closure of that merger in 2016, I was promoted to Vice President of PHI FP&A. After three years, I transitioned to Vice President of the Exelon Utilities Finance team, and in 2020 I was named Vice President of Regulatory Policy & Strategy at PHI. In 2022, I was promoted to Senior Vice President, Chief Financial Officer and Treasurer of PECO. Prior to joining Constellation Energy, I worked for several years in consulting and healthcare finance.

4. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (1) summarize PECO's continued efforts to control customer costs and reduce customer bills; (2) provide an overview of PECO's principal accounting exhibits and its budgeting process; (3) describe the nature and allocation of costs for services that PECO receives from EBSC; and (4) discuss the Corporate Alternative Minimum Tax ("CAMT").

II. PECO'S EFFORTS TO CONTROL CUSTOMER COSTS AND MITIGATE IMPACTS TO CUSTOMER BILLS

5. Q. Please describe PECO's efforts to control customer costs and mitigate impacts to customer bills.

A. PECO works to minimize financial impacts on customers in two ways. First, PECO diligently manages its own expenses to minimize costs for which customers will ultimately be responsible. Second, PECO supports programs and investments to help customers reduce their overall energy usage and costs, including a number of

low-income-focused programs to better support the Company's most vulnerable customers. For example, in 2025, PECO launched its Customer Relief Fund, which is designed to provide immediate bill assistance to limited and moderate-income households experiencing rising energy costs. PECO's customer programs are discussed further in the direct testimony of Brendan J. Taylor (PECO Statement No. 1) and Jacqueline Golden (PECO Statement No. 12).

6. Q. Have these efforts negatively impacted PECO's service to customers?

A. Absolutely not. While PECO has undertaken efforts to control customer costs, it has done so in a manner to maintain the same level of safe and reliable service our customers expect and, where possible, improve such service.

7. Q. What are some examples of PECO's efforts to control its costs?

A. The Company works proactively to identify initiatives to further improve productivity through best practices across the organization, leverage new technologies and equipment to reduce costly repairs on aging infrastructure, and deliver other operational efficiencies. Company witness Jennifer Hanna (PECO Statement No. 2) discusses the Company's efficiency efforts in greater detail. Recent examples of these initiatives include:

- Strategically bringing emergent contracting work in-house, where it can be performed more efficiently by internal employees and benefit from centralized oversight and better management of workload allocation, all of which lower operating costs.

- Advancing Condition Based Maintenance, enabling more effective deployment of field crews to higher value work, resulting in improved system reliability and lower operating costs.

As described in Section III of my testimony, PECO also actively manages the creation and execution of its budget, taking reasonable and prudent steps to minimize its operations & maintenance ("O&M") expenses and mitigate inflationary impacts on its customers. Additionally, PECO takes steps to minimize its financing costs and utilizes the EBSC to improve efficiencies and lower its costs.

8. Q. Have these factors been successful in minimizing increases in the Company's O&M expense?

A. Yes. Based on these efforts, PECO's projected annual O&M growth rate through the FPFTY is only 2.1% when adjusted for storms, bad debt, and pension expense (which are variable year to year and largely outside the Company's control) – nearly 20% lower than the projected 2.6% inflation increase in the Consumer Price Index.[1] The Company has been able to successfully mitigate continued inflationary impacts, which contribute to increases in the Company's labor costs, material costs, contracting rates, and borrowing costs. Furthermore, the 2.1% annual increase is inclusive of the Company's Vegetation Strategic Reliability Improvement Initiative, a new aggressive and targeted vegetation management initiative that the Company is implementing to improve service in areas with poor reliability performance due to vegetation interference. This initiative is discussed in further detail in Ms. Hanna's testimony.

[1] Inflation projected to average 2.6% over 2026-2027 (2.9% in 2026 and 2.4% in 2027) per S&P Global Dec. 2025, Consumer Price Index (CPI) Philadelphia-Wilmington-Atlantic City-PA-NJ-DE-MD Area.

9. Q. Why is it important for PECO to maintain its investment-grade credit rating and minimize its borrowing costs?

A. Maintaining PECO's investment grade credit ratings is important to reducing customer costs. PECO projects that it will need to invest approximately $2.8 billion in electric distribution plant between January 1, 2026 and December 31, 2027. A meaningful portion of these planned investments will be financed with debt and other forms of capital. The Company's credit ratings will impact the cost it will need to pay to attract such capital, and ultimately such costs will be borne by PECO's electric customers. For example, continuing to maintain a strong credit rating will help PECO control its credit spreads, which in turn will help control the all-in cost of long-term debt financing. Therefore, it is important that the Company maintain its favorable credit metrics in order to minimize customer costs.

10. Q. Please describe how inflationary pressures have impacted the Company's borrowing costs.

A. Sustained inflationary pressure has contributed to elevated interest rates, which have directly increased the Company's borrowing costs. As noted earlier, this is expected to continue. The average 30 Year Treasury rate, which serves as a risk-free benchmark rate in many financial products, including thirty-year maturity bonds that are typically issued by utility companies, demonstrates this sustained inflationary pressure. The 30 Year Treasury yield has remained high in recent years due to continued inflationary pressures, with the average rate increasing 20% since 2023.[2]

[2] *See* Daily Treasury Rates, U.S. Department of the Treasury, https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_bill_rates&field_tdr_date_value=2026.

As a result, it is more expensive for the Company to finance its ongoing operations and capital investments, a portion of which are funded through debt, consistent with the Company's Pennsylvania Public Utility Commission ("Commission")-approved capital structure. Interest rate increases pushed up the Company's average cost of borrowing from 4.58% in 2025, as forecasted in the Company's prior electric rate case filing, to 4.78% in 2027, as forecasted in the Company's current electric rate case filing. The Company's cost of debt is further detailed in the testimony of Company witness Michael J. Trzaska (PECO Statement No. 4) and in PECO Exhibit MJT-1, Schedule B-6.

11. Q. Notwithstanding the current high inflationary environment, how has PECO minimized its borrowing costs?

A. PECO works closely with its banking partners to understand market conditions at the time of issuance of debt to determine what tenor and timing will ultimately generate the most investor demand, thereby securing a lower interest cost for the benefit of customers. In September 2025, PECO successfully priced a two tranche first mortgage bond ("FMB") issuance totaling $1.05 billion. The first tranche was a $525,000,000, ten-year FMB offering at a spread of 68 basis points over the ten-year U.S. Treasury for an all-in coupon rate of 4.875%. The second tranche was a $525,000,000 thirty-year FMB offering at a spread of 75 basis points over the thirty-year U.S. Treasury for an all-in coupon rate of 5.650%. The deal was well-received by investors. The strength of PECO's name and credit profile – PECO maintains an investment-grade credit rating – continues to drive strong investor demand, permitting PECO to tighten the credit spread from the initial launch. The

transactions resulted in the second and third lowest utility transaction credit spreads (68 and 75 basis points, respectively) in 2025 at the time of issuance. Moreover, PECO's thirty-year tranche with a 75 basis point credit spread ties for the tightest thirty-year new issue spread for the Company since 2009. Additionally, instead of issuing all thirty-year bonds in 2025, the Company opted for a split of ten-year and thirty-year bonds to reduce the overall interest expense borne by customers while being prudent about managing the Company's debt maturity profile.

III. OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS

12. Q. Please provide an overview of PECO's principal accounting exhibits.

A. PECO's principal accounting exhibits are Exhibits MJT-1, MJT-2, and MJT-3, which represent PECO's revenue requirement for the FPFTY, future test year ("FTY"), and historical test year ("HTY"), respectively, and are sponsored by Mr. Trzaska (PECO Statement No. 4). Exhibit MJT-1 includes PECO's claimed measures of value (i.e., rate base), basic accounting data, a detailed development of the major components of the Company's rate base claim, detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis, and a discussion of FTY and HTY data. As explained by Mr. Trzaska, Exhibits MJT-2 and MJT-3 follow a similar format, and each of the three exhibits is based, in part, upon data provided by other PECO witnesses.

13. Q. Please describe PECO's budgeting process.

A. One of the key goals of the annual planning process is to integrate and align PECO's operational, regulatory, and financial plans. The operational plan includes goals focused on achieving at least top quartile safety performance, reliability, and customer satisfaction. The operational plan is also consistent with statutory and Commission-imposed regulatory requirements. The Company sets spending targets in its financial plan to achieve its operational goals and comply with such regulatory requirements. As I explained earlier, the Company attempts to minimize its O&M expenses to the extent possible and has generally been successful in controlling these expenses at a lower compound annual growth rate than the rate of inflation.

The planning process starts with a review and update of PECO's operational and regulatory goals and initiatives to determine if changes are required for the future. Any significant changes in such goals and initiatives are taken into consideration when updating the Company's Long Range Plan ("LRP"). The LRP consists of a five-year outlook and is updated with key assumptions (e.g., inflation rates, interest rates) and with detailed input provided by "responsibility areas" (e.g., Electric Operations and Customer Operations). Each responsibility area reviews its historic expense levels, current and anticipated employee staffing levels, performance assessments, regulatory requirements, operational goals, specific projects, and other factors and develops a responsibility area-specific LRP. The individual responsibility area LRPs are typically submitted for review by each department in June of each year and are carefully analyzed for consistency,

completeness, and appropriateness. The responsibility area LRPs are then consolidated into a single LRP and delivered to PECO's senior management (i.e., the Chief Executive Officer, Chief Operating Officer, and Chief Financial Officer) for review and approval in September.

Once that LRP has been updated and approved, its data is thoroughly scrutinized to formulate a detailed two-year budget. The two-year budget is developed by responsibility area, similar to the LRP process described above. The Company then develops its financing plan to ensure that PECO can maintain investment-grade credit ratings. Based on that plan, PECO determines the amount it can borrow to fund its spending plans and the dividend levels that will achieve its targeted capital structure. The consolidated budget is then submitted to PECO senior management for review and approval. The PECO board reviews and approves the Company's capital, O&M, dividend, and financing plan annually.

14. Q. Is that the end of the process?

A. No. Although the budget, as approved, remains in place throughout the year and is not formally amended, it is reviewed and updated on a monthly basis to reflect estimates derived from the Company's latest data. Actual results are then compared to both the original budget and the latest estimates. Any significant variances are thoroughly investigated to determine why the Company's actuals have departed from its estimated budget and actions are taken as appropriate.

15. Q. Do the personnel in each of the responsibility areas develop their budgets by Federal Energy Regulatory Commission ("FERC") account?

A. No, the responsibility areas do not budget by FERC account. Rather, the responsibility area budgets are prepared on the basis of business activities (i.e., GAAP[3] basis) and related cost elements such as payroll, employee benefits, outside services, etc.

16. Q. Has PECO's budgeting process been reviewed by the Commission?

A. Yes. PECO's budgeting process was reviewed by the Commission during its Focused Management and Operations Audit of PECO in 2022 ("2022 Audit").[4] The Commission's auditors found no deficiencies or weaknesses in the way PECO prepares its budgets.

17. Q. Mr. Trzaska presents the budgeted data for the twelve months ending December 31, 2027 on a FERC account basis in Schedules B-2, B-3, and B-4 of Exhibit MJT-1. How were those figures derived?

A. As Mr. Trzaska explains more fully in his testimony, he analyzed PECO's recorded FERC account balances for the twelve months ending December 31, 2025 to determine their composition (e.g., payroll, benefits, rent) and then distributed the FPFTY budgeted costs to the appropriate FERC account based on his findings. The results of Mr. Trzaska's proposed distribution of costs were then reviewed and confirmed with members of my staff.

[3] "GAAP" stands for "generally accepted accounting principles."
[4] *See* Focused Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (issued July 2022).

18. Q. Do Exhibits MJT-1, MJT-2, and MJT-3 contain all of the data needed to evaluate PECO's claimed revenue requirement?

A. No. While MJT-1, MJT-2, and MJT-3 present, in considerable detail, the Company's rate base, revenue, expense, and tax claims, much of the supporting data is provided in the separately bound volumes comprising the Company's responses to the Commission's rate case filing requirements at 52 Pa. Code §§ 53.52, 53.53, and 53.56 and supplemental data requests issued by the Commission's staff. I note that, consistent with the approach to develop responsibility area budgets on the basis of business activities (GAAP basis) as described above, many of the Company's responses to the filing requirements and supplemental data requests that accompany this rate filing were prepared on the basis of business activities (GAAP basis). As a result, there may be differences between those responses and figures in MJT-1, MJT-2, and MJT-3, which were prepared on a FERC account basis.

19. Q. How does the Company's approach to determining plant additions for rate base reflected in Mr. Trzaska's testimony differ from the capital budgeting process you describe above?

A. With respect to capital budgeting, the Company accounts for capital expenditures in the period when such expenditures are made. The Company determines plant additions based upon when plant is expected to be placed into service. This can, and often does, differ from the period in which capital spending occurs. In determining plant additions for rate base, PECO included only the plant that it expects will actually be placed in service by the end of the FPFTY. I note, however,

that the larger projects with which that plant is associated for PECO's budgeting purposes may show an overall project completion date that is beyond the end of the FPFTY, as components of a project may extend beyond the FPFTY.

20. Q. How do PECO's 2025 actual expenses and rate base additions compare to its projections in its 2024 case?

A. The Company's 2025 actual capital additions were greater than its projections in the 2024 electric base rate proceeding, and are detailed in the report that was provided on March 19, 2026 to the Commission's Bureau of Technical Utility Services, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate.

With respect to 2025 O&M expense, PECO's actual expenditures were approximately $45 million higher ($822 million) than projected in the Company's 2024 base rate case ($777 million). However, much of the variance was due to factors predominantly beyond the Company's control. Adjusted for these factors (i.e., storm, bad debt, and pension), PECO spent approximately $9 million more than estimated in its 2024 base rate case ($730 million vs. $721 million).

IV. EXELON BUSINESS SERVICES COMPANY

21. Q. Does PECO procure certain shared services from an affiliated service company?

A. Yes. Like many other energy holding company enterprises, Exelon created a service company, the EBSC, following the merger of PECO and the former Unicom Corporation, to house specific support functions that it believed could be staffed more efficiently and economically on a centralized basis.

22. Q. What types of services does the EBSC make available and to whom?

A. The EBSC is designed to provide a range of what would typically be regarded as in-house services in the case of a stand-alone utility. In broad terms, those services fall into the following categories: IT; supply; finance; commercial operations; human resources; government and regulatory affairs and public policy; legal and corporate governance; utility operations; real estate; executive services; communications; and security. The EBSC offers its services to PECO and other affiliated members of the Exelon family of utility companies, which include Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Delmarva Power & Light Company, and Potomac Electric Power Company.

23. Q. Is PECO required to utilize the EBSC's services?

A. No, PECO is not required to use the EBSC's services. Under the terms of the General Services Agreement ("GSA") between PECO and the EBSC, which was approved in the PECO/Unicom merger proceeding at Docket No. A-110550F0147, PECO has the discretion to determine whether and to what extent to utilize the EBSC's services in all areas except corporate governance.

24. Q. What role does the EBSC play in PECO's electric distribution operations?

A. PECO's overall approach is to use its own personnel or independent contractors to staff the day-to-day operations of its electric delivery system, as well as its customer-service functions (e.g., call center and billing services). Other services, such as employee benefits administration, mass purchasing, insurance, and treasury, to name a few, are provided by the EBSC. Certain highly specialized

services, for which it would not be cost effective to maintain the required expertise at either PECO or the EBSC, are obtained through contracting with outside firms.

25. Q. What is the principal advantage of the service company structure?

A. The EBSC enables PECO to realize economies of scale and scope that, in my judgment, could be very difficult to achieve on an individual-company basis. Indeed, if PECO were to try to maintain a full complement of comparably qualified personnel on its own payroll, the total cost PECO would incur to obtain the same level and quality of service it receives from the EBSC likely would be considerably higher.

26. Q. How does the EBSC price the services it provides to PECO?

A. The GSA provides that the services furnished by the EBSC to PECO are to be billed at the EBSC's cost. Prior to the enactment of the Energy Policy Act of 2005, the Exelon utility companies were subject to the affiliate-transaction and cost-allocation rules prescribed by the United States Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935 ("PUHCA"), which generally mandated that service companies, such as the EBSC, offer their services to affiliates at fully distributed cost. The "at cost" rules were incorporated into the GSA, and their continued use in the provision of non-power goods and services has been approved by the FERC, which assumed some of the SEC's oversight responsibilities when PUHCA was repealed, in part, several years ago.

27. Q. How is the cost of services provided to PECO determined?

A. Direct charges are made for services where possible. Otherwise, costs are allocated on the basis of the allocation factors/methodologies identified in the GSA, which were previously reviewed and approved by the SEC. These allocations and methodologies were also reviewed as part of the Commission's 2022 Audit, and the Commission's auditors found no issues with respect to PECO's cost allocation methodology.

28. Q. How does PECO satisfy itself that the services it procures from the EBSC are provided at a competitive price?

A. PECO takes several steps to ensure that the services it procures from the EBSC are provided at a competitive price. First, PECO and the management of EBSC work together to identify PECO's needs and to define service priorities and major new initiatives. As a consequence, PECO has meaningful input into the development of the EBSC's budget for the upcoming year, and I, as PECO's Chief Financial Officer, ultimately approve the service level arrangements ("SLAs"). SLAs are annual agreements between the EBSC and Exelon's operating companies (including PECO) entered into under the express authority of the Commission-approved GSA that detail the specific services that the EBSC will provide during the following year, including the scope of services, unit cost expectations, and performance measures. Services are grouped by function so that budgeted and actual costs can be tracked.

Second, the EBSC's monthly billings are carefully scrutinized by PECO personnel. Variances between actual and budgeted charges are reviewed by PECO

personnel with their EBSC counterparts to ensure that all costs are properly justified.

In addition, for functions that are not already outsourced, PECO obtains extensive information regarding the composition of the EBSC's costs, which PECO can then periodically review for reasonableness. PECO's review process, which was developed in conjunction with the Commission's management auditors, along with allocation factors and methodologies used for EBSC costs, was reviewed as part of the Commission's audits of the Company in 2014 and 2022. In 2017, the Commission conducted a Management Efficiency Investigation to evaluate PECO's implementation of recommendations from the 2014 Audit.[5] The Commission again examined PECO's affiliated interest and cost allocations processes and concluded that PECO (and EBSC) had taken steps to verify that "shared services are being provided in an efficient and cost-effective manner and/or improvement opportunities are identified to ensure service offerings are fair and reasonable." PECO has also worked to implement recommendations made by the Commission, including those related to its payroll and accounts payable systems and the sharing of benchmarking reviews among EBSC, PECO, and other Exelon companies.

29. Q. What is PECO's claim in this proceeding for EBSC services?

A. PECO has included $172.3 million in its FPFTY expense claim for charges from EBSC. A breakdown of those costs is attached as PECO Exhibit MEH-1.

[5] *See* PECO Energy Company Management Efficiency Investigation Evaluating the Implementation of Selected Management Audit Recommendations from the 2014 Focused Management and Operations Audit, Docket No. D-2016-2562303 (Aug. 2017).

V. CORPORATE ALTERNATIVE MINIMUM TAX

30. Q. How did the enactment of the Inflation Reduction Act ("IRA") impact PECO?

A. The IRA implemented a new CAMT beginning in 2023 that imposes a 15% tax on adjusted financial statement income on "applicable corporations." Applicable corporations, including Exelon and its subsidiaries, now pay the greater of 15% of their adjusted financial statement income or their regular federal tax liability. Beginning in 2023, based on available tax guidance, Exelon and its subsidiaries, including PECO, were each subject to CAMT.

31. Q. For CAMT purposes, how was the adjusted financial statement income determined?

A. The starting point for calculating adjusted financial statement income is GAAP financial statement net income. Pursuant to the federal tax statute,[6] GAAP financial statement net income is adjusted for federal income taxes, accelerated tax depreciation, pension and other postemployment benefits.[7]

32. Q. How does PECO calculate the CAMT?

A. PECO calculates the CAMT based on its standalone separate company books and records.

33. Q. Why did PECO's CAMT exceed its regular tax liability?

A. Certain expenditures that qualify for accelerated tax deductions in the calculation of a corporation's regular tax liability, such as tax repairs and certain overhead costs, are required to be capitalized for financial statement purposes. Prior to the issuance of new guidance by the U.S. Department of Treasury and the Internal

[6] 26 U.S.C. § 56A.
[7] These adjustments ensure the same treatment of these items for CAMT and regular tax purposes.

Revenue Service ("IRS") discussed later in my testimony, these expenditures were required to be capitalized and depreciated for purposes of calculating CAMT rather than immediately deducted. As a result, PECO's regular tax liability has been lower than its CAMT liability.

34. Q. How is the Company accounting for the CAMT in its financial statements?

A. For income tax accounting purposes, a current income tax liability and current income tax expense will be recorded for the CAMT liability but will be equally offset by recording a deferred tax asset and a reduction to deferred income tax expense to reflect the CAMT credit carryforward. As a result, there is no net incremental income tax expense associated with the CAMT. Corporations are entitled to a CAMT tax credit equal to the amount by which the CAMT liability exceeds the regular tax liability. This amount may not be carried back to prior years but can be carried forward indefinitely and used in future years when the regular tax liability exceeds the CAMT liability. For income tax accounting purposes, a deferred tax asset is established for the CAMT credit carryforward.

35. Q. What is the ratemaking impact associated with CAMT?

A. PECO includes the deferred tax asset associated with the CAMT credit carryforward as an increase to rate base.

36. Q. Why is it appropriate to include the deferred tax asset related to CAMT in rate base?

A. Accelerated tax deductions related to utility property generate cash tax benefits that reduce the cost of capital. For ratemaking purposes, rate base is adjusted downward to reflect the lower cost of capital attributable to accelerated tax deductions. The

CAMT has the opposite effect; it reduces the realization of the tax benefits associated with accelerated tax deductions, such as tax repairs and certain other overhead capitalization adjustments that are not deductible in the calculation of CAMT. The Accumulated Deferred Income Taxes ("ADIT") associated with tax repairs and other property-related tax adjustments are included in PECO's rate base as a downward adjustment. Therefore, to reflect the appropriate cost of capital, the deferred tax asset associated with the CAMT credit carryforward should likewise be included in rate base as an adjustment that offsets ADIT.

37. Q. Was the ratemaking impact for CAMT contested in the Company's prior rate case?

A. No. The inclusion of PECO's CAMT credit carryforward as an increase to rate base was an uncontested issue in Docket No. R-2024-3046932.

38. Q. Has the U.S. Department of Treasury and the IRS issued any new CAMT guidelines that impact PECO?

A. Yes. On February 18, 2026, the U.S. Department of Treasury and the IRS issued Notice 2026-7. The newly issued guidance permits regulated utilities a repair deduction equal to the one claimed for regular tax purposes in the calculation of the CAMT. This will allow PECO to reduce its CAMT liability and the corresponding deferred tax asset related to CAMT credits carryforwards, which will result in a reduction to rate base.

39. Q. How does this new CAMT guidance benefit customers and underscore the Company's commitment to advocating for its customers?

A. Under CAMT, corporate taxpayers are permitted to deduct accelerated tax depreciation in the determination of the CAMT. However, prior to the issuance of Notice 2026-7, corporate taxpayers were not permitted to deduct tax repairs that were capitalized for financial accounting purposes to determine the CAMT. This had a disproportionate impact on capital-intensive companies with aging assets and resulted in utilities being significantly and disproportionately impacted by the CAMT. These CAMT impacts would have compounded in perpetuity, resulting in significant and permanent annual increases in customer bills.

Since the imposition of CAMT, Exelon has worked to educate the U.S. Department of Treasury and other policymakers on the importance of permitting a tax repairs deduction for regulated utilities equal to the one claimed for regular tax purposes in the calculation of the CAMT through the submission of comments in an IRS proceeding regarding CAMT implementation.[8] We believe that these efforts contributed to the U.S. Department of Treasury issuing Notice 2026-7 permitting a tax repairs deduction for CAMT purposes.

The repairs deduction reduces PECO's CAMT liability, and the corresponding deferred tax asset related to the CAMT credit carryforwards reduces PECO's rate base, resulting in a lower revenue requirement and providing a direct benefit to customers. The reduction in PECO's CAMT liability also

[8] *See* Comments of Exelon Corporation (Nov. 25, 2024), available at https://www.regulations.gov/comment/IRS-2024-0046-0008.

improves financial credit metrics resulting in lower borrowing costs and increases the availability of capital needed for investments in critical electric infrastructure.

VI. CONCLUSION

40. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Marissa Humphrey, hereby state that I am a Senior Vice President, Chief Financial Officer and Treasurer for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 3 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Marissa Humphrey

PECO Exhibit MEH-1:
PECO Energy Company Business Services
Company Operations and Maintenance Costs

PECO Energy Co. **PECO Exhibit MEH-1**
BSC Operations & Maintenance Costs
Presentation Basis: PECO Electric Distribution

($ in millions)

		2027 Budget
1	Legal Governance	8.9
2	Executive Services	10.8
3	Security	2.3
4	Government and Regulatory Affairs & Public Policy	1.7
5	Exelon Utility Operations	13.0
6	Communications	5.0
7	Finance	25.1
8	Human Resources	7.8
9	Real Estate	0.6
10	Supply Services	1.0
11	**Subtotal of Non-IT EBSC**	**76.2**
12	**IT EBSC**	**96.2**
13	**Total EBSC Charges**	**172.3**

Note: non-recoverable costs, including charitable contributions and lobbying costs, have been removed from the schedules above

PECO Statement No. 4:
Direct Testimony of Michael J. Trzaska

PECO ENERGY COMPANY
STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO'S OVERALL REVENUE REQUIREMENT; CERTAIN RATEMAKING ADJUSTMENTS; AND STORM RESERVE ACCOUNT

DATED: March 30, 2026

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DIRECT TESTIMONY
OF
MICHAEL J. TRZASKA

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Michael J. Trzaska. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rate Specialist in the Regulatory Policy and Strategy Department. My duties and responsibilities in that capacity include performing financial analysis, project management and regulatory strategy for gas and electric operations throughout the Company's service territory. I am responsible for providing expert testimony on behalf of the Company with respect to various regulatory issues.

3. Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Accounting from Drexel University in 1987 and a Master of Science in Finance degree from LaSalle University in 1996.

4. Q. Please describe your work experience in the energy industry.

A. Upon graduation from Drexel University in 1987, I was hired by PECO and have been with the Company since that time in various positions of increasing responsibility.

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

A. The principal purpose of my direct testimony is to explain the preparation and presentation of data supporting PECO's request for a general base rate increase for its electric distribution operations. More specifically, I explain how the components of the Company's overall revenue requirement were developed. This includes certain portions of the claimed measures of value and the pro forma ratemaking adjustments that were made to calculate the Company's revenue requirement based on data for a fully projected future test year ending December 31, 2027 ("FPFTY"), a future test year ending December 31, 2026 ("FTY"), and a historic test year ended December 31, 2025 ("HTY"). For purposes of supporting PECO's proposed increase in base rate distribution operating revenue under its proposed rates, the Company is relying principally upon data for the FPFTY.

I will also describe the Company's proposal to establish a Storm Reserve Account in this case.

6. Q. Are you sponsoring all or portions of any exhibits in this proceeding?

A. Yes. I am sponsoring PECO Exhibits MJT-1, MJT-2, MJT-3, and MJT-4. PECO Exhibits MJT-1, MJT-2, and MJT-3 comprise PECO's principal accounting exhibits for the FPFTY, the FTY, and the HTY, respectively.[1] The base data for the FPFTY that I used to develop PECO Exhibit MJT-1 were derived, for the most part, from PECO's capital and operating budgets for the 12 months ending December 31, 2027, while the corresponding data for the FTY used to develop

[1] PECO Exhibits MJT-1, MJT-2 and MJT-3 each contain multiple schedules and each page of the exhibit is numbered on a continuous sequential basis. Specific schedule pages will be cited to using the applicable exhibit pagination. For example, the second page of Schedule B-1, which is the third page of Exhibit MJT-1, will be cited as "Exhibit MJT-1, Schedule B-1, page 3."

PECO Exhibit MJT-2 were derived from PECO's capital and operating budgets for the 12 months ending December 31, 2026. The data for the HTY used to develop PECO Exhibit MJT-3 are the data actually recorded in PECO's books of account for the 12 months ended December 31, 2025.

In addition to sponsoring the exhibits described above, I am responsible for responses to certain Pennsylvania Public Utility Commission ("Commission") standard data filing requirements. PECO Exhibit MJT-4 contains a summary of PECO's annual storm damage expense from 2010 through 2025.

7. Q. Will you discuss separately PECO Exhibit MJT-1, PECO Exhibit MJT-2, and PECO Exhibit MJT-3?

A. Yes, I will. However, because PECO is basing its proposed rate increase on the adjusted FPFTY data, most of my direct testimony is devoted to explaining PECO Exhibit MJT-1. My testimony regarding PECO Exhibits MJT-2 and MJT-3, which are essentially identical in format to PECO Exhibit MJT-1, will briefly address the pro forma adjustments that were made to budget data for the 12 months ending December 31, 2026 and historic actual data for the 12 months ended December 31, 2025, respectively, because the nature of those adjustments is the same or similar to adjustments that I will have already discussed in the context of PECO Exhibit MJT-1. However, I will specifically address any additional adjustments or other differences among those exhibits.

8. Q. Please provide an overview of your accounting exhibits.

A. Exhibit MJT-1, which presents PECO's revenue requirement for the FPFTY ending December 31, 2027, is comprised of five sections, as follows:

Section I consists of a summary schedule setting forth PECO's claimed measures of value (i.e., rate base) and the derivation of the Company's requested rate increase.

Section II contains basic accounting data, primarily extracted from the Company's financial records, including a FPFTY-end balance sheet; statements of net operating income and FPFTY revenues; a schedule of expense items by primary account; and a calculation of PECO's tax expenses. Also included are schedules developing PECO's embedded costs of debt and equity, its FPFTY capital structure, and the Company's overall claimed rate of return.

Section III provides a detailed development of the major components of the Company's rate base claim. This section includes summaries of the original cost and accumulated depreciation at FPFTY-end of the various categories of utility plant, including allocated common plant, and calculations of PECO's working capital, a pension asset, materials and supplies, accumulated deferred income taxes ("ADIT"), regulatory liability for excess ADIT, and customer deposits and advances.

Section IV contains detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis. These adjustments are summarized on Schedules D-3 to D-17, and, together with certain tax adjustments, are carried forward to Schedule D-1 to derive PECO's pro forma operating income at present and proposed rates.

Section V briefly describes the FTY and HTY data.

Exhibits MJT-2 and MJT-3 are essentially identical in format. Adjustments were made to budgeted data, where necessary, to ensure that the Company's claimed revenue, expenses, and taxes are representative of the levels that the Company expects to experience on a normalized, ongoing basis, and in accordance with the Commission's established ratemaking precedent.

Because PECO is basing its requested rate increase on FPFTY data, Exhibit MJT-1 is key to understanding and evaluating the derivation of the Company's claimed revenue requirement. Exhibit MJT-2 follows the same format as Exhibit MJT-1 but presents information for the FTY ending on December 31, 2026. Exhibit MJT-3 follows the same format as Exhibits MJT-1 and MJT-2, but presents information for the HTY, which ended on December 31, 2025. This information is being furnished in accordance with the Commission's filing requirements and provides a basis for comparing PECO's FPFTY claims to the actual results of historic operations, adjusted for ratemaking purposes, for the HTY.

9. Q. How is the balance of your testimony structured?

A. In Section II of my testimony, I present an overview of PECO's FPFTY revenue requirement and explain, in summary fashion, how the claimed measures of value, pro forma present rate revenues, operating expenses, depreciation, and taxes were determined. Section III of my testimony provides a more detailed description of the individual components comprising PECO's requested measures of value for the FPFTY, while Section IV of my testimony discusses the derivation, including appropriate ratemaking adjustments, of PECO's revenue and expense claims for the FPFTY. Section V of my testimony briefly describes the FTY and the HTY data.

Section VI of my testimony describes the Company's proposed Storm Reserve Account and explains why adoption of this proposal is appropriate.

II. OVERVIEW OF PECO'S FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

10. Q. Please provide an overview of how the Company's FPFTY measures of value were determined.

A. PECO's measures of value, as presented in PECO Exhibit MJT-1, consist of eight principal components: (1) the depreciated original cost of utility plant-in-service (original cost less accumulated depreciation); (2) ADIT; (3) a pension asset; (4) customer deposits; (5) customer advances for construction; (6) material and supplies; (7) the regulatory liability for excess ADIT; and (8) cash working capital. Each is described briefly below.

Depreciated Original Cost of Utility Plant-in-Service. To determine utility plant-in-service as of the end of the FTY, I began with the closing plant balances actually recorded on the Company's books of account on December 31, 2025, including allocated common plant. To those balances, I added the budgeted capital expenditures for PECO projects that are scheduled to close to plant-in-service (i.e., be placed into service) during the FTY and subtracted the anticipated plant retirements. The same process was used to develop utility plant-in-service balances as of the end of the FPFTY, beginning with the projected balance of plant-in-service on December 31, 2026, adding capital expenditures projected to be closed to plant-in-service by the end of the FPFTY, and subtracting anticipated retirements. The Company's claim for accumulated depreciation was determined in a similar fashion, starting with the accumulated depreciation on December 31, 2025 assigned

to each plant account, and bringing those data forward to reflect additional depreciation accruals, plant retirements, and cost of removal net of salvage for the period through December 31, 2026. Accumulated depreciation on December 31, 2027 was then deducted from the projected balance of utility plant as of that date to derive the Company's claimed FPFTY year-end net utility plant of $11.5 billion.

Pension Asset. PECO has included a pension asset in measures of value that consists of the portion of PECO's cash pension contributions that it will have neither recovered as an operating expense nor capitalized to utility plant because the capitalized amounts are based on costs determined pursuant to Financial Accounting Standards Codification Topic 715 ("ASC 715"), which was formerly Statement of Financial Accounting Standards 87 or "SFAS 87".

ADIT. The credit balance of ADIT includes the liability for deferred Federal income taxes, net of an offset (debit) for the ADIT assets related to Federal income tax paid by the Company in advance of recognizing the associated tax determinants for financial reporting purposes, which consist principally of contributions-in-aid-of-construction ("CIAC") recognized as income for income tax purposes.

Customer Deposits, Customer Advances for Construction, and Material and Supplies. The claimed levels of customer deposits and customer advances for construction (both are deducted in determining the measures of value) and material and supplies (which are added) are based on 13-month historic averages for the period ended December 31, 2025, consistent with Commission precedent.

Regulatory Liability for Excess ADIT. Due to the reduction in the Federal corporate tax rate that became effective on January 1, 2018, pursuant to the Tax

Cuts and Jobs Act ("TCJA"), there is "excess" ADIT. Excess ADIT represents taxes that were deferred prior to January 1, 2018 at the then-applicable 35% tax rate but will be paid to the Federal government, after January 1, 2018 at the current 21% tax rate. The excess ADIT is to be returned to customers over periods that correspond to the periods over which the ADIT would have been paid to the government if the Federal corporate tax rate had not been reduced. To reflect that obligation, the Company has transferred its excess ADIT from the Company's ADIT account to a new regulatory liability account. In addition, on July 8, 2022, Governor Tom Wolf signed Act 53 of 2022 into law. Act 53 incrementally changes the annual rate of Pennsylvania state tax on corporate net income ("CNI") from 9.99% to 4.99% over a period of nine years. Prior to Act 53 taking effect, the CNI tax rate was 9.99%. Act 53 initially lowered the CNI tax rate to 8.99% beginning on January 1, 2023. The CNI tax rate will be lowered each January 1 until the CNI tax rate reaches 4.99% by January 1, 2031. As a result, the Company made a reclassification of ADIT to excess ADIT at the end of 2022. It is important to note that this reclassification was based on the CNI tax rate of 4.99% in 2031. The impact of the CNI tax rate reduction in 2023 was addressed in the Company's 2022 base rate case proceeding at Docket No. R-2022-3031113, where a nine-year amortization for the associated excess ADIT was adopted as part of the approved settlement in that proceeding.[2] The additional impact of CNI tax rate reductions beyond 2023 were passed to customers through the Company's State Tax Adjustment Clause or through a base rate case proceeding. The sum of the

[2] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2022-3031113 (Order entered Oct. 27, 2022).

Company's ADIT account and its regulatory liability for excess ADIT on December 31, 2027 is deducted from the Company's measures of value.

Cash Working Capital. Cash working capital was calculated using a lead-lag study and includes elements that are consistent with past practice and Commission precedent.

The components of the measures of value described above are shown in PECO Exhibit MJT-1 on Schedule A-1 at lines 1 to 14 and are discussed in more detail in Section III of my testimony.

11. Q. How were the revenues at present rates derived?

A. Revenues at present rates were developed by adjusting the budgeted revenues for PECO's electric operations for the FPFTY to: (1) remove revenues related to portions of the Company's business that are not subject to the jurisdiction of the Commission; (2) remove revenues billed under the surcharge (i.e., non-base rate revenue) that recovers the cost of implementing the Company's energy efficiency and conservation programs pursuant to Act 129; (3) annualize revenues related to changes in the number of customers to reflect year-end levels as of the end of the FPFTY; (4) normalize revenues to reflect 365.25 days; and (6) reflect various pro forma revenue adjustments, which are summarized on Schedule D-5 of PECO Exhibit MJT-1 and are discussed in more detail later in my testimony.

12. Q. How were PECO's claimed operating expenses for the FPFTY determined?

A. The pro forma FPFTY expenses were determined using PECO's budget for the 12-month period ending December 31, 2027 as a starting point. Budgeted expenses, which were prepared based on business activities and related cost elements such as

payroll, employee benefits, and outside contracting costs, were distributed to Federal Energy Regulatory Commission ("FERC") accounts based upon the actual distribution experienced by the Company during the calendar year ended December 31, 2025. The budget data were then annualized or normalized in accordance with established Commission ratemaking practices, and other appropriate adjustments were made, all of which are included in Schedule D of PECO Exhibit MJT-1. The necessary adjustments were made to the appropriate FERC accounts.

13. Q. Please describe how the taxes-other-than-income were determined for the FPFTY.

A. Those amounts were determined using budgeted amounts for the FPFTY, with pro forma adjustments to payroll taxes to reflect the impact of the increase to FPFTY salaries and wages ("S&W") and other adjustments to reflect known and measurable changes, as shown on Schedule D-16 of PECO Exhibit MJT-1.

14. Q. Please describe the calculation of depreciation expense for the FPFTY.

A. The development of annual depreciation for electric and common plant is set forth on Schedule D-17 of PECO Exhibit MJT-1. Each of pages 85 through 87 have columns numbered 1 through 5. Each of pages 88 through 90 have columns numbered 6 through 11. Each of pages 91 through 93 have columns numbered 12 through 17. Columns 1 through 5 show the annual depreciation for electric distribution, transmission, and common plant. Column 6 shows the allocation factors used to allocate annual depreciation to the Electric Division. The allocation factor is 100% for electric distribution plant. For common plant, the allocation factor is 76.98%, which is the portion of common plant allocated to the Electric

Division. Columns 7 through 11 show the annual depreciation allocated to the Electric Division. The figures in columns 7 through 11 for common plant reflect the amounts in columns 1 through 6 multiplied by the allocation factor of 76.98%. Column 12 is designed to allocate utility costs between Commission jurisdictional service and non-Commission jurisdictional service. Accordingly, the amounts shown in columns 13 through 17 represent the amounts properly allocated in their entirety to Commission-jurisdictional service for the Electric Division. For all of the columns, the total for FERC Account 403 Depreciation Expense is shown on line 90 and the total for FERC Account 404 Amortization of Limited-Term Plant is shown on line 118.

The annual depreciation expense budgeted by the Company for electric plant and total-Company common plant is $457.1 million, which is the sum of the amounts shown in column 1, lines 90 and 118. This amount is the annual depreciation developed by Company witness Mariana Hufford (PECO Statement No. 6) based on utility plant that will be in service on December 31, 2026 (as shown in Schedule D-17, column 3) and utility plant additions that will be in service on December 31, 2027 (as shown in Schedule D-17, column 2). As Ms. Hufford explains, the budgeted annual depreciation amounts for both plant-in-service on December 31, 2026 and for additions during the 12 months ending December 31, 2027 were calculated using depreciation rates that reflect the service life parameters developed in the Company's 2023 service life study. The annual depreciation for plant additions made during the 12-month period ending December 31, 2027 is based on their expected actual in-service dates and, therefore, reflects less than 12

months of depreciation for that plant. Accordingly, Schedule D-17, column 4, adjusts the amounts in column 1 to annualize the annual depreciation on plant additions made during the 12-month period ending December 31, 2027. Depreciation expense does not include Asset Retirement Obligations.

The resulting pro forma FPFTY depreciation expense of $492.7 million related to electric plant and common plant is shown in column 5. The resulting pro forma FPFTY depreciation expense for electric distribution and common plant allocable to the Electric Division's Commission-jurisdictional service is $407.8 million, as shown in column 17. That amount is the sum of $369.1 million shown on line 90 and $38.7 million shown on line 118.

15. Q. How were income taxes calculated?

A. Income taxes were calculated using procedures consistent with Commission practice. Federal income tax expense was calculated at the 21% Federal corporate tax rate that became effective on January 1, 2018, pursuant to the TCJA.

The interest expense deduction was synchronized with the Company's measures of value and claimed weighted average cost of long-term debt. The normalization method was used to reflect the tax-book timing differences associated with the use of accelerated methods of tax depreciation to the extent permitted by the Commission and legal precedent. Tax expense was reduced to reflect the amortization of the unamortized investment tax credits ("ITCs"). Tax expense was also reduced to reflect the flow-back of excess ADIT that results from the TCJA's reduction of the Federal corporate tax rate and Pennsylvania CNI tax

rate reductions. The income tax claimed for the FPFTY at present rate and proposed rate revenue levels is shown on PECO Exhibit MJT-1, Schedule D-18.

16. Q. Please describe how the pro forma revenue increase and revenues at proposed rates were established.

A. Schedule A-1 of PECO Exhibit MJT-1 shows the calculation of PECO's claimed revenue requirement and its requested revenue increase. Column 2, lines 1 to 14, summarize the pro forma measures of value.

Column 2, line 19, shows the Company's electric distribution base rate revenue at present rates. Column 3, line 19, shows the increase over revenues at present rates needed to recover the Company's FPFTY revenue requirement, which is $429.1 million.

Lines 24 to 46 of column 2 set forth the calculation of the increase above present rate revenue required to provide the Company with the opportunity to earn the overall rate of return of 8.08% calculated on Schedule B-7. The resulting required increase in net operating income on line 42 was increased by the Gross Revenue Conversion Factor ("GRCF"), shown on line 44, to provide for Late Payment Charge ("LPC") revenue, uncollectible accounts expenses, gross receipts taxes, regulatory fees and income taxes on the increased revenues requested. The revenue increase shown on line 46 of column 2 is the difference between present rate revenue and revenues at proposed rates. The increase in unadjusted present rate revenue of $429.1 million is shown on line 46 of column 2 and line 19 of column 3. Column 3, lines 19 through 31, also contains the calculation of the revenue and expenses related to the proposed revenue increase.

Measures of value, revenues, and expenses at proposed rates are shown in column 4, with the resulting overall rate of return of 8.08% shown on line 33 of column 4.

17. Q. What is the overall required increase in annual revenues for the Company's jurisdictional distribution operations for the FPFTY?

A. As shown on line 46 of PECO Exhibit MJT-1, Schedule A-1, the proposed increase in annual operating revenues is approximately $429.1 million.

18. Q. What is contained in Schedule B?

A. Schedule B consists of a balance sheet for the total Company on December 31, 2027 reflecting the Company's budget for the 12 months ending December 31, 2027 (Schedule B-1); a statement of Pennsylvania jurisdictional net operating income for the 12 months ending December 31, 2027 (Schedule B-2); a statement of Pennsylvania jurisdictional operating revenue for the 12 months ending December 31, 2027 (Schedule B-3); a statement of Pennsylvania jurisdictional operating and maintenance expense for the 12 months ending December 31, 2027 (Schedule B-4); a detailed breakdown of Pennsylvania jurisdictional taxes other than income for the 12 months ending December 31, 2027 (Schedule B-5); PECO's projected composite cost of long-term debt on December 31, 2027 (Schedule B-6); and the calculation of PECO's claimed overall rate of return for the FPFTY (Schedule B-7).

III. MEASURES OF VALUE

A. Summary of Measures of Value

19. Q. Please describe Schedule C-1 of PECO Exhibit MJT-1.

A. Schedule C-1, page 16, summarizes the measures of value for the FPFTY for the Company's total Electric Division and its Pennsylvania jurisdictional operations. Column 1 identifies the schedule where each of the measures of value elements is derived, and columns 2 to 4 show the Company's total Electric Division, non-Pennsylvania, and Pennsylvania jurisdictional amounts, respectively. The Company's claimed measures of value for the FPFTY, as shown in column 4, on line 14, is approximately $10.95 billion.

B. Plant-In-Service

20. Q. Please describe Schedule C-2 of PECO Exhibit MJT-1.

A. Schedule C-2 contains six pages and presents the Company's claimed FPFTY utility plant-in-service.

21. Q. What is shown on Schedule C-2, page 17?

A. Schedule C-2, page 17, is a summary of estimated year-end plant-in-service balances for the FPFTY by functional plant category. Column 2 shows the total-Company electric plant-in-service balance, and column 3 reflects the removal of transmission-related plant. Column 4 reflects the Company's estimated electric distribution plant-in-service at the end of the FPFTY of $13.2 billion (line 52), which is shown on PECO Exhibit MJT-1, Schedule A-1, column 4, line 2.

22. Q. How was total utility plant-in-service for electric distribution operations of $13.2 billion, shown on Schedule C-2, page 17, column 4, line 52, determined?

A. The amount of $15.8 billion shown on Schedule C-2, page 17, column 2, line 52 represents the estimated plant-in-service balance on December 31, 2027 for the Company's Electric Division, including distribution and transmission plant, and is based on utility plant-in-service on December 31, 2025, including distribution and transmission, plus budgeted capital expenditures estimated to be closed to plant-in-service during the FTY and FPFTY, less the estimated retirements in the FTY and FPFTY.

Page 17, column 3 sets forth the adjustments needed to remove intangible plant assigned to transmission, transmission plant included in the transmission accounts, and the portion of general plant allocated to transmission operations. The calculation of the intangible plant and general plant allocated to transmission is described in connection with pages 20 to 22 of Schedule C-2. Column 7 reflects the Company's estimated electric distribution plant-in-service at the end of the FPFTY.

23. Q. What is shown on page 18 of Schedule C-2?

A. Page 18 sets forth the Company's estimated additions to be closed to plant-in-service during the FPFTY. These data were developed based on the FTY and FPFTY capital budgets. The total Company additions of $1.5 billion are shown on line 46, column 1.

24. Q. What is shown on Schedule C-2, page 19?

A. Page 19 of Schedule C-2 presents the estimated plant retirements for the FPFTY, based on the average of actual retirements for the period of January 1, 2023 through December 31, 2025.

25. Q. What is contained on pages 20 to 22 of Schedule C-2?

A. Pages 20 to 22 detail the adjustments necessary to remove all transmission-related intangible, general, and transmission plant recorded in transmission accounts under FERC jurisdiction from the account balances, as shown in column 8. As shown in column 6, 87.46% of general plant was allocated to the distribution function. The allocation factors are based on S&W actually recorded in PECO's transmission accounts as a percentage of its total actual S&W in 2025. Beginning January 1, 2025, FERC Order No. 898 created new function-specific utility accounts for computer hardware, software, and communication equipment. As part of implementation, PECO reclassified eligible balances as of January 1, 2025 to the new Order No. 898 accounts, and the resulting plant-in-service and accumulated depreciation balances reflected in Schedules C-2 and C-3 incorporate those reclassifications. Schedule C-2 also includes an adjustment in FERC account 371 reflecting the $3 million investment for the Company's proposed Battery Energy Storage System ("BESS") Leasing Pilot Program as shown on page 21, column 2, line 91. The details of this program are discussed in greater detail by Company witness Steven DeMott (PECO Statement No. 11).

C. Accumulated Depreciation

26. Q. What is the purpose of Schedule C-3 of PECO Exhibit MJT-1?

A. This schedule, consisting of five pages, presents the provision for accumulated depreciation on December 31, 2027 by FERC account, as developed by Ms. Hufford, and adjustments related to transmission plant and cost of removal net of salvage, as explained more fully below. PECO's accumulated depreciation of approximately $2.2 billion is summarized on page 23 of Schedule C-3 and then carried forward to line 3 of Schedule A-1.

27. Q. Please describe page 23 of Schedule C-3.

A. This page shows the accumulated depreciation balance for the FPFTY by account category, including the accumulated depreciation balance for total electric operations, as shown in column 2, and the adjustments, as shown in column 3, to remove the transmission-related accumulated depreciation, in order to derive the Pennsylvania jurisdictional pro forma accumulated depreciation, as shown in column 4.

28. Q. What is contained on pages 24 to 26 of Schedule C-3?

A. Pages 24 to 26 show the accumulated depreciation balance by FERC account at the end of the FPFTY, including the accumulated depreciation balance for total electric operations, as shown in column 1, and the adjustments, as shown in column 8, to remove the transmission-related accumulated depreciation, in order to derive the Pennsylvania jurisdictional pro forma accumulated depreciation shown in column 7. To determine the accumulated depreciation balance at the end of FPFTY, the Company started with the accumulated depreciation balance on December 31, 2025

and added depreciation expense, less retirements and cost of removal net of salvage, for the FTY and FPFTY. As shown in column 6, 87.46% of accumulated general plant was allocated to the distribution function. The allocation factor was developed in the same manner as the allocation factors I described in connection with Schedule C-2 (i.e., S&W actually recorded in PECO's transmission accounts as a percentage of its total actual S&W in 2025). Schedule C-3, page 27 shows the cost of removal net of salvage included in the FPFTY accumulated depreciation calculations, based on the average of actual cost of removal net of salvage for the period of January 1, 2023 through December 31, 2025. Schedule C-3 also includes an adjustment in FERC account 371 reflecting $200,000 of depreciation for the BESS Pilot Program investment ($3 million gross plant depreciated over 15-year useful life), as shown on page 25, column 2, line 89.

D. Cash Working Capital

29. Q. What is set forth on Schedule C-4, page 28, of PECO Exhibit MJT-1?

A. This is a summary of the Cash Working Capital ("CWC") calculations, which are detailed on pages 29 to 36 of this schedule. The total of $341.7 million shown on line 33 is included in PECO's claimed measures of value, as shown on PECO Exhibit MJT-1, Schedule A-1, columns 2 and 4, line 7

30. Q. Please describe page 28 of Schedule C-4.

A. Page 28 summarizes the derivation of PECO's revenue collection lag and overall operating expense payment lag. The revenue lag of 57.60 days is shown on line 3. The expense lag days for each of the components of operating and maintenance expenses appear on lines 6 to 12. Line 15 shows the lag associated with payments

to electric generation suppliers ("EGSs") for the purchase of receivables ("POR") from EGSs pursuant to the Company's Commission-approved POR program. The composite operating and maintenance expense and POR payment lag of 35.00 days is shown on line 19. The net lag of 22.59 days (57.60 - 35.00) shown on line 21 is multiplied by the average daily operating expense balance on line 25 to arrive at the base CWC amount of $245.8 million for operating expenses shown on line 27. The average daily operating expense balance of $10.9 million on line 25 was determined by dividing the total pro forma annual operating expenses, excluding uncollectible accounts expense, of $3.97 billion on line 17, column 2, by the number of days in a year, 365. The other components of CWC are shown on lines 29 to 31 and will be described in connection with my discussion of related supporting schedules.

31. Q. Please describe the revenue lag calculation shown on Schedule C-4, page 29.

A. The total revenue lag days of 57.60 days is shown on page 29, line 29, and consists of three parts. First, the average of the month-end accounts receivable balances for the 13 months ended December 31, 2025 (shown in column 2 on line 21) was divided into the annual revenue billed during the 12 months ended December 31, 2025, (column 3 on line 21) to calculate the accounts receivable turnover rate of 8.82 (column 4, line 21). A turnover rate of 8.82 is equivalent to 41.39 revenue lag days (365 days divided by 8.82 accounts receivable turnover rate), as shown in column 5 on line 21. This is referred to as the collection lag or the payment portion of the revenue lag. The payment portion of the revenue lag is added to: (1) the one-day lag between the meter reading date and the day that bills are recorded as revenue and accounts receivable by the Company; and (2) the 15.21-day period from the

mid-point of the service period until the meter reading date, to calculate the total revenue lag of 57.60 days, as shown on line 29.

32. Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the days in an average month (365 days divided by 12, or 30.42 days) divided by two, or 15.21 days.

33. Q. Please describe page 30 of Schedule C-4.

A. Schedule C-4, page 30, shows the calculation of the expense lags used in the CWC calculation. Lines 1 to 5 reflect the payroll expense lag. The payroll amounts for the FPFTY are developed on Schedule D-6. The lag periods for the payment of union and non-union payroll are combined because all employees are paid on the same schedule. The lag days reflect PECO's 2026 payment cycles, the last full year for which the payment cycles are known. Lines 7 to 15 show the lag in the payment of pension costs during the FPFTY. The lag period is calculated using a mid-point of July 1 and the payment dates shown in column 2. This results in an average payment lead of 167 days, which was applied to the pro forma pension expense derived from Schedule D-9, page 75, line 13 and shown on Schedule C-4, page 28, line 7.

34. Q. How did you develop the lag days associated with the purchased energy costs shown on line 14 of Schedule C-4, page 36?

A. Effective January 1, 2011, PECO started to purchase power for its default service customers through a Supply Master Agreement. To calculate its CWC requirements, the Company determined, on a monthly basis for the FPFTY, the number of days between the mid-point of the applicable service month and the

payment date, which is estimated to be the first business day after the 19th calendar day of the following month. This procedure yields a composite expense lag of 35.79 days, as shown on Schedule C-4, page 36, line 14.

35. Q. Does the Company plan to purchase 100% of its energy requirements from contract suppliers?

A. No, it does not. Based on the Commission's Final Order in PECO's most recent default service proceeding (Docket No. P-2024-3046008), the Company purchases 1.0% of the energy requirements of its residential default service customers on the spot market and will continue to do so through May 31, 2029.

36. Q. Have you calculated a separate expense lag for spot market purchases?

A. Yes. The spot market purchases will be paid weekly, on Friday, for purchases made through the week ended the previous Tuesday. This results in a payment lag of 12.5 days, consisting of 3.5 days from the mid-point to the end of the seven-day service period, and nine days for the period between the end of the service period and the payment date. Since the payments will be made by wire transfer, the total lag days will be 12.5 as calculated on page 36, lines 16 to 24.

37. Q. Please address the transmission service charges paid to the PJM Interconnection LLC ("PJM") for transmission service provided by PJM.

A. PJM transmission service charges are paid on the same schedule as the spot market purchases. Consequently, the total lag days for PJM transmission service charges are also 12.5 days.

38. How was the expense lag of 37.64 days for POR payments determined?

A. PECO pays electric generation suppliers ("EGSs") 20 days after the billing date for commercial and industrial accounts and 25 days after the billing date for residential accounts. The weighted average payment lag for all accounts is 21.44 days, as shown on page 36, line 31. Bill processing takes one day (page 36, line 33), and there is an average of 15.21 days from the mid-point of a service period to the meter reading date (page 36, line 35). The total payment lag, therefore, is 37.64 days (page 36, line 37).

39. Q. Please describe how you determined the payment lag associated with other operating and maintenance expenses.

A. The average payment lag for all remaining expenses, as set forth on lines 22 to 27 of Schedule C-4, page 30, was derived from data for the four months shown in detail on Schedule C-4, page 31. More specifically, the Company obtained a listing of all cash disbursements during each of the four months displayed in a format that shows the payee, the date of service or the invoice receipt date, the amount of the disbursement, the date the payment cleared the bank, the account to which the disbursement was charged and certain other data. Each month contains thousands of cash disbursements.

40. Q. How did you utilize the data?

A. I used the data in the column showing the number of days it took each disbursement to clear the bank from the invoice receipt date or service date to calculate the dollar days (the amount of the disbursement times the number of days the payment took to clear the bank) and sorted the disbursements by amount. I then eliminated

disbursements that should not be included in a CWC calculation or that are included elsewhere in the CWC calculation.

41. Q. What disbursements did you eliminate from the balances used on page 31 of Schedule C-4?

A. First, I eliminated all disbursements related to capital charges because they are not part of the Company's claimed operating expenses. Second, I eliminated all disbursements under $1,000 since those amounts, while significant in number, would not have a meaningful impact on the overall lag-day calculation. Third, I removed all commodity purchases since those are reflected in separate CWC calculations, as I previously described, and are recovered through a separate surcharge. Fourth, I removed all amounts charged to non-expense accounts and any charitable contributions. This process was completed for each of the four months shown on page 31, lines 1 to 11. The total cash disbursements for all four months of $106.4 million, as shown in column 2, on line 14, of page 31 of Schedule C-4, and the related dollar-days of $4.6 billion, shown in column 3, were used to calculate the payment lag for general expenses of 43.21 days shown in column 4. The 43.21 lag days for Other Disbursements were then brought forward to Schedule C-4, page 28, line 12.

42. Q. Describe what is shown on Schedule C-4, page 32.

A. This page shows the calculation of the net payment lag days for the tax expense components of PECO's CWC allowance. The first two columns, which are not numbered, identify the type of tax and show the applicable payment schedule for each tax. The payment dates are shown in column 1. The payment lead or (lag)

from the mid-point of the year is shown in column 3. The pro forma amount of the payment for each tax is shown in column 4. For example, the pro forma Federal income tax amount, based on the Company's proposed revenue level, is $72.8 million, as shown in column 4, line 1 through 4. The required amounts are shown by payment date for each tax in column 6. The weighted lead (lag) amount for each payment for each tax is calculated in column 7. The weighted lead (lag) days are netted against the revenue lag days shown on page 33, column 4. The net payment lag shown on page 33, column 5, is used to calculate the average daily amount for working capital shown on page 33, column 7. The net total of the amounts in column 7 is shown on Schedule C-4, page 28, column 2, line 30.

43. Q. Please describe the calculation of the interest expense lag shown on page 34 and included on page 28 of Schedule C-4.

A. This calculation measures the lag associated with the semi-annual payment of interest on outstanding debt. The pro forma interest expense is the amount resulting from the synchronized interest calculation using the pro forma measures of value and the weighted cost of debt included in PECO's requested rate of return. The daily interest expense amount, calculated on line 6, is multiplied by the net payment lag of 33.65 days for a reduction to the working capital allowance of $22.5 million, as shown on line 10 and on page 28 at line 31.

44. Q. Please explain how the average prepayments of $8.4 million shown on Schedule C-4, page 28, line 29, were determined.

A. Page 35 of Schedule C-4 shows the calculation of the average prepaid expenses included in the CWC. The Company reviewed its prepaid accounts and selected

only those prepaid expenses that were related, in whole or in part, to its electric delivery operations. The resulting prepaid accounts are shown in columns 2 to 17. Where items related entirely to the electric operations, such as the PUC Assessment in column 6, the total and average monthly amount were charged entirely to electric distribution, as shown on line 17 in columns 2 to 10. Where the account related to both electric and gas operations, the total and average were distributed using an appropriate allocation factor that eliminates both gas-related expenses and non-jurisdictional expenses, as shown on line 17 in columns 11 to 14. Finally, where the prepaid expense is related to electric distribution and gas operations, a factor was used to isolate only electric distribution operations, as shown on line 17 in columns 15 to 17. The 13-month average for prepaid expenses for the electric distribution operations is $8.4 million as shown on line 25 of Schedule C-4, page 35 and on Schedule C-4, page 28, line 29.

45. Q. What is the total amount of CWC included in the claimed measures of value?

A. That amount is the $341.7 million shown on Schedule C-4, page 28, column 2, line 33, and on Schedule A-1, page 1, column 2, line 7.

E. Pension Asset

46. Q. Please describe Schedule C-5.

A. Schedule C-5 shows the calculation of the pension asset of $161.3 million (column 2, line 8) that the Company has included in measures of value. The pension asset represents the portion of the Company's net aggregate total of pension costs to be incurred at the end of the FPFTY, calculated in the manner required for ratemaking purposes, that was not, and will not be, recovered in operating expenses and was

also not, and will not be, capitalized to its plant accounts. This asset represents the difference between the manner in which pension expense is calculated for ratemaking purposes and the manner in which pension costs are determined for purposes of calculating the labor loading rate used to capitalize a portion of pension costs under applicable Generally Accepted Accounting Principles ("GAAP"). Specifically, for ratemaking purposes, consistent with Commission policy and practice, PECO has historically claimed for recovery its cash contributions to its pension fund, while GAAP requires pension costs to be determined on the basis of different rules, which are set forth in ASC 715. PECO must capitalize and include in its plant accounts an amount that is based on pension costs calculated on the basis of ASC 715. This means that the amounts that are assumed for ratemaking to be included in PECO's plant accounts (based on the application of a capitalization rate to the cash pension contribution) necessarily differ from the amounts that are actually capitalized by PECO by applying, as it must, GAAP rules.

Using the FPFTY ending December 31, 2027, as an example, as shown on Schedule D-9, PECO's total pension cash contribution will be $7.5 million, of which 76.67% is attributable to electric distribution operations. PECO's capitalization rate is 48.37%. Therefore, $2.8 million ($7.5 million x 76.67% x 48.37 %) was assumed to be capitalized and included in applicable plant accounts. However, in the FPFTY, as in each prior 12-month period, the amount PECO included in applicable plant accounts for capitalized pension costs was calculated on the basis of ASC 715, as GAAP and applicable financial reporting mandates require. For the FPFTY ending December 31, 2027, the pension cost actually

capitalized would be 6.1 million. As a consequence, there was a gap of ($3.1) million of pension costs. As shown on Schedule C-5, the pension asset balance at the end of the FPFTY will be $161.3 million for electric distribution operations.

47. Q. Why should the pension asset be included in PECO's rate base?

A. The pension asset reflects the difference between: (1) the amount of pension cost the Commission's assumes was included in PECO's plant accounts; and (2) the amount of pension costs actually included in PECO's plant accounts. That difference is $161.3 million. The pension asset, therefore, consists of $161.3 million of PECO-supplied capital that was actually contributed to PECO's pension fund and assumed for ratemaking purposes to be included in PECO's plant accounts, but was not recorded in PECO's plant accounts because GAAP rules will not allow it. PECO has included the pension asset in rate base in this case because, unless it is given rate base recognition, PECO will never recover the carrying costs it incurs on those PECO-supplied funds.

In addition, PECO's pension expense is reduced by the returns associated with the externally funded pension asset. Returns earned on pension assets within the pension fund remain within the fund, reduce pension contributions and costs on a going-forward basis, and, in that way, benefit customers.

48. Q. PECO previously proposed a pension asset in its last fully litigated base rate case at Docket No. R-2020-3018929 (the "2020 Gas Rate Case"). What was the disposition of the Company's proposal at that time?

A. PECO's pension asset proposal was opposed by the Commission's Bureau of Investigation and Enforcement and the Office of Consumer Advocate. In the 2020

Gas Rate Case, the Commission recognized the conceptual basis for including a pension asset in rate base due to the difference between the amounts the Commission assumes will be capitalized for ratemaking purposes and the amounts that are actually capitalized under GAAP rules that public companies must follow.[3] Nonetheless, the Commission concluded that excluding the pension asset from rate base in that case was a "better practice" that strikes an "appropriate balance" of company and customer interests.[4]

49. Q. Does recognition of a pension asset as PECO proposes in this case reasonably balance the Company's and customer interests as envisioned by the Commission in the 2020 Gas Rate Case?

A. Yes. PECO's proposal to include a pension asset in rate base necessarily requires the recognition (as a deduction from rate base) of any similarly calculated pension liability that could arise in the future. Thus, PECO's approach affords both the Company and customers an accurate accounting for actual costs, including the time value of money, in a manner that is both certain and timely. In contrast, the Commission's ruling in the 2020 Gas Rate Case disregards the impact of the time-value of PECO-supplied funds and, as such, either PECO or its customers could be experiencing an unjustified penalty or windfall at any given point in time. In short, the exclusion of PECO's pension asset from rate base again in this case would perpetuate an imbalance of customer and company interests.

[3] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021), p. 67.

[4] *Id.* at 68.

50. Q. What is the purpose of Schedule C-6?

A. Schedule C-6, page 38 shows the December 31, 2027 balance of ADIT that is deducted in determining the measures of value. The ADIT shown in column 6, line 22 of $812.8 million reflects the Federal income tax that must be deferred in compliance with the normalization provisions pertaining to the use of accelerated tax depreciation for Federal income tax purposes on test year plant balances and other tax-book timing differences that have been normalized. The accelerated tax depreciation used in the determination of taxable income for Federal and state income tax expense calculations is reflected on Schedule D-18. As discussed in the direct testimony of Company witness Marissa Humphrey (PECO Statement No. 3), the ADIT includes the deferred tax asset associated with the new corporate alternative minimum tax ("CAMT") implemented by the IRS beginning in 2023.

51. Q. Have you made an adjustment for the Federal income tax on CIAC?

A. It was not necessary to make a separate adjustment for CIAC. CIAC is treated as a capital contribution for ratemaking purposes but is treated as taxable income for Federal income tax purposes. PECO pays the Federal income tax due on CIAC in the year the CIAC is received and included in taxable income. The associated tax payment is recorded as a debit to the ADIT account, which normally carries a credit balance. Consequently, the net effect of the calculation of ADIT properly reflects the tax-book timing difference related to taxes paid on CIAC.

52. Q. What is the amount of ADIT used in the measures of value?

A. The amount for electric distribution operations is $812.8 million, as shown in column 6, line 22 of Schedule C-6, page 38 and on line 9 of Schedule A-1, in columns 2 and 4.

F. Customer Deposits

53. Q. Please explain how you determined the amount of customer deposits on Schedule C-7 that was deducted from the claimed measures of value on Schedule A-1.

A. The customer deposits shown on Schedule C-7, page 39, in column 4 (lines 1-13) reflect the month-end balances for the 13 months ended December 2025. The Company maintains a joint customer deposit account because many of its customers use both its electric and natural gas services. Total Company customer deposits were allocated between electric and gas operations based on electric and gas customer class revenues. Schedule C-7 shows the customer deposits related solely to the Company's electric distribution operations.

54. Q. Where are these amounts of customer deposits and interest shown?

A. The total of customer deposits for all classes of electric distribution customers is a deduction to measures of value of $66.9 million, as shown on Schedule C-7, page 39, line 17, and on Schedule A-1, line 10 of columns 2 and 4. The calculated interest expense related to these customer deposits of $3.3 million, as shown in Schedule D-12, is included in the Company's operating expenses as shown on PECO Exhibit MJT-1, Schedule D-3, page 51, column 16, line 94.

G. Common Plant

55. Q. What is shown on Schedule C-8?

A. This schedule shows the common plant, net of accumulated depreciation, included in the measure of value on Schedule A-1.

H. Customer Advances for Construction

56. Q. What is contained on Schedule C-9?

A. This schedule shows the average monthly balance of customer advances for construction of $10.5 million on line 19, which is deducted in calculating the measures of value on Schedule A-1, line 11, columns 2 and 4.

57. Q. How were the monthly balances determined?

A. The Company was able to identify the specific amounts attributable to its electric distribution operations based on a review of its accounting records.

I. Unamortized Prepaid BESS Lease Payment Balance

58. Q. Please describe Schedule C-10.

A. As explained by Mr. DeMott, PECO expects to collect $2.1 million in prepaid lease payments under the BESS Leasing Pilot Program and those payments will be amortized over ten years. The figure of $1.89 million shown on line 3 of Schedule C-10 reflects the unamortized balance of prepaid BESS lease payments as of December 31, 2027, which is deducted from the Company's measures of value.

J. Materials and Supplies

59. Q. Please describe Schedule C-11.

A. Schedule C-11 shows the derivation of PECO's claim for materials and supplies and undistributed stores expense. The materials and supplies balances in column 2

were specifically identified as electric distribution-related amounts and, therefore, 100% of those amounts is shown on line 22 in column 2. The undistributed stores expense shown in column 3 reflects amounts attributable to PECO's total utility operations and, therefore, the electric distribution allocation factor of 67.32% was applied to determine the 13-month average of monthly balances, as shown on line 22, in column 3. The claimed amount of $53.1 million reflected in column 4 is based on the 13-month average for the period ended December 31, 2025 and is shown on line 13, columns 2 and 4, of the measures of value on Schedule A-1.

K. ADIT – Regulatory Liability

60. Q. What is shown on Schedule C-12?

A. Schedule C-12 shows the calculation of excess ADIT that has been removed from the ADIT account and recorded as a regulatory liability.

61. Q. What is the Company's claimed measures of value in this proceeding?

A. PECO's claimed measures of value, or rate base, equals $10.95 billion, as shown on line 16 of Schedule A-1.

IV. REVENUES AND EXPENSES

62. Q. What is shown on Schedule D-1 of PECO Exhibit MJT-1?

A. Schedule D-1 is a summary income statement that depicts PECO's claimed electric revenues, expenses and taxes at present and proposed rate levels. The derivation of most of the individual line items will be discussed in connection with the remaining schedules in Section D. Schedule D-1 also shows the proposed revenue increase of $429.1 million on line 13 in column 3.

63. Q. What is the indicated net operating income at proposed rates?

A. As shown on Schedule D-1, column 4, line 30 and on Schedule A-1, column 4, line 26, that amount is $1.0 billion.

64. Q. Please describe Schedule D-2.

A. Schedule D-2 shows the derivation of the various line items on Schedule D-1, column 2. Schedule D-2 begins with the Company's budgeted revenues and expenses for its Pennsylvania jurisdictional electric operations for the FPFTY, in column 1, and then annualizes and/or normalizes those figures through adjustments summarized in column 2. The pro forma data in column 3 are summarized and brought forward to Schedule D-1 and used in the determination of the required revenue increase. The various revenue adjustments in column 2 are summarized on Schedule D-3 and listed by adjustment on Schedule D-5, and the expense adjustments are summarized on Schedule D-3 and described in more detail on the separate adjustment schedules beginning with Schedule D-6 and continuing through Schedule D-17.

65. Q. Please describe Schedule D-3.

A. Schedule D-3 summarizes the various adjustments that were made to the budgeted revenue and expense data to derive the pro forma amounts at present rates that appear in column 3 of Schedule D-2 and are included in the adjusted amounts that are carried forward to column 1 of Schedule D-3. The FPFTY budgeted amounts are shown in column 1 and the revenue adjustment totals are shown in columns 2 to 9. The various expense adjustments are reflected in columns 10 to 21. Each of the pro forma adjustments will be described in connection with the specific

schedule supporting the adjustment. The pro forma adjusted amounts for the FPFTY are shown in column 23.

66. Q. Please describe Schedule D-4.

A. Schedule D-4 contains four pages and presents a summary of the pro forma operating expenses shown on Schedule D-3 by FERC account.

A. Revenue Adjustments

67. Q. Please describe Schedule D-5.

A. Schedule D-5 presents a summary of the separate pro forma adjustments to revenue for the FPFTY. Each of these adjustments will be described in detail in connection with the separate calculation of the adjustment shown on Schedules D-5A to D-5H.

68. Q. How did you calculate the revenue adjustment shown on Schedule D-5A?

A. This adjustment annualizes distribution revenues for the projected number of customers at the end of the FPFTY. As shown on lines 1 to 5, for all customer classifications this calculation determines the pro forma test year distribution revenues, excluding reconcilable surcharges, at present rates for the FPFTY. The average distribution revenues on line 5 were divided by the average number of customers for the year included in the budget for the 12 months ending on December 31, 2027 on line 7 to determine the average distribution revenue per customer on line 9. The average distribution revenue, or margin, per customer for the FPFTY on line 9 was then multiplied by the difference between: (1) the average number of customers (line 7); and (2) the number of customers at the end of the FPFTY (line 11), which difference is shown on line 13, yielding additional revenue of approximately $2.8 million for the residential, residential heating and small

commercial and industrial customer classes, as shown on line 15 by customer classification. This pro forma adjustment is then reflected on Schedule D-5, page 60, column 2 by customer classification.

69. Q. Please describe the adjustment calculated on Schedule D-5B.

A. This adjustment annualizes the cost of the discounts provided to customers enrolled in PECO's Customer Assistance Program ("CAP") in the form of a bill credit, reflecting the number of CAP customers at the end of the FPFTY. As shown in line 8 of columns 2 and 3, the average CAP discount per CAP customer is determined by dividing the total budgeted CAP discount on line 1 by the average number of CAP customers shown on line 7. The average CAP discount per CAP customer is then multiplied by the difference between the FPFTY year-end CAP customers on line 10 and the average number of CAP customers shown on line 7. This yields a total increase in the CAP discount of $3.3 million, which is offset by an uncollectible accounts factor of 8.2% and CWC factor of 3.7% as shown on line 15. These offset factors are discussed in more detail by Company witness Joseph A. Bisti (PECO Statement No. 9). Thus, the total net increase of $2.9 million is shown on line 17, which is brought forward to column 3 in Schedule D-5.

70. Q. Please describe the adjustment on Schedule D-5C.

A. This adjustment shows the reductions in revenue that the Company expects to experience related to the reductions in load that the Company must achieve in order to comply with the energy efficiency and conservation provisions of Act 129 of 2008 ("Act 129"). The Company's implementation of its approved programs has yielded considerable benefits for customers by helping them to save energy and, in

some cases, to reduce demand. The energy savings, however, have caused and will continue to cause substantial reductions in the Company's distribution revenues. The Company is proposing to recognize those distribution revenue reductions by reducing budgeted FPFTY distribution revenues by the average of the projected incremental revenue losses to be experienced in 2028 over revenue losses included in the 2027 budget.

71. Q. What is the total amount of the pro forma revenue adjustment the Company is proposing?

A. As shown on Schedule D-5C, page 63, column 5, line 27, the Company is proposing a pro forma revenue adjustment to its FPFTY budgeted revenue of $5.0 million, which will allow the Company to recover its lost revenue for 2028 through the rates established in this proceeding.

72. Q. In your opinion, is it reasonable for PECO to request that these energy savings be recognized in the determination of its revenue requirement?

A. Yes, for primarily two reasons. First, Act 129 specifically contemplates that the Commission consider revenue reductions attributable to the mandated energy efficiency programs in establishing base rates. My adjustments are designed to achieve that end by setting rates based on sales levels that reflect the incremental lost revenues related to mandatory Act 129 usage reductions in 2028. Second, it would be unfair to require PECO to implement these programs, or be subjected to possible penalties for non-compliance with legislatively imposed energy-reduction goals, and then deny it rate recovery of the lost revenues, particularly given the tremendous benefits that inure to customers. This adjustment aligns the customer

and Company interests in promoting energy-conservation, providing significant savings to the customers and permitting PECO to recover lost revenues during the same period that the customers are receiving the benefits of reduced bills from the legislatively-mandated and Commission-approved programs.

73. Q. Please describe the adjustment shown on Schedule D-5D.

A. This adjustment removes the budgeted revenues associated with the recovery of costs associated with developing and implementing PECO's energy-efficiency and conservation programs. Act 129 allows such costs to be recovered through a separate Section 1307 reconcilable adjustment clause. PECO will continue to utilize its Energy Efficiency and Conservation Plan surcharge mechanism for the recovery of these costs in the future. Therefore, the associated surcharge revenues have been removed from base rate revenue.

74. Q. Please describe the adjustment shown on Schedule D-5E.

A. This adjustment shows the increase in revenue from customer pre-paid lease payments for the BESS Leasing Pilot Program, as described by Mr. DeMott in PECO Statement No. 11. The $210,000 shown in column 2, line 3, which is brought forward to column 6 in Schedule D-5, represents $2.1 million of estimated pre-paid lease payments amortized over the 10-year lease term.

75. Q. Please describe the adjustment shown on Schedule D-5F.

A. This adjustment normalizes revenue the Company budgeted for the FPFTY by increasing variable distribution service charge revenue to reflect an additional 0.25 days. The Company's budgeted revenue for the FPFTY is based on 365 days, reflecting the 28 calendar days in February 2027. This adjustment normalizes

revenue to reflect the average number of days in the month of February over a four-year cycle that includes one leap year. The customer charge revenue does not change irrespective of the number of days in a year and, therefore, is not adjusted in this schedule. Additionally, the classes have variable distribution service charges that apply to kilowatt hours of usage and, therefore, are sensitive to the number of days of usage in the test year. Line 1 of Schedule D-5F shows the non-customer and non-reconcilable surcharge distribution revenue for the classes for February 2025. Lines 2 and 4 show the number of days in February 2027 and the normalized number of days in that month over a four-year cycle. The difference is shown in line 5. The adjustment necessary to normalize revenues for 0.25 days is shown, by class on line 7.

76. Q. Please describe the adjustments for miscellaneous items shown on Schedule D-5H.

A. Schedule D-5-H includes two adjustments to refund or charge over or under-collection balances to customers. First, column 2, line 6 shows the refund amount of $876,000 associated with the final reconciliation of the Company's Incremental COVID-19-Related Uncollectible Expense Surcharge and column 2, line 12 reflects a $145,000 charge associated with the final reconciliation of the Company's Fiber Affiliate Revenue Surcharge. The total net refund amount of $731,000 (line 13), is amortized over a period of two years as shown on line 14, column 2, which results in a total estimated annual amortization amount for this case of approximately $366,000, as shown on line 15, column 2, which is brought forward to column 9 in Schedule D-5.

B. Operating Expense Adjustments

77. Q. Does the Company budget its operating expenses by FERC account?

A. No. As I mentioned previously, it does not. Rather, the Company budgets its operating expenses by cost element or business activity, such as payroll, employee benefits, and rent.

78. Q. How were the FPFTY data restated by FERC account for purposes of preparing the Company's supporting data in this case?

A. The amounts recorded in FERC accounts as of the end of the HTY were analyzed to develop a chart showing charges for each cost element within each FERC account in the transmission function, the distribution function, the Administration and General ("A&G") transmission function, the A&G distribution function and the A&G general function. After this process was completed, I then distributed the forecasted FPFTY charges by cost elements in those cost categories to the corresponding FERC accounts based upon the ratios experienced in the HTY. For example, I determined how much of the S&W expensed in the HTY was charged to each FERC account in the HTY distribution function and then distributed the FPFTY forecasted distribution S&W to distribution FERC accounts based on those ratios. This process was used for each cost category to transform the FPFTY expense forecast by cost element to a FERC-based forecast. This FERC-based forecast is brought forward to Schedule B-4.

79. Q. Why was it necessary to transform the FPFTY cost-category forecast to a FERC-account based forecast?

A. It was done for two reasons. First, the Company's annual reports to the Commission are presented on a FERC-account basis and, therefore, having the FPFTY forecast presented in the same format facilitates a comparison of the FPFTY forecast data to prior years' experience. Second, it was necessary to have the FPFTY data available by FERC account for use by Company witness Jiang Ding (PECO Statement No. 8) in the cost-of-service study.

80. Q. In your opinion, does this process result in a fair presentation of the Company's FPFTY forecast expenses by FERC account?

A. Yes, it does.

81. Q. Were each of the pro forma adjustments reflected on Schedule D-4 also assigned to the appropriate FERC accounts?

A. Yes, they were.

82. Q. Are the various pro forma expense adjustments presented on Schedule D-4 shown by the type of expense and also by the FERC account distribution?

A. Yes, they are. The expense categories are identified in the headers of the columns on Schedule D-4, and each adjustment is described in connection with a separate schedule showing its derivation. These adjustments are shown by FERC expense category on Schedule D-4 and also on the Section D summary schedules.

83. Q. Please describe Schedule D-6.

A. Schedule D-6 consists of four pages and shows the calculation of the FPFTY annualization adjustments for S&W. Pages 69 and 70 show the calculation of the

pro forma adjustments for overall S&W. Pages 71 and 72 contain the forecasted data for the FPFTY summarized by FERC account categories showing a total to be expensed of $179.5 million on page 72, column 1, line 72. Column 2 on pages 71 and 72 show the annualization adjustment of $7.8 million distributed to the FERC expense categories, while column 3 provides the pro forma amounts for S&W expense, which totals $187.3 million, as shown on page 72, column 3, line 72. The adjustment of $7.8 million is reflected on Schedule D-4, column 3.

84. Q. How was the annualization adjustment derived?

A. The calculation is shown on Schedule D-6, pages 69 and 70. The adjustment annualizes budgeted S&W expense to reflect the number of employees at the end of the FPFTY and certain wage increases to become effective during the FPFTY or shortly after the FPFTY. More specifically, I have annualized: (1) the 3.0% wage increase for union employees forecasted to be effective on January 1, 2027 (lines 7 to 9 in column 2); (2) the 3.0% wage increase for non-union employees forecasted to be effective on March 1, 2027 (lines 7 to 9 in column 3); (3) the projected 3.0% wage increase for union employees to be effective on January 1, 2028 (lines 13 to 15 in column 2); and (4) the projected 3.0% wage increase for non-union employees to be effective on March 1, 2028 (lines 13 to 15 in column 3).

85. Q. Please explain the adjustment shown on lines 6 to 10 of Schedule D-6, page 70.

A. This adjustment normalizes an estimated cash payment to be made to union employees in connection with the anticipated ratification of a new union contract later in 2026. The portion of the estimated payment that will be expensed ($1.303 million) was split between electric distribution, electric transmission and gas

operations, and the amount allocated to electric distribution operations $1.0 million was divided by six to reflect the estimated six-year term of the contract. The resulting amount of $167,000 shown in column 2, line 10, was added to the pro forma adjustment for S&W.

86. Q. Please explain the calculations shown on Schedule D-6, page 70, column 2, lines 15-19.

A. These calculations annualize an increase in the number of employees during the FPFTY. As shown in line 15, column 2, the projected number of Company employees at the FPFTY year-end is 2,441. The average number of employees during the FPFTY is projected to be 2,418, which is the figure that the Company used to develop the S&W in its budget which is shown in line 16, column 2. The detailed calculation of the average number of employees included in the budgeted expense level is shown on Schedule D-8, page 77, in lines 2 to 15. The increase in employees shown in Schedule D-6, page 70, line 17 was then multiplied by average annual S&W per employee shown in Schedule D-6, page 70, line, 18, to determine the total annualization adjustment to S&W of $1.8 million due to the increase in number of employees, as shown on Schedule D-6, page 70, line 19.

87. Q. What is the total pro forma adjustment for S&W expense for the FPFTY?

A. The total amount is $7.8 million, which is an increase of 4.34% from the Company's S&W budget for the FPFTY, as shown on Schedule D-6, page 70, lines 23 and 25.

88. Q. Please describe Schedule D-7 of PECO Exhibit MJT-1.

A. Schedule D-7 shows the adjustment to normalize rate case expense. The Company expended approximately $142,000 on this filing during the 12 months ended December 31, 2025 (line 4) and has budgeted an additional $3.106 million (line 9) during the 12 months ending December 31, 2026. This total, $3.2 million (line 11), is normalized over a period of two years, as shown on line 13, column 2, which results in a total estimated normalized annual cost for this case of approximately $1.6 million, as shown on line 14, column 2. Accordingly, an adjustment of $37,000 has been made to the Company's FPFTY budget amount, as shown on line 17, and the adjustment amount was brought forward to Schedule D-3, column 11, line 113.

89. Q. Please describe Schedule D-8 of PECO Exhibit MJT-1.

A. The bottom half of Schedule D-8 annualizes the non-pension employee benefits expense to reflect the full year's level of costs associated with the number of employees during the FPFTY. The annualization, reflecting an increase of $263,000 in non-pension benefit expense, was derived by using the increase in the number of employees, on line 22, and the budgeted average non-pension benefit expense per employee of approximately $11,000 on line 21.

90. Q. Please explain how you calculated the change in number of employees to a year-end level on Schedule D-8.

A. Line 15 shows the 12-month average of employees that is reflected in the Company's budget. I compared the 12-month average to the number of employees reflected in the budget to be employed on December 31, 2027. The difference is shown on line 16. Because the average and year-end employee numbers reflect

rounding to obtain the levels of full-time equivalent employees, the difference between those figures does not exactly match the figure on line 16.

91. Q. What is contained in PECO Exhibit MJT-1 Schedule D-9?

A. Schedule D-9 shows the calculation of the Company's claim for pension expense, which is based on a five-year average of actual and projected contributions to its pension plan. The portion of the pension cost assigned to electric distribution operating expense in the FPFTY is $3.0 million, as shown on line 13. Accordingly, an adjustment of ($3.1) million has been made to the Company's FPFTY budget amount, as shown on line 15, and the adjustment amount was brought forward to Schedule D-3, column 13, line 112.

92. Q. What is presented on Schedule D-10 of PECO Exhibit MJT-1?

A. Schedule D-10 calculates an adjustment to the Company's budgeted uncollectible accounts expenses. Lines 1 to 4 calculate net uncollectible accounts charged off, excluding CAP Pre-Program Arrearage ("PPA") write-offs, as a percentage of total tariff revenue, based on an average of annual data for the period of January 1, 2023 through December 31, 2025. That percentage was used to adjust the amount of uncollectible accounts expense in the budget to conform to the method historically used by the Commission for this expense. The resulting 1.1158% shown on line 4, column 7, of Schedule D-10 is applied to the pro forma revenues at present rates for the FPFTY to calculate the total pro forma amount for uncollectible accounts expense at present rates for the FPFTY of $58.7 million shown in column 8 on line 14. This is a net increase of $21.3 million, as shown on line 18 and brought forward to page 51 of Schedule D-3 (column 14, line 93). In addition, the 1.1158% write-

off rate is used in determining the level of uncollectible accounts expense at proposed rates, as shown in column 3 on line 19 of Schedule D-1.

93. Q. Please describe Schedule D-11.

A. Schedule D-11 calculates an adjustment for incremental costs incurred by the Company related to its request for Federal funding from the US Department of Energy's Grid Resilience and Innovation Partnerships program, as part of the Infrastructure Investment and Jobs Act ("IIJA"). The Company was selected to negotiate an award of up to $100 million under this program to support modernization of its grid. To date, PECO has received $4.7 million of total IIJA funding, of which $2.6 million is related to electric distribution operations. Schedule D-11, column 2, line 1 shows the incremental expense of $451,000 incurred in pursuing Federal funding under the IIJA for its electric distribution operations in years 2024 and 2025, which is amortized over two years to arrive at the annual amortization of $226,000, as shown on Schedule D-11, page 80, column 2, line 3. Accordingly, an adjustment of ($53,000) has been made to the Company's FPFTY budget amount, as shown on line 5, and the adjustment amount was brought forward to Schedule D-3, column 15, line 124.

94. Q. Please describe the pro forma adjustment on Schedule D-12.

A. The adjustment shown on Schedule D-12 captures the interest expense that the Company must pay on customer deposits. Since the average balance of customer deposits is a reduction to measures of value, the interest expense is included as a pro forma expense for the FPFTY. The interest for residential customer deposits was calculated using an annual rate of interest of 7.0% and a monthly rate of

0.583%. An annual rate of 3.5% (a monthly rate of 0.292%) was used for commercial and industrial customers. The total pro forma expense of $3.3 million is shown on Schedule D-12, line 33 and brought forward to Schedule D-3, page 51.

95. Q. Please describe the pro forma adjustment on Schedule D-13.

A. This adjustment shown on line 13 reflects an increase of $6.9 million to FPFTY budget expenses for storm damage restoration expenses. PECO is proposing, for ratemaking purposes, to normalize storm damage expense based on a five-year historical storm damage expense. A five-year average includes a period long enough to reflect appropriate levels of expense associated with normal storm events, including major storms, less the amounts related to extraordinary storm damage costs exceeding 5% of income as of the end of the HTY,[5] as shown on Schedule D-13A, line 1.

96. Q. Please describe the pro forma adjustment on Schedule D-13A.

A. In accordance with the Commission-approved settlement of the Company's last electric base rate case at Docket No. R-2024-3046931, PECO recorded $22.7 million of storm damage costs that the Company incurred in January 2024 to a regulatory asset. That regulatory asset also includes deferred amounts totaling $51.7 million related to damage from storm events that occurred in February 2025 and June 2025 as approved by the Commission at Docket Nos. P-2025-3054294

[5] General Instruction 7 of the Uniform System of Accounts states that utilities may treat as extraordinary those events that are of an "unusual nature and infrequent occurrence" that are "events…of significant effect which are abnormal and significantly different from the ordinary and typical activities of the company, and which would not reasonably be expected to recur in the foreseeable future." 18 CFR Pt. 101. The rule goes on to note that generally, an item should result in expenses totaling more than 5% of income to be treated as an "extraordinary item." *Id.*

and P-2025-3057123, respectively. Schedule D-13A includes an amortization to recover PECO's deferred storm damage costs over a five-year period.

97. Q. Please describe the pro forma adjustment on Schedule D-15.

A. As explained by Mr. Demott in PECO Statement No. 11, PECO proposes to invest $3 million in its BESS Leasing Pilot Program, which amounts to $200,000 in annual depreciation expense over the 15-year useful life of each system. The depreciation expense associated with the Company's BESS Leasing Pilot Program is not reflected in PECO's claims for annual depreciation for electric distribution and common plant developed in Schedule D-17. As such, Schedule D-15 includes an adjustment to recover annual deprecation associated with BESS installed by PECO pursuant to its proposed pilot program.

C. Taxes – Other Than Income Taxes

98. Q. Please describe Schedule D-16 of PECO Exhibit MJT-1.

A. Schedule D-16 contains three pages. Page 82 is a summary showing the budgeted amounts for the FPFTY (column 2) for the total Company, adjustments to eliminate the non-Pennsylvania jurisdictional amounts (column 3), the total pro forma adjustments (column 5), and the pro forma expenses claimed in this case (column 6). The calculations for payroll-related changes are made on Schedule D-16, page 83, while the changes in the gross receipts tax ("GRT") are shown on page 84. The increase in payroll taxes, shown on page 83, line 5, was calculated using the ratio of tax expense to payroll expense in the FPFTY forecast applied to the payroll tax expense for the FPFTY, which is an increase of $625,000. This amount is then reflected on page 82 in column 5, line 5. The adjustment to decrease GRT by $5.45

million shown on line 8, in column 5 of page 82, is calculated on page 84. Total pro forma taxes other than income are $254.4 million, as shown on Schedule D-16, page 82, line 10, column 6.

99. Q. Did you make an adjustment to recognize the additional GRT attributable to the revenue increase allowed by the Commission in this proceeding?

A. Yes. As will be described in connection with PECO Exhibit MJT-1, Schedule D-19, the incremental GRT is recovered through the application of the Gross Revenue Conversion Factor ("GRCF") used to determine the amount of revenue required to provide the increase in net income claimed by PECO.

D. Depreciation Expense

100. Q. What is shown on PECO Exhibit MJT-1, Schedule D-17, pages 85 to 93?

A. I described Schedule D-17 in detail earlier in my testimony. As I explained, Schedule D-17 shows the development of the Company's claims for annual depreciation for electric distribution and common plant. Schedule D-17 starts with the annual depreciation for electric distribution and common plant developed by Ms. Hufford and presented in PECO Exhibit MH-3. The adjustments set forth on Schedule D-17, in addition to allocating a portion of common plant to the Electric Division, annualize depreciation expense related to FPFTY additions to reflect a full year's depreciation for that plant. PECO's total depreciation expense annualization adjustment for the Company's electric distribution business is $27.3 million, which is the sum of the amounts shown on Schedule D-17, column 16, line 120.

E. Income Taxes

101. Q. Please describe the income tax calculation shown on PECO Exhibit MJT-1, Schedule D-18, pages 94 and 95.

A. This schedule calculates the pro forma income tax expense for the FPFTY at present and proposed rates, as set forth in columns 2 and 4, respectively. Line 1 shows the revenue at present rates, the revenue increase (with the related late payment charge increase) and revenue at proposed rates. Line 2 shows the total operating expenses at present rates, as well as changes related to the revenue increase and at the proposed rates from Schedule D-1. Line 3 shows the operating income before income taxes. Synchronized interest expense is calculated on lines 5 to 7 using the total measures of value for the FPFTY on line 5 and the weighted cost of debt calculated on Schedule B-7. The resulting interest expense on line 7 is used to reduce the taxable income to the amount shown on line 8.

In compliance with Commission practice, the difference between accelerated tax depreciation (line 10) and pro forma book depreciation (line 11) is used to adjust the state taxable income as shown on line 8 to reflect the fact that the effects of accelerated depreciation are flowed through for state income tax purposes. In addition, there are adjustments to other tax-book differences and flow-through amounts, as shown on lines 13 to 18. These adjustments result in the net reduction of state taxable income from line 8 to line 20. The statutory state income tax rate of 6.99% was used to determine the pro forma current state income tax expense shown on line 26. Federal income tax expense is calculated on lines 28 to 38 with a Federal corporate income tax rate of 21%. Line 43 shows the total current

State and Federal income tax expense before the amount for deferred income taxes is calculated. Lines 45 to 54 reflect the Federal and state deferred income taxes.

The total income tax expense before other adjustments is shown on line 56 at present and proposed rates in columns 1 and 3 respectively, including the flow-back of excess ADIT resulting from the lower Federal corporate income tax rate under the TCJA and from the reduction of the Pennsylvania CNI tax rate, as discussed above. The other adjustments include the amortization of ITC for electric distribution plant, including the portion of common plant allocated to electric distribution, as shown on line 59.

102. Q. Please explain the nature and calculation of the ITC amortization.

A. The ITC reflects tax credits used by the Company in years prior to 1987, the amortization of which will not have been completed by the end of the FPFTY. While the availability of the ITC ended in 1987, the credit has been amortized over the useful lives of the assets that generated it. The amortization for the FPFTY ending December 31, 2027 reduces income tax expense at both present and proposed rates, shown on Schedule D-18, page 95.

103. Q. Please explain the adjustment to flow-back excess ADIT.

A. As I previously explained, the TCJA reduced the Federal corporate income tax rate from 35% to 21% effective January 1, 2018, and the Company's ADIT balances as of December 31, 2017 reflect taxes that were deferred at the higher corporate income tax rates in effect prior to January 1, 2018. PECO has recorded excess ADIT in a regulatory liability account. For ADIT that relates to tax-book timing differences associated with utility plant subject to the normalization requirements

of the Internal Revenue Code, PECO is required to flow back the difference between its ADIT balance and what its ADIT balance would have been if the deferrals had been made at the current 21% corporate tax rate (excess ADIT) over the remaining lives used in its books of account for the property that gave rise to the reserve for deferred taxes. The Company used the Average Rate Adjustment Method, as defined by applicable IRS regulations, for this purpose. Shorter flow-back periods are permissible for property that is not subject to normalization requirements. Schedule D-18, page 98, line 49, reflects the annual amount of the regulatory liability to be flowed back. As I explained earlier, for the excess ADIT resulting from changes to the Pennsylvania CNI tax rate, the Company made a reclassification of ADIT to excess ADIT at the end of 2022 based on the CNI tax rate of 4.99% in year 2031. The Company has been utilizing its State Tax Adjustment Clause to pass through the impact to customers since the beginning of 2023. Schedule D-18, page 95, line 50 reflects the annual amount of the regulatory liability to be flowed back to customers over a period of nine years.

104. Q. What is PECO's total income tax expense claim in this proceeding?

A. As shown on Schedule D-18, page 95, line 61, column 2, pro forma income tax benefit at present rates equals $17.5 million. The increment for income tax expense associated with the proposed revenue increase is shown in column 3, in the amount of $105.8 million, and the total pro forma income tax expense at proposed rates of $123.3 million is shown in column 4.

105. Q. Please explain Schedule D-19.

A. This schedule shows the calculation of the GRCF used on Schedule A-1 to determine the revenues required to achieve the overall rate of return requested by PECO. The conversion factor captures the additional late payment revenue, uncollectible accounts expense, GRT, regulatory fees, and Federal and state income taxes attributable to the additional revenues resulting from the proposed rate increase.

V. FUTURE TEST YEAR AND HISTORIC TEST YEAR

106. Q. Please describe the process used to prepare the pro forma FTY and HTY presentations in PECO Exhibit MJT-2 and PECO Exhibit MJT-3, respectively.

A. The basic process was the same as described in connection with PECO Exhibit MJT-1, except I used budgeted data for the FTY and actual recorded data for the HTY as the starting point for each exhibit. As with the FPFTY, I reviewed the budgeted data for the FTY and recorded data for the HTY and, where appropriate, made pro forma adjustments. In addition, I used data from PECO Exhibit MJT-1 as the basis for several of the pro forma amounts used in PECO Exhibits MJT-2 and MJT-3.

107. Q. What assumptions did you make to determine what pro forma adjustments would be necessary for the FTY and HTY?

A. I included pro forma adjustments that reflected the annualization and normalization of FTY and HTY elements and adjustments for future events that have impacted the FPFTY. For example, I have annualized S&W expense for increases and

adjusted for the year-end number of employees, as I did in the FPFTY. The pro forma adjustments for the FTY and HTY are numbered consistently with the adjustments for the FPFTY. For example, the adjustment for S&W is on Schedule D-6 in all three test years to facilitate reference between the FPFTY, the FTY and the HTY. Where there is no adjustment required for the FTY or the HTY, the correlation simply shows that further adjustment is not applicable.

108. Q. Referring now to PECO Exhibit MJT-2, for the FTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 15, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 17 to 32, and the revenue increase required on lines 34 to 45.

109. What is contained on Schedules B-1 to B-5?

A. These schedules contain budgeted financial data for the FTY, with the separation of the total electric operating income statement into non-Pennsylvania and Pennsylvania jurisdictional amounts.

110. Please describe Schedules B-6 and B-7.

A. These two schedules contain the FTY pro forma capital structure and rate of return. As shown on lines 1 to 6 of Schedule B-7, the Company is using its expected capital structure at the end of the FTY and cost rates, as shown on Schedule B-7.

111. Q. Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the FTY is $9.96 billion, as shown on column 4, line 13.

112. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of six pages and shows the utility plant-in-service balances on December 31, 2021 for the Company's electric distribution operations, as well as the additions, retirements and adjustments for the FTY. Pages 20 to 22 contain the summary of pro forma plant-in-service balances by plant grouping and reflects adjustment to plant. Page 17 shows the plant-in-service by FERC accounts. Pages 18 and 19 show the additions to plant and retirements from plant during the FTY. The total pro forma plant-in-service at the end of the FTY is $12.0 billion and is shown on Schedule C-2, page 17, column 4, line 51.

113. Q. Please describe Schedule C-3.

A. Schedule C-3 contains five pages and shows the accumulated depreciation on December 31, 2026. These pages show the pro forma balances by FERC account developed using the same procedures employed for the FPFTY. The accumulated depreciation at the end of the FTY is $2.1 billion, as shown on page 23, column 4, line 52.

114. Q. What is contained in Schedule C-4?

A. Schedule C-4 consists of nine pages that show the calculation of the CWC allowance for the FTY of $331.1 million on page 28, line 33. The information for average prepayments on line 29 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the 13-month average for the period ended December 31, 2025. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, commodity purchases and other disbursements utilized in PECO Exhibit MJT-1 were also used

in the FTY calculation. Page 28 provides a summary of the calculations for each of the elements of the CWC for the FTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest and preferred dividends are the pro forma amounts for the FTY, while the prepayment amount is the 13-month average of month-end balances through December 31, 2025. The resulting $331.1 million of CWC shown on line 33 is brought forward to Schedule A-1 in the calculation of the measures of value.

115. Q. Please describe pages 29 to 36 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the FTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the FTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same as those described in connection with the corresponding PECO Exhibit MJT-1 schedules.

116. Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the Company's claim for a pension asset to be included in the measures of value. The procedures to determine the asset are the same as those described with respect to PECO Exhibit MJT-1, Schedule C-5, except that the pension asset balance for the FTY reflects data through December 31, 2026, which, on a net aggregate basis, is $163.2 million, as shown on line 7.

117. Q. Please describe the calculations on Schedule C-6.

A. These calculations show the ADIT for the FTY. The procedures followed to determine FTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY except that year-end December 31, 2026 balances were used. The resulting ADIT of $734.8 million for the total of electric distribution utility plant and the electric distribution portion of the common plant for the FTY is shown on line 13. As shown on Schedule C-12, line 9, $271.1 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

118. Q. Please describe the data presented on Schedules C-7, C-9, and C-11.

A. The data on these three schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1, since the same 13-month period was used.

119. Q. Please describe the calculation of common plant shown on Schedule C-8.

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the FTY.

120. Q. What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the FTY, the pro forma revenue deficiency, and the pro forma required revenue level.

121. Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenues and expenses budgeted for the FTY, pro forma adjustments, and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5

and explained in connection with other supporting schedules to be described later in my testimony.

122. Q. Please describe Schedule D-3.

A. Schedule D-3 contains nine pages which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes-other-than-income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

123. Q. What is contained in Schedule D-4?

A. This schedule contains four pages and shows the budgeted and pro forma adjustment amounts for the FTY by revenue category and by FERC account for expenses.

124. Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the FTY budgeted revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5H. All of these adjustments were prepared using the same methodology as described in connection with PECO Exhibit MJT-1.

125. Q. Please describe the adjustment shown on Schedule D-5A.

A. The adjustment shown on Schedule D-5A annualizes revenues for customer growth during the FTY. The process utilized is the same as described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

126. Q. What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the FTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on Schedule D-5B of PECO Exhibit MJT-1.

127. Q. Please describe the adjustment shown on Schedule D-5C.

A. This adjustment reflects the average of the revenue losses associated with the load reductions mandated by Act 129. The Company is using the same calculation for the FTY that was used for the corresponding adjustment for the FPFTY.

128. Q. Please describe the adjustment shown on Schedule D-5D.

A. Similar to Schedule D-5D of PECO Exhibit MJT-1, this schedule removes the Energy Efficiency and Conservation program costs and related cost recovery that was included in the Company's FTY budget. The Company will continue to use the approved surcharge mechanism to recover its Energy Efficiency and Conservation program related costs and, as consequence, the costs and revenues related to the surcharge are properly removed from base rate revenue and base rate revenue requirement.

129. Q. Please describe the adjustment shown on Schedule D-5F.

A. This schedule shows the development of a normalized level of distribution revenue based on the average number of days per year in a four-year cycle.

130. Q. Please describe the adjustment shown on Schedule D-5H.

A. This schedule reflects the refund associated with the final reconciliation of the Company's Incremental COVID-19-Related Uncollectible Expense Surcharge and

the charge associated with the final reconciliation of the Company's Fiber Affiliate Revenue Surcharge.

131. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the FTY. Pages 71 and 72 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category. Pages 69 and 70 show the calculation of the annualization adjustments of S&W, the normalization of the union contract ratification payment and a one-time labor cost increase, which follow the same procedures described in connection with the FPFTY using the data from FTY for the wage increases.

132. Q. What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

133. Q. Please describe the adjustment shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the FTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

134. Q. Please describe the adjustment shown on Schedule D-9.

A. This adjustment for pension expense and to annualize non-pension benefits follows the same procedures used for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-9.

135. Q. Are the adjustments shown on Schedules D-10 to D-13 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

136. Q. Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the FTY.

137. Q. Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant amounts at the end of the FTY, similar to the pro forma adjustment described in connection with the pro forma adjustment in PECO Exhibit MJT-1.

138. Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the FTY reflecting the revenues, expenses and measures of value included in the pro forma present rate data for the Company and a 21% Federal corporate tax rate. In addition to the tax depreciation amounts, the ITC amortization was calculated, as shown on pages 94 and 95 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 61 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

139. Q. Referring now to PECO Exhibit MJT-3, for the HTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 15, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 17-32, and the revenue increase required on lines 34-45.

140. Q. What is contained on Schedules B-1 to B-5?

A. These schedules contain recorded financial data for the HTY, with the separation of the total electric operation income into non-Pennsylvania and Pennsylvania jurisdictional amounts.

141. Q. Please describe Schedules B-6 and B-7.

A. These two schedules contain the pro forma capital structure and rate of return used for the HTY. As shown on lines 1 to 6 of Schedule B-7, the Company is using its capital structure at the end of the HTY and cost rates as shown on Schedule B-7.

142. Q. Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the HTY is $9.1 billion, as shown on column 4, line 13.

143. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of six pages and shows the utility plant-in-service balances on December 31, 2025 for the Company's distribution operations, as well as the adjustments for the HTY. Pages 20 to 22 contain the summary of pro forma plant-in-service balances by plant grouping. Page 17 shows the plant-in-service by FERC account. Pages 18 and 19 are left blank intentionally because they reflect schedules that are used for the FTY and FPFTY but are not relevant to the HTY. Finally,

adjustments to plant are reflected on pages 20 to 22 of Schedule C-2. The total pro forma plant-in-service at the end of the HTY is $11.1 billion and is shown Schedule C-2, page 17, column 4, line 52.

144. Q. Please describe Schedule C-3.

A. Schedule C-3 contains five pages and shows the accumulated depreciation on December 31, 2025. These pages show the pro forma balances by FERC account following the same procedures employed for the FPFTY. The accumulated depreciation at the end of the HTY is $2.1 billion, as shown on page 23, column 4, line 52.

145. Q. What is contained in Schedule C-4?

A. Schedule C-4 consists of nine pages that show the calculation of the CWC allowance for the HTY of $290.4 million on page 28, line 33. The information for average prepayments on line 29 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the 13-month average for the period ended December 31, 2025. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, commodity purchases, and other disbursements utilized in PECO Exhibit MJT-1 were also used in the FTY calculation.

Page 28 provides a summary of the calculations for each of the elements of the CWC for the HTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest and preferred dividends are the pro forma amounts for the HTY, while the prepayment amount is the 13-month average of month-end balances through December 31, 2025. The resulting

$290.4 million of CWC shown on line 33 is brought forward to Schedule A-1 in the calculation of the measures of value.

146. Q. Please describe what is shown on pages 29 to 36 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the HTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the HTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same and were described in connection with the corresponding schedules in PECO Exhibit MJT-1.

147. Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the Company's claim for a pension asset included in the measures of value. The procedures to determine the asset are the same as those described in connection with PECO Exhibit MJT-1, Schedule C-5, except that the pension asset balance for the HTY reflects data through December 31, 2025, which, on a net aggregate basis, is $163.7 million, as shown on line 5.

148. Q. Please describe the calculations shown on Schedule C-6.

A. These calculations show the ADIT for the HTY. The procedures followed to determine HTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY, except that year-end December 31, 2025 balances were used. The resulting ADIT of $563.0 million for the total of electric distribution plant and the electric distribution portion of common plant for the HTY is shown on line 6.

As shown on Schedule C-12, line 3, $274.1 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

149. Q. Please describe the data presented on Schedules C-7, C-9, and C-11.

A. The data on these three schedules are the same as the data presented and described in connection with PECO Exhibit MJT-1, because the same 13-month period was used.

150. Q. Please describe the calculation of common plant shown on Schedule C-8.

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the FTY.

151. What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the HTY, the pro forma revenue deficiency and the pro forma required revenue level.

152. Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenue and expenses for the HTY, pro forma adjustments and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

153. Q. Please describe Schedule D-3.

A. Schedule D-3 contains nine pages, which provide a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes other than income taxes. Each of the adjustments will be

described in connection with the specific schedule containing the calculation of the adjustment.

154. Q. What is contained in Schedule D-4?

A. This schedule contains four pages and shows the recorded amounts and pro forma adjustment amounts for the HTY by revenue category and by FERC account for expenses.

155. Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the HTY revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5H. All of these adjustments were prepared using the same methodology described in connection with PECO Exhibit MJT-1, except Schedule D-5H, which is the weather normalization adjustment to distribution revenue recorded in 2025.

156. Q. Please describe the adjustment shown on Schedule D-5A.

A. This adjustment on Schedule D-5A annualizes revenues for customer growth during the HTY. The process utilized is the same as that described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

157. Q. What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the HTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on PECO Exhibit MJT-1, Schedule D-5B.

158. Q. Please describe the adjustment shown on Schedule D-5C.

A. This adjustment reflects the average of the revenue losses associated with the load reductions mandated by Act 129. The Company is using the same calculation for the HTY that was used for the corresponding adjustment for the FPFTY.

159. Q. Please describe the adjustment on Schedule D-5D.

A. Similar to the comparable schedule in PECO Exhibit MJT-1, Schedule D-5D removes the Energy Efficiency and Conservation program-related costs and cost recovery that was recorded in the HTY. The Company will continue to use the Commission-approved surcharge mechanism to recover Energy Efficiency and Conservation program related costs.

160. Q. Please describe the adjustment on Schedule D-5F.

A. This schedule shows the development of a normalized level of distribution revenue based on average number of days per year in a four-year cycle, which I previously explained.

161. Q. Please describe the adjustment shown on Schedule D-5G.

A. Schedule D-5G shows the adjustment to normalize HTY distribution revenue to reflect normal weather for weather sensitive load as discussed by Company witness John Coursey in PECO Statement No. 5. This adjustment does not apply to the FTY and the FPFTY because the distribution revenue for both of those years was budgeted on the basis of normal weather.

162. Please describe the adjustment shown on Schedule D-5H.

A. This schedule reflects the refund associated with the final reconciliation of the Company's Incremental COVID-19-Related Uncollectible Expense Surcharge and

the charge associated with the final reconciliation of the Company's Fiber Affiliate Revenue Surcharge.

163. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the HTY. Pages 71 and 72 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category. Pages 69 and 70 show the calculation of the annualization adjustments of S&W, the normalization of the union contract ratification payment and a one-time labor cost increase, which follow the same procedures described in connection with the FPFTY using the data from the HTY for the wage increases.

164. Q. What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

165. Q. Please describe the adjustments shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the HTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

166. Q. Please describe the adjustment on Schedule D-9.

A. This adjustment to pension expense in the HTY follows the same procedures used for the FPFTY, which were described in connection with PECO Exhibit MJT-1, Schedule D-9.

167. Q. Are the adjustments on Schedules D-10 to D-13 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

168. Q. Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the FTY.

169. Q. Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant balances at the end of the HTY, similar to the pro forma adjustments described in connection with the comparable schedules in PECO Exhibits MJT-1 and MJT-2.

170. Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the HTY reflecting the Company revenue, expenses and measures of value included in the pro forma present rate data and a 21% Federal corporate tax rate. In addition to the tax depreciation amount, ITCs were calculated for electric operations, as shown on pages 94 and 95 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 61 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

VI. STORM RESERVE ACCOUNT

171. Q. What level of storm damage expenses is recovered in PECO's base rates?

A. Since its first electric base rate case following restructuring in 2010, the Company has normalized storm damage expense based on a five-year historical average of actual storm damage expense consistent with prior Commission practice. This means that PECO recovers only a "normal" level of storm damage expense through base rates. Stated another way, base rates are not designed to reflect experience that deviates materially from a historically derived baseline of "normal" storm damage expense. As a result, base rates may reflect more than actual costs in a given year with a lower than "normal" level of storm activity. On the other hand, higher than "normal" levels of storm activities are not reflected in the level of expense recovered in base rates. When the Company and other utilities experience extraordinary storm damage expenses, they can petition the Commission for approval to defer those expenses for accounting purposes.

172. Q. Has the Company's experience with storms changed since PECO began using a five-year average to normalize storm damage expense in 2010?

A. Yes. Over the last 15 years, severe weather events have become more common in PECO's service area, such as Superstorm Sandy (2012), Winter Storm Nika (2014), Nor'easter Riley/Quinn (2018), Tropical Storm Isaias (2020), derechos (2020), and severe thunderstorms, heavy rain and/or high winds (2024 and 2025). In the first half of 2025 alone, PECO experienced two major events affecting close to 590,000 customers. As a result, PECO submitted two petitions for deferral of extraordinary

storm expenses in 2025, each of which was granted. Prior to 2025, PECO had not made a single petition for deferral of storm damage expenses.

In addition, PECO's service area has also experienced a rise in the number of storms. In the last five years, PECO experienced 101 significant storms impacting nearly 2.7 million customers, none of which individually met the Commission's requirement for exclusion from the calculation of reliability performance indices (affecting 10% of customers).

173. Q. Please describe the Company's request to establish a tracker and deferral account for storm damage expenses.

A. As evidenced by the pattern and levels of annual storm damage expense over the past 15 years shown on Exhibit MJT-4, PECO has experienced increasing volatilities in frequency, severity and duration of weather events that are outside the Company's control. Due to the volatility in weather events from year to year, actual storm damage expense can be notably lower or higher than the amounts reflected in PECO's base rates. Therefore, PECO is asking for Commission permission to defer and record any amounts above or below the Company's base rate allowance for storm damage expense to a Storm Reserve Account. Deferral accounting authorization is a fair way to ensure that PECO recovers its actual storm damage expenses – no more or less – and that customers are only paying for actual storm costs.

174. Q. What is the difference between the Storm Reserve Account and a rate adjustment clause established under Section 1307 of the Code?

A. Under the Storm Reserve Account proposed by PECO, the differences between the storm expenses included in the Company's rates and its actual storm expenses will be tracked and recorded in deferral accounts. The net balance in the accounts would represent a deferral – either as a regulatory liability or regulatory asset – that would be credited to, or recovered from, customers in a subsequent base rate case by means of an appropriate amortization. In contrast, a rate adjustment mechanism established under Section 1307 of the Public Utility Code typically involves billing customers a charge calculated to recover a projected annual cost. Annually (or more frequently), the amount billed to customers is reconciled to the utility's actual cost and the difference is either recovered from or refunded to customers through the experience or "E" factor of the formula for the rate adjustment clause. In that way, customer rates are periodically adjusted to reflect changes in actual costs and the reconciliation of prior period over or under-collections.

Under a rate adjustment clause, customer rates are subject to change between base rate cases. Under the deferred accounting mechanism, the Company is proposing for storm expenses, variations between projected and actual expenses to be recorded and deferred, but customer rates will not reflect the net impact of those variations until new rates are authorized in a future base rate case.

175. Q. Why is it appropriate for PECO to record the amount of storm damage expenses above or below the amount authorized in rates to the Storm Reserve Account between base rate cases?

A. The Commission regularly authorizes utilities to defer costs for accounting purposes arising from extraordinary and non-recurring events to provide the utility with an opportunity to claim those costs for recovery in a future rate proceeding. The Commission has granted petitions to defer storm damage expenses in recognition of the fact that this type of cost might evade legitimate recovery under typical ratemaking practices because storm damage expenses are not within the control of a utility and are difficult to project for purposes of prospective recovery in base rates.[6]

176. Q. How would the storm reserve accounting work?

A. Each month, the amount of storm damage expense included for recovery in base rates, excluding expenses related to damage from extraordinary storm events ("base level"), will be compared to the Company's actual monthly expense. In this case, the monthly amount for base level set forth in PECO Exhibit MJT-1, Schedule D-13, allocated to each month based on the total monthly retail distribution revenue in this proceeding. Actual storm costs, excluding expenses related to damage from extraordinary storm events, incurred above or below the base level will be credited or debited, as applicable, in the Storm Reserve Account on the Company's books for accounting purposes. In its next base rate case, the Company shall seek rate recognition of the net credit or debit balance in the Storm Reserve Account with

[6] *See*, *e.g.*, *Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Opinion and Order entered Apr. 23, 2014), pp. 15, 21-22.

interest, which will represent either a regulatory asset or regulatory liability as applicable, amortized over two years as either an increase or decrease, respectively, to storm damage expense. PECO's proposal for interest on any over- or under-recovery will protect customers from any timing deviation of the recovery and actual storm costs. Expenses related to damage from extraordinary storm events will be accounted for separately in accordance with the current practice of petitioning the Commission for approval to defer such expenses.

VII. CONCLUSION

177. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Michael J. Trzaska, hereby state that I am a Principal Regulatory and Rates Specialist for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 4 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Michael J. Trzaska

PECO Exhibit MJT-1:
Principal Accounting Exhibit
Fully Projected Future Test Year ending 2027

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
A-1 Overall Summary

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$13,154,586		$13,154,586
3	Accumulated Depreciation	C-3	2,223,678		2,223,678
4	Common Plant - Net of Accum Depr	C-8	620,339		620,339
5	Net Plant in service	L2 - L3 + L4	$11,551,247		$11,551,247
6					
7	Working Capital	C-1	$341,717		$341,717
8	Pension Assets / (Liability)	C-1	161,288		161,288
9	Accum Deferred Income Taxes	C-1	(812,801)		(812,801)
10	Customer Deposits	C-1	(66,853)		(66,853)
11	Customer Advances for Construction	C-1	(10,468)		(10,468)
12	Unamortized Payment for BESS	C-1	(1,890)		(1,890)
13	Materials and Supplies	C-1	53,088		53,088
14	Accum Deferred Income Taxes - Reg Liability	C-1	(263,652)		(263,652)
15					
16	TOTAL RATE BASE	SUM L5 to L14	$10,951,677		$10,951,677
17					
18	**OPERATING REVENUES AND EXPENSES**				
19	Base Customer Charges	D-5	$2,221,611	$429,106	$2,650,717
20	Electric Cost Revenue	D-5	$1,612,994		1,612,994
21	Other Operating Revenues	D-5	$53,936	1,486	55,422
22	Total Revenues	SUM L19 to L21	$3,888,542	$430,592	$4,319,134
23					
24	Operating Expenses	D-1	$3,279,289	$31,662	$3,310,951
25					
26	OIBIT	L22 - L24	$609,253	$398,930	$1,008,183
27					
28	Income Taxes @ Eff Inc Tax Rate	D-18	($17,483)		($17,483)
29	Income Taxes @ Statutory Rates	D-18		(105,805)	(105,805)
30					
31	NET OPERATING INCOME	SUM L26 to L29	$591,770	$293,125	$884,895
32					
33	RATE OF RETURN	L31 / L16	5.40%		8.08%
34					
35	**REVENUE INCREASE REQUIRED**				
36	Rate of Return at Present Rates	L33	5.40%		
37					
38	Rate of Return Required	B-7	8.08%		
39					
40	Change in ROR	L38 - L36	2.68%		
41					
42	Change in Operating Income	L16 * L40	$293,125		
43					
44	Gross Revenue Conversion Factor	D-19	1.464		
45					
46	Change in Revenues	L42 * L44	$429,106		
47					
48	**RETURN ON COMMON EQUITY**				
49	Common Equity Ratio	B-7	53.40%		
50	Common Equity Rate Base	L16 * L49	$5,848,195		
51	NET OPERATING INCOME	L31	$591,770		
52	Synchronized Interest Expense	D-18	$244,222		
53	NET OPERATING INCOME - COMMON EQUITY	L51 - L52	$347,548		
54	RATE OF RETURN ON COMMON EQUITY	L53 / L50	5.94%		

Line No.	Description	(1) Reference	(2) Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$23,169,467
3	Construction Work In Progress (107)		1,447,716
4	Total Utility Plant	L2 + L3	$24,617,183
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,226,843
6	Net Utility Plant	L4 - L5	$19,390,340
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,732
11	Invest in Assoc Company (123)		7,540
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$58,614
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$25,000
17	Customer Accounts Receivable (142)		678,393
18	Other Accounts Receivable (143)		32,249
19	Accum. Prov. for Uncollectible (144)		(137,955)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		1,710
22	Plant Materials & Supplies (154)		97,053
23	Gas Stored - Current (164.1		43,922
24	Liquefied Natural Gas stored (164.2)		3,187
25	Prepayments (165)		73,829
26	Accrued Utility Revenues (173)		324,703
27	Miscellaneous Current & Accrued Assets (174)		2,920
28	Total Current and Accrued Assets	SUM L16 to L27	$1,145,010
29			
30	**Deferred Debits**		
31	Unamortized Debt Expense (181)		$64,321
32	Other Regualtory Assets (182.3)		1,766,805
33	Miscellaneous Deferred Debits (186)		893,284
34	Unamortized Loss on Reacquired Debt (189)		487
35	Accumulated Deferred Income Taxes (190)		0
36	Total Deferred Debits	SUM L31 to L35	$2,724,897
37			
38	**TOTAL ASSETS**	L6+L13+L28+L36	$23,318,861

Line No.	Description	(1) Reference	(2) Total - PECO
39	**Proprietary Capital**		
40	Common Stock Issued (201)		$1,423,004
41	Preferred Stock Issued (204)		
42	Other Paid-In Capital (208-211)		4,980,451
43	Capital Stock Expense (214)		(87)
44	Retained Earnings (215, 215.2, 216)		2,946,157
45	Unappropriated Undistributed Subsidiary Earnings (216.1)		
46	Accum Other Comprehensive Income (219)		
47	Total Propriety Capital & Margins	SUM L40 to L46	$9,349,525
48			
49	**Long Term Debt**		
50	Bonds (221)		$7,975,000
51	Advances from Associated Companies (223)		184,419
52	Other Long-Term Debt (224)		
53	Unamortized Premium on LTD (225)		
54	Unamortized Discount on LTD (226)		(22,573)
55	Total Long-Term Debt	SUM L50 to L54	$8,136,846
56			
57	**Other Non-Current Liabilities**		
58	Obligations under Capital Leases (227)		
59	Accum. Prov for Injuries & Damages (228.2)		$62,513
60	Accum. Prov for Pensions & Benefits (228.3)		300,379
61	Accum. Miscellaneous Operating Prov (228.4)		11,729
62	Asset Retirement Obligation (230)		25,844
63	Total Other Non-Current Liabilities	SUM L58 to L62	$400,465
64			
65	**Current and Accrued Liabilities**		
66	Notes Payable (231)		$285,689
67	Accounts Payable (232)		784,359
68	Notes Payable to Assoc. Companies (233)		
69	Accounts Payable to Assoc. Companies (234)		25,774
70	Customer Deposits (235)		93,432
71	Taxes Accrued (236)		20,830
72	Interest Accrued (237)		107,630
73	Dividends Declared (238)		
74	Tax Collections Payable (241)		86
75	Misc Current & Accrued Liabilities (242)		156,513
76	Total Current & Accrued Liabilities	SUM L66 to L75	$1,474,315
77			
78	**Other Deferred Credits**		
79	Customer Advances for Construction (252)		$15,732
80	Other Deferred Credits (253)		8,645
81	Other Regulatory Liabilities (254)		564,296
82	Deferred Investment Tax Credit (255)		244
83	Unamortized Gain on Reacquired Debt (257)		
84	Accumulated Deferred Income Taxes (281-283)		3,368,794
85	Total Other Deferred Credits	SUM L79 to L84	$3,957,711
86			
87	**TOTAL LIABILITIES AND OTHER CREDITS**	L47+L55+L63+L76+L85	$23,318,861

			(1)	(2)	(3)
Line No.	Category	Description	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$2,068,118		$2,068,118
2		Electric Cost Revenue	1,612,994		1,612,994
3		Transmission - All Classes	241,020		241,020
4		Other Revenues	341,220	$287,649	53,571
5		Total Operating Revenues	$4,263,352	$287,649	$3,975,703
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,743,081	$100,297	$2,642,784
8		Depreciation & Amortization Expense	436,482	55,968	380,514
9		Amortization of Regulatory Expense	16,626		16,626
10		Taxes Other Than Income Taxes - Other	264,542	5,324	259,218
11		Total Operating Expenses	$3,460,730	$161,589	$3,299,142
12					
13	**Net Utility Operating Income Before Income Tax**		**$802,621**	**$126,060**	**$676,561**

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$1,159,793		$1,159,793
2			Residential - House Heating	440.1	224,225		224,225
3			C & I Small	442.0	372,296		372,296
4			C & I Large	442.1	275,702		275,702
5			Street Lighting	444.0	10,676		10,676
6			Railroads & Railways	446.0	25,425		25,425
7			Intercompany	448.0			
8			Transmission - All Classes		241,020		241,020
9			Sub-total - Customer & Distribution Revenues		$2,309,138		$2,309,138
10							
11		Electric Cost Revenue	Residential	440.0	$1,040,649		$1,040,649
12			Residential - House Heating	440.1	259,956		259,956
13			C & I Small	442.0	228,809		228,809
14			C & I Large	442.1	82,981		82,981
15			Street Lighting	444.0	600		600
16			Intercompany	448.0			
17			Sub-total - Electric Cost Revenue		$1,612,994		$1,612,994
18							
19		Other Operating Revenues	Forfeited Discounts	450.0	$18,527		$18,527
20			Miscellaneous Service Revenues	451.0	3,923		3,923
21			Rent For Electric Property	454.0	39,926	$12,218	27,708
22			Other Electric Revenues	456.0	3,413		3,413
23			Transmission of Electricity for Others	456.1	275,430	275,430	
24			Sub-total - Other Operating Revenues		$341,220	$287,649	$53,571
25							
26			**TOTAL OPERATING REVENUES**		$4,263,352	$287,649	$3,975,703

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
27							
28	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,513,792		$1,513,792
29			Operation & Supervision	560.0	9,382	$9,382	
30			Load Dispatching	561.0			
31			Scheduling, System Control & Dispatch	561.4	117,611		117,611
32			Transmission Service Studies	561.6	17,068	17,068	
33			Generation Service Studies	561.7			
34			Reliability, Planning & Standard Development	561.8	108,093		108,093
35			Station Expense	562.0	1,146	1,146	
36			Overhead Lines	563.0	453	453	
37			Underground Lines Expense	564.0			
38			Miscellaneous Expense	566.0	(4,727)	(4,727)	
39			Rents	567.0	14,156	14,156	
40			Maintenance of Structures	569.0	2,566	2,566	
41			Maintenance of Computer Hardware	569.1	120	120	
42			Maintenance of Computer Software	569.2	(1,123)	(1,123)	
43			Maintenance of Communication Equipment	569.3	120	120	
44			Maintenance of Station Equipment	570.0	261	261	
45			Maintenance of Overhead Lines	571.0	8,412	8,412	
46			Maintenance of Underground Lines	572.0	440	440	
47			Maintenance of Misc Transmission Plant	573.0	2,800	2,800	
48			Operation & Supervision	580.0	559		559
49			Load Dispatching	581.0			
50			Station Expenses	582.0	7,134		7,134
51			Overhead Lines Expenses	583.0	17,711		17,711
52			Underground Lines Expense	584.0	11,338		11,338
53			Meter Expenses	586.0	6,378		6,378
54			Customer Installations Expense	587.0	13,098		13,098
55			Miscellaneous Expense	588.0	89,315		89,315
56			Rents	589.0	4,105		4,105
57			Maintenance of Structures	591.0	7,189		7,189
58			Maintenance of Station Equipment	592.0	16,937		16,937
59			Maintenance of Overhead Lines	593.0	193,120		193,120
60			Maintenance of Underground Lines	594.0	35,822		35,822
61			Maintenance of Line Transformers	595.0	2,606		2,606
62			Maintenance of Street Lighting & Signal Systems	596.0	1,821		1,821
63			Maintenance of Misc. Distribution	598.0	17,497		17,497

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
64			Supervision	901.0			
65			Meter Reading	902.0	250		250
66			Customer Records and Collection	903.0	101,485		101,485
67			Uncollectible Accounts	904.0	37,384		37,384
68			Miscellaneous Customer Accounts	905.0	3,503		3,503
69			Customer Assistance	908.0	114,591		114,591
70			Informational & Instructional	909.0	2,438		2,438
71			Miscellaneous Customer & Informational	910.0	935		935
72			Demonstrating & Selling	912.0	714		714
73			Miscellaneous Sales	916.0			
74			Administrative and General Salaries	920.0	69,121	31,688	37,433
75			Office Supplies and Expenses	921.0	3,979	(294)	4,273
76			Administrative Expenses Transferred-Credit	922.0			
77			Outside Service Employed	923.0	113,185	11,847	101,338
78			Property Insurance	924.0	1,101	131	970
79			Injuries & Damages	925.0	18,553		18,553
80			Employee Pensions and Benefits	926.0	38,179	2,561	35,618
81			Regulatory Commission Expenses	928.0	11,137	1,324	9,813
82			Duplicate Charges-Credit	929.0	(1,150)	925	(2,075)
83			Miscellaneous General Expenses	930.2	1,863	377	1,487
84			Maintenance of General Plant	935.0	9,948		9,948
85			Sub-total - O&M Expenses		$2,742,417	$99,633	$2,642,784
86							
87		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$399,628	$51,345	$348,283
88				404.0	36,854	4,623	32,231
89			Sub-total - Depreciation & Amortization Expense		$436,482	$55,968	$380,514
90							
91		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3	$16,626		$16,626
92			Sub-total - Amortization of Regulatory Expense		$16,626		$16,626
93							
94		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$264,542	$5,324	$259,218
95			Sub-total -Taxes Other Than Income Taxes - Other		$264,542	$5,324	$259,218
96							
97			**TOTAL OPERATING EXPENSES**		$3,460,067	$160,925	$3,299,142
98							
99			**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**		**$803,285**	**$126,724**	**$676,561**
100							

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$1,159,793		$1,159,793
2			Residential - House Heating	440.1	224,225		224,225
3			C & I Small	442.0	372,296		372,296
4			C & I Large	442.1	275,702		275,702
5			Railroads & Railways	446.0	10,676		10,676
6			Street Lighting	444.0	25,425		25,425
7			Intercompany	448.0			
8			Transmission - All Classes		241,020		241,020
9			Sub-total - Customer & Distribution Revenue		$2,309,138		$2,309,138
10							
11		**Electric Cost Revenue**	Residential	440.0	$1,040,649		$1,040,649
12			Residential - House Heating	440.1	259,956		259,956
13			C & I Small	442.0	228,809		228,809
14			C & I Large	442.1	82,981		82,981
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	600		600
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,612,994		$1,612,994
19							
20			**TOTAL OPERATING REVENUE**		$3,922,132		$3,922,132
21							
22	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$18,527		$18,527
23			Miscellaneous Service Revenues	451.0	3,923		3,923
24			Sub-total - Other Operating Revenue		$22,450		$22,450
25							
26		**Other Electric Revenue**	Rent For Electric Property	454.0	$39,926	$12,218	$27,708
27			Other Electric Revenues	456.0	3,413		3,413
28			Transmission of Electricity for Others	456.1	275,430	275,430	
29			Sub-total - Other Electric Revenue		$318,770	$287,649	$31,121
30							
31			**TOTAL OTHER REVENUE**		$341,220	$287,649	$53,571
32							
33			**TOTAL REVENUE**		**$4,263,352**	**$287,649**	**$3,975,703**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
B-4 O+M Expenses

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,513,792		$1,513,792
2			**TOTAL POWER SUPPLY EXPENSES**		$1,513,792		$1,513,792
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$9,382	$9,382	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	117,611		117,611
7			Transmission Service Studies	561.6	17,068	17,068	
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	108,093		108,093
10			Station Expense	562.0	1,146	1,146	
11			Overhead Lines	563.0	453	453	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	(4,727)	(4,727)	
14			Rents	567.0	14,156	14,156	
15			Sub-total Transmission Operations	SUM L4 to L14	$263,183	$37,478	$225,704
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	$2,566	$2,566	
18			Maintenance of Computer Hardware	569.1	120	120	
19			Maintenance of Computer Software	569.2	(1,123)	(1,123)	
20			Maintenance of Communication Equipment	569.3	120	120	
21			Maintenance of Station Equipment	570.0	261	261	
22			Maintenance of Overhead Lines	571.0	8,412	8,412	
23			Maintenance of Underground Lines	572.0	440	440	
24			Maintenance of Misc Transmission Plant	573.0	2,800	2,800	
25			Maint Energy Storage Equipment & Structures	578.2	(6)	(6)	
26			Misc Distribution Expenses	588.0	(10)	(10)	
27			Maintenan Energy Storage Equipment	592.2	1	1	
28			Maintenance of Overhead Lines	593.0	679	679	
29			Sub-total Transmission Maintenance	SUM L17 to L28	$14,259	$14,259	
30							
31			**TOTAL TRANSMISSION EXPENSE**	L15 + L29	$277,442	$51,738	$225,704
32							
33	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$559		$559
34			Load Dispatching	581.0			
35			Station Expenses	582.0	7,134		7,134
36			Overhead Lines Expenses	583.0	17,711		17,711
37			Underground Lines Expense	584.0	11,338		11,338
38			Meter Expenses	586.0	6,378		6,378
39			Customer Installations Expense	587.0	13,098		13,098
40			Miscellaneous Expense	588.0	89,315		89,315
41			Rents	589.0	4,105		4,105
42			Sub-total Distribution Operations	SUM L33 to L41	$149,637		$149,637
43							
44		Distribution Maintenance	Maintenance of Structures	591.0	$7,189		$7,189
45			Maintenance of Station Equipment	592.0	16,937		16,937
46			Maintenance of Overhead Lines	593.0	193,120		193,120
47			Maintenance of Underground Lines	594.0	35,822		35,822

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
48			Maintenance of Line Transformers	595.0	2,606		2,606
49			Maintenance of Street Lighting & Signal Systems	596.0	1,821		1,821
50			Maintenance of Misc. Distribution	598.0	17,497		17,497
51			Sub-total Distribution Maintenance	SUM L44 to L50	$274,993		$274,993
52							
53			**TOTAL DISTRIBUTION EXPENSE**	L42 + L51	$424,631		$424,631
54							
55	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
56			Meter Reading	902.0	$250		$250
57			Customer Records and Collection	903.0	101,485		101,485
58			Uncollectible Accounts	904.0	37,384		37,384
59			Miscellaneous Customer Accounts	905.0	3,503		3,503
60			**TOTAL CUSTOMER ACCOUNTS**	SUM L55 to L59	$142,622		$142,622
61							
62	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$114,591		$114,591
63			Informational & Instructional	909.0	2,438		2,438
64			Miscellaneous Customer & Informational	910.0	935		935
65			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L62 to L64	$117,964		$117,964
66							
67	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$714		$714
68			Miscellaneous Sales	916.0			
69			**TOTAL SALES EXPENSE**	SUM L67 to L68	$714		$714
70							
71	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$69,121	$31,688	$37,433
72			Office Supplies and Expenses	921.0	3,979	(294)	4,273
73			Administrative Expenses Transferred-Credit	922.0			
74			Outside Service Employed	923.0	113,185	$11,847	101,338
75			Property Insurance	924.0	1,101	$131	970
76			Injuries & Damages	925.0	18,553		18,553
77			Employee Pensions and Benefits	926.0	38,179	$2,561	35,618
78			Regulatory Commission Expenses	928.0	11,137	$1,324	9,813
79			Duplicate Charges-Credit	929.0	(1,150)	$925	(2,075)
80			Miscellaneous General Expenses	930.2	1,863	$377	1,487
81			Sub-total A&G Operations	SUM L71 to L80	$255,969	$48,559	$207,410
82							
83		A&G Maintenance	Maintenance of General Plant	935.0	9,948		9,948
84							
85			TOTAL ADMINISTRATION & GENERAL	L81 + L83	$265,917	$48,559	$217,358
86							
87			**TOTAL O&M EXPENSE**	L2+L31+L53+L60+L65+L69+L85	**$2,743,081**	**$100,297**	**$2,642,784**
88							
89			TOTAL OPERATIONS EXPENSE		$2,453,828	$86,038	$2,367,791
90			TOTAL MAINTENANCE EXPENSE		289,253	14,259	274,993
91			**TOTAL O&M EXPENSE**	L89 + L90	**$2,743,081**	**$100,297**	**$2,642,784**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
B-4 O+M Expenses - A+G Detail

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$37,433	0.0000%		$37,433
2			Office Supplies and Expenses	921.0	4,273	0.0000%		4,273
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	101,338	0.0000%		101,338
5			Property Insurance	924.0	970	0.0000%		970
6			Injuries and Damages	925.0	18,553	0.0000%		18,553
7			Employee Pensions and Benefits	926.0	35,619	0.0000%		35,619
8			Regulatory Commission Expenses	928.0	9,813	0.0000%		9,813
9			Duplicate Charges-Credit	929.0	(2,075)	0.0000%		(2,075)
10			Miscellaneous General Expenses	930.2	1,486	0.0000%		1,486
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$207,410			$207,410
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,948	0.0000%		$9,948
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$217,358			$217,358
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	$31,688	100.0000%	$31,688	
17			Office Supplies and Expenses	921.0	(294)	100.0000%	(294)	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	11,847	100.0000%	11,847	
20			Property Insurance	924.0	131	100.0000%	131	
21			Injuries and Damages	925.0		100.0000%		
22			Employee Pensions and Benefits	926.0	2,562	100.0000%	2,562	
23			Regulatory Commission Expenses	928.0	1,324	100.0000%	1,324	
24			Duplicate Charges-Credit	929.0	925	100.0000%	925	
25			Miscellaneous General Expenses	930.2	376	100.0000%	376	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$48,559		$48,559	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0		100.0000%		
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$48,559		$48,559	
30								

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
B-4 O+M Expenses - A+G Detail

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0	($1)	12.5447%	($0)	($1)
32			Office Supplies and Expenses	921.0	0	12.5447%	0	0
33			Administrative Expenses Transferred-Credit	922.0		12.5447%		
34			Outside Service Employed	923.0		12.5447%		
35			Property Insurance	924.0		12.5447%		
36			Injuries and Damages	925.0		12.5447%		
37			Employee Pensions and Benefits	926.0	(1)	12.5447%	(0)	(1)
38			Regulatory Commission Expenses	928.0		12.5447%		
39			Duplicate Charges-Credit	929.0		12.5447%		
40			Miscellaneous General Expenses	930.2	1	12.5447%	0	1
41			Sub-total A&G Operations - General	SUM L31 to L40	($0)		($0)	($0)
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0		12.5447%		
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	($0)		($0)	($0)
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$69,121		$31,688	$37,433
47			Office Supplies and Expenses	921.0	3,979		(294)	4,273
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	113,185		11,847	101,338
50			Property Insurance	924.0	1,101		131	970
51			Injuries & Damages	925.0	18,553			18,553
52			Employee Pensions and Benefits	926.0	38,179		2,561	35,618
53			Regulatory Commission Expenses	928.0	11,137		1,324	9,813
54			Duplicate Charges-Credit	929.0	(1,150)		925	(2,075)
55			Miscellaneous General Expenses	930.2	1,863		377	1,487
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$255,969		$48,559	$207,410
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,948			$9,948
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	**$265,917**		**$48,559**	**$217,358**

Line No.	Description	Percentage	Total	Transmission Elimination	Distribution
		(1)	(2)	(3)	(4)
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$8,306	($1,443)	$6,863
2	Use Tax Accrued	17.372%	2,848	(495)	2,353
3	Real Estate Tax Accrued	17.372%	7,607	(1,321)	6,285
4	Miscellaneous TOTI	12.545%		-	
5	Payroll Tax Accrued	12.545%	16,456	(2,064)	14,392
6	Gross Receipt Tax		229,324		229,324
7	**Total**		**$264,542**	**($5,324)**	**$259,218**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%		
2					7.05%		0.35%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					0.92%		0.06%	
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%		
6					6.43%		0.32%	
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
8					3.68%		0.22%	
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
10					2.15%		0.12%	
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
12					3.06%		0.15%	
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%		
14					3.68%		0.16%	
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
16					3.98%		0.15%	
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%		
18					3.98%		0.16%	
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%		
20					3.98%		0.17%	
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
22					3.98%		0.12%	
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
24					4.29%		0.12%	
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%		
26					4.60%		0.14%	
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%		
28					4.60%		0.13%	
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%		
30					4.29%		0.20%	
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%		
32					5.21%		0.23%	
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%		
34					7.05%		0.38%	
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%		
36					6.43%		0.37%	
37		PECO - FMB - $750 - 5.80% - Due 8-1-56		750,000		5.87%		
38					9.19%		0.54%	
39		PECO - FMB - $750 - 5.90% - Due 8-1-57		750,000		5.97%		
40					9.19%		0.55%	
41								
42		Sub-total Mortgage Bonds	SUM L1 to L41	$7,975,000	97.74%		4.64%	
43								
44	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%		
45					0.99%		0.07%	
46		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%		
47					0.01%			
48		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
49					1.26%		0.07%	
50								
51		Sub-total Capital Securities	SUM L44 to L50	$184,419	2.26%		0.14%	
52								
53		Total Long-Term Debt	L42 + L51	$8,159,419	100.00%		4.78%	
54								
55		Adjustments for Tenders & Calls		(385)				
56								
57		Net Long-Term Debt	L53 + L55	$8,159,034				
58								
59		Annualized Cost		390,020				
60								
61		Adjustment for Tenders & Calls Reacquired		68				
62								
63		**Total**	L59 + L61	$390,088				**4.78%**

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$8,159,034	46.60%	4.78%	2.23%
3					
4	Common Equity	$9,349,525	53.40%	10.95%	5.85%
5					
6	Total	$17,508,559	100.00%		8.08%

Line No.	Description	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
		(1)	(2)	(3)	(4)
1	Utility Plant	C-2	$15,758,972	$2,604,386	$13,154,586
2	Accumulated Depreciation	C-3	2,960,813	737,135	2,223,678
3	Common Plant	C-8	620,339		620,339
4	**Net Plant in Service**	L1 - L2 + L3	$13,418,499	$1,867,251	$11,551,247
5					
6	Working Capital	C-4	$341,717		$341,717
7	Pension Assets / (Liability)	C-5	161,288		161,288
8	Accumulated Deferred Income Taxes	C-6	(812,801)		(812,801)
9	Customer Deposits	C-7	(66,853)		(66,853)
10	Customer Advances for Construction	C-9	(10,468)		(10,468)
11	Unamortized Payment for BESS	C-10	(1,890)		(1,890)
12	Material & Supplies	C-11	53,088		53,088
13	ADIT - Reg Liability	C-12	(263,652)		(263,652)
14	**Total Measures of Value**	SUM L4 to L13	**$12,818,928**	**$1,867,251**	**$10,951,677**

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	Adjusted FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$142
3		E303 - Misc Intangible Plant		6,914		6,914
4		Sub-total Intangible Plant	SUM L1 to L3	$7,077	$20	$7,056
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$92,459	$92,459	
7		E351.1 - Computer Hardware		11,615	11,615	
8		E351.2 - Computer Software		27,516	27,516	
9		E351.3 - Communication Equipment		31,961	31,961	
10		E352 - Structures and Improvements		295,182	295,182	
11		E353 - Station Equipment		1,218,185	1,218,185	
12		E354 - Towers and Fixtures		307,289	307,289	
13		E355 - Poles and Fixtures		45,534	45,534	
14		E356 - Overhead Conductors, Devices		267,055	267,055	
15		E357 - Underground Conduit		90,216	90,216	
16		E358 - Undergrnd Conductors, Devices		183,378	183,378	
17		E359 - Roads and Trails		2,668	2,668	
18		E359.1 - ARO Costs Transm Plt		875	875	
19		Sub-total Transmission Plant	SUM L6 to L18	$2,573,934	$2,573,934	
20						
21	**Distribution Plant**	E360 - Land and Land Rights		$56,497		$56,497
22		E361 - Structures and Improvements		319,617		319,617
23		E362 - Station Equipment		1,387,485		1,387,485
24		E363.1 - Computer Hardware		11,877		11,877
25		E363.2 - Computer Software		181,334		181,334
26		E363.3 - Communication Equipment		137,623		137,623
27		E364 - Poles, Towers and Fixtures		1,925,544		1,925,544
28		E365 - Overhead Conductors, Devices		2,730,320		2,730,320
29		E366 - Underground Conduit		1,362,310		1,362,310
30		E367 - Undergrnd Conductors, Devices		2,654,822		2,654,822
31		E368 - Line Transformers		1,145,141		1,145,141
32		E369 - Services		516,670		516,670
33		E370 - Meters		413,020		413,020
34		E371 - Installs on Customer Premise		16,772		16,772
35		E373 - Street Lighting, Signal Systems		72,331		72,331
36		E374 - ARO Costs Distribution Plant		4,017		4,017
37		Sub-total Distribution Plant	SUM L21 to L36	$12,935,381		$12,935,381
38						
39	**General Plant**	E389 - Land and Land Rights		$1,063	$133	$930
40		E390 - Structures and Improvements		74,761	9,379	65,382
41		E391 - Office Furniture, Equipment		9,412	1,181	8,231
42		E393 - Stores Equipment		44	5	38
43		E394 - Tools, Shop, Garage Equipment		73,447	9,214	64,233
44		E395 - Laboratory Equipment		97	12	85
45		E397.1 - Computer Hardware		7,858	986	6,872
46		E397.2 - Computer Software		27,247	3,418	23,829
47		E397.3 - Communication Equipment		44,479	5,580	38,899
48		E398 - Miscellaneous Equipment		2,002	251	1,750
49		E399.1 - ARO Costs General Plant		2,171	272	1,898
50		Sub-total General Plant	SUM L39 to L49	$242,581	$30,432	$212,149
51						
52		**Total**	L4+L19+L37+L50	**$15,758,972**	**$2,604,386**	**$13,154,586**

Line No.	Category	Account	(1) Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E350 - Land and Land Rights	
5		E351.1 - Computer Hardware	$1,473
6		E351.2 - Computer Software	3,491
7		E351.3 - Communication Equipment	4,054
8		E352 - Structures and Improvements	75,440
9		E353 - Station Equipment	86,990
10		E354 - Towers and Fixtures	6,145
11		E355 - Poles and Fixtures	7,352
12		E356 - Overhead Conductors, Devices	23,488
13		E357 - Underground Conduit	26,954
14		E358 - Undergrnd Conductors, Devics	28,056
15		E359 - Roads and Trails	17
16		E359.1 - ARO Costs Transmission Plt	138
17		Sub-total Transmission Plant	$263,598
18			
19	**Distribution Plant**	E361 - Structures and Improvements	$35,233
20		E362 - Station Equipment	49,401
21		E363.1 - Computer Hardware	120
22		E363.2 - Computer Software	1,165
23		E363.3 - Communication Equipment	842
24		E364 - Poles, Towers and Fixtures	251,980
25		E365 - Overhead Conductors, Devices	247,747
26		E366 - Underground Conduit	173,430
27		E367 - Undergrnd Conductors, Devics	281,160
28		E368 - Line Transformers	141,707
29		E369 - Services	14,912
30		E370 - Meters	18,784
31		E371 - Installs on Customer Premise	3,000
32		E373 - Street Lighting,Signal Systm	2,043
33		E374 - ARO Costs Distribution Plt	290
34		Sub-total Distribution Plant	$1,221,815
35			
36	**General Plant**	E390 - Structures and Improvements	$3,167
37		E391 - Office Furniture, Equipment	4,627
38		E394 - Tools, Shop, Garage Equipmnt	3,830
39		E397.1 - Computer Hardware	1,895
40		E397.2 - Computer Software	6,704
41		E397.3 - Communication Equipment	10,406
42		E398 - Miscellaneous Equipment	6
43		E399.1 - ARO Costs General Plt	
44		Sub-total General Plant	$30,635
45			
46		**Total**	**$1,516,048**

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E352 - Structures and Improvements	($1,539)
5		E353 - Station Equipment	(3,859)
6		E354 - Towers and Fixtures	(344)
7		E355 - Poles and Fixtures	-
8		E356 - Overhead Conductors, Devices	(871)
9		E357 - Underground Conduit	(25)
10		E358 - Undergrnd Conductors, Devics	(117)
11		E359.1 - ARO Costs Transmission Plt	(2)
12		Sub-total Transmission Plant	($6,758)
13			
14	**Distribution Plant**	E361 - Structures and Improvements	($938)
15		E362 - Station Equipment	(12,300)
16		E363.1 - Computer Hardware	(3,886)
17		E363.2 - Computer Software	(4,967)
18		E363.3 - Communication Equipment	(223)
19		E364 - Poles, Towers and Fixtures	(32,793)
20		E365 - Overhead Conductors, Devices	(18,080)
21		E366 - Underground Conduit	(1,242)
22		E367 - Undergrnd Conductors, Devics	(31,383)
23		E368 - Line Transformers	(23,239)
24		E369 - Services	(178)
25		E370 - Meters	(161)
26		E373 - Street Lighting,Signal Systm	(562)
27		E374 - ARO Costs Distribution Plt	(43)
28		Sub-total Distribution Plant	($129,996)
29			
30	**General Plant**	E390 - Structures and Improvements	($183)
31		E391 - Office Furniture, Equipment	(510)
32		E393 - Stores Equipment	(1)
33		E394 - Tools, Shop, Garage Equipmnt	(1,148)
34		E395 - Laboratory Equipment	-
35		E397.1 - Computer Hardware	(587)
36		E397.2 - Computer Software	(2,348)
37		E397.3 - Communication Equipment	(952)
38		E398 - Miscellaneous Equipment	
39		E399.1 - ARO Costs General Plt	(125)
40		Sub-total General Plant	($5,852)
41			
42		**Total**	**($142,606)**

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs								
2										
3		E302 - Franchises and Consents	$163		$163	100.00%	$163	87.46%	$142	$20
4			$163		$163		$163		$142	$20
5										
6		E303 - Misc Intangible Plant	$6,914		$6,914	100.00%	$6,914	100.00%	$6,914	
7			$6,914		$6,914		$6,914		$6,914	
8										
9		Sub-total Intangible Plant	$7,077		$7,077		$7,077		$7,056	$20
10										
11	**Transmission Plant**	E350 - Land and Land Rights	$92,459		$92,459	100.00%	$92,459			$92,459
12			$92,459		$92,459		$92,459			$92,459
13										
14		E351.1 - Computer Hardware - Transm	$11,615		$11,615	100.00%	$11,615			$11,615
15			$11,615		$11,615		$11,615			$11,615
16										
17		E351.2 - Computer Software- Transmissior	$27,516		$27,516	100.00%	$27,516			$27,516
18			$27,516		$27,516		$27,516			$27,516
19										
20		E351.3 - Comm Equipment- Transm	$31,961		$31,961	100.00%	$31,961			$31,961
21			$31,961		$31,961		$31,961			$31,961
22										
23		E352 - Structures and Improvements	295,182		295,182	100.00%	295,182			295,182
24			295,182		295,182		295,182			295,182
25										
26		E353 - Station Equipment	1,218,185		1,218,185	100.00%	1,218,185			1,218,185
27			1,218,185		1,218,185		1,218,185			1,218,185
28										
29		E354 - Towers and Fixtures	307,289		307,289	100.00%	307,289			307,289
30			307,289		307,289		307,289			307,289
31										
32		E355 - Poles and Fixtures	45,534		45,534	100.00%	45,534			45,534
33			45,534		45,534		45,534			45,534
34										
35		E356 - Overhead Conductors, Devices	267,055		267,055	100.00%	267,055			267,055
36			267,055		267,055		267,055			267,055
37										
38		E357 - Underground Conduit	90,216		90,216	100.00%	90,216			90,216
39			90,216		90,216		90,216			90,216
40										
41		E358 - Undergrnd Conductors, Devices	183,378		183,378	100.00%	183,378			183,378
42			183,378		183,378		183,378			183,378
43										
44		E359 - Roads and Trails	2,668		2,668	100.00%	2,668			2,668
45			2,668		2,668		2,668			2,668
46										
47		E359.1 - ARO Costs Transm Plt	875		875	100.00%	875			875
48			875		875		875			875
49										
50		Sub-total Transmission Plant	$2,573,934		$2,573,934		$2,573,934			$2,573,934
51										

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
52	**Distribution Plant**	E360 - Land and Land Rights	$56,497		$56,497	100.00%	$56,497	100.00%	$56,497	
53			$56,497		$56,497		$56,497		$56,497	
54										
55		E361 - Structures and Improvements	319,617		319,617	100.00%	319,617	100.00%	319,617	
56			319,617		319,617		319,617		319,617	
57										
58		E362 - Station Equipment	1,387,485		1,387,485	100.00%	1,387,485	100.00%	1,387,485	
59			1,387,485		1,387,485		1,387,485		1,387,485	
60										
61		E363.1 - Computer Hardware	11,877		11,877	100.00%	11,877	100.00%	11,877	
62			11,877		11,877		11,877		11,877	
63										
64		E363.2 - Computer Software	181,334		181,334	100.00%	181,334	100.00%	181,334	
65			181,334		181,334		181,334		181,334	
66										
67		E363.3 - Communication Equipment	137,623		137,623	100.00%	137,623	100.00%	137,623	
68			137,623		137,623		137,623		137,623	
69										
70		E364 - Poles, Towers and Fixtures	1,925,544		1,925,544	100.00%	1,925,544	100.00%	1,925,544	
71			1,925,544		1,925,544		1,925,544		1,925,544	
72										
73		E365 - Overhead Conductors, Devices	2,730,320		2,730,320	100.00%	2,730,320	100.00%	2,730,320	
74			2,730,320		2,730,320		2,730,320		2,730,320	
75										
76		E366 - Underground Conduit	1,362,310		1,362,310	100.00%	1,362,310	100.00%	1,362,310	
77			1,362,310		1,362,310		1,362,310		1,362,310	
78										
79		E367 - Undergrnd Conductors, Devices	2,654,822		2,654,822	100.00%	2,654,822	100.00%	2,654,822	
80			2,654,822		2,654,822		2,654,822		2,654,822	
81										
82		E368 - Line Transformers	1,145,141		1,145,141	100.00%	1,145,141	100.00%	1,145,141	
83			1,145,141		1,145,141		1,145,141		1,145,141	
84										
85		E369 - Services	516,670		516,670	100.00%	516,670	100.00%	516,670	
86			516,670		516,670		516,670		516,670	
87										
88		E370 - Meters	413,020		413,020	100.00%	413,020	100.00%	413,020	
89			413,020		413,020		413,020		413,020	
90										
91		E371 - Installs on Customer Premise	13,772	$3,000	16,772	100.00%	16,772	100.00%	16,772	
92			13,772		16,772		16,772		16,772	
93										
94		E373 - Street Lighting, Signal Systems	72,331		72,331	100.00%	72,331	100.00%	72,331	
95			72,331		72,331		72,331		72,331	
96										
97		E374 - ARO Costs Distribution Plant	4,017		4,017	100.00%	4,017	100.00%	4,017	
98		Electric Nonrecoverable 100%								
99			4,017		4,017		4,017		4,017	
100										
101		Sub-total Distribution Plant	$12,932,381		$12,935,381		$12,935,381		$12,935,381	
102										

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
103	**General Plant**	E389 - Land and Land Rights	$1,063		$1,063	100.00%	$1,063	87.46%	$930	$133
104			$1,063		$1,063		$1,063		$930	$133
105										
106		E390 - Structures and Improvements	74,761		74,761	100.00%	74,761	87.46%	65,383	9,379
107			74,761		74,761		74,761		65,383	9,379
108										
109		E391 - Office Furniture, Equipment	9,412		9,412	100.00%	9,412	87.46%	8,231	1,181
110			9,412		9,412		9,412		8,231	1,181
111										
112		E393 - Stores Equipment	44		44	100.00%	44	87.46%	38	5
113			44		44		44		38	5
114										
115		E394 - Tools, Shop, Garage Equipment	73,447		73,447	100.00%	73,447	87.46%	64,234	9,214
116			73,447		73,447		73,447		64,234	9,214
117										
118		E395 - Laboratory Equipment	97		97	100.00%	97	87.46%	85	12
119			97		97		97		85	12
120										
124		E397.1 - Computer Hardware	7,858		7,858	100.00%	7,858	87.46%	6,872	986
125			7,858		7,858		7,858		6,872	986
126										
127		E397.2 - Computer Software	27,247		27,247	100.00%	27,247	87.46%	23,829	3,418
128			27,247		27,247		27,247		23,829	3,418
129										
130		E397.3 - Communication Equipment	44,479		44,479	100.00%	44,479	87.46%	38,899	5,580
131			44,479		44,479		44,479		38,899	5,580
132										
133		E398 - Miscellaneous Equipment	2,002		2,002	100.00%	2,002	87.46%	1,751	251
134			2,002		2,002		2,002		1,751	251
135										
136		E399.1 - ARO Costs General Plant	2,171		2,171	100.00%	2,171	87.46%	1,898	272
137			2,171		2,171		2,171		1,898	272
138										
139		Sub-total General Plant	$242,581		$242,581		$242,581		$212,149	$30,431
140										
141										
142		**Total**	**$15,755,972**		**$15,758,972**		**$15,758,972**		**$13,154,587**	**$2,604,385**

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	Adjusted FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant				
4		Sub-total Intangible Plant	SUM L1 to L3			
5						
6	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
7		E351.1 - Computer Hardware		$9,629	$9,629	
8		E351.2 - Computer Software		23,825	23,825	
9		E351.3 - Communication Equipment		17,444	17,444	
10		E352 - Structures and Improvements		21,202	21,202	
11		E353 - Station Equipment		293,139	293,139	
12		E354 - Towers and Fixtures		183,024	183,024	
13		E355 - Poles and Fixtures		8,513	8,513	
14		E356 - Overhead Conductors, Devices		99,055	99,055	
15		E357 - Underground Conduit		9,011	9,011	
16		E358 - Undergrnd Conductors, Devices		56,941	56,941	
17		E359 - Roads and Trails		2,303	2,303	
18		E359.1 - ARO Costs Transmission Plt		240	240	
19		Sub-total Transmission Plant	SUM L6 to L18	$724,326	$724,326	
20						
21	**Distribution Plant**	E360 - Land and Land Rights		$310		$310
22		E361 - Structures and Improvements		57,133		$57,133
23		E362 - Station Equipment		492,797		$492,797
24		E363.1 - Computer Hardware		10,759		$10,759
25		E363.2 - Computer Software		93,902		$93,902
26		E363.3 - Communication Equipment		75,166		$75,166
27		E364 - Poles, Towers and Fixtures		(2,932)		(2,932)
28		E365 - Overhead Conductors, Devices		328,256		$328,256
29		E366 - Underground Conduit		225,322		225,322
30		E367 - Undergrnd Conductors, Devices		148,586		148,586
31		E368 - Line Transformers		150,614		150,614
32		E369 - Services		227,180		227,180
33		E370 - Meters		274,521		274,521
34		E371 - Installs on Customer Premises		11,947		11,947
35		E373 - Street Lighting, Signal Systems		38,073		38,073
36		E374 - ARO Costs Distribution Plant		2,749		2,749
37		Sub-total Distribution Plant	SUM L21 to L36	$2,134,385		$2,134,385
38						
39	**General Plant**	E389 - Land and Land Rights				
40		E390 - Structures and Improvements		$20,778	$2,607	$18,171
41		E391 - Office Furniture, Equipment		500	63	437
42		E393 - Stores Equipment		40	5	35
43		E394 - Tools, Shop, Garage Equipmnt		32,860	4,122	28,738
44		E395 - Laboratory Equipment		97	12	85
45		E397.1 - Computer Hardware		5,716	717	4,999
46		E397.2 - Computer Software		20,288	2,545	17,743
47		E397.3 - Communication Equipment		20,404	2,560	17,845
48		E398 - Miscellaneous Equipment		(619)	(78)	(541)
49		E399.1 - ARO Costs General Plt		2,039	256	1,784
50		Sub-total General Plant	SUM L39 to L49	$102,102	$12,809	$89,294
51						
52		**Total**	L4+L19+L37+L50	**$2,960,813**	**$737,135**	**$2,223,678**

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents								
2										
3										
4		E303 - Misc Intangible Plant				100.00%				
5						100.00%				
6										
7		Sub-total Intangible Plant								
8										
9	**Transmission Plant**	E350 - Land and Land Rights	($0)		($0)	100.00%	($0)			($0)
10			($0)		($0)		($0)			($0)
11										
12		E351.1 - Computer Hardware	$9,629		9,629	100.00%	$9,629			$9,629
13			$9,629		$9,629		$9,629			$9,629
14										
15		E351.2 - Computer Software	$23,825		23,825	100.00%	$23,825			$23,825
16			$23,825		$23,825		$23,825			$23,825
17										
18		E351.3 - Communication Equipment	$17,444		17,444	100.00%	$17,444			$17,444
19			$17,444		$17,444		$17,444			$17,444
20										
21		E352 - Structures and Improvements	21,202		21,202	100.00%	21,202			21,202
22			21,202		21,202		21,202			21,202
23										
24		E353 - Station Equipment	293,139		293,139	100.00%	293,139			293,139
25			293,139		293,139		293,139			293,139
26										
27		E354 - Towers and Fixtures	183,024		183,024	100.00%	183,024			183,024
28			183,024		183,024		183,024			183,024
29										
30		E355 - Poles and Fixtures	8,513		8,513	100.00%	8,513			8,513
31			8,513		8,513		8,513			8,513
32										
33		E356 - Overhead Conductors, Devices	99,055		99,055	100.00%	99,055			99,055
34			99,055		99,055		99,055			99,055
35										
36		E357 - Underground Conduit	9,011		9,011	100.00%	9,011			9,011
37			9,011		9,011		9,011			9,011
38										
39		E358 - Undergrnd Conductors, Devices	56,941		56,941	100.00%	56,941			56,941
40			56,941		56,941		56,941			56,941
41										
42		E359 - Roads and Trails	2,303		2,303	100.00%	2,303			2,303
43			2,303		2,303		2,303			2,303
44										
45		E359.1 - ARO Costs Transmission Plt	240		240	100.00%	240			240
46			240		240		240			240
47										
48		Sub-total Transmission Plant	$724,326		$724,326		$724,326			$724,326
49										

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
50	**Distribution Plant**	E360 - Land and Land Rights	310		310	100.00%	310	100.00%	310	
51			310		310		310		310	
52										
53		E361 - Structures and Improvements	$57,133		57,133	100.00%	$57,133	100.00%	$57,133	
54			$57,133		$57,133		$57,133		$57,133	
55										
56		E362 - Station Equipment	492,797		492,797	100.00%	492,797	100.00%	492,797	
57			492,797		492,797		492,797		492,797	
58										
59		E363.1 - Computer Hardware	10,759		10,759	100.00%	10,759	100.00%	10,759	
60			10,759		10,759		10,759		10,759	
61										
62		E363.2 - Computer Software	93,902		93,902	100.00%	93,902	100.00%	93,902	
63			93,902		93,902		93,902		93,902	
64										
65		E363.3 - Communication Equipment	75,166		75,166	100.00%	75,166	100.00%	75,166	
66			75,166		75,166		75,166		75,166	
67										
68		E364 - Poles, Towers and Fixtures	(2,932)		(2,932)	100.00%	(2,932)	100.00%	(2,932)	
69			(2,932)		(2,932)		(2,932)		(2,932)	
70										
71		E365 - Overhead Conductors, Devices	328,256		328,256	100.00%	328,256	100.00%	328,256	
72			328,256		328,256		328,256		328,256	
73										
74		E366 - Underground Conduit	225,322		225,322	100.00%	225,322	100.00%	225,322	
75			225,322		225,322		225,322		225,322	
76										
77		E367 - Undergrnd Conductors, Devices	148,586		148,586	100.00%	148,586	100.00%	148,586	
78			148,586		148,586		148,586		148,586	
79										
80		E368 - Line Transformers	150,614		150,614	100.00%	150,614	100.00%	150,614	
81			150,614		150,614		150,614		150,614	
82										
83		E369 - Services	227,180		227,180	100.00%	227,180	100.00%	227,180	
84			227,180		227,180		227,180		227,180	
85										
86		E370 - Meters	274,521		274,521	100.00%	274,521	100.00%	274,521	
87			274,521		274,521		274,521		274,521	
88										
89		E371 - Installs on Customer Premises	11,747	200	11,947	100.00%	11,947	100.00%	11,947	
90			11,747		11,947		11,947		11,947	
91										
92		E373 - Street Lighting, Signal Systems	38,073		38,073	100.00%	38,073	100.00%	38,073	
93			38,073		38,073		38,073		38,073	
94										
95		E374 - ARO Costs Distribution Plant	2,749		2,749	100.00%	2,749	100.00%	2,749	
96										
97			2,749		2,749		2,749		2,749	
98										
99		Sub-total Distribution Plant	$2,134,185		$2,134,385		$2,134,385		$2,134,385	
100										

Line No.	Description	Account	(1) FPFTY Amount	(2) Proforma Adjs.	(3) Adjusted FPFTY Amount	(4) Utility Allocation Factor	(5) Allocated to Utility	(6) Jurisdictional Allocation Factor	(7) Allocated to Jurisdiction	(8) Allocated to Non Jurisdiction
101	**General Plant**	E389 - Land and Land Rights				100.00%		87.46%		
102										
103										
104		E390 - Structures and Improvements	$20,778		$20,778	100.00%	$20,778	87.46%	$18,171	$2,607
105			$20,778		$20,778		$20,778		$18,171	$2,607
106										
107		E391 - Office Furniture, Equipment	500		500	100.00%	500	87.46%	437	63
108			500		500		500		437	63
109										
110		E393 - Stores Equipment	40		40	100.00%	40	87.46%	35	5
111			40		40		40		35	5
112										
113		E394 - Tools, Shop, Garage Equipmnt	32,860		32,859.97	100.00%	32,859.97	87.46%	28,737.75	4,122
114			32,860		32,860		32,860		28,738	4,122
115										
116		E395 - Laboratory Equipment	97		97	100.00%	97	87.46%	85	12
117			97		97		97		85	12
118										
119		E397.1 - Computer Hardware	5,716		5,716	100.00%	5,716	87.46%	4,999	717
120			5,716		5,716		5,716		4,999	717
121										
122		E397.2 - Computer Software	20,288		20,288	100.00%	20,288	87.46%	17,743	2,545
123			20,288		20,288		20,288		17,743	2,545
124										
125		E397.3 - Communication Equipment	20,404		20,404	100.00%	20,404	87.46%	17,845	2,560
126			20,404		20,404		20,404		17,845	2,560
127										
128		E398 - Miscellaneous Equipment	(619)		(619)	100.00%	(619)	87.46%	(541)	(78)
129			(619)		(619)		(619)		(541)	(78)
130										
131		E399.1 - ARO Costs General Plt	2,039		2,039	100.00%	2,039	87.46%	1,784	256
132			2,039		2,039		2,039		1,784	256
133										
134		Sub-total General Plant	$102,102		$102,102		$102,102		$89,294	$12,809
135										
136		**Total**	**$2,960,613**		**$2,960,813**		**$2,960,813**		**$2,223,678**	**$737,135**

Line No.	Category	Account	(1) Reference	(2) FPFTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		
2		Sub-total Electric - Intangible Plant		
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		
5		E351.3 - Communication Equipment		($15)
6		E352 - Structures and Improvements		(2,906)
7		E353 - Station Equipment		(2,976)
8		E354 - Towers and Fixtures		(747)
9		E355 - Poles and Fixtures		(6)
10		E356 - Overhead Conductors, Devices		(1,779)
11		E357 - Underground Conduit		(40)
12		E358 - Undergrnd Conductors, Devics		(801)
13		E359 - Roads and Trails		
14		Sub-total Electric - Transmission	SUM L4 to L13	($9,270)
15				
16	**Electric - Distribution**	E361 - Structures and Improvements		($1,967)
17		E362 - Station Equipment		(11,020)
18		E363.3 - Communication Equipment		(123)
19		E364 - Poles, Towers and Fixtures		(23,657)
20		E365 - Overhead Conductors, Devices		(23,161)
21		E366 - Underground Conduit		(3,986)
22		E367 - Undergrnd Conductors, Devics		(27,589)
23		E368 - Line Transformers		(3,927)
24		E369 - Services		(765)
25		E370 - Meters		(474)
26		E373 - Street Lighting, Signal Systems		(134)
27		Sub-total Electric - Distribution	SUM L16 to L26	($96,802)
28				
29	**Electric - General Plant**	E390 - Structures and Improvements		($166)
30		E391 - Office Furniture, Equipment		(23)
31		E394 - Tools, Shop, Garage Equipmnt		(41)
32		E397.3 - Communication Equipment		(282)
33		E398 - Miscellaneous Equipment		(226)
34		Sub-total Electric - General Plant	SUM L29 to L33	($738)
35				
36		**Total**	Lines 2+14+27+34	**($106,810)**

Line No.	Description	(1) Reference	(2) FPFTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			57.60	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$187,276	13.56	$2,539,929
7	Pension Expense		2,988	(167.00)	(499,015)
8	Commodity Purchased - [A]		1,501,553	35.79	53,743,084
9	Commodity Purchased - [B]		12,239	12.50	152,984
10	PJM Transmission Purchased - By-passable		102,810	12.50	1,285,127
11	PJM Transmission Purchased - Non By-passable		122,894	12.50	1,536,178
12	Other Expenses		611,821	43.21	26,434,675
13	Sub-Total O&M	SUM L6 to L12	$2,541,582		$85,192,964
14					
15	Payment to Suppliers		$1,428,686	37.64	$53,782,349
16					
17	Total O&M and POR Payments	L13 + L15	$3,970,268		$138,975,312
18					
19	O&M Expense / POR Payment Lag Days			35.00	
20					
21	Net Lead/(Lag) Days	L3 - L19		22.59	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$10,877		
26					
27	Working Capital for O&M Expense		$245,764		
28					
29	Average Prepayments		$8,432		
30	Accrued Taxes		110,012		
31	Interest Payments		(22,491)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$341,717**		
34					
35	Pro Forma O&M Expense		$2,600,307		
36	Uncollectible Expense		58,726		
37	Pro Forma Cash O&M Expense	L35 - L36	$2,541,582		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$441,873			
4	January		511,639	$416,118		
5	February		536,250	394,707		
6	March		520,942	364,969		
7	April		498,684	325,032		
8	May		477,882	316,108		
9	June		518,591	365,739		
10	July		619,727	508,393		
11	August		625,228	489,153		
12	September		552,426	394,187		
13	October		521,995	365,223		
14	November		503,475	288,094		
15	December		533,971	427,625		
16						
17	Total	SUM L3 to L15	$6,862,683	$4,655,348		
18						
19	Average A/R Balance		13			
20						
21	Factor		$527,899	$4,655,348	8.82	41.39
22						
23	Collection Days Lag					41.39
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12 * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**57.60**

Line No.	Category	Description	(1) Reference	(2) Payment Date	(3) Mid-point of Service Period	(4) Expense Amount	(5) (Lead)/Lag Days	(6) Dollar Days
1	PAYROLL	Union & Non-Union Payroll				$179,478		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$2,434,166
4								
5		**Payroll Lag**	SUM L1 to L3			$179,478	**13.56**	$2,434,166
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2027	7/1/2027	$10,508	(167.00)	($1,754,836)
12								
13		Sub-total	SUM L7 to L11			$10,508		($1,754,836)
14								
15		**Lag Days for Pension Payment**					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.79**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.64**	
20								
21								
22	OTHER O & M EXPENSES	March				$15,875		$656,144
23		June				18,479		697,875
24		September				36,511		1,651,476
25		December				35,501		1,590,220
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$106,366	**43.21**	$4,595,716

Line No.	Months	Description	(1) Number of CDs	(2) Cash Disbursements	(3) Dollar-Days	(4) Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643	-	
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705	-	
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,894	$106,366	$4,595,716	**43.21**

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/15/2027	7/1/2027	77	$72,831	25.00%	$18,208	$1,402,004
2		Second Payment	6/15/2027	7/1/2027	16	72,831	25.00%	18,208	291,325
3		Third Payment	9/15/2027	7/1/2027	(76)	72,831	25.00%	18,208	(1,383,796)
4		Fourth Payment	12/15/2027	7/1/2027	(167)	72,831	25.00%	18,208	(3,040,709)
5		Sub-total FEDERAL INCOME TAX					100.00%	$72,831	($2,731,176)
6									
7	**STATE INCOME TAX**	First Payment	3/15/2027	7/1/2027	108	$9,335	25.00%	$2,334	$252,047
8		Second Payment	6/15/2027	7/1/2027	16	9,335	25.00%	2,334	37,340
9		Third Payment	9/15/2027	7/1/2027	(76)	9,335	25.00%	2,334	(177,366)
10		Fourth Payment	12/15/2027	7/1/2027	(167)	9,335	25.00%	2,334	(389,739)
11		Sub-total STATE INCOME TAX					100.00%	$9,335	($277,718)
12									
13	**PURTA**	First Payment	5/1/2027	7/1/2027	61	$6,863	100.00%	$6,863	$418,660
14		Subtotal PURTA					100.00%	$6,863	$418,660
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2027	7/1/2027	29	$6,285	100.00%	$6,285	$182,275
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$6,285	$182,275
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/15/2027	7/1/2027	108	$223,870	100.00%	$223,870	$24,177,962
27		Sub-total GROSS RECEIPTS TAX					100.00%	$223,870	$24,177,962

Line No.	Description	(1) Total Payment Amount	(2) Weighted Dollar Days	(3) Payment Lead/(Lag) Days	(4) Revenue Lag Days	(5) Net Payment Lead/(Lag) Days	(6) Net Payment Lead/(Lag) Dollars Days	(7) Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$72,831	($2,731,176)	(37.50)	57.60	20.10	$1,463,760	$4,010
2	STATE INCOME TAX	$9,335	($277,718)	(29.75)	57.60	27.85	$259,962	$712
3	PURTA	$6,863	$418,660	61.00	57.60	118.60	$813,970	$2,230
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$6,285	$182,275	29.00	57.60	86.60	$544,299	$1,491
6	GROSS RECEIPTS TAX	$223,870	$24,177,962	108.00	57.60	165.60	$37,072,413	$101,568

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of FPFTY		$10,951,677
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.78%
4	Pro Forma Interest Expense	L1 * L2 * L3	$243,946
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$668
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	57.60
9	Interest Payment Lag Days	L8 - L7	(33.65)
10	**Total Interest for Working Capital**	L6 * L9	**($22,491)**

Line No.	Description	Reference	EPRI Dues	EEI Dues	EAP Membership Dues	Prepaid Rents & Pole Attachments	PUC Assessment Electric	Land Leasing	Maintenance	IT License & Maintenance	Business Support Systems	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	December				$285	$230	$4,323	$143	$117	$148	$599	$3,449	$0	$27	$478	$172	$112	$566	
2	January			530	262	702	3,742		78	98	558	3,449	(16)	14	498	166	232	580	
3	February			482	238	666	2,993		78	80	462	3,449	(32)	0	500	110	198	554	
4	March		217	434	214	481	2,245	136	78	62	519	2,376	150	0	503	82	439	538	
5	April		217	386	190	330	1,497		78	50	422	2,376	134	0	528	136	378	540	
6	May		217	337	166	298	748		78	37	325	2,376	117	0	527	237	340	489	
7	June		126	289	143	121	0	130	78	25	454	1,888	100	0	530	484	302	499	
8	July		126	241	119	603	4,605		78	164	614	1,888	84	0	562	405	264	445	
9	August		126	193	95	423	3,893		78	163	506	1,888	67	0	445	356	226	520	
10	September		117	145	71	601	8,182	123	78	203	475	2,231	50	0	471	306	188	655	
11	October		36	96	48	449	7,273		78	176	457	2,231	33	0	470	256	150	748	
12	November		36	48	24	282	6,364		78	149	339	2,231	17	0	500	318	112	748	
13	December		(54)	570		238	5,455	117	78	122	297	2,048	0	0	505	271	74	942	
14																			
15	Total	SUM L1 to L13	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																			
17	Distribution %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.32%	67.32%	67.32%	67.32%	74.52%	74.52%	74.52%	
18																			
19	Distribution Amount	L15 * L17	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$21,465	$474	$28	$4,387	$2,458	$2,248	$5,831	
20																			
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																			
23	Monthly Average	L19 / L21	$90	$289	$143	$417	$3,948	$50	$81	$114	$464	$1,651	$36	$2	$337	$189	$173	$449	
24																			
25	**Rate Case Amount**																		**$8,432**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in FPFTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	3.00	37.50	
4	March	14.00	19.00	3.00	36.00	
5	April	15.50	19.00	1.00	35.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	2.00	36.50	
8	July	15.00	19.00	1.00	35.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	1.00	35.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	3.00	37.50	
13	December	15.00	19.00	1.00	35.00	
14	**Payment Lag - Contract Purchases**					**35.79**
15						
16	**Spot Market Purchases in FPFTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	29%	7.18		
30	Nonresidential	20.00	71%	14.25		
31	Weighted Lag Days				21.44	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.64**

Line No.	Description	(1) Reference	(2) Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Activities in FTY - Total		(1,509)
3	Activities in FPFTY - Total		(5,054)
4	Balance at End of FPFTY - Total		$434,927
5	Allocation % to Utility		76.67%
6	Utility Amount	L4 * L5	$333,469
7	Allocation % to Distribution Capital		48.37%
8	Balance at End of FPFTY - Distribution Capital	L6 * L7	$161,288

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - CIAC		($12,383)	100.00%	($12,383)	100.00%	($12,383)
2		ADIT - Common Plant		106,546	100.00%	106,546	67.32%	71,730
3		ADIT - Electric Common Plant		24,741	100.00%	24,741	87.46%	21,638
4		ADIT - Electric Distribution		665,968	100.00%	665,968	100.00%	665,968
5		ADIT - Corp. Alternative Minimum Tax		(183,957)	100.00%	(183,957)	100.00%	(183,957)
6		Sub-total	SUM L1 to L5	$600,915		$600,915		$562,995
7								
8	**FTY**	DIT - CIAC		$1,681	100.00%	$1,681	100.00%	$1,681
9		DIT - Common Plant		(7,346)	100.00%	(7,346)	67.32%	(4,945)
10		DIT - Electric Common Plant		(1,696)	100.00%	(1,696)	87.46%	(1,484)
11		DIT - Electric Distribution		32,421	100.00%	32,421	100.00%	32,421
12		DIT - Corp. Alternative Minimum Tax		144,110	100.00%	144,110	100.00%	144,110
13		Sub-total	SUM L8 to L12	$169,171		$169,171		$171,784
14								
15	**FPFTY**	DIT - CIAC		$1,762	100.00%	$1,762	100.00%	$1,762
16		DIT - Common Plant		(3,973)	100.00%	(3,973)	67.32%	(2,675)
17		DIT - Electric Common Plant		8,045	100.00%	8,045	87.46%	7,035
18		DIT - Electric Distribution		44,673	100.00%	44,673	100.00%	44,673
19		DIT - Corp. Alternative Minimum Tax		27,226	100.00%	27,226	100.00%	27,226
20		Sub-total	SUM L15 to L19	$77,732		$77,732		$78,022
21								
22		**Total**	L6 + L13 + L20	**$847,818**		**$847,818**		**$812,801**

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$22,499	$36,282	$58,780
2	January		22,580	35,889	58,469
3	February		23,154	36,470	59,623
4	March		24,246	37,775	62,021
5	April		25,771	39,113	64,884
6	May		26,839	39,833	66,672
7	June		27,171	39,865	67,035
8	July		27,725	40,669	68,394
9	August		28,297	40,986	69,283
10	September		29,109	41,497	70,606
11	October		29,946	43,006	72,952
12	November		30,524	43,769	74,292
13	December		30,889	45,192	76,081
14					
15	Total	SUM L1 to L13	$348,750	$520,343	$869,092
16					
17	Average Monthly Balance	L15 / 13	$26,827	$40,026	$66,853
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$26,827
21	Small C&I				33,270
22	Large C&I				6,746
23	Other				11
24					
25	**Total**	SUM L20 to L23			**$66,853**

Line No.	Category	Account	Reference	(1) FPFTY Amount	(2) Allocated to Non Jurisdiction	(3) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$424,321	$138,656	$285,666
6						
7		E389 - Land and Land Rights		$6,770	$2,212	$4,558
8						
9		E390 - Structures and Improvements		$526,840	$172,155	$354,684
10		E391 - Office Furniture, Equipment		114,869	37,536	77,333
11		E392 - Transportation Equipment		253,538	82,849	170,689
12		E393 - Stores Equipment		2,519	823	1,696
13		E394 - Tools, Shop, Garage Equipmnt		2,692	880	1,812
14		E396 - Power Operated Equipment		870	284	586
15		E397 - Communication Equipment		151,896	49,635	102,261
16		E398 - Miscellaneous Equipment		479	156	322
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		240	79	162
19		Sub Total - General Plant	SUM L9 to L18	$1,053,944	$344,397	$709,546
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,485,712	$485,486	$1,000,226
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$237,746	$77,688	$160,058
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$77,546	$25,340	$52,206
31		E391 - Office Furniture, Equipment		55,218	18,044	37,175
32		E392 - Transportation Equipment		128,597	42,022	86,575
33		E393 - Stores Equipment		619	202	417
34		E394 - Tools, Shop, Garage Equipmnt		1,401	458	943
35		E396 - Power Operated Equipment		381	124	256
36		E397 - Communication Equipment		62,681	20,482	42,199
37		E398 - Miscellaneous Equipment		493	161	332
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(408)	(133)	(274)
40		Sub Total - General Plant	SUM L30 to L39	$326,529	$106,700	$219,829
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$564,274	$184,388	$379,886
42						
43		Net Common Plant	L20 - L41	$921,437	$301,098	$620,339
44						
45						
46		Common Plant in Service to Utility	L20	$1,485,712	$485,486	$1,000,226
47		Common Plant Accum Depreciation to Utility	L41	564,274	184,388	379,886
48		**Net Common Plant to Utility**	L46 - L47	**$921,437**	**$301,098**	**$620,339**

Line No.	Description	(1) Reference	(2) Total
1	HTY 13-Month Average		
2	December		$8,256
3	January		10,444
4	February		8,761
5	March		7,609
6	April		7,944
7	May		7,480
8	June		8,730
9	July		13,442
10	August		12,482
11	September		11,891
12	October		12,405
13	November		12,916
14	December		13,718
15			
16	13-Month Total	SUM L2 to L14	$136,078
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$10,468**

Line No.	Description	(1) Reference	(2) Total
1	Total Payments to be Received from Customers		$2,100
2	Less: Payments to be Recognized for Revenue in 2027		(210)
3	**Unamortized Balance of Customer Payments**	L1 - L2	**$1,890**

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$51,593	$0	$51,593
3	January		53,064	(535)	52,530
4	February		55,613	(319)	55,294
5	March		55,645	(560)	55,085
6	April		57,445	(2,433)	55,012
7	May		56,753	(911)	55,842
8	June		55,119	(1,049)	54,070
9	July		56,000	(1,747)	54,253
10	August		52,558	(2,066)	50,492
11	September		52,239	(2,581)	49,657
12	October		52,308	(2,857)	49,451
13	November		51,470	(2,421)	49,049
14	December		52,109	0	52,109
15					
16	Total	SUM L2 to L14	$701,915	($17,478)	$684,437
17					
18	Distribution Expense Allocation Factor		100.00%	67.32%	
19					
20	Allocation to Distribution	L16 * L18	$701,915	($11,767)	
21					
22	**Average Monthly Balance**	L20 / 13	**$53,993**	**($905)**	**$53,088**

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - Distribution		$274,076	100.00%	$274,076	100.00%	$274,076
2		ADIT - CIAC			100.00%		100.00%	
3		Sub-total HTY	L1 + L2	274,076		274,076		274,076
4								
5	**FTY**	DIT - Distribution		($3,010)	100.00%	($3,010)	100.00%	($3,010)
6		DIT - CIAC			100.00%		100.00%	
7		Sub-total FTY	L5 + L6	($3,010)		($3,010)		($3,010)
8								
9	**FPFTY**	DIT - Distribution		($7,414)	100.00%	($7,414)	100.00%	($7,414)
10		DIT - CIAC			100.00%		100.00%	
11		Sub-total FPFTY	L9 + L10	($7,414)		($7,414)		($7,414)
12								
13		**Total**	L3 + L7 + L11	**$263,652**		**$263,652**		**$263,652**

Line No.	Category	Description	(1) Reference	(2) Pro Forma Adjusted at Present Rates	(3) Proposed Rate Increase	(4) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$2,175,185		$2,175,185
2		Residential - House Heating		479,313		479,313
3		C & I Small		576,801		576,801
4		C & I Large		326,933		326,933
5		Railroads & Railways		9,662		9,662
6		Street Lighting		25,692		25,692
7		Intercompany				
8		Transmission - All Classes		241,020		241,020
9		Forfeited Discounts		18,527	$1,486	20,013
10		Miscellaneous Service Revenues		3,923		3,923
11		Rent For Electric Property		27,708		27,708
12		Other Electric Revenues		3,779		3,779
13		Revenue Increase			$429,106	429,106
14		Total Operating Revenues	SUM L1 to L13	$3,888,542	$430,592	$4,319,134
15						
16	**Operating Expenses**	Power Supply		$1,513,792		$1,513,792
17		Transmission Expense		225,704		225,704
18		Distribution Expense		435,914		435,914
19		Customer Accounts Expense		168,808	$4,788	173,596
20		Customer Service and Information Expense		38,807		38,807
21		Sales Expense		734		734
22		Administrative & General		216,547	1,557	218,104
23		Sub-total O&M Expense	SUM L16 to L22	$2,600,307	$6,345	$2,606,652
24						
25		Depreciation & Amortization Expense		$408,021		$408,021
26		Amortization of Regulatory Expense		16,572		16,572
27		Taxes Other Than Income Taxes - Other		$254,389	$25,317	$279,706
28		Total Operating Expenses	SUM L23 to L27	$3,279,289	$31,662	$3,310,951
29						
30	**Net Operating Income - BIT**		L14 - L28	**$609,253**	**$398,930**	**$1,008,183**

Line No.	Category	Description	Reference	(1) FPFTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$2,200,442	($25,257)	$2,175,185
2		Residential - House Heating		484,181	(4,868)	479,313
3		C & I Small		601,105	(24,304)	576,801
4		C & I Large		358,683	(31,750)	326,933
5		Railroads & Railways		10,676	(1,014)	9,662
6		Street Lighting		26,025	(333)	25,692
7		Intercompany				
8		Transmission - All Classes		241,020		241,020
9		Forfeited Discounts		18,527		18,527
10		Miscellaneous Service Revenues		3,923		3,923
11		Rent For Electric Property		27,708		27,708
12		Other Electric Revenues		3,413	366	3,779
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$3,975,703	($87,161)	$3,888,542
15						
16	**Operating Expenses**	Power Supply		$1,513,792		$1,513,792
17		Transmission Expense		225,704		225,704
18		Distribution Expense		424,631	$11,284	435,914
19		Customer Accounts Expense		142,622	26,186	168,808
20		Customer Service and Information Expense		117,964	(79,157)	38,807
21		Sales Expense		714	21	734
22		Administrative & General		217,358	(810)	216,547
23		Sub-total O&M Expense	SUM L16 to L22	$2,642,784	($42,477)	$2,600,307
24						
25		Depreciation & Amortization Expense		$380,514	$27,507	$408,021
26		Amortization of Regulatory Expense		16,626	(53)	16,572
27		Taxes Other Than Income Taxes - Other		259,218	(4,829)	254,389
28		Total Operating Expenses	SUM L23 to L27	$3,299,142	($19,852)	$3,279,289
29						
30	**Net Operating Income - BIT**		L14 - L28	**$676,561**	**($67,309)**	**$609,253**

Line No.	Category	Description	Description	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E BESS	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
1	**Operating Revenues**	Residential	Elec Cost	$1,040,649							
2			Cust & Dist	1,159,793	1,157	(2,563)	(2,128)	(22,525)	167	634	
3			Sub-total Residential	$2,200,442	$1,157	($2,563)	($2,128)	($22,525)	$167	$634	
4											
5		Residential - House Heating	Elec Cost	$259,956							
6			Cust & Dist	224,225	1,221	(319)	(470)	(5,526)	43	184	
7			Sub-total Residential - House Heating	$484,181	$1,221	($319)	($470)	($5,526)	$43	$184	
8											
9		C & I Small	Elec Cost	$228,809							
10			Cust & Dist	372,296	448		(1,377)	(23,578)		203	
11			Sub-total C & I Small	$601,105	$448		($1,377)	($23,578)		$203	
12											
13		C & I Large	Elec Cost	$82,981							
14			Cust & Dist	275,702			(1,025)	(30,894)		169	
15			Sub-total C & I Large	$358,683			($1,025)	($30,894)		$169	
16											
17		Railroads & Railways	Cust & Dist	$10,676				(1,014)			
18			Sub-total Railroads & Railways	$10,676				($1,014)			
19											
20		Street Lighting	Elec Cost	$600							
21			Cust & Dist	25,425				(333)			
22			Sub-total Street Lighting	$26,025				($333)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes	$241,020							
29			Sub-total Transmission - All Classes	$241,020							
30											
31		Forfeited Discounts	Forfeited Discounts	$18,527							
32			Sub-total Forfeited Discounts	$18,527							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$3,923							
35			Sub-total Miscellaneous Service Revenues	$3,923							
36											
37		Rent For Electric Property	Rent For Electric Property	$27,708							
38			Sub-total Rent For Electric Property	$27,708							
39											
40		Other Electric Revenues	Other Electric Revenues	$3,413							
41			Sub-total Other Electric Revenues	$3,413							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$3,975,703**	**$2,826**	**($2,882)**	**($5,000)**	**($83,870)**	**$210**	**$1,190**	
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,513,792							

Line No.	Category	Description	Description	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E BESS	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
49			Sub-total Power Supply	$1,513,792							
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch	117,611							
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development	108,093							
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense	225,704							
71											
72		Distribution Expense	Operation & Supervision	$559							
73			Load Dispatching								
74			Station Expense	7,134							
75			Overhead Lines Expenses	17,711							
76			Underground Lines Expense	11,338							
77			Meter Expenses	6,378							
78			Customer Installations Expense	13,098							
79			Miscellaneous Expense	89,315							
80			Rents	4,105							
81			Maintenance of Structures	7,189							
82			Maintenance of Station Equipment	16,937							
83			Maintenance of Overhead Lines	193,120							
84			Maintenance of Underground Lines	35,822							
85			Maintenance of Line Transformers	2,606							
86			Maintenance of Street Lighting & Signal Systems	1,821							
87			Maintenance of Misc. Distribution	17,497							
88			Sub-total Distribution Expense	$424,631							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$250							
92			Customer Records and Collection	101,485							
93			Uncollectible Accounts.	37,384							
94			Miscellaneous Customer Accounts Expenses.	3,503							
95			Sub-total Total Customer Accounts	$142,622							
96											

Line No.	Category	Description	Description	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E BESS	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
97		Customer Service and Information	Customer Assistance	$114,591				(79,206)			
98			Informational & Instructional	2,438							
99			Miscellaneous Customer & Informational	935							
100			Sub-total Customer Service & Information	$117,964				($79,206)			
101											
102		Sales	Demonstrating & Selling	$714							
103			Miscellaneous Sales								
104			Sub-total Sales	$714							
105											
106		Administrative & General	Administrative and General Salaries	$37,433							
107			Office Supplies and Expenses	4,273							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	101,338							
110			Property Insurance	970							
111			Injuries & Damages	18,553							
112			Employee Pensions and Benefits	35,618							
113			Regulatory Commission Expenses	9,813							
114			Duplicate Charges-Credit	(2,075)							
115			Miscellaneous General Expenses	1,487							
116			Maintenance of General Plant	9,948							
117			Sub-total Administrative & General	$217,358							
118											
119			**Total O&M Expense**	$2,642,784				($79,206)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$380,514							
122			Sub-total Depreciation & Amortization Expense	$380,514							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$16,626							
125			Sub-total Amortization of Regulatory Expense	$16,626							
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$259,218							
128			Sub-total Taxes Other Than Income Taxes - Other	$259,218							
129											
130			**Total Operating Expenses**	**$3,299,142**				**($79,206)**			
131											
132	**Net Operating Income Before Income Tax**			**$676,561**	**$2,826**	**($2,882)**	**($5,000)**	**($4,664)**	**$210**	**$1,190**	

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost									
2			Cust & Dist									
3			Sub-total Residential									
4												
5		Residential - House Heating	Elec Cost									
6			Cust & Dist									
7			Sub-total Residential - House Heating									
8												
9		C & I Small	Elec Cost									
10			Cust & Dist									
11			Sub-total C & I Small									
12												
13		C & I Large	Elec Cost									
14			Cust & Dist									
15			Sub-total C & I Large									
16												
17		Railroads & Railways	Cust & Dist									
18			Sub-total Railroads & Railways									
19												
20		Street Lighting	Elec Cost									
21			Cust & Dist									
22			Sub-total Street Lighting									
23												
24		Intercompany	Elec Cost									
25			Cust & Dist									
26			Sub-total Interdepartmental									
27												
28		Transmission - All Classes	Transmission - All Classes									
29			Sub-total Transmission - All Classes									
30												
31		Forfeited Discounts	Forfeited Discounts									
32			Sub-total Forfeited Discounts									
33												
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues									
35			Sub-total Miscellaneous Service Revenues									
36												
37		Rent For Electric Property	Rent For Electric Property									
38			Sub-total Rent For Electric Property									
39												
40		Other Electric Revenues	Other Electric Revenues	$366								
41			Sub-total Other Electric Revenues	$366								
42												
43		Revenue Increase	Revenue Increase									
44			Sub-total Revenue Increase									
45												
46			**Total Operating Revenues**	**$366**								
47												
48	**Operating Expenses**	Power Supply	Purchased Power									

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
49			Sub-total Power Supply									
50												
51		Transmission Expense	Operation & Supervision									
52			Load Dispatching									
53			Scheduling, System Control & Dispatch									
54			Transmission Service Studies									
55			Generation Service Studies									
56			Reliability, Planning & Standard Development									
57			Station Expense									
58			Overhead Lines									
59			Underground Lines Expense									
60			Miscellaneous Expense									
61			Rents									
62			Maintenance of Structures									
63			Maintenance of Computer Hardware									
64			Maintenance of Computer Software									
65			Maintenance of Communication Equipment									
66			Maintenance of Station Equipment									
67			Maintenance of Overhead Lines									
68			Maintenance of Underground Lines									
69			Maintenance of Misc Transmission Plant									
70			Sub-total Transmission Expense									
71												
72		Distribution Expense	Operation & Supervision	$18								
73			Load Dispatching									
74			Station Expense	14								
75			Overhead Lines Expenses	122								
76			Underground Lines Expense	128								
77			Meter Expenses	112								
78			Customer Installations Expense	269								
79			Miscellaneous Expense	320								
80			Rents									
81			Maintenance of Structures	66								
82			Maintenance of Station Equipment	346								
83			Maintenance of Overhead Lines	1,978								6,933
84			Maintenance of Underground Lines	672								
85			Maintenance of Line Transformers	34								
86			Maintenance of Street Lighting & Signal Systems	6								
87			Maintenance of Misc. Distribution	141								
88			Sub-total Distribution Expense	$4,224								$6,933
89												
90		Customer Accounts	Supervision									
91			Meter Reading	0								
92			Customer Records and Collection	1,489								
93			Uncollectible Accounts.					21,341				
94			Miscellaneous Customer Accounts Expenses.	41							3,315	
95			Sub-total Total Customer Accounts	$1,530				$21,341			$3,315	
96												

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
97		Customer Service and Information	Customer Assistance		$49							
98			Informational & Instructional									
99			Miscellaneous Customer & Informational									
100			Sub-total Customer Service & Information		$49							
101												
102		Sales	Demonstrating & Selling		$21							
103			Miscellaneous Sales									
104			Sub-total Sales		$21							
105												
106		Administrative & General	Administrative and General Salaries		$1,850							
107			Office Supplies and Expenses									
108			Administrative Expenses Transferred-Credit									
109			Outside Service Employed									
110			Property Insurance									
111			Injuries & Damages		72							
112			Employee Pensions and Benefits		1		263	(3,086)				
113			Regulatory Commission Expenses			37						
114			Duplicate Charges-Credit									
115			Miscellaneous General Expenses		0							
116			Maintenance of General Plant		51							
117			Sub-total Administrative & General		$1,974	$37	$263	($3,086)				
118												
119			**Total O&M Expense**		$7,798	$37	$263	($3,086)	$21,341		$3,315	$6,933
120												
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense									
122			Sub-total Depreciation & Amortization Expense									
123												
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense							(53)		
125			Sub-total Amortization of Regulatory Expense							($53)		
126												
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other									
128			Sub-total Taxes Other Than Income Taxes - Other									
129												
130			**Total Operating Expenses**		**$7,798**	**$37**	**$263**	**($3,086)**	**$21,341**	**($53)**	**$3,315**	**$6,933**
131												
132	**Net Operating Income Before Income Tax**			**$366**	**($7,798)**	**($37)**	**($263)**	**$3,086**	**($21,341)**	**$53**	**($3,315)**	**($6,933)**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
D-3 Adjustments to Net Operating Income

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 BESS Depr	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Elec Cost						$1,040,649
2			Cust & Dist					($25,257)	1,134,536
3			Sub-total Residential					($25,257)	$2,175,185
4									
5		Residential - House Heating	Elec Cost						$259,956
6			Cust & Dist					($4,868)	219,357
7			Sub-total Residential - House Heating					($4,868)	$479,313
8									
9		C & I Small	Elec Cost						$228,809
10			Cust & Dist					($24,304)	347,992
11			Sub-total C & I Small					($24,304)	$576,801
12									
13		C & I Large	Elec Cost						$82,981
14			Cust & Dist					($31,750)	243,952
15			Sub-total C & I Large					($31,750)	$326,933
16									
17		Railroads & Railways	Cust & Dist					($1,014)	$9,662
18			Sub-total Railroads & Railways					($1,014)	$9,662
19									
20		Street Lighting	Elec Cost						$600
21			Cust & Dist					($333)	25,092
22			Sub-total Street Lighting					($333)	$25,692
23									
24		Intercompany	Elec Cost						
25			Cust & Dist						
26			Sub-total Interdepartmental						
27									
28		Transmission - All Classes	Transmission - All Classes						$241,020
29			Sub-total Transmission - All Classes						$241,020
30									
31		Forfeited Discounts	Forfeited Discounts						$18,527
32			Sub-total Forfeited Discounts						$18,527
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$3,923
35			Sub-total Miscellaneous Service Revenues						$3,923
36									
37		Rent For Electric Property	Rent For Electric Property						$27,708
38			Sub-total Rent For Electric Property						$27,708
39									
40		Other Electric Revenues	Other Electric Revenues					$366	$3,779
41			Sub-total Other Electric Revenues					$366	$3,779
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($87,161)**	**$3,888,542**
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,513,792

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 BESS Depr	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
49			Sub-total Power Supply						$1,513,792
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						117,611
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						108,093
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						225,704
71									
72		Distribution Expense	Operation & Supervision					$18	$577
73			Load Dispatching						
74			Station Expense					14	7,147
75			Overhead Lines Expenses					122	17,832
76			Underground Lines Expense					128	11,466
77			Meter Expenses					112	6,490
78			Customer Installations Expense					269	13,367
79			Miscellaneous Expense					320	89,634
80			Rents						4,105
81			Maintenance of Structures					66	7,254
82			Maintenance of Station Equipment					346	17,283
83			Maintenance of Overhead Lines	127				9,037	202,158
84			Maintenance of Underground Lines					672	36,494
85			Maintenance of Line Transformers					34	2,640
86			Maintenance of Street Lighting & Signal Systems					6	1,828
87			Maintenance of Misc. Distribution					141	17,638
88			Sub-total Distribution Expense	$127				$11,284	$435,914
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$250
92			Customer Records and Collection					1,489	102,973
93			Uncollectible Accounts.					21,341	58,726
94			Miscellaneous Customer Accounts Expenses.					3,356	6,859
95			Sub-total Total Customer Accounts					$26,186	$168,808
96									

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 BESS Depr	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
97		Customer Service and Information	Customer Assistance					($79,157)	$35,434
98			Informational & Instructional						2,438
99			Miscellaneous Customer & Informational						935
100			Sub-total Customer Service & Information					($79,157)	$38,807
101									
102		Sales	Demonstrating & Selling					$21	$734
103			Miscellaneous Sales						
104			Sub-total Sales					$21	$734
105									
106		Administrative & General	Administrative and General Salaries					$1,850	$39,282
107			Office Supplies and Expenses						4,273
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						101,338
110			Property Insurance						970
111			Injuries & Damages					72	18,625
112			Employee Pensions and Benefits					(2,821)	32,797
113			Regulatory Commission Expenses					37	9,851
114			Duplicate Charges-Credit						(2,075)
115			Miscellaneous General Expenses					0	1,487
116			Maintenance of General Plant					51	10,000
117			Sub-total Administrative & General					($810)	$216,547
118									
119			**Total O&M Expense**	$127				($42,477)	$2,600,307
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense		$200		$27,307	$27,507	$408,021
122			Sub-total Depreciation & Amortization Expense		$200		$27,307	$27,507	$408,021
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					($53)	$16,572
125			Sub-total Amortization of Regulatory Expense					($53)	$16,572
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			(4,829)		($4,829)	$254,389
128			Sub-total Taxes Other Than Income Taxes - Other			($4,829)		($4,829)	$254,389
129									
130			**Total Operating Expenses**	**$127**	**$200**	**($4,829)**	**$27,307**	**($19,852)**	**$3,279,289**
131									
132	**Net Operating Income Before Income Tax**			**($127)**	**($200)**	**$4,829**	**($27,307)**	**($67,309)**	**$609,253**

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset	(9) D-12 Customer Deposit Interest
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,513,792								
2			Sub-total Power Supply	$1,513,792								
3												
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision									
5			561.0 Load Dispatching									
6			561.4 Scheduling, System Control & Dispatch	117,611								
7			561.6 Transmission Service Studies									
8			561.7 Generation Service Studies									
9			561.8 Reliability, Planning & Standard Development	108,093								
10			562.0 Station Expense									
11			563.0 Overhead Lines									
12			564.0 Underground Lines Expense									
13			566.0 Miscellaneous Expense									
14			567.0 Rents									
15			Sub-total Transmission Operations	$225,704								
16												
17		**Transmission Maintenance**	569.0 Maintenance of Structures									
18			569.1 Maintenance of Computer Hardware									
19			569.2 Maintenance of Computer Software									
20			569.3 Maintenance of Communication Equipment									
21			570.0 Maintenance of Station Equipment									
22			571.0 Maintenance of Overhead Lines									
23			572.0 Maintenance of Underground Lines									
24			573.0 Maintenance of Misc Transmission Plant									
25			Sub-total Transmission Maintenance									
26												
27			Sub-total TRANSMISSION EXPENSE	$225,704								
28												
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$559	$18							
30			581.0 Load Dispatching									
31			582.0 Station Expense	7,134	14							
32			583.0 Overhead Lines Expenses	17,711	122							
33			584.0 Underground Lines Expense	11,338	128							
34			586.0 Meter Expenses	6,378	112							
35			587.0 Customer Installations Expense	13,098	269							
36			588.0 Miscellaneous Expense	89,315	320							
37			589.0 Rents	4,105								
38			Sub-total Distribution Operations	$149,637	$982							
39												
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$7,189	$66							
41			592.0 Maintenance of Station Equipment	16,937	346							
42			593.0 Maintenance of Overhead Lines	193,120	1,978							
43			594.0 Maintenance of Underground Lines	35,822	672							
44			595.0 Maintenance of Line Transformers	2,606	34							
45			596.0 Maintenance of Street Lighting & Signal Systems	1,821	6							
46			598.0 Maintenance of Misc. Distribution	17,497	141							
47			Sub-total Distribution Maintenance	$274,993	$3,242							
48												

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset	(9) D-12 Customer Deposit Interest
49			Sub-total DISTRIBUTION EXPENSE	$424,631		$4,224						
50												
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision									
52			902.0 Meter Reading	$250		0						
53			903.0 Customer Records and Collection	101,485		1,489						
54			904.0 Uncollectible Accounts.	37,384						21,341		
55			905.0 Miscellaneous Customer Accounts Expenses.	3,503		41						3,315
56			Sub-total Customer Accounts	$142,622		$1,530				$21,341		$3,315
57												
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance	$114,591	($79,206)	$49						
59			909.0 Informational & Instructional	2,438								
60			910.0 Miscellaneous Customer & Informational	935								
61			Sub-total Customer Service & Information	$117,964	($79,206)	$49						
62												
63	**SALES**	**Sales**	912.0 Demonstrating & Selling	$714		$21						
64			916.0 Miscellaneous Sales									
65			Sub-total Sales	$714		$21						
66												
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries	$37,433		$1,850						
68			921.0 Office Supplies and Expenses	4,273								
69			922.0 Administrative Expenses Transferred-Credit									
70			923.0 Outside Service Employed	101,338								
71			924.0 Property Insurance	970								
72			925.0 Injuries & Damages	18,553		72						
73			926.0 Employee Pensions and Benefits	35,618		1			263	(3,086)		
74			928.0 Regulatory Commission Expenses	9,813			37					
75			929.0 Duplicate Charges-Credit	(2,075)								
76			930.2 Miscellaneous General Expenses	1,487		0						
77			Sub-total A&G Operations	$207,410		$1,923	$37	$263		($3,086)		
78												
79		A&G Maintenance	935.0 Maintenance of General Plant	$9,948		$51						
80												
81			Sub-total ADMINISTRATION & GENERAL	$217,358		$1,974	$37	$263		($3,086)		
82												
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$348,283								
84			404.0 Amort. Of Limited-Term Electric Plant.	32,231								
85			Sub-total Depreciation & Amortization Expense	$380,514								
86												
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$16,626							($53)	
88			Sub-total Amortization of Regulatory Expense	$16,626							($53)	
89												
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$259,218								
91			Sub-total Taxes Other Than Income Taxes - Other	$259,218								
92												
93			**Total**	**$3,299,142**	**($79,206)**	**$7,798**	**$37**	**$263**	**($3,086)**	**$21,341**	**($53)**	**$3,315**

Line No.	Category	Description	Account	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 BESS Depreciation	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.							$1,513,792
2			Sub-total Power Supply							$1,513,792
3										
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision							
5			561.0 Load Dispatching							
6			561.4 Scheduling, System Control & Dispatch							117,611
7			561.6 Transmission Service Studies							
8			561.7 Generation Service Studies							
9			561.8 Reliability, Planning & Standard Development							108,093
10			562.0 Station Expense							
11			563.0 Overhead Lines							
12			564.0 Underground Lines Expense							
13			566.0 Miscellaneous Expense							
14			567.0 Rents							
15			Sub-total Transmission Operations							$225,704
16										
17		**Transmission Maintenance**	569.0 Maintenance of Structures							
18			569.1 Maintenance of Computer Hardware							
19			569.2 Maintenance of Computer Software							
20			569.3 Maintenance of Communication Equipment							
21			570.0 Maintenance of Station Equipment							
22			571.0 Maintenance of Overhead Lines							
23			572.0 Maintenance of Underground Lines							
24			573.0 Maintenance of Misc Transmission Plant							
25			Sub-total Transmission Maintenance							
26										
27			Sub-total TRANSMISSION EXPENSE							$225,704
28										
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision						$18	$577
30			581.0 Load Dispatching							
31			582.0 Station Expense						$14	$7,147
32			583.0 Overhead Lines Expenses						$122	$17,832
33			584.0 Underground Lines Expense						$128	$11,466
34			586.0 Meter Expenses						$112	$6,490
35			587.0 Customer Installations Expense						$269	$13,367
36			588.0 Miscellaneous Expense						$320	$89,634
37			589.0 Rents							$4,105
38			Sub-total Distribution Operations						$982	$150,619
39										
40		**Distribution Maintenance**	591.0 Maintenance of Structures						$66	$7,254
41			592.0 Maintenance of Station Equipment						346	17,283
42			593.0 Maintenance of Overhead Lines	6,933	127				9,037	202,158
43			594.0 Maintenance of Underground Lines						672	36,494
44			595.0 Maintenance of Line Transformers						34	2,640
45			596.0 Maintenance of Street Lighting & Signal Systems						6	1,828
46			598.0 Maintenance of Misc. Distribution						141	17,638
47			Sub-total Distribution Maintenance	$6,933	$127				$10,302	$285,295
48										

Line No.	Category	Description	Account	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 BESS Depreciation	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE	$6,933	$127				$11,284	$435,914
50										
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision							
52			902.0 Meter Reading						$0	$250
53			903.0 Customer Records and Collection						$1,489	102,973
54			904.0 Uncollectible Accounts.						21,341	58,726
55			905.0 Miscellaneous Customer Accounts Expenses.						3,356	6,859
56			Sub-total Customer Accounts						$26,186	$168,808
57										
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance						($79,157)	$35,434
59			909.0 Informational & Instructional							2,438
60			910.0 Miscellaneous Customer & Informational							935
61			Sub-total Customer Service & Information						($79,157)	$38,807
62										
63	**SALES**	**Sales**	912.0 Demonstrating & Selling						$21	$734
64			916.0 Miscellaneous Sales							
65			Sub-total Sales						$21	$734
66										
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries						$1,850	$39,282
68			921.0 Office Supplies and Expenses							4,273
69			922.0 Administrative Expenses Transferred-Credit							
70			923.0 Outside Service Employed							101,338
71			924.0 Property Insurance							970
72			925.0 Injuries & Damages						72	18,625
73			926.0 Employee Pensions and Benefits						(2,821)	32,797
74			928.0 Regulatory Commission Expenses						37	9,851
75			929.0 Duplicate Charges-Credit							(2,075)
76			930.2 Miscellaneous General Expenses						0	1,487
77			Sub-total A&G Operations						($862)	$206,548
78										
79		A&G Maintenance	935.0 Maintenance of General Plant						$51	$10,000
80										
81			Sub-total ADMINISTRATION & GENERAL						($810)	$216,547
82										
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.			$200		$20,780	$20,980	$369,263
84			404.0 Amort. Of Limited-Term Electric Plant.					6,527	6,527	38,758
85			Sub-total Depreciation & Amortization Expense			$200		$27,307	$27,507	$408,021
86										
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.						($53)	$16,572
88			Sub-total Amortization of Regulatory Expense						($53)	$16,572
89										
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.				($4,829)		($4,829)	$254,389
91			Sub-total Taxes Other Than Income Taxes - Other				($4,829)		($4,829)	$254,389
92										
93			**Total**	**$6,933**	**$127**	**$200**	**($4,829)**	**$27,307**	**($19,852)**	**$3,279,289**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
D-5 Revenue Adjustment Summary

Line No.	Category	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E BESS	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) D-5H Other Adjustments	(10) Adjustments Sub-total	(11) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$1,159,793	$1,157	($2,563)	($2,128)	($22,525)	$167	$634			($25,257)	$1,134,536
2			Residential - House Heating	440.1	224,225	1,221	(319)	(470)	(5,526)	43	184			(4,868)	219,357
3			C & I Small	442.0	372,296	448	-	(1,377)	(23,578)		203			(24,304)	347,992
4			C & I Large	442.1	275,702		-	(1,025)	(30,894)		169			(31,750)	243,952
5			Railroads & Railways	446.0	10,676		-	-	(1,014)					(1,014)	9,662
6			Street Lighting	444.0	25,425		-		(333)					(333)	25,092
7			Intercompany	448.0											
8			Transmission - All Classes		241,020										241,020
9			Sub-total - Customer & Distribution Revenues		$2,309,138	$2,826	($2,882)	($5,000)	($83,870)	$210	$1,190			($87,527)	$2,221,611
10															
11		**Electric Cost Revenue**	Residential	440.0	$1,040,649										$1,040,649
12			Residential - House Heating	440.1	259,956										259,956
13			C & I Small	442.0	228,809										228,809
14			C & I Large	442.1	82,981										82,981
15			Railroads & Railways	446.0											
16			Street Lighting	444.0	600										600
17			Intercompany	448.0											
18			Sub-total - Electric Cost Revenue		$1,612,994										$1,612,994
19															
20			**Total OPERATING REVENUE**		$3,922,132	$2,826	($2,882)	($5,000)	($83,870)	$210	$1,190			($87,527)	$3,834,606
21															
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$27,708										$27,708
23			Other Electric Revenues	456.0	3,413								366	$366	3,779
24			Transmission of Electricity for Others	456.1											
25			Sub-total - Other electric Revenue		$31,121								$366	$366	$31,487
26															
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$18,527										$18,527
28			Miscellaneous Service Revenues	451.0	3,923										3,923
29			Sub-total - Other Operating Revenue		$22,450										$22,450
30															
31			**Total OTHER REVENUE**		$53,571								$366	$366	$53,936
32															
33			**Total REVENUE**		**$3,975,703**	**$2,826**	**($2,882)**	**($5,000)**	**($83,870)**	**$210**	**$1,190**		**$366**	**($87,161)**	**$3,888,542**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Total FPFTY Revenues		$2,332,500	$517,172	$648,328	$386,320	$1,034,647
2	Commodity Billings in Revenues		(1,172,707)	(292,947)	(276,032)	(110,618)	(386,649)
3	Weather Adjustment						
4	Total Reconcilable Surcharge in Revenues		(17,237)	(4,158)	(19,119)	(22,430)	(41,550)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$1,142,556	$220,067	$353,177	$253,272	$606,448
6							
7	Average Monthly Customers in FPFTY		1,348,092	210,225	155,655	3,156	158,811
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.848	$1.047	$2.269	$80.251	$3.819
10							
11	Number of Customers at end of FPFTY		1,349,457	211,391	155,852	3,156	159,008
12							
13	Increase in Customers during FPFTY	L11 - L7	1,366	1,166	197		197
14							
15	**Annualization of Revenue**	L9 * L13	**$1,157**	**$1,221**	**$448**		**$448**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales
1	CAP Discount		($210,969)	($26,278)
2				
3				
4	**ANNUALIZATION TO YEAR END CUSTOMERS**			
5				
6	Annual CAP Customers		1,532,199	192,664
7	Average Monthly CAP Customers		127,683	16,055
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.652)	($1.637)
9				
10	CAP Customers at End of FPFTY		129,444	16,277
11	Increase of CAP Customers	L10 - L7	1,761	221
12				
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($2,909)	($362)
14	Write-Offs & Working Capital Factor		11.9%	11.9%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$346	$43
16				
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($2,563)**	**($319)**

Line No.	Description	Reference	(1) 2027 Revenue Loss	(2) 2028 Revenue Loss	(3) 2028 Revenue Loss Over 2027	(4) Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2027 - Included in FPFTY Year Budget**					
2	Residential		($4,203)			
3	Residential Heaing		(929)			
4	Small C&I		(2,165)			
5	Large C&I		(1,604)			
6	Total	SUM L2 to L5	($8,901)			
7						
8	**Target Revenue Impact in 2028**					
9	Residential			($8,459)		
10	Residential Heaing			(1,870)		
11	Small C&I			(4,919)		
12	Large C&I			(3,654)		
13	Total	SUM L9 to L12		($18,902)		
14						
15	**Incremental Revenue Impact Over FPFTY Budget**					
16	Residential	L9 - L2			($4,256)	
17	Residential Heaing	L10 - L3			(941)	
18	Small C&I	L11 - L4			(2,754)	
19	Large C&I	L12 - L5			(2,050)	
20	Total	SUM L16 to L19			($10,001)	
21						
22	**Average Annual Incremental Revenue Not in FPFTY Budget**					
23	Residential	L16 / 2				($2,128)
24	Residential Heaing	L17 / 2				(470)
25	Small C&I	L18 / 2				(1,377)
26	Large C&I	L19 / 2				(1,025)
27	**Total**	SUM L23 to L26				**($5,000)**

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($22,525)
2	440001: Residential Heating Sales		(5,526)
3	442001: C&I Sales-Small		(23,578)
4	442002: C&I Sales-Large		(30,894)
5	444000: Public Street/Highway Lighting		(333)
6	446000: Sales-Railroad/Railway		(1,014)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($83,870)**
8			
9	O&M Expense		($79,206)

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential - Revenue for BESS		$167
2	440001: Residential Heating Sales - BESS		43
3	Increase in Revenue	L1 + L2	**$210**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-5F Leap Year Revenue Normalization

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Revenue in February of FPFTY		$71,010	$20,653	$22,758	$18,899	$41,657
2	Days in February of FPFTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$2,536	$738	$813	$675	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$634**	**$184**	**$203**	**$169**	**$372**

Line No.	Account	(1) Total
1	Residental Sales	
2	Residental Heating Sales	
3	C&I Sales-Small	
4	C&I Sales-Large	
5		
6	**Total**	

Line No.	Description	(1) Reference	(2) Total
1	Final Incremental COVID-19 Uncollectible Surcharge (ICUS) Reconciliation		
2	Residential		$935
3	Small C&I		(32)
4	Large C&I		(17)
5	Street Lighting		(11)
6	Sub-total ICUS Under Refund	SUM L2 to L5	$876
7	Final Fiber Affiliate Revenue Surcharge (FARS) Reconciliation		
8	Residential		($168)
9	Small C&I		(9)
10	Street Lighting		371
11	Large C&I & Railroads		(50)
12	Sub-total FARS Over Refund	SUM L8 to L11	$145
13	Total ICUS and FARS	L6 - L12	$731
14	Amortization Years		2
15	**Pro Forma Adjustment Amount**	L13 / L14	**$366**

Line No.	Description	(1) Reference	(2) Union	(3) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,106	1,191
2	Number of Employees @ HTY - Total		2,297	2,297
3	Percentage of Employees @ HTY	L1 / L2	48.14%	51.86%
4	Distribution of Budget S&W Expense		$86,406	$93,071
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$465
10		L4 + L9	$86,406	$93,537
11				
12	**Annualize January 1 and March 1, 2028 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		3.00%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$2,592	$2,806
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$88,998**	**$96,343**

Line No.	Description	(1) Reference	(2) Amount
1	Distribution of S&W Expense		$179,478
2			
3	Annualized S&W Including Wage Increases		$185,341
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		76.67%
8	Union Contract Payment for Utility	L6 * L7	$999
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$167
11			
12	Adjusted S&W for Employees in FPFTY	L3 + L10	$185,508
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		2,441
16	Average Number of Employees in FPFTY - Total		2,418
17	Annualization for Number of Employees	L15 - L16	23
18	Annual S&W per Employee	L12 / L16	$76.7
19	Annualization of S&W for New Employees	L17 * L18	$1,768
20			
21	Pro Forma FPFTY S&W	L12 + L19	$187,276
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$7,798**
24			
25	S&W Pro Forma Factor	L23 / L1	4.34%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$405	$18	$422
26			581.0 Load Dispatching			
27			582.0 Station Expense	313	14	327
28			583.0 Overhead Lines Expenses	2,806	122	2,927
29			584.0 Underground Lines Expense	2,951	128	3,079
30			586.0 Meter Expenses	2,574	112	2,686
31			587.0 Customer Installations Expense	6,191	269	6,460
32			588.0 Miscellaneous Expense	7,356	320	7,676
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,516	66	1,581
35			592.0 Maintenance of Station Equipment	7,966	346	8,312
36			593.0 Maintenance of Overhead Lines	45,525	1,978	47,503
37			594.0 Maintenance of Underground Lines	15,469	672	16,141
38			595.0 Maintenance of Line Transformers	772	34	805
39			596.0 Maintenance of Street Lighting & Signal Systems	141	6	147
40			598.0 Maintenance of Misc. Distribution	3,236	141	3,377
41			Sub-total Distribution Operations	$97,218	$4,224	$101,443
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	$0	$0	$0
45			903.0 Customer Records and Collection	34,262	1,489	35,751
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	944	41	985
48			Sub-total Customer Accounts	$35,207	$1,530	$36,736
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,137	$49	$1,187
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational			
53			Sub-total Customer Service & Information	$1,137	$49	$1,187
54						
55	**Sales**		912.0 Demonstrating & Selling	$472	$21	$493
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$472	$21	$493
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$42,573	$1,850	$44,423
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,652	72	1,724
65			926.0 Employee Pensions and Benefits	33	1	34
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	3	0	3
69			935.0 Maintenance of General Plant	1,183	51	1,234
70			Sub-total Administration & General	$45,443	$1,974	$47,418
71						
72			**Total**	**$179,478**	**$7,798**	**$187,276**
73						
74	**Percent Increas**		**Percent Increase**			4.34%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$111
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		$31
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$142
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,740
8	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		366
9	Total Expenditure Expected in FTY	SUM L7 to L8	$3,106
10			
11	Total Rate Case Expense	L4 + L9	$3,248
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,624
15			
16	Annual Amortization Amount Included in Budget		$1,587
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$37**

Line No.	Description	(1) Reference	(2) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,390
3	Employees at Ten Months Prior		2,391
4	Employees at Nine Months Prior		2,394
5	Employees at Eight Months Prior		2,405
6	Employees at Seven Months Prior		2,407
7	Employees at Six Months Prior		2,417
8	Employees at Five Months Prior		2,428
9	Employees at Four Months Prior		2,430
10	Employees at Three Months Prior		2,431
11	Employees at Two Months Prior		2,441
12	Employees at One Month Prior		2,441
13	Employees at End of FPFTY		2,441
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	2,418
16	Additional Employees in FPFTY		23
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$27,615
20	Number of Employees for Budget		2,418
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	23
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$263**

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$1,408
2	Pension Contribution for Three Years Prior to FPFTY		3,690
3	Pension Contribution for Two Years Prior to FPFTY		11,760
4	Pension Contribution for One Year Prior to FPFTY		10,374
5	Pension Contribution for FPFTY		10,508
6			
7	Average Pension Contribution	Average L1 to L5	$7,548
8			
9	Percent to Electric Distribution		76.67%
10	Total Amount to Electric Distribution	L7 * L9	$5,787
11	Pension Capitalization Factor		48.37%
12	Pension Contribution To Be Capitalized	L10 * L11	$2,799
13	Pension Contribution To Be Expensed	L10 - L12	$2,988
14	FPFTY Distribution Pension Expense		6,074
15	**Additional Pension Expense**	L13 - L14	**($3,086)**

Line No.	Description	Reference	Reference	Charge Off Amounts	InPA Charge Off Amounts	Net Charge Off Amounts	Billed Revenue	Percent	Totals
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$42,650	$17	$42,632	$3,880,008	1.0988%	
2		One Year Prior to HTY		28,792	2	28,791	4,036,898	0.7132%	
3		HTY		68,853		68,853	4,655,348	1.4790%	
4		Three Year Average	SUM L1 to L3 / 3	$46,765	$6	$46,759	$4,190,751	1.1158%	
5									
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY					$3,834,606		
7									
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6				$3,834,606		
9									
10	Tariff Revenue - Shopping Revenue	FPFTY					1,428,686		
11									
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10				$5,263,292		
13									
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12						$58,726
15									
16	Uncollectible Accounts (904)	FPFTY							$37,384
17									
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16						**$21,341**

Line No.	Description	(1) Reference	(2) Total
1	Actual IIJA Related Incremental Costs in 2024 and 2025		$451
2	Amortization Years		2
3	Total Pro Forma Adjustment Amount	L1 / L2	$226
4	Annual Amortization Amount Included in Budget		$279
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**($53)**

Line No.	Description	Description	Reference	(1) Interest Rate	(2) Deposit Amount	(3) Interest on Deposit Amount	(4) Interest Sub Total	(5) Interest Total
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				22,580	132		
4	February				23,154	135		
5	March				24,246	141		
6	April				25,771	150		
7	May				26,839	157		
8	June				27,171	158		
9	July				27,725	162		
10	August				28,297	165		
11	September				29,109	170		
12	October				29,946	175		
13	November				30,524	178		
14	December				30,889	180		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,903	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				35,889	105		
20	February				36,470	106		
21	March				37,775	110		
22	April				39,113	114		
23	May				39,833	116		
24	June				39,865	116		
25	July				40,669	119		
26	August				40,986	120		
27	September				41,497	121		
28	October				43,006	125		
29	November				43,769	128		
30	December				45,192	132		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,412	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,315**

Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
		(1)	(2)	(3)	(4)	(5)	(6)
1	2021		-	1.26853	$54,400	$69,009	
2	2022		0.07799	1.26853	$22,457	$28,488	
3	2023		0.04436	1.17676	$41,173	$48,451	
4	2024		0.03550	1.12677	$54,149	$61,014	
5	2025		0.03283	1.08815	$42,147	$45,862	
6	2026		0.02879	1.05356			
7	2027		0.02408	1.02408			
8							
9	Average Storm Restoration Expense at 2027 cost levels	Avg. Col 5, L1 to L5					$50,565
10							
11	FPFTY Budget						$43,632
12							
13	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$6,933**

Line No.	Description	(1) Reference	(2) Total
1	Deferred Storm Expense		$74,434
2	Amortization Years		5
3	Total Pro Forma Adjustment Amount	L1 / L2	$14,887
4	Annual Amortization Amount Included in Budget		$14,760
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**$127**

Line No.	Description	(1) Reference	(2) Total
1	BESS Plant in Service		$3,000
2	Amortization Perod	Years	15
3	Annual Depreciation Expense	L1 / L2	$200

Line No.	Description	Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
		(1)	(2)	(3)	(4)	(5)	(6)
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$8,306	($1,443)	$6,863		$6,863
2	Use Tax Accrued	17.372%	2,848	(495)	2,353		2,353
3	Real Estate Tax Accrued	17.372%	7,607	(1,321)	6,285		6,285
4	Miscellaneous TOTI	12.545%		-			
5	Payroll Tax Accrued	12.545%	16,456	(2,064)	14,392	625	15,017
6	Sub-total TOTI - Other	SUM L1 to L5	$35,217	($5,324)	$29,894	$625	$30,519
7							
8	Gross Receipt Tax		$229,324		$229,324	($5,454)	$223,870
9							
10	**Total**	L6 + L8	**$264,542**	**($5,324)**	**$259,218**	**($4,829)**	**$254,389**

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$179,478
2	Payroll Tax Expense		$14,392
3	Payroll Tax Expense - Percent	L2 / L1	8.02%
4	Pro Forma Increase in S&W		$7,798
5	**Payroll Tax Pro Forma**	L3 * L4	**$625**

Line No.	Description	Reference	(1) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		
2			
3	Residential		$2,175,185
4	Residential Heating		479,313
5	Small C&I		576,801
6	Large C&I		326,933
7	Railroads & Railways		9,662
8	Street Lighting & Highway		25,692
9	Interdepartmental Sales - Electric		
10	Transmission		241,020
11	Sub-total	SUM L3 to L10	$3,834,606
12			
13	Forfeited Discounts - Electric		$18,527
14	Uncollectible Accounts		(58,726)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($40,198)
17			
18	Total FPFTY at Present Rates	L11 + L16	$3,794,407
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$223,870
23			
24	FPFTY Budget		$229,324
25			
26	**Net Adjustment**	L22 - L24	**($5,454)**

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$5,006	$592	$4,414	$592	$5,598
2			PECO Elec 3650 PA LTIIP	6,043	576	5,467	576	6,619
3			PECO Elec 3660 PA LTIIP	6,979	1,030	5,949	1,030	8,009
4			PECO Elec 3670 PA LTIIP	12,072	1,506	10,566	1,506	13,577
5			PECO Elec 3705 SM UD RES PA	7,734		7,734		7,734
6			PECO Elec 3706 Non DOE Rcv PA	1,785		1,785		1,785
7			PECO Elec 3707 SM RES PA	8,426	186	8,240	186	8,612
8			PECO Elec 3708 SM SCI PA	751	4	747	4	755
9			PECO Elec 3709 SM LCI PA	1,473	28	1,445	28	1,501
10			PECO Electric 3611 PA	1,784	127	1,657	127	1,911
11			PECO Electric 3612 PA	4,455	314	4,141	314	4,769
12			PECO Electric 3613 PA	185	0	184	0	185
13			PECO Electric 3620 PA	24,466	717	23,749	717	25,182
14			PECO Electric 3631 PA	5,100	47	5,053	47	5,147
15			PECO Electric 3632 PA	24,778	282	24,496	282	25,060
16			PECO Electric 3633 PA	8,388	333	8,055	333	8,721
17			PECO Electric 3640 PA	39,245	2,677	36,568	2,677	41,922
18			PECO Electric 3650 PA	53,492	2,637	50,855	2,637	56,129
19			PECO Electric 3660 PA	14,111	1,074	13,037	1,074	15,185
20			PECO Electric 3670 PA	44,438	2,156	42,282	2,156	46,594
21			PECO Electric 3680 PA	26,446	1,727	24,719	1,727	28,173
22			PECO Electric 3691 PA	4,118	157	3,961	157	4,275
23			PECO Electric 3692 PA	4,521	29	4,492	29	4,550
24			PECO Electric 3701 PA	214	10	204	10	224
25			PECO Electric 3710 PA	4		4		4
26			PECO Electric 3730 PA	600		600	-	600
27			PECO Electric 3731 PA	56	0	56	0	56
28			PECO Electric 3732 PA	857	14	843	14	872
29			PECO Electric 3733 PA	24		24		24
30			Sub-total Electric - Distribution	$307,550	$16,222	$291,328	$16,222	$323,772
31			Sub-total Electric - Distribution	$307,550	$16,222	$291,328	$16,222	$323,772
32								
33		Electric - General Plant	PECO Common 3901 PA	$4,946	$102	$4,844	$102	$5,049
34			PECO Common 3902 IL	16		16		16
35			PECO Common 3902 PA	6,497	667	5,830	667	7,164
36			PECO Common 3903 PA	296	39	256	39	335
37			PECO Common 3911 PA	13		13		13
38			PECO Common 3912 PA	2,298	31	2,267	31	2,329
39			PECO Common 3913 IL	4,227	364	3,863	364	4,591
40			PECO Common 3913 PA	16,417	2,617	13,800	2,617	19,034
41			PECO Common 3930 PA	146	6	140	6	152
43			PECO Common 3942 PA	69	0	68	0	69
44			PECO Common 3970 PA	6,647	166	6,481	166	6,813
45			PECO Elec 3949 SM Tools PA	5		5		5
46			PECO Elec 3979 SM Comm Equip PA	69	23	45	23	92

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
47			PECO Electric 3901 PA	1,742	179	1,563	179	1,921
48			PECO Electric 3902 PA	355	5	351	5	360
49			PECO Electric 3903 PA	6		6		6
51			PECO Electric 3912 PA	82	3	79	3	85
52			PECO Electric 3913 PA	749	256	493	256	1,005
53			PECO Electric 3930 PA	4		4		4
54			PECO Electric 3940 PA	5,036	216	4,820	216	5,252
55			PECO Electric 3951 PA	4		4		4
57			PECO Electric 3971 PA	1,553	149	1,404	149	1,703
58			PECO Electric 3972 PA	2,474	708	1,766	708	3,182
59			PECO Electric 3973 PA	2,289	585	1,704	585	2,875
60			PECO Electric 3980 PA	207	13	194	13	219
61			Sub-total Electric - General Plant	$56,146	$6,131	$50,015	$6,131	$62,277
62			Sub-total Electric - General Plant	$56,146	$6,131	$50,015	$6,131	$62,277
63								
64		Electric - Transmission	PECO Electric 3511 PA	$3,217	$84	$3,133	$84	$3,302
65			PECO Electric 3512 PA	1,030	574	456	574	1,604
66			PECO Electric 3513 PA	1,667	374	1,293	374	2,041
67			PECO Electric 3521 PA	2,245	363	1,882	363	2,607
68			PECO Electric 3522 MD	1		1		1
69			PECO Electric 3522 NJ	0		0		0
70			PECO Electric 3522 PA	3,133	351	2,783	351	3,484
71			PECO Electric 3523 PA	86		86		86
72			PECO Electric 3530 NJ	63		63		63
73			PECO Electric 3530 PA	21,534	836	20,698	836	22,370
74			PECO Electric 3540 DE	87		87		87
75			PECO Electric 3540 MD	49		49		49
76			PECO Electric 3540 NJ	207		207		207
77			PECO Electric 3540 PA	3,440	64	3,376	64	3,504
78			PECO Electric 3550 PA	723	68	654	68	791
79			PECO Electric 3560 DE	5		5		5
80			PECO Electric 3560 MD	12		12		12
81			PECO Electric 3560 NJ	754	97	657	97	851
82			PECO Electric 3560 PA	2,749	261	2,488	261	3,011
83			PECO Electric 3570 PA	1,444	251	1,193	251	1,695
84			PECO Electric 3580 PA	3,029	268	2,761	268	3,297
85			PECO Electric 3590 MD	2	0	2	0	2
86			PECO Electric 3590 NJ	4		4		4
87			PECO Electric 3590 PA	20		20	-	20
88			Sub-total Electric - Transmission	$45,502	$3,592	$41,910	$3,592	$49,094
89								
90			Sub-total 403.0 Depreciation Expense	$409,198	$25,945	$383,252	$25,945	$435,143
91			Sub-total Electric - Transmission	$45,502	$3,592	$41,910	$3,592	$49,094
92								
93	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	$152		$152		$152

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
94			PECO Com 303-CFP MEU SW	135		135		135
95			PECO Com 303-CFP MMA SW	137		137		137
96			PECO Com 303-DSS Platform Enhanc SW	147		147		147
97			PECO Com 303-EU Custom Hardening SW	277		277		277
98			PECO Com 303-EU EAM SW	1,544	1,276	268	1,276	2,820
99			PECO Com 303-EU GIS Core SW	6,981		6,981		6,981
100			PECO Com 303-EU Reliab-Auto SW	139		139		139
101			PECO Com 303-Grid FR Workstream SW	99		99		99
102			PECO Com 303-IGA Enhance Prog SW-C	278		278		278
103			PECO Com 303-LMR SW C	367		367		367
104			PECO Com 303-MO New Bus. Portal SW	170		170		170
105			PECO Com 3030-Apollo SW	5,365	4,440	925	4,440	9,805
106			PECO Com 3030-BIDA-AMI Ph2 SW	2		2		2
107			PECO Com 3030-Cloud Serv 3 yr	766		766		766
108			PECO Com 3030-Cloud Serv 5 yr	4,851	153	4,698	153	5,003
109			PECO Com 3030-Common MDM SW	228		228		228
110			PECO Com 3030-EU Digital Program We	1,679		1,679		1,679
111			PECO Com 3030-EU oneMDS SW	4,314		4,314		4,314
112			PECO Com 3030-I Sign Up and Move	385		385		385
113			PECO Com 3030-IT Cust Mobile App SW	50		50		50
114			PECO Com 3030-IVR System PA	177		177		177
115			PECO Com 3030-Misc 5 yr FR PA	19,631	3,826	15,805	3,826	23,457
116			Sub-total Electric - Intangible Plant	$47,875	$9,695	$38,180	$9,695	$57,570
117								
118			Sub-total 404.0 Amort. of Limited-Term Electric Plant	$47,875	$9,695	$38,180	$9,695	$57,570
119								
120			**Total**	$457,073	$35,640	$421,432	$35,640	$492,713
121			Sub-total Electric - Intangible Plant	$47,875	$9,695	$38,180	$9,695	$57,570
122								
123			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.	$47,875	$9,695	$38,180	$9,695	$57,570

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$5,006	$592	$4,414	$592	$5,598
2			PECO Elec 3650 PA LTIIP	1.0000	$6,043	576	5,467	576	$6,619
3			PECO Elec 3660 PA LTIIP	1.0000	$6,979	1,030	5,949	1,030	$8,009
4			PECO Elec 3670 PA LTIIP	1.0000	$12,072	1,506	10,566	1,506	$13,577
5			PECO Elec 3705 SM UD RES PA	1.0000	$7,734		7,734		$7,734
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$1,785		1,785		$1,785
7			PECO Elec 3707 SM RES PA	1.0000	$8,426	186	8,240	186	$8,612
8			PECO Elec 3708 SM SCI PA	1.0000	$751	4	747	4	$755
9			PECO Elec 3709 SM LCI PA	1.0000	$1,473	28	1,445	28	$1,501
10			PECO Electric 3611 PA	1.0000	$1,784	127	1,657	127	$1,911
11			PECO Electric 3612 PA	1.0000	$4,455	314	4,141	314	$4,769
12			PECO Electric 3613 PA	1.0000	$185	0	184	0	$185
13			PECO Electric 3620 PA	1.0000	$24,466	717	23,749	717	$25,182
14			PECO Electric 3631 PA	1.0000	$5,100	47	5,053	47	$5,147
15			PECO Electric 3632 PA	1.0000	$24,778	282	24,496	282	$25,060
16			PECO Electric 3633 PA	1.0000	$8,388	333	8,055	333	$8,721
17			PECO Electric 3640 PA	1.0000	$39,245	2,677	36,568	2,677	$41,922
18			PECO Electric 3650 PA	1.0000	$53,492	2,637	50,855	2,637	$56,129
19			PECO Electric 3660 PA	1.0000	$14,111	1,074	13,037	1,074	$15,185
20			PECO Electric 3670 PA	1.0000	$44,438	2,156	42,282	2,156	$46,594
21			PECO Electric 3680 PA	1.0000	$26,446	1,727	24,719	1,727	$28,173
22			PECO Electric 3691 PA	1.0000	$4,118	157	3,961	157	$4,275
23			PECO Electric 3692 PA	1.0000	$4,521	29	4,492	29	$4,550
24			PECO Electric 3701 PA	1.0000	$214	10	204	10	$224
25			PECO Electric 3710 PA	1.0000	$4		4		$4
26			PECO Electric 3730 PA	1.0000	$600	-	$600	-	$600
27			PECO Electric 3731 PA	1.0000	$56	0	56	0	$56
28			PECO Electric 3732 PA	1.0000	$857	14	843	14	$872
29			PECO Electric 3733 PA	1.0000	$24		24		$24
30			Sub-total Electric - Distribution		$307,550	$16,222	$291,328	$16,222	$323,772
31			Sub-total Electric - Distribution		$307,550	$16,222	$291,328	$16,222	$323,772
32									
33		Electric - General Plant	PECO Common 3901 PA	0.7698	$3,808	$79	$3,729	$79	$3,886
34			PECO Common 3902 IL	0.7698	12		12		12
35			PECO Common 3902 PA	0.7698	5,001	513	4,488	513	5,515
36			PECO Common 3903 PA	0.7698	228	30	197	30	258
37			PECO Common 3911 PA	0.7698	10		10		10
38			PECO Common 3912 PA	0.7698	1,769	24	1,745	24	1,793
39			PECO Common 3913 IL	0.7698	3,254	280	2,974	280	3,534
40			PECO Common 3913 PA	0.7698	12,638	2,015	10,624	2,015	14,653
41			PECO Common 3930 PA	0.7698	112	5	108	5	117
43			PECO Common 3942 PA	0.7698	53	0	53	0	53
44			PECO Common 3970 PA	0.7698	5,117	128	4,989	128	5,245
45			PECO Elec 3949 SM Tools PA	1.0000	5		5		5
46			PECO Elec 3979 SM Comm Equip PA	1.0000	69	23	45	23	92

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
47			PECO Electric 3901 PA	1.0000	1,742	179	1,563	179	1,921
48			PECO Electric 3902 PA	1.0000	355	5	351	5	360
49			PECO Electric 3903 PA	1.0000	6		6		6
51			PECO Electric 3912 PA	1.0000	82	3	79	3	85
52			PECO Electric 3913 PA	1.0000	749	256	493	256	1,005
53			PECO Electric 3930 PA	1.0000	4		4		4
54			PECO Electric 3940 PA	1.0000	5,036	216	4,820	216	5,252
55			PECO Electric 3951 PA	1.0000	4		4		4
57			PECO Electric 3971 PA	1.0000	1,553	149	1,404	149	1,703
58			PECO Electric 3972 PA	1.0000	2,474	708	1,766	708	3,182
59			PECO Electric 3973 PA	1.0000	2,289	585	1,704	585	2,875
60			PECO Electric 3980 PA	1.0000	207	13	194	13	219
61			Sub-total Electric - General Plant		$46,576	$5,212	$41,364	$5,212	$51,788
62			Sub-total Electric - General Plant		$46,576	$5,212	$41,364	$5,212	$51,788
63									
64		Electric - Transmission	PECO Electric 3511 PA	1.0000	$3,217	$84	$3,133	$84	$3,302
65			PECO Electric 3512 PA	1.0000	1,030	574	456	574	1,604
66			PECO Electric 3513 PA	1.0000	1,667	374	1,293	374	2,041
67			PECO Electric 3521 PA	1.0000	2,245	363	1,882	363	2,607
68			PECO Electric 3522 MD	1.0000	1		1		1
69			PECO Electric 3522 NJ	1.0000	0		0		0
70			PECO Electric 3522 PA	1.0000	3,133	351	2,783	351	3,484
71			PECO Electric 3523 PA	1.0000	86		86		86
72			PECO Electric 3530 NJ	1.0000	63		63		63
73			PECO Electric 3530 PA	1.0000	21,534	836	20,698	836	22,370
74			PECO Electric 3540 DE	1.0000	87		87		87
75			PECO Electric 3540 MD	1.0000	49		49		49
76			PECO Electric 3540 NJ	1.0000	207		207		207
77			PECO Electric 3540 PA	1.0000	3,440	64	3,376	64	3,504
78			PECO Electric 3550 PA	1.0000	723	68	654	68	791
79			PECO Electric 3560 DE	1.0000	5		5		5
80			PECO Electric 3560 MD	1.0000	12		12		12
81			PECO Electric 3560 NJ	1.0000	754	97	657	97	851
82			PECO Electric 3560 PA	1.0000	2,749	261	2,488	261	3,011
83			PECO Electric 3570 PA	1.0000	1,444	251	1,193	251	1,695
84			PECO Electric 3580 PA	1.0000	3,029	268	2,761	268	3,297
85			PECO Electric 3590 MD	1.0000	2	0	2	0	2
86			PECO Electric 3590 NJ	1.0000	4		4		4
87			PECO Electric 3590 PA	1.0000	20	-	20	-	20
88			Sub-total Electric - Transmission		$45,502	$3,592	$41,910	$3,592	$49,094
89									
90			Sub-total 403.0 Depreciation Expense		$399,628	$25,026	$374,602	$25,026	$424,654
91			Sub-total Electric - Transmission		$45,502	$3,592	$41,910	$3,592	$49,094
92									
93	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.7698	$117		$117		$117

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
94			PECO Com 303-CFP MEU SW	0.7698	104		104		104
95			PECO Com 303-CFP MMA SW	0.7698	106		106		106
96			PECO Com 303-DSS Platform Enhanc SW	0.7698	113		113		113
97			PECO Com 303-EU Custom Hardening SW	0.7698	213		213		213
98			PECO Com 303-EU EAM SW	0.7698	1,189	982	206	982	2,171
99			PECO Com 303-EU GIS Core SW	0.7698	5,374		5,374		5,374
100			PECO Com 303-EU Reliab-Auto SW	0.7698	107		107		107
101			PECO Com 303-Grid FR Workstream SW	0.7698	76		76		76
102			PECO Com 303-IGA Enhance Prog SW-C	0.7698	214		214		214
103			PECO Com 303-LMR SW C	0.7698	283		283		283
104			PECO Com 303-MO New Bus. Portal SW	0.7698	131		131		131
105			PECO Com 3030-Apollo SW	0.7698	4,130	3,418	712	3,418	7,548
106			PECO Com 3030-BIDA-AMI Ph2 SW	0.7698	2		2		2
107			PECO Com 3030-Cloud Serv 3 yr	0.7698	590		590		590
108			PECO Com 3030-Cloud Serv 5 yr	0.7698	3,734	118	3,616	118	3,851
109			PECO Com 3030-Common MDM SW	0.7698	176		176		176
110			PECO Com 3030-EU Digital Program We	0.7698	1,293		1,293		1,293
111			PECO Com 3030-EU oneMDS SW	0.7698	3,321		3,321		3,321
112			PECO Com 3030-I Sign Up and Move	0.7698	296		296		296
113			PECO Com 3030-IT Cust Mobile App SW	0.7698	39		39		39
114			PECO Com 3030-IVR System PA	0.7698	137		137		137
115			PECO Com 3030-Misc 5 yr FR PA	0.7698	15,112	2,945	12,166	2,945	18,057
116			Sub-total Electric - Intangible Plant		$36,854	$7,463	$29,391	$7,463	$44,317
117									
118			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$36,854	$7,463	$29,391	$7,463	$44,317
119									
120			**Total**		$436,482	$32,489	$403,993	$32,489	$468,972
121			Sub-total Electric - Intangible Plant		$36,854	$7,463	$29,391	$7,463	$44,317
122									
123			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$36,854	$7,463	$29,391	$7,463	$44,317

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$5,006	$592	$4,414	$592	$5,598
2			PECO Elec 3650 PA LTIIP	1.0000	$6,043	$576	$5,467	$576	$6,619
3			PECO Elec 3660 PA LTIIP	1.0000	$6,979	$1,030	$5,949	$1,030	$8,009
4			PECO Elec 3670 PA LTIIP	1.0000	$12,072	$1,506	$10,566	$1,506	$13,577
5			PECO Elec 3705 SM UD RES PA	1.0000	$7,734		$7,734		$7,734
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$1,785		$1,785		$1,785
7			PECO Elec 3707 SM RES PA	1.0000	$8,426	$186	$8,240	$186	$8,612
8			PECO Elec 3708 SM SCI PA	1.0000	$751	$4	$747	$4	$755
9			PECO Elec 3709 SM LCI PA	1.0000	$1,473	$28	$1,445	$28	$1,501
10			PECO Electric 3611 PA	1.0000	$1,784	$127	$1,657	$127	$1,911
11			PECO Electric 3612 PA	1.0000	$4,455	$314	$4,141	$314	$4,769
12			PECO Electric 3613 PA	1.0000	$185	$0	$184	$0	$185
13			PECO Electric 3620 PA	1.0000	$24,466	$717	$23,749	$717	$25,182
14			PECO Electric 3631 PA	1.0000	$5,100	$47	$5,053	$47	$5,147
15			PECO Electric 3632 PA	1.0000	$24,778	$282	$24,496	$282	$25,060
16			PECO Electric 3633 PA	1.0000	$8,388	$333	$8,055	$333	$8,721
17			PECO Electric 3640 PA	1.0000	$39,245	$2,677	$36,568	$2,677	$41,922
18			PECO Electric 3650 PA	1.0000	$53,492	$2,637	$50,855	$2,637	$56,129
19			PECO Electric 3660 PA	1.0000	$14,111	$1,074	$13,037	$1,074	$15,185
20			PECO Electric 3670 PA	1.0000	$44,438	$2,156	$42,282	$2,156	$46,594
21			PECO Electric 3680 PA	1.0000	$26,446	$1,727	$24,719	$1,727	$28,173
22			PECO Electric 3691 PA	1.0000	$4,118	$157	$3,961	$157	$4,275
23			PECO Electric 3692 PA	1.0000	$4,521	$29	$4,492	$29	$4,550
24			PECO Electric 3701 PA	1.0000	$214	$10	$204	$10	$224
25			PECO Electric 3710 PA	1.0000	$4		$4		$4
26			PECO Electric 3730 PA	1.0000	$600		$600		$600
27			PECO Electric 3731 PA	1.0000	$56	$0	$56	$0	$56
28			PECO Electric 3732 PA	1.0000	$857	$14	$843	$14	$872
29			PECO Electric 3733 PA	1.0000	$24		$24		$24
30			Sub-total Electric - Distribution		$307,550	$16,222	$291,328	$16,222	$323,772
31			Sub-total Electric - Distribution		$307,550	$16,222	$291,328	$16,222	$323,772
32									
33		Electric - General Plant	PECO Common 3901 PA	0.8746	$3,330	$69	$3,261	$69	$3,399
34			PECO Common 3902 IL	0.8746	11		11		11
35			PECO Common 3902 PA	0.8746	4,374	449	3,925	449	4,823
36			PECO Common 3903 PA	0.8746	199	26	173	26	225
37			PECO Common 3911 PA	0.8746	8		8		8
38			PECO Common 3912 PA	0.8746	1,547	21	1,526	21	1,568
39			PECO Common 3913 IL	0.8746	2,846	245	2,601	245	3,091
40			PECO Common 3913 PA	0.8746	11,053	1,762	9,291	1,762	12,815
41			PECO Common 3930 PA	0.8746	98	4	94	4	102
43			PECO Common 3942 PA	0.8746	46	0	46	0	46
44			PECO Common 3970 PA	0.8746	4,475	112	4,363	112	4,587
45			PECO Elec 3949 SM Tools PA	0.8746	4		4		4
46			PECO Elec 3979 SM Comm Equip PA	0.8746	60	20	40	20	80

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
47			PECO Electric 3901 PA	0.8746	1,524	157	1,367	157	1,680
48			PECO Electric 3902 PA	0.8746	311	4	307	4	315
49			PECO Electric 3903 PA	0.8746	6		6		6
51			PECO Electric 3912 PA	0.8746	72	3	69	3	74
52			PECO Electric 3913 PA	0.8746	655	224	431	224	879
53			PECO Electric 3930 PA	0.8746	3		3		3
54			PECO Electric 3940 PA	0.8746	4,404	189	4,215	189	4,593
55			PECO Electric 3951 PA	0.8746	3		3		3
57			PECO Electric 3971 PA	0.8746	1,359	131	1,228	131	1,489
58			PECO Electric 3972 PA	0.8746	2,163	619	1,544	619	2,783
59			PECO Electric 3973 PA	0.8746	2,002	512	1,490	512	2,514
60			PECO Electric 3980 PA	0.8746	181	11	169	11	192
61			Sub-total Electric - General Plant		$40,733	$4,558	$36,175	$4,558	$45,292
62			Sub-total Electric - General Plant		$40,733	$4,558	$36,175	$4,558	$45,292
63									
64		Electric - Transmission	PECO Electric 3511 PA						
65			PECO Electric 3512 PA						
66			PECO Electric 3513 PA						
67			PECO Electric 3521 PA						
68			PECO Electric 3522 MD						
69			PECO Electric 3522 NJ						
70			PECO Electric 3522 PA						
71			PECO Electric 3523 PA						
72			PECO Electric 3530 NJ						
73			PECO Electric 3530 PA						
74			PECO Electric 3540 DE						
75			PECO Electric 3540 MD						
76			PECO Electric 3540 NJ						
77			PECO Electric 3540 PA						
78			PECO Electric 3550 PA						
79			PECO Electric 3560 DE						
80			PECO Electric 3560 MD						
81			PECO Electric 3560 NJ						
82			PECO Electric 3560 PA						
83			PECO Electric 3570 PA						
84			PECO Electric 3580 PA						
85			PECO Electric 3590 MD						
86			PECO Electric 3590 NJ						
87			PECO Electric 3590 PA						
88			Sub-total Electric - Transmission						
89									
90			Sub-total 403.0 Depreciation Expense		$348,283	$20,780	$327,503	$20,780	$369,063
91			Sub-total Electric - Transmission						
92									
93	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.8746	102		102		102

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
94			PECO Com 303-CFP MEU SW	0.8746	91		91		91
95			PECO Com 303-CFP MMA SW	0.8746	92		92		92
96			PECO Com 303-DSS Platform Enhanc SW	0.8746	99		99		99
97			PECO Com 303-EU Custom Hardening SW	0.8746	187		187		187
98			PECO Com 303-EU EAM SW	0.8746	1,039	859	180	859	1,899
99			PECO Com 303-EU GIS Core SW	0.8746	4,700		4,700		4,700
100			PECO Com 303-EU Reliab-Auto SW	0.8746	94		94		94
101			PECO Com 303-Grid FR Workstream SW	0.8746	66		66		66
102			PECO Com 303-IGA Enhance Prog SW-C	0.8746	187		187		187
103			PECO Com 303-LMR SW C	0.8746	247		247		247
104			PECO Com 303-MO New Bus. Portal SW	0.8746	114		114		114
105			PECO Com 3030-Apollo SW	0.8746	3,612	2,989	623	2,989	6,601
106			PECO Com 3030-BIDA-AMI Ph2 SW	0.8746	1		1		1
107			PECO Com 3030-Cloud Serv 3 yr	0.8746	516		516		516
108			PECO Com 3030-Cloud Serv 5 yr	0.8746	3,266	103	3,163	103	3,368
109			PECO Com 3030-Common MDM SW	0.8746	154		154		154
110			PECO Com 3030-EU Digital Program We	0.8746	1,131		1,131		1,131
111			PECO Com 3030-EU oneMDS SW	0.8746	2,905		2,905		2,905
112			PECO Com 3030-I Sign Up and Move	0.8746	259		259		259
113			PECO Com 3030-IT Cust Mobile App SW	0.8746	34		34		34
114			PECO Com 3030-IVR System PA	0.8746	119		119		119
115			PECO Com 3030-Misc 5 yr FR PA	0.8746	13,216	2,576	10,640	2,576	15,792
116			Sub-total Electric - Intangible Plant		$32,231	$6,527	$25,704	$6,527	$38,758
117									
118			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$32,231	$6,527	$25,704	$6,527	$38,758
119									
120			**Total**		$380,514	$27,307	$353,207	$27,307	$407,821
121			Sub-total Electric - Intangible Plant		$32,231	$6,527	$25,704	$6,527	$38,758
122									
123			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$32,231	$6,527	$25,704	$6,527	$38,758

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$3,888,542	$430,592	$4,319,134
2	Operating Expenses		3,279,289	31,662	3,310,951
3	OIBIT	L1 - L2	$609,253	$398,930	$1,008,183
4					
5	Rate Base		$10,951,677		$10,951,677
6	Weighted Cost of Debt		2.230%		2.230%
7	Synchronized Interest Expense	L5 * L6	$244,222		$244,222
8	Base Taxable Income	L3 - L7	$365,030	$398,930	$763,960
9					
10	State Accelerated Tax Depreciation		$354,699		$354,699
11	Pro Forma Book Depreciation		408,021		408,021
12	State Tax Depreciation (Over) Under Book	L11 - L10	$53,322		$53,322
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		1,458		1,458
14	Other Property Basis Adjustments (CIAC/ICM)		(102,036)		(102,036)
15	Removal Costs/Software		(10,066)		(10,066)
16	AFUDC Equity		-		-
17	Permanent Adjustments		4,234		4,234
18	Repair Deduction		(377,000)		(377,000)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($65,058)	$398,930	$333,872
21					
22	State Income Tax Rate		6.99%	6.99%	6.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$4,548	($27,885)	($23,338)
24	Net Operating Loss Utilization %		60.00%	60.00%	60.00%
25	Net Operating Loss Utilization	- L24 * L23	(2,729)	16,731	14,003
26	State Income Tax Benefit / (Expense)	L23 + L25	$1,819	($11,154)	($9,335)
27					
28	Federal Accelerated Tax Depreciation		$363,401		$363,401
29	Pro Forma Book Depreciation		408,021		408,021
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$44,620		$44,620
31	Regulatory Asset Programs M-1		1,458		1,458
32	Other Property Basis Adjustments (CIAC/ICM)		(115,508)		(115,508)
33	Removal Costs/Software		(10,066)		(10,066)
34	AFUDC Equity		-		-
35	Permanent Adjustments		4,234		4,234
36	Repair Deduction		(377,000)		(377,000)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($85,413)	$387,776	$302,363
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$17,937	($81,433)	($63,496)
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$19,756	($92,587)	($72,831)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($15,791)	$3,514	($12,277)
47	Deferred Taxes on Timing Differences- State		(7,030)		(7,030)
48	Deferred Taxes on State NOL		2,729	(16,731)	(14,003)
49	Excess Deferred Amortization		6,781		6,781
50	Excess Deferred Amortization - State (Net of Federal)		552		552
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(24,461)		(24,461)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	($37,221)	($13,218)	($50,439)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	($17,466)	($105,805)	($123,270)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		($17)		($17)
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	($17,483)	($105,805)	($123,287)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	($15,551)	($77,919)	($93,471)
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	($1,931)	($27,885)	($29,816)
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**($17,483)**	**($105,805)**	**($123,287)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		18,527
4	Total Customer Revenue		3,922,132
5	Shopping Revenue		1,428,686
6	LPC REVENUE	L3 / (L4 + L5)	0.003462
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.011158)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003628)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.929677
13			
14	STATE INCOME TAX RATE		6.990%
15			
16	STATE INCOME TAX FACTOR	-	(0.064984)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.864692
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.181585)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.683107
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.463899
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	24.657%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		6.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.069900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.930100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.195321)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.734779
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.360953
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	26.522%

PECO Exhibit MJT-2:
Principal Accounting Exhibit
Future Test Year ending 2026

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
A-1 Overall Summary

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$12,041,093		$12,041,093
3	Accumulated Depreciation	C-3	2,134,209		2,134,209
4	Common Plant - Net of Accum Depr	C-8	589,038		589,038
5	Net Plant in service	L2 - L3 + L4	$10,495,922		$10,495,922
6					
7	Working Capital	C-1	$331,116		$331,116
8	Pension Assets / (Liability)	C-1	163,162		163,162
9	Accum Deferred Income Taxes	C-1	(734,779)		(734,779)
10	Customer Deposits	C-1	(66,853)		(66,853)
11	Customer Advances for Construction	C-1	(10,468)		(10,468)
12	Materials and Supplies	C-1	53,088		53,088
13	Accum Deferred Income Taxes - Reg Liability	C-1	(271,066)		(271,066)
14					
15	TOTAL RATE BASE	SUM L5 to L13	$9,960,123		$9,960,123
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$2,157,924	$298,434	$2,456,358
19	Electric Cost Revenue	D-5	$1,513,506		1,513,506
20	Other Operating Revenues	D-5	$52,950	1,059	54,009
21	Total Revenues	SUM L18 to L20	$3,724,380	$299,493	$4,023,874
22					
23	Operating Expenses	D-1	$3,100,734	$22,020	$3,122,754
24					
25	OIBIT	L21 - L23	$623,646	$277,473	$901,120
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	($26,634)		($26,634)
28	Income Taxes @ Statutory Rates	D-18		(74,688)	(74,688)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$597,012	$202,785	$799,798
31					
32	RATE OF RETURN	L30 / L15	5.99%		8.03%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	5.99%		
36					
37	Rate of Return Required	B-7	8.03%		
38					
39	Change in ROR	L37 - L35	2.04%		
40					
41	Change in Operating Income	L15 * L39	$202,785		
42					
43	Gross Revenue Conversion Factor	D-19	1.472		
44					
45	Change in Revenues	L41 * L43	$298,434		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	53.40%		
49	Common Equity Rate Base	L15 * L48	$5,318,706		
50	NET OPERATING INCOME	L30 / L15	$597,012		
51	Synchronized Interest Expense	D-18	$217,131		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$379,882		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	7.14%		

Line No.	Description	(1) Reference	(2) Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$21,059,422
3	Construction Work In Progress (107)		1,220,330
4	Total Utility Plant	L2 + L3	$22,279,752
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,653,056
6	Net Utility Plant	L4 - L5	$17,626,696
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,599
11	Invest in Assoc Company (123)		7,258
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$58,466
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$25,000
17	Customer Accounts Receivable (142)		670,914
18	Other Accounts Receivable (143)		32,249
19	Accum. Prov. for Uncollectible (144)		(158,892)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		1,710
22	Plant Materials & Supplies (154)		90,271
23	Gas Stored - Current (164.1		44,585
24	Liquefied Natural Gas stored (164.2)		3,369
25	Prepayments (165)		73,503
26	Accrued Utility Revenues (173)		303,923
27	Miscellaneous Current & Accrued Assets (174)		2,920
28	Total Current and Accrued Assets	SUM L16 to L27	$1,089,553
29			
30	**Deferred Debits**		
31	Unamortized Debt Expense (181)		$59,895
32	Other Regualtory Assets (182.3)		1,576,512
33	Miscellaneous Deferred Debits (186)		898,338
34	Unamortized Loss on Reacquired Debt (189)		561
35	Accumulated Deferred Income Taxes (190)		0
36	Total Deferred Debits	SUM L31 to L35	$2,535,305
37			
38	**TOTAL ASSETS**	L6+L13+L28+L36	$21,310,020

Line No.	Description	(1) Reference	(2) Total - PECO
39	**Proprietary Capital**		
40	Common Stock Issued (201)		$1,423,004
41	Preferred Stock Issued (204)		
42	Other Paid-In Capital (208-211)		4,396,960
43	Capital Stock Expense (214)		(87)
44	Retained Earnings (215, 215.2, 216)		2,671,097
45	Unappropriated Undistributed Subsidiary Earnings (216.1)		
46	Accum Other Comprehensive Income (219)		
47	Total Propriety Capital & Margins	SUM L40 to L46	$8,490,974
48			
49	**Long Term Debt**		
50	Bonds (221)		$7,225,000
51	Advances from Associated Companies (223)		184,419
52	Other Long-Term Debt (224)		
53	Unamortized Premium on LTD (225)		
54	Unamortized Discount on LTD (226)		(23,777)
55	Total Long-Term Debt	SUM L50 to L54	$7,385,642
56			
57	**Other Non-Current Liabilities**		
58	Obligations under Capital Leases (227)		
59	Accum. Prov for Injuries & Damages (228.2)		$62,513
60	Accum. Prov for Pensions & Benefits (228.3)		300,354
61	Accum. Miscellaneous Operating Prov (228.4)		11,729
62	Asset Retirement Obligation (230)		25,844
63	Total Other Non-Current Liabilities	SUM L58 to L62	$400,440
64			
65	**Current and Accrued Liabilities**		
66	Notes Payable (231)		$166,667
67	Accounts Payable (232)		776,814
68	Notes Payable to Assoc. Companies (233)		
69	Accounts Payable to Assoc. Companies (234)		22,766
70	Customer Deposits (235)		93,432
71	Taxes Accrued (236)		24,426
72	Interest Accrued (237)		92,818
73	Dividends Declared (238)		
74	Tax Collections Payable (241)		86
75	Misc Current & Accrued Liabilities (242)		158,156
76	Total Current & Accrued Liabilities	SUM L66 to L75	$1,335,166
77			
78	**Other Deferred Credits**		
79	Customer Advances for Construction (252)		$15,732
80	Other Deferred Credits (253)		8,645
81	Other Regulatory Liabilities (254)		565,616
82	Deferred Investment Tax Credit (255)		264
83	Unamortized Gain on Reacquired Debt (257)		
84	Accumulated Deferred Income Taxes (281-283)		3,107,542
85	Total Other Deferred Credits	SUM L79 to L84	$3,697,798
86			
87	**TOTAL LIABILITIES AND OTHER CREDITS**	L47+L55+L63+L76+L85	$21,310,020

Line No.	Category	Description	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,997,614		$1,997,614
2		Electric Cost Revenue	1,513,506		1,513,506
3		Transmission - All Classes	226,232		226,232
4		Other Revenues	324,865	$272,280	52,584
5		Total Operating Revenues	$4,062,218	$272,280	$3,789,938
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,589,597	$96,788	$2,492,809
8		Depreciation & Amortization Expense	393,146	49,375	343,772
9		Amortization of Regulatory Expense	1,099		1,099
10		Taxes Other Than Income Taxes - Other	253,387	5,190	248,197
11		Total Operating Expenses	$3,237,229	$151,352	$3,085,877
12					
13	**Net Utility Operating Income Before Income Tax**		**$824,989**	**$120,928**	**$704,061**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$1,130,090		$1,130,090
2			Residential - House Heating	440.1	217,436		217,436
3			C & I Small	442.0	353,486		353,486
4			C & I Large	442.1	261,609		261,609
5			Street Lighting	444.0	24,657		24,657
6			Railroads & Railways	446.0	10,337		10,337
7			Intercompany	448.0			
8			Transmission - All Classes		226,232		226,232
9			Sub-total - Customer & Distribution Revenues		$2,223,847		$2,223,847
10							
11		Electric Cost Revenue	Residential	440.0	$976,446		$976,446
12			Residential - House Heating	440.1	241,229		241,229
13			C & I Small	442.0	214,828		214,828
14			C & I Large	442.1	80,396		80,396
15			Street Lighting	444.0	607		607
16			Intercompany	448.0			
17			Sub-total - Electric Cost Revenue		$1,513,506		$1,513,506
18							
19		Other Operating Revenues	Forfeited Discounts	450.0	$18,329		$18,329
20			Miscellaneous Service Revenues	451.0	3,923		3,923
21			Rent For Electric Property	454.0	39,124	$12,085	27,040
22			Other Electric Revenues	456.0	3,293		3,293
23			Transmission of Electricity for Others	456.1	260,195	260,195	
24			Sub-total - Other Operating Revenues		$324,865	$272,280	$52,584
25							
26			**TOTAL OPERATING REVENUES**		$4,062,218	$272,280	$3,789,938

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
27							
28	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,418,435		$1,418,435
29			Operation & Supervision	560.0	9,162	$9,162	
30			Load Dispatching	561.0			
31			Scheduling, System Control & Dispatch	561.4	110,360		110,360
32			Transmission Service Studies	561.6	15,087	15,087	
33			Generation Service Studies	561.7			
34			Reliability, Planning & Standard Development	561.8	101,429		101,429
35			Station Expense	562.0	1,151	1,151	
36			Overhead Lines	563.0	456	456	
37			Underground Lines Expense	564.0			
38			Miscellaneous Expense	566.0	(2,634)	(2,634)	
39			Rents	567.0	14,455	14,455	
40			Maintenance of Structures	569.0	2,420	2,420	
41			Maintenance of Computer Hardware	569.1	118	118	
42			Maintenance of Computer Software	569.2	(955)	(955)	
43			Maintenance of Communication Equipment	569.3	118	118	
44			Maintenance of Station Equipment	570.0	654	654	
45			Maintenance of Overhead Lines	571.0	9,086	9,086	
46			Maintenance of Underground Lines	572.0	458	458	
47			Maintenance of Misc Transmission Plant	573.0	2,746	2,746	
48			Maint Energy Storage Equipment & Structures	578.2	(3)	(3)	
49			Operation & Supervision	580.0	530		530
50			Load Dispatching	581.0			
51			Station Expenses	582.0	6,973		6,973
52			Overhead Lines Expenses	583.0	17,302		17,302
53			Underground Lines Expense	584.0	11,059		11,059
54			Meter Expenses	586.0	6,216		6,216
55			Customer Installations Expense	587.0	12,650		12,650
56			Miscellaneous Expense	588.0	87,589		87,589
57			Rents	589.0	4,215		4,215
58			Maintenance of Structures	591.0	7,015		7,015
59			Maintenance of Station Equipment	592.0	16,512		16,512
60			Maintenance of Overhead Lines	593.0	188,602		188,602
61			Maintenance of Underground Lines	594.0	34,508		34,508
62			Maintenance of Line Transformers	595.0	2,663		2,663
63			Maintenance of Street Lighting & Signal Systems	596.0	1,761		1,761
64			Maintenance of Misc. Distribution	598.0	17,317		17,317

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
65			Supervision	901.0			
66			Meter Reading	902.0	245		245
67			Customer Records and Collection	903.0	98,222		98,222
68			Uncollectible Accounts	904.0	34,396		34,396
69			Miscellaneous Customer Accounts	905.0	3,433		3,433
70			Customer Assistance	908.0	99,468		99,468
71			Informational & Instructional	909.0	2,389		2,389
72			Miscellaneous Customer & Informational	910.0	908		908
73			Demonstrating & Selling	912.0	682		682
74			Miscellaneous Sales	916.0			
75			Administrative and General Salaries	920.0	64,927	27,843	37,084
76			Office Supplies and Expenses	921.0	4,053	(167)	4,220
77			Administrative Expenses Transferred-Credit	922.0			
78			Outside Service Employed	923.0	110,986	11,620	99,366
79			Property Insurance	924.0	1,079	128	951
80			Injuries & Damages	925.0	16,346		16,346
81			Employee Pensions and Benefits	926.0	33,325	2,245	31,080
82			Regulatory Commission Expenses	928.0	10,511	892	9,619
83			Duplicate Charges-Credit	929.0	(1,117)	909	(2,026)
84			Miscellaneous General Expenses	930.2	1,884	368	1,516
85			Maintenance of General Plant	935.0	9,776		9,776
86				Sub-total - O&M Expenses	$2,588,967	$96,158	$2,492,809
87							
88		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$358,836	$45,070	$313,766
89				404.0	34,310	4,304	30,006
90				Sub-total - Depreciation & Amortization Expense	$393,146	$49,375	$343,772
91							
92		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3	$1,099		$1,099
93				Sub-total - Amortization of Regulatory Expense	$1,099		$1,099
94							
95		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$253,387	$5,190	$248,197
96				Sub-total -Taxes Other Than Income Taxes - Other	$253,387	$5,190	$248,197
97							
98				**TOTAL OPERATING EXPENSES**	$3,236,599	$150,723	$3,085,877
99							
100				**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**	**$825,618**	**$121,557**	**$704,061**
101							

Line No.	Category	Description	Description	Account	FTY Amount (1)	Non-Jurisdictional (2)	Jurisdictional (3)
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$1,130,090		$1,130,090
2			Residential - House Heating	440.1	217,436		217,436
3			C & I Small	442.0	353,486		353,486
4			C & I Large	442.1	261,609		261,609
5			Railroads & Railways	446.0	10,337		10,337
6			Street Lighting	444.0	24,657		24,657
7			Intercompany	448.0			
8			Transmission - All Classes		226,232		226,232
9			Sub-total - Customer & Distribution Revenue		$2,223,847		$2,223,847
10							
11		**Electric Cost Revenue**	Residential	440.0	$976,446		$976,446
12			Residential - House Heating	440.1	241,229		241,229
13			C & I Small	442.0	214,828		214,828
14			C & I Large	442.1	80,396		80,396
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	607		607
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,513,506		$1,513,506
19							
20			**TOTAL OPERATING REVENUE**		$3,737,353		$3,737,353
21							
22	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$18,329		$18,329
23			Miscellaneous Service Revenues	451.0	3,923		3,923
24			Sub-total - Other Operating Revenue		$22,252		$22,252
25							
26		**Other Electric Revenue**	Rent For Electric Property	454.0	$39,124	$12,085	$27,040
27			Other Electric Revenues	456.0	3,293		3,293
28			Transmission of Electricity for Others	456.1	260,195	260,195	
29			Sub-total - Other Electric Revenue		$302,613	$272,280	$30,333
30							
31			**TOTAL OTHER REVENUE**		$324,865	$272,280	$52,584
32							
33			**TOTAL REVENUE**		**$4,062,218**	**$272,280**	**$3,789,938**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
B-4 O+M Expenses

Line No.	Category	Description	Account	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,418,435		$1,418,435
2			**TOTAL POWER SUPPLY EXPENSES**		$1,418,435		$1,418,435
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$9,162	$9,162	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	110,360		110,360
7			Transmission Service Studies	561.6	15,087	15,087	
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	101,429		101,429
10			Station Expense	562.0	1,151	1,151	
11			Overhead Lines	563.0	456	456	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	(2,634)	(2,634)	
14			Rents	567.0	14,455	14,455	
15			Sub-total Transmission Operations	SUM L4 to L14	$249,467	$37,678	$211,789
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	$2,420	$2,420	
18			Maintenance of Computer Hardware	569.1	118	118	
19			Maintenance of Computer Software	569.2	(955)	(955)	
20			Maintenance of Communication Equipment	569.3	118	118	
21			Maintenance of Station Equipment	570.0	654	654	
22			Maintenance of Overhead Lines	571.0	9,086	9,086	
23			Maintenance of Underground Lines	572.0	458	458	
24			Maintenance of Misc Transmission Plant	573.0	2,746	2,746	
25			Maint Energy Storage Equipment & Structures	578.2	(3)	(3)	
26			Misc Distribution Expenses	588.0	(10)	(10)	
27			Maintenan Energy Storage Equipment	592.2	1	1	
28			Maintenance of Overhead Lines	593.0	640	640	
29			Sub-total Transmission Maintenance	SUM L17 to L28	$15,272	$15,272	
30							
31			**TOTAL TRANSMISSION EXPENSE**	L15 + L29	$264,739	$52,950	$211,789
32							
33	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$530		$530
34			Load Dispatching	581.0			
35			Station Expenses	582.0	6,973		6,973
36			Overhead Lines Expenses	583.0	17,302		17,302
37			Underground Lines Expense	584.0	11,059		11,059
38			Meter Expenses	586.0	6,216		6,216
39			Customer Installations Expense	587.0	12,650		12,650
40			Miscellaneous Expense	588.0	87,589		87,589
41			Rents	589.0	4,215		4,215
42			Sub-total Distribution Operations	SUM L33 to L41	$146,533		$146,533
43							
44		Distribution Maintenance	Maintenance of Structures	591.0	$7,015		$7,015
45			Maintenance of Station Equipment	592.0	16,512		16,512
46			Maintenance of Overhead Lines	593.0	188,602		188,602
47			Maintenance of Underground Lines	594.0	34,508		34,508

Line No.	Category	Description	Account	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
48			Maintenance of Line Transformers	595.0	2,663		2,663
49			Maintenance of Street Lighting & Signal Systems	596.0	1,761		1,761
50			Maintenance of Misc. Distribution	598.0	17,317		17,317
51			Sub-total Distribution Maintenance	SUM L44 to L50	$268,377		$268,377
52							
53			**TOTAL DISTRIBUTION EXPENSE**	L42 + L51	$414,911		$414,911
54							
55	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
56			Meter Reading	902.0	$245		$245
57			Customer Records and Collection	903.0	98,222		98,222
58			Uncollectible Accounts	904.0	34,396		34,396
59			Miscellaneous Customer Accounts	905.0	3,433		3,433
60			**TOTAL CUSTOMER ACCOUNTS**	SUM L55 to L59	$136,296		$136,296
61							
62	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$99,468		$99,468
63			Informational & Instructional	909.0	2,389		2,389
64			Miscellaneous Customer & Informational	910.0	908		908
65			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L62 to L64	$102,765		$102,765
66							
67	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$682		$682
68			Miscellaneous Sales	916.0			
69			**TOTAL SALES EXPENSE**	SUM L67 to L68	$682		$682
70							
71	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$64,927	$27,843	$37,084
72			Office Supplies and Expenses	921.0	4,053	(167)	4,220
73			Administrative Expenses Transferred-Credit	922.0			
74			Outside Service Employed	923.0	110,986	$11,620	99,366
75			Property Insurance	924.0	1,079	$128	951
76			Injuries & Damages	925.0	16,346		16,346
77			Employee Pensions and Benefits	926.0	33,325	$2,245	31,080
78			Regulatory Commission Expenses	928.0	10,511	$892	9,619
79			Duplicate Charges-Credit	929.0	(1,117)	$909	(2,026)
80			Miscellaneous General Expenses	930.2	1,884	$368	1,516
81			Sub-total A&G Operations	SUM L71 to L80	$241,993	$43,838	$198,156
82							
83		A&G Maintenance	Maintenance of General Plant	935.0	9,776		9,776
84							
85			TOTAL ADMINISTRATION & GENERAL	L81 + L83	$251,769	$43,838	$207,932
86							
87			**TOTAL O&M EXPENSE**	L2+L31+L53+L60+L65+L69+L85	$2,589,597	$96,788	$2,492,809
88							
89			TOTAL OPERATIONS EXPENSE		$2,305,947	$81,516	$2,224,432
90			TOTAL MAINTENANCE EXPENSE		283,649	15,272	268,377
91			**TOTAL O&M EXPENSE**	L89 + L90	**$2,589,597**	**$96,788**	**$2,492,809**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
B-4 O+M Expenses - A+G Detail

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$37,085	0.0000%		$37,085
2			Office Supplies and Expenses	921.0	4,220	0.0000%		4,220
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	99,366	0.0000%		99,366
5			Property Insurance	924.0	951	0.0000%		951
6			Injuries and Damages	925.0	16,346	0.0000%		16,346
7			Employee Pensions and Benefits	926.0	31,080	0.0000%		31,080
8			Regulatory Commission Expenses	928.0	9,619	0.0000%		9,619
9			Duplicate Charges-Credit	929.0	(2,026)	0.0000%		(2,026)
10			Miscellaneous General Expenses	930.2	1,515	0.0000%		1,515
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$198,156			$198,156
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,776	0.0000%		$9,776
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$207,932			$207,932
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	$27,843	100.0000%	$27,843	
17			Office Supplies and Expenses	921.0	(167)	100.0000%	(167)	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	11,620	100.0000%	11,620	
20			Property Insurance	924.0	128	100.0000%	128	
21			Injuries and Damages	925.0		100.0000%		
22			Employee Pensions and Benefits	926.0	2,245	100.0000%	2,245	
23			Regulatory Commission Expenses	928.0	892	100.0000%	892	
24			Duplicate Charges-Credit	929.0	909	100.0000%	909	
25			Miscellaneous General Expenses	930.2	368	100.0000%	368	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$43,838		$43,838	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0		100.0000%		
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$43,838		$43,838	
30								

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0	($1)	12.5447%	($0)	($1)
32			Office Supplies and Expenses	921.0	0	12.5447%	0	0
33			Administrative Expenses Transferred-Credit	922.0		12.5447%		
34			Outside Service Employed	923.0		12.5447%		
35			Property Insurance	924.0		12.5447%		
36			Injuries and Damages	925.0		12.5447%		
37			Employee Pensions and Benefits	926.0	(1)	12.5447%	(0)	(0)
38			Regulatory Commission Expenses	928.0		12.5447%		
39			Duplicate Charges-Credit	929.0		12.5447%		
40			Miscellaneous General Expenses	930.2	1	12.5447%	0	1
41			Sub-total A&G Operations - General	SUM L31 to L40	$0		$0	$0
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0		12.5447%		
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	$0		$0	$0
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$64,927		$27,843	$37,084
47			Office Supplies and Expenses	921.0	4,053		(167)	4,220
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	110,986		11,620	99,366
50			Property Insurance	924.0	1,079		128	951
51			Injuries & Damages	925.0	16,346			16,346
52			Employee Pensions and Benefits	926.0	33,325		2,245	31,080
53			Regulatory Commission Expenses	928.0	10,511		892	9,619
54			Duplicate Charges-Credit	929.0	(1,117)		909	(2,026)
55			Miscellaneous General Expenses	930.2	1,884		368	1,516
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$241,993		$43,838	$198,156
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,776			$9,776
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	**$251,769**		**$43,838**	**$207,932**

Line No.	Description	Percentage	Total	Transmission Elimination	Distribution
		(1)	(2)	(3)	(4)
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$8,306	($1,443)	$6,863
2	Use Tax Accrued	17.372%	2,848	(495)	2,353
3	Real Estate Tax Accrued	17.372%	7,421	(1,289)	6,132
4	Miscellaneous TOTI	12.545%		-	
5	Payroll Tax Accrued	12.545%	15,650	(1,963)	13,686
6	Gross Receipt Tax		219,162		219,162
7	**Total**		**$253,387**	**($5,190)**	**$248,197**

				(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost	
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%			
2					7.76%		0.39%		
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%			
4					1.01%		0.06%		
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%			
6					7.09%		0.35%		
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%			
8					4.05%		0.24%		
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%			
10					2.36%		0.14%		
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%			
12					3.37%		0.16%		
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%			
14					4.05%		0.17%		
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%			
16					4.39%		0.17%		
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%			
18					4.39%		0.18%		
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%			
20					4.39%		0.18%		
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%			
22					4.39%		0.14%		
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%			
24					4.72%		0.14%		
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%			
26					5.06%		0.16%		
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%			
28					5.06%		0.15%		
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%			
30					4.72%		0.22%		
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%			
32					5.74%		0.26%		
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%			
34					7.76%		0.41%		
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%			
36					7.09%		0.41%		
37		PECO - FMB - $750 - 5.80% - Due 8-1-56		750,000		5.87%			
38					10.12%		0.59%		
39									
40		Sub-total Mortgage Bonds	SUM L1 to L39	$7,225,000	97.51%		4.52%		
41									
42	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%			
43					1.09%		0.08%		
44		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%			
45					0.01%				
46		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%			
47					1.39%		0.08%		
48									
49		Sub-total Capital Securities	SUM L42 to L48	$184,419	2.49%		0.16%		
50									
51		Total Long-Term Debt	L40 + L49	$7,409,419	100.00%		4.68%		
52									
53		Adjustments for Tenders & Calls		(453)					
54									
55		Net Long-Term Debt	L51 + L53	$7,408,966					
56									
57		Annualized Cost		346,761					
58									
59		Adjustment for Tenders & Calls Reacquired		68					
60									
61		**Total**	L57 + L59	$346,829					**4.68%**

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$7,408,966	46.60%	4.68%	2.18%
3					
4	Common Equity	$8,490,974	53.40%	10.95%	5.85%
5					
6	Total	**$15,899,940**	**100.00%**		**8.03%**

Line No.	Description	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
		(1)	(2)	(3)	(4)
1	Utility Plant	C-2	$14,385,530	$2,344,436	$12,041,093
2	Accumulated Depreciation	C-3	2,841,244	707,035	2,134,209
3	Common Plant	C-8	589,038		589,038
4	**Net Plant in Service**	L1 - L2 + L3	$12,133,323	$1,637,401	$10,495,922
5					
6	Working Capital	C-4	$331,116		$331,116
7	Pension Assets / (Liability)	C-5	163,162		163,162
8	Accumulated Deferred Income Taxes	C-6	(734,779)		(734,779)
9	Customer Deposits	C-7	(66,853)		(66,853)
10	Customer Advances for Construction	C-9	(10,468)		(10,468)
11	Material & Supplies	C-11	53,088		53,088
12	ADIT - Reg Liability	C-12	(271,066)		(271,066)
13	**Total Measures of Value**	SUM L4 to L12	**$11,597,524**	**$1,637,401**	**$9,960,123**

Line No.	Category	Account	Reference	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Intangible Plant**	E302 - Franchises and Consents		$163	$20	$142
2		E303 - Misc Intangible Plant		6,914		6,914
3		Sub-total Intangible Plant	SUM L1 to L3	$7,077	$20	$7,056
4						
5	**Transmission Plant**	E350 - Land and Land Rights		$92,459	$92,459	
6		E351.1 - Computer Hardware		10,141	10,141	
7		E351.2 - Computer Software		24,025	24,025	
8		E351.3 - Communication Equipment		27,907	27,907	
9		E352 - Structures and Improvements		221,281	221,281	
10		E353 - Station Equipment		1,135,054	1,135,054	
11		E354 - Towers and Fixtures		301,489	301,489	
12		E355 - Poles and Fixtures		38,182	38,182	
13		E356 - Overhead Conductors, Devices		244,438	244,438	
14		E357 - Underground Conduit		63,287	63,287	
15		E358 - Undergrnd Conductors, Devices		155,439	155,439	
16		E359 - Roads and Trails		2,651	2,651	
17		E359.1 - ARO Costs Transmission Plt		739	739	
18		Sub-total Transmission Plant	SUM L5 to L17	$2,317,093	$2,317,093	
19						
20	**Distribution Plant**	E360 - Land and Land Rights		$56,497		$56,497
21		E361 - Structures and Improvements		285,322		285,322
22		E362 - Station Equipment		1,350,384		1,350,384
23		E363.1 - Computer Hardware		15,643		15,643
24		E363.2 - Computer Software		185,136		185,136
25		E363.3 - Communication Equipment		137,005		137,005
26		E364 - Poles, Towers and Fixtures		1,706,357		1,706,357
27		E365 - Overhead Conductors, Devices		2,500,653		2,500,653
28		E366 - Underground Conduit		1,190,122		1,190,122
29		E367 - Undergrnd Conductors, Devices		2,405,045		2,405,045
30		E368 - Line Transformers		1,026,673		1,026,673
31		E369 - Services		501,936		501,936
32		E370 - Meters		394,397		394,397
33		E371 - Installs on Customer Premise		13,772		13,772
34		E373 - Street Lighting, Signal Systems		70,851		70,851
35		E374 - ARO Costs Distribution Plant		3,770		3,770
36		Sub-total Distribution Plant	SUM L20 to L35	$11,843,563		$11,843,563
37						
38	**General Plant**	E389 - Land and Land Rights		$1,063	$133	$930
39		E390 - Structures and Improvements		71,777	9,004	62,772
40		E391 - Office Furniture, Equipment		5,295	664	4,630
41		E393 - Stores Equipment		44	6	39
42		E394 - Tools, Shop, Garage Equipment		70,765	8,877	61,887
43		E395 - Laboratory Equipment		97	12	85
44		E397.1 - Computer Hardware		6,549	822	5,727
45		E397.2 - Computer Software		22,890	2,872	20,019
46		E397.3 - Communication Equipment		35,026	4,394	30,632
47		E398 - Miscellaneous Equipment		1,996	250	1,746
48		E399.1 - ARO Costs General Plant		2,295	288	2,007
49		Sub-total General Plant	SUM L38 to L48	$217,797	$27,323	$190,474
50						
51		**Total**	L3+L18+L36+L49	**$14,385,530**	**$2,344,436**	**$12,041,093**

Line No.	Category	Account	(1) Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E350 - Land and Land Rights	
5		E351.1 - Computer Hardware	$53
6		E351.2 - Computer Software	125
7		E351.3 - Communication Equipment	145
8		E352 - Structures and Improvements	32,528
9		E353 - Station Equipment	37,713
10		E354 - Towers and Fixtures	2,370
11		E355 - Poles and Fixtures	3,322
12		E356 - Overhead Conductors, Devices	9,649
13		E357 - Underground Conduit	12,169
14		E358 - Undergrnd Conductors, Devics	12,250
15		E359 - Roads and Trails	8
16		E359.1 - ARO Costs Transmission Plt	63
17		Sub-total Transmission Plant	$110,394
18			
19	**Distribution Plant**	E361 - Structures and Improvements	$31,273
20		E362 - Station Equipment	42,970
21		E363.1 - Computer Hardware	208
22		E363.2 - Computer Software	2,022
23		E363.3 - Communication Equipment	1,338
24		E364 - Poles, Towers and Fixtures	222,642
25		E365 - Overhead Conductors, Devices	218,912
26		E366 - Underground Conduit	154,546
27		E367 - Undergrnd Conductors, Devics	248,298
28		E368 - Line Transformers	126,206
29		E369 - Services	13,243
30		E370 - Meters	16,735
31		E371 - Installs on Customer Premiss	
32		E373 - Street Lighting,Signal Systm	1,811
33		E374 - ARO Costs Distribution Plt	259
34		Sub-total Distribution Plant	$1,080,463
35			
36	**General Plant**	E390 - Structures and Improvements	$3,212
37		E391 - Office Furniture, Equipment	4,689
38		E394 - Tools, Shop, Garage Equipmnt	3,882
39		E397.1 - Computer Hardware	159
40		E397.2 - Computer Software	563
41		E397.3 - Communication Equipment	1,966
42		E398 - Miscellaneous Equipment	9
43		Sub-total General Plant	$14,480
44			
45		**Total**	**$1,205,337**

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E352 - Structures and Improvements	($1,539)
5		E353 - Station Equipment	(3,859)
6		E354 - Towers and Fixtures	(344)
7		E355 - Poles and Fixtures	-
8		E356 - Overhead Conductors, Devices	(871)
9		E357 - Underground Conduit	(25)
10		E358 - Undergrnd Conductors, Devics	(117)
11		E359.1 - ARO Costs Transmission Plt	(2)
12		Sub-total Transmission Plant	($6,758)
13			
14	**Distribution Plant**	E361 - Structures and Improvements	($938)
15		E362 - Station Equipment	(12,300)
16		E363.1 - Computer Hardware	(3,886)
17		E363.2 - Computer Software	(4,967)
18		E363.3 - Communication Equipment	(223)
19		E364 - Poles, Towers and Fixtures	(32,793)
20		E365 - Overhead Conductors, Devices	(18,080)
21		E366 - Underground Conduit	(1,242)
22		E367 - Undergrnd Conductors, Devics	(31,383)
23		E368 - Line Transformers	(23,239)
24		E369 - Services	(178)
25		E370 - Meters	(161)
26		E373 - Street Lighting,Signal Systm	(562)
27		E374 - ARO Costs Distribution Plt	(43)
28		Sub-total Distribution Plant	($129,996)
29			
30	**General Plant**	E390 - Structures and Improvements	($183)
31		E391 - Office Furniture, Equipment	(510)
32		E393 - Stores Equipment	(1)
33		E394 - Tools, Shop, Garage Equipmnt	(1,148)
34		E395 - Laboratory Equipment	-
35		E397.1 - Computer Hardware	(587)
36		E397.2 - Computer Software	(2,348)
37		E397.3 - Communication Equipment	(952)
38		E398 - Miscellaneous Equipment	
39		E399.1 - ARO Costs General Plt	(125)
40		Sub-total General Plant	($5,852)
41			
42		**Total**	**($142,606)**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents	$163	100.00%	$163	87.46%	$142	$20
2			$163		$163		$142	$20
3								
4		E303 - Misc Intangible Plant	$6,914	100.00%	$6,914	100.00%	$6,914	
5			$6,914		$6,914		$6,914	
6								
7		Sub-total Intangible Plant	$7,077		$7,077		$7,056	$20
8								
9	**Transmission Plant**	E350 - Land and Land Rights	$92,459	100.00%	$92,459			$92,459
10			$92,459		$92,459			$92,459
11								
12		E351.1 - Computer Hardware	$10,141	100.00%	$10,141			$10,141
13			$10,141		$10,141			$10,141
14								
15		E351.2 - Computer Software	$24,025	100.00%	$24,025			$24,025
16			$24,025		$24,025			$24,025
17								
18		E351.3 - Communication Equipment	$27,907	100.00%	$27,907			$27,907
19			$27,907		$27,907			$27,907
20								
21		E352 - Structures and Improvements	221,281	100.00%	221,281			221,281
22			221,281		221,281			221,281
23								
24		E353 - Station Equipment	1,135,054	100.00%	1,135,054			1,135,054
25			1,135,054		1,135,054			1,135,054
26								
27		E354 - Towers and Fixtures	301,489	100.00%	301,489			301,489
28			301,489		301,489			301,489
29								
30		E355 - Poles and Fixtures	38,182	100.00%	38,182			38,182
31			38,182		38,182			38,182
32								
33		E356 - Overhead Conductors, Devices	244,438	100.00%	244,438			244,438
34			244,438		244,438			244,438
35								
36		E357 - Underground Conduit	63,287	100.00%	63,287			63,287
37			63,287		63,287			63,287
38								
39		E358 - Undergrnd Conductors, Devices	155,439	100.00%	155,439			155,439
40			155,439		155,439			155,439
41								
42		E359 - Roads and Trails	2,651	100.00%	2,651			2,651
43			2,651		2,651			2,651
44								
45		E359.1 - ARO Costs Transmission Plt	739	100.00%	739			739
46			739		739			739
47								
48		Sub-total Transmission Plant	$2,317,093		$2,317,093			$2,317,093
49								

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
50	**Distribution Plant**	E360 - Land and Land Rights	$56,497	100.00%	$56,497	100.00%	$56,497	
51			$56,497		$56,497		$56,497	
52								
53		E361 - Structures and Improvements	285,322	100.00%	285,322	100.00%	285,322	
54			285,322		285,322		285,322	
55								
56		E362 - Station Equipment	1,350,384	100.00%	1,350,384	100.00%	1,350,384	
57			1,350,384		1,350,384		1,350,384	
58								
59		E363.1 - Computer Hardware	15,643	100.00%	15,643	100.00%	15,643	
60			15,643		15,643		15,643	
61								
62		E363.2 - Computer Software	185,136	100.00%	185,136	100.00%	185,136	
63			185,136		185,136		185,136	
64								
65		E363.3 - Communication Equipment	137,005	100.00%	137,005	100.00%	137,005	
66			137,005		137,005		137,005	
67								
68		E364 - Poles, Towers and Fixtures	1,706,357	100.00%	1,706,357	100.00%	1,706,357	
69			1,706,357		1,706,357		1,706,357	
70								
71		E365 - Overhead Conductors, Devices	2,500,653	100.00%	2,500,653	100.00%	2,500,653	
72			2,500,653		2,500,653		2,500,653	
73								
74		E366 - Underground Conduit	1,190,122	100.00%	1,190,122	100.00%	1,190,122	
75			1,190,122		1,190,122		1,190,122	
76								
77		E367 - Undergrnd Conductors, Devices	2,405,045	100.00%	2,405,045	100.00%	2,405,045	
78			2,405,045		2,405,045		2,405,045	
79								
80		E368 - Line Transformers	1,026,673	100.00%	1,026,673	100.00%	1,026,673	
81			1,026,673		1,026,673		1,026,673	
82								
83		E369 - Services	501,936	100.00%	501,936	100.00%	501,936	
84			501,936		501,936		501,936	
85								
86		E370 - Meters	394,397	100.00%	394,397	100.00%	394,397	
87			394,397		394,397		394,397	
88								
89		E371 - Installs on Customer Premise	13,772	100.00%	13,772	100.00%	13,772	
90			13,772		13,772		13,772	
91								
92		E373 - Street Lighting, Signal Systems	70,851	100.00%	70,851	100.00%	70,851	
93			70,851		70,851		70,851	
94								
95		E374 - ARO Costs Distribution Plant	3,770	100.00%	3,770	100.00%	3,770	
96		Electric Nonrecoverable 100%						
97			3,770		3,770		3,770	
98								
99		Sub-total Distribution Plant	$11,843,563		$11,843,563		$11,843,563	
100								

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
101	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.46%	$930	$133
102			$1,063		$1,063		$930	$133
103								
104		E390 - Structures and Improvements	71,777	100.00%	71,777	87.46%	62,773	9,004
105			71,777		71,777		62,773	9,004
106								
107		E391 - Office Furniture, Equipment	5,295	100.00%	5,295	87.46%	4,630	664
108			5,295		5,295		4,630	664
109								
110		E393 - Stores Equipment	44	100.00%	44	87.46%	39	6
111			44		44		39	6
112								
113		E394 - Tools, Shop, Garage Equipment	70,765	100.00%	70,765	87.46%	61,887	8,877
114			70,765		70,765		61,887	8,877
115								
116		E395 - Laboratory Equipment	97	100.00%	97	87.46%	85	12
117			97		97		85	12
118								
119		E397.1 - Computer Hardware	6,549	100.00%	6,549	87.46%	5,727	822
120			6,549		6,549		5,727	822
121								
122		E397.2 - Computer Software	22,890	100.00%	22,890	87.46%	20,019	2,872
123			22,890		22,890		20,019	2,872
124								
125		E397.3 - Communication Equipment	35,026	100.00%	35,026	87.46%	30,632	4,394
126			35,026		35,026		30,632	4,394
127								
128		E398 - Miscellaneous Equipment	1,996	100.00%	1,996	87.46%	1,746	250
129			1,996		1,996		1,746	250
130								
131		E399.1 - ARO Costs General Plant	2,295	100.00%	2,295	87.46%	2,007	288
132			2,295		2,295		2,007	288
133								
134		Sub-total General Plant	$217,797		$217,797		$190,475	$27,322
135								
136								
137		**Total**	**$14,385,530**		**$14,385,530**		**$12,041,094**	**$2,344,436**

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	E302 - Franchises and Consents				
2		E303 - Misc Intangible Plant				
3		Sub-total Intangible Plant	SUM L1 to L3			
4						
5	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
6		E351.1 - Computer Hardware		$6,411	$6,411	
7		E351.2 - Computer Software		$22,795	$22,795	
8		E351.3 - Communication Equipment		$15,791	$15,791	
9		E352 - Structures and Improvements		20,168	20,168	
10		E353 - Station Equipment		278,358	278,358	
11		E354 - Towers and Fixtures		180,281	180,281	
12		E355 - Poles and Fixtures		7,797	7,797	
13		E356 - Overhead Conductors, Devices		98,705	98,705	
14		E357 - Underground Conduit		7,632	7,632	
15		E358 - Undergrnd Conductors, Devices		54,827	54,827	
16		E359 - Roads and Trails		2,277	2,277	
17		E359.1 - ARO Costs Transmission Plt		201	201	
18		Sub-total Transmission Plant	SUM L5 to L17	$695,243	$695,243	
19						
20	**Distribution Plant**	E360 - Land and Land Rights		$310		$310
21		E361 - Structures and Improvements		53,590		$53,590
22		E362 - Station Equipment		491,766		$491,766
23		E363.1 - Computer Hardware		9,545		$9,545
24		E363.2 - Computer Software		74,091		$74,091
25		E363.3 - Communication Equipment		67,124		$67,124
26		E364 - Poles, Towers and Fixtures		9,266		$9,266
27		E365 - Overhead Conductors, Devices		309,347		$309,347
28		E366 - Underground Conduit		209,459		$209,459
29		E367 - Undergrnd Conductors, Devices		150,429		$150,429
30		E368 - Line Transformers		151,334		151,334
31		E369 - Services		219,483		219,483
32		E370 - Meters		254,773		254,773
33		E371 - Installs on Customer Premises		11,743		11,743
34		E373 - Street Lighting, Signal Systems		37,216		37,216
35		E374 - ARO Costs Distribution Plant		2,531		2,531
36		Sub-total Distribution Plant	SUM L20 to L35	$2,052,007		$2,052,007
37						
38	**General Plant**	E389 - Land and Land Rights				
39		E390 - Structures and Improvements		$19,022	$2,386	$16,636
40		E391 - Office Furniture, Equipment		201	25	176
41		E393 - Stores Equipment		37	5	32
42		E394 - Tools, Shop, Garage Equipmnt		28,940	3,630	25,309
43		E395 - Laboratory Equipment		93	12	81
44		E396 - Power Operated Equipment		-	-	
45		E397.1 - Computer Hardware		4,749	596	4,154
46		E397.2 - Computer Software		20,162	2,529	17,632
47		E397.3 - Communication Equipment		19,349	2,427	16,922
48		E398 - Miscellaneous Equipment		(600)	(75)	(525)
49		E399.1 - ARO Costs General Plt		2,041	256	1,785
50		Sub-total General Plant	SUM L38 to L49	$93,994	$11,792	$82,202
51						
52		**Total**	L3+L18+L36+L50	**$2,841,244**	**$707,035**	**$2,134,209**

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant		100.00%				
5				100.00%				
6								
7		Sub-total Intangible Plant						
8								
9	**Transmission Plant**	E350 - Land and Land Rights	($0)	100.00%	($0)			($0)
10			($0)		($0)			($0)
11								
12		E351.1 - Computer Hardware	$6,411	100.00%	$6,411			$6,411
13			$6,411		$6,411			$6,411
14								
15		E351.2 - Computer Software	$22,795	100.00%	$22,795			$22,795
16			$22,795		$22,795			$22,795
17								
18		E351.3 - Communication Equipment	$15,791	100.00%	$15,791			$15,791
19			$15,791		$15,791			$15,791
20								
21		E352 - Structures and Improvements	20,168	100.00%	20,168			20,168
22			20,168		20,168			20,168
23								
24		E353 - Station Equipment	278,358	100.00%	278,358			278,358
25			278,358		278,358			278,358
26								
27		E354 - Towers and Fixtures	180,281	100.00%	180,281			180,281
28			180,281		180,281			180,281
29								
30		E355 - Poles and Fixtures	7,797	100.00%	7,797			7,797
31			7,797		7,797			7,797
32								
33		E356 - Overhead Conductors, Devices	98,705	100.00%	98,705			98,705
34			98,705		98,705			98,705
35								
36		E357 - Underground Conduit	7,632	100.00%	7,632			7,632
37			7,632		7,632			7,632
38								
39		E358 - Undergrnd Conductors, Devices	54,827	100.00%	54,827			54,827
40			54,827		54,827			54,827
41								
42		E359 - Roads and Trails	2,277	100.00%	2,277			2,277
43			2,277		2,277			2,277
44								
45		E359.1 - ARO Costs Transmission Plt	201	100.00%	201			201
46			201		201			201
47								
48		Sub-total Transmission Plant	$695,243		$695,243			$695,243
49								

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
50	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
51			310		310		310	
52								
53		E361 - Structures and Improvements	$53,590	100.00%	$53,590	100.00%	$53,590	
54			$53,590		$53,590		$53,590	
55								
56		E362 - Station Equipment	491,766	100.00%	491,766	100.00%	491,766	
57			491,766		491,766		491,766	
58								
59		E363.1 - Computer Hardware	9,545	100.00%	9,545	100.00%	9,545	
60			9,545		9,545		9,545	
61								
62		E363.2 - Computer Software	74,091	100.00%	74,091	100.00%	74,091	
63			74,091		74,091		74,091	
64								
65		E363.3 - Communication Equipment	67,124	100.00%	67,124	100.00%	67,124	
66			67,124		67,124		67,124	
67								
68		E364 - Poles, Towers and Fixtures	9,266	100.00%	9,266	100.00%	9,266	
69			9,266		9,266		9,266	
70								
71		E365 - Overhead Conductors, Devices	309,347	100.00%	309,347	100.00%	309,347	
72			309,347		309,347		309,347	
73								
74		E366 - Underground Conduit	209,459	100.00%	209,459	100.00%	209,459	
75			209,459		209,459		209,459	
76								
77		E367 - Undergrnd Conductors, Devices	150,429	100.00%	150,429	100.00%	150,429	
78			150,429		150,429		150,429	
79								
80		E368 - Line Transformers	151,334	100.00%	151,334	100.00%	151,334	
81			151,334		151,334		151,334	
82								
83		E369 - Services	219,483	100.00%	219,483	100.00%	219,483	
84			219,483		219,483		219,483	
85								
86		E370 - Meters	254,773	100.00%	254,773	100.00%	254,773	
87			254,773		254,773		254,773	
88								
89		E371 - Installs on Customer Premises	11,743	100.00%	11,743	100.00%	11,743	
90			11,743		11,743		11,743	
91								
92		E373 - Street Lighting, Signal Systems	37,216	100.00%	37,216	100.00%	37,216	
93			37,216		37,216		37,216	
94								
95		E374 - ARO Costs Distribution Plant	2,531	100.00%	2,531	100.00%	2,531	
96								
97			2,531		2,531		2,531	
98								
99		Sub-total Distribution Plant	$2,052,007		$2,052,007		$2,052,007	
100								

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
101	**General Plant**	E389 - Land and Land Rights				87.46%		
102								
103								
104		E390 - Structures and Improvements	$19,022	100.00%	$19,022	87.46%	$16,636	$2,386
105			$19,022		$19,022		$16,636	$2,386
106								
107		E391 - Office Furniture, Equipment	201	100.00%	201	87.46%	176	25
108			201		201		176	25
109								
110		E393 - Stores Equipment	37	100.00%	37	87.46%	32	5
111			37		37		32	5
112								
113		E394 - Tools, Shop, Garage Equipmnt	28,940	100.00%	28,940	87.46%	25,309	3,630
114			28,940		28,940		25,309	3,630
115								
116		E395 - Laboratory Equipment	93	100.00%	93	87.46%	81	12
117			93		93		81	12
118								
119		E397.1 - Computer Hardware	4,749	100.00%	4,749	87.46%	4,154	596
120			4,749		4,749		4,154	596
121								
122		E397.2 - Computer Software	20,162	100.00%	20,162	87.46%	17,633	2,529
123			20,162		20,162		17,633	2,529
124								
125		E397.3 - Communication Equipment	19,349	100.00%	19,349	87.46%	16,922	2,427
126			19,349		19,349		16,922	2,427
127								
128		E398 - Miscellaneous Equipment	(600)	100.00%	(600)	87.46%	(525)	(75)
129			(600)		(600)		(525)	(75)
130								
131		E399.1 - ARO Costs General Plt	2,041	100.00%	2,041	87.46%	1,785	256
132			2,041		2,041		1,785	256
133								
134		Sub-total General Plant	$93,994		$93,994		$82,203	$11,791
135								
136		**Total**	**$2,841,244**		**$2,841,244**		**$2,134,210**	**$707,035**

Line No.	Category	Account	(1) Reference	(2) FTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		
2		Sub-total Electric - Intangible Plant		
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		
5		E351.3 - Communication Equipment		($15)
6		E352 - Structures and Improvements		(2,906)
7		E353 - Station Equipment		(2,976)
8		E354 - Towers and Fixtures		(747)
9		E355 - Poles and Fixtures		(6)
10		E356 - Overhead Conductors, Devices		(1,779)
11		E357 - Underground Conduit		(40)
12		E358 - Undergrnd Conductors, Devics		(801)
13		E359 - Roads and Trails		
14		Sub-total Electric - Transmission	SUM L4 to L13	($9,270)
15				
16	**Electric - Distribution**	E361 - Structures and Improvements		($1,967)
17		E362 - Station Equipment		(11,020)
18		E363.3 - Communication Equipment		(123)
19		E364 - Poles, Towers and Fixtures		(23,657)
20		E365 - Overhead Conductors, Devices		(23,161)
21		E366 - Underground Conduit		(3,986)
22		E367 - Undergrnd Conductors, Devics		(27,589)
23		E368 - Line Transformers		(3,927)
24		E369 - Services		(765)
25		E370 - Meters		(474)
26		E373 - Street Lighting, Signal Systems		(134)
27		Sub-total Electric - Distribution	SUM L16 to L26	($96,802)
28				
29	**Electric - General Plant**	E390 - Structures and Improvements		($166)
30		E391 - Office Furniture, Equipment		(23)
31		E394 - Tools, Shop, Garage Equipmnt		(41)
32		E397.3 - Communication Equipment		(282)
33		E398 - Miscellaneous Equipment		(226)
34		Sub-total Electric - General Plant	SUM L29 to L33	($738)
35				
36		**Total**	Lines 2+14+27+34	**($106,810)**

Line No.	Description	(1) Reference	(2) FTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			57.60	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$175,913	13.56	$2,385,821
7	Pension Expense		3,361	(167.00)	(561,340)
8	Commodity Purchased - [A]		1,406,976	35.54	50,006,272
9	Commodity Purchased - [B]		11,458	12.50	143,229
10	PJM Transmission Purchased - By-passable		104,412	12.50	1,305,156
11	PJM Transmission Purchased - Non By-passable		107,377	12.50	1,342,209
12	Other Expenses		619,165	43.21	26,751,988
13	Sub-Total O&M	SUM L6 to L12	$2,428,663		$81,373,336
14					
15	Payment to Suppliers		$1,428,686	37.64	$53,782,349
16					
17	Total O&M and POR Payments	L13 + L15	$3,857,350		$135,155,685
18					
19	O&M Expense / POR Payment Lag Days			35.04	
20					
21	Net Lead/(Lag) Days	L3 - L19		22.56	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$10,568		
26					
27	Working Capital for O&M Expense		$238,410		
28					
29	Average Prepayments		$8,432		
30	Accrued Taxes		104,302		
31	Interest Payments		(20,027)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$331,116**		
34					
35	Pro Forma O&M Expense		$2,485,568		
36	Uncollectible Expense		56,905		
37	Pro Forma Cash O&M Expense	L35 - L36	$2,428,663		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$441,873			
4	January		511,639	$416,118		
5	February		536,250	394,707		
6	March		520,942	364,969		
7	April		498,684	325,032		
8	May		477,882	316,108		
9	June		518,591	365,739		
10	July		619,727	508,393		
11	August		625,228	489,153		
12	September		552,426	394,187		
13	October		521,995	365,223		
14	November		503,475	288,094		
15	December		533,971	427,625		
16						
17	Total	SUM L3 to L15	$6,862,683	$4,655,348		
18						
19	Average A/R Balance		13			
20						
21	Factor		$527,899	$4,655,348	8.82	41.39
22						
23	Collection Days Lag					41.39
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12 * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**57.60**

Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)
1	PAYROLL	Union & Non-Union Payroll				$170,057		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$2,306,396
4								
5		**Payroll Lag**	SUM L1 to L3			$170,057	**13.56**	$2,306,396
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2026	7/1/2026	$10,374	(167.00)	($1,732,458)
12								
13		Sub-total	SUM L7 to L11			$10,374		($1,732,458)
14								
15		**Lag Days for Pension Payment**					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.54**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.64**	
20								
21								
22	OTHER O & M EXPENSES	March				$15,875		$656,144
23		June				18,479		697,875
24		September				36,511		1,651,476
25		December				35,501		1,590,220
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$106,366	**43.21**	$4,595,716

Line No.	Months	Description	(1) Number of CDs	(2) Cash Disbursements	(3) Dollar-Days	(4) Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643	-	
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705	-	
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,894	$106,366	$4,595,716	**43.21**

Line No.	Description	Description	(1) Payment Date	(2) Mid Point Date	(3) Lead/(Lag) Payment Days	(4) Total Payment Amount	(5) Payment Percentage	(6) Payment Amount	(7) Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/15/2026	7/1/2026	77	$59,091	25.00%	$14,773	$1,137,500
2		Second Payment	6/15/2026	7/1/2026	16	59,091	25.00%	14,773	236,364
3		Third Payment	9/15/2026	7/1/2026	(76)	59,091	25.00%	14,773	(1,122,727)
4		Fourth Payment	12/15/2026	7/1/2026	(167)	59,091	25.00%	14,773	(2,467,045)
5		Sub-total FEDERAL INCOME TAX					100.00%	$59,091	($2,215,908)
6									
7	**STATE INCOME TAX**	First Payment	3/16/2026	7/1/2026	107	$9,429	25.00%	$2,357	$252,220
8		Second Payment	6/16/2026	7/1/2026	15	9,429	25.00%	2,357	35,358
9		Third Payment	9/15/2026	7/1/2026	(76)	9,429	25.00%	2,357	(179,147)
10		Fourth Payment	12/15/2026	7/1/2026	(167)	9,429	25.00%	2,357	(393,651)
11		Sub-total STATE INCOME TAX					100.00%	$9,429	($285,220)
12									
13	**PURTA**	First Payment	5/1/2026	7/1/2026	61	$6,863	100.00%	$6,863	$418,660
14		Subtotal PURTA					100.00%	$6,863	$418,660
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2026	7/1/2026	29	$6,132	100.00%	$6,132	$177,830
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$6,132	$177,830
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/16/2026	7/1/2026	107	$214,338	100.00%	$214,338	$22,934,209
27		Sub-total GROSS RECEIPTS TAX					100.00%	$214,338	$22,934,209

Line No.	Description	(1) Total Payment Amount	(2) Weighted Dollar Days	(3) Payment Lead/(Lag) Days	(4) Revenue Lag Days	(5) Net Payment Lead/(Lag) Days	(6) Net Payment Lead/(Lag) Dollars Days	(7) Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$59,091	($2,215,908)	(37.50)	57.60	20.10	$1,187,605	$3,254
2	STATE INCOME TAX	$9,429	($285,220)	(30.25)	57.60	27.35	$257,858	$706
3	PURTA	$6,863	$418,660	61.00	57.60	118.60	$813,970	$2,230
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$6,132	$177,830	29.00	57.60	86.60	$531,023	$1,455
6	GROSS RECEIPTS TAX	$214,338	$22,934,209	107.00	57.60	164.60	$35,279,658	$96,657

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of FTY		$9,960,123
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.68%
4	Pro Forma Interest Expense	L1 * L2 * L3	$217,218
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$595
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	57.60
9	Interest Payment Lag Days	L8 - L7	(33.65)
10	**Total Interest for Working Capital**	L6 * L9	**($20,027)**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
C-4 Prepayments

Line No.	Description	Reference	EPRI Dues	EEI Dues	EAP Membership Dues	Prepaid Rents & Pole Attachments	PUC Assessment Electric	Land Leasing	Maintenance	IT License & Maintenance	Business Support Systems	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	December				$285	$230	$4,323	$143	$117	$148	$599	$3,449	$0	$27	$478	$172	$112	$566	
2	January			530	262	702	3,742		78	98	558	3,449	(16)	14	498	166	232	580	
3	February			482	238	666	2,993		78	80	462	3,449	(32)	0	500	110	198	554	
4	March		217	434	214	481	2,245	136	78	62	519	2,376	150	0	503	82	439	538	
5	April		217	386	190	330	1,497		78	50	422	2,376	134	0	528	136	378	540	
6	May		217	337	166	298	748		78	37	325	2,376	117	0	527	237	340	489	
7	June		126	289	143	121	0	130	78	25	454	1,888	100	0	530	484	302	499	
8	July		126	241	119	603	4,605		78	164	614	1,888	84	0	562	405	264	445	
9	August		126	193	95	423	3,893		78	163	506	1,888	67	0	445	356	226	520	
10	September		117	145	71	601	8,182	123	78	203	475	2,231	50	0	471	306	188	655	
11	October		36	96	48	449	7,273		78	176	457	2,231	33	0	470	256	150	748	
12	November		36	48	24	282	6,364		78	149	339	2,231	17	0	500	318	112	748	
13	December		(54)	570		238	5,455	117	78	122	297	2,048	0	0	505	271	74	942	
14																			
15	Total	SUM L1 to L13	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																			
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.32%	67.32%	67.32%	67.32%	74.52%	74.52%	74.52%	
18																			
19	Distribution Amount	L15 * L17	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$21,465	$474	$28	$4,387	$2,458	$2,248	$5,831	
20																			
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																			
23	Monthly Average	L19 / L21	$90	$289	$143	$417	$3,948	$50	$81	$114	$464	$1,651	$36	$2	$337	$189	$173	$449	
24																			
25	**Rate Case Amount**																		**$8,432**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in FTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.00	19.00	1.00	34.00	
5	April	15.50	19.00	1.00	35.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	3.00	37.50	
8	July	15.00	19.00	1.00	35.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	2.00	36.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	2.00	36.00	
14	**Payment Lag - Contract Purchases**					**35.54**
15						
16	**Spot Market Purchases in FTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	29%	7.18		
30	Nonresidential	20.00	71%	14.25		
31	Weighted Lag Days				21.44	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.64**

Line No.	Description	(1) Reference	(2) Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Activities in FTY - Total		(1,509)
3	Balance at End of FPFTY - Total		$439,981
4	Allocation % to Utility		76.67%
5	Utility Amount	L4 * L5	$337,345
6	Allocation % to Distribution Capital		48.37%
7	Balance at End of FTY - Distribution Capital	L6 * L7	**$163,162**

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - CIAC		($12,383)	100.00%	($12,383)	100.00%	($12,383)
2		ADIT - Common Plant		106,546	100.00%	106,546	67.32%	71,730
3		ADIT - Electric Common Plant		24,741	100.00%	24,741	87.46%	21,638
4		ADIT - Electric Distribution		665,968	100.00%	665,968	100.00%	665,968
5		ADIT - Corp. Alternative Minimum Tax		(183,957)	100.00%	(183,957)	100.00%	(183,957)
6		Sub-total	SUM L1 to L5	$600,915		$600,915		$562,995
7								
8	**FTY**	DIT - CIAC		$1,681	100.00%	$1,681	100.00%	$1,681
9		DIT - Common Plant		(7,346)	100.00%	(7,346)	67.32%	(4,945)
10		DIT - Electric Common Plant		(1,696)	100.00%	(1,696)	87.46%	(1,484)
11		DIT - Electric Distribution		32,421	100.00%	32,421	100.00%	32,421
12		DIT - Corp. Alternative Minimum Tax		144,110	100.00%	144,110	100.00%	144,110
13		Sub-total	SUM L8 to L12	$169,171		$169,171		$171,784
14								
15		**Total**	L6 + L13 + L20	**$770,086**		**$770,086**		**$734,779**

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$22,499	$36,282	$58,780
2	January		22,580	35,889	58,469
3	February		23,154	36,470	59,623
4	March		24,246	37,775	62,021
5	April		25,771	39,113	64,884
6	May		26,839	39,833	66,672
7	June		27,171	39,865	67,035
8	July		27,725	40,669	68,394
9	August		28,297	40,986	69,283
10	September		29,109	41,497	70,606
11	October		29,946	43,006	72,952
12	November		30,524	43,769	74,292
13	December		30,889	45,192	76,081
14					
15	Total	SUM L1 to L13	$348,750	$520,343	$869,092
16					
17	Average Monthly Balance	L15 / 13	$26,827	$40,026	$66,853
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$26,827
21	Small C&I				33,270
22	Large C&I				6,746
23	Other				11
24					
25	**Total**	SUM L20 to L23			**$66,853**

Line No.	Category	Account	(1) Reference	(2) FTY Amount	(3) Allocated to Non Jurisdiction	(4) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$383,514	$125,321	$258,193
6						
7		E389 - Land and Land Rights		$6,770	$2,212	$4,558
8						
9		E390 - Structures and Improvements		$482,427	$157,643	$324,784
10		E391 - Office Furniture, Equipment		102,089	33,360	68,729
11		E392 - Transportation Equipment		244,211	79,801	164,410
12		E393 - Stores Equipment		2,187	715	1,473
13		E394 - Tools, Shop, Garage Equipmnt		2,788	911	1,877
14		E396 - Power Operated Equipment		870	284	586
15		E397 - Communication Equipment		141,134	46,118	95,015
16		E398 - Miscellaneous Equipment		665	217	448
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		289	94	194
19		Sub Total - General Plant	SUM L9 to L18	$976,660	$319,143	$657,517
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,367,621	$446,898	$920,724
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$204,130	$66,704	$137,426
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$74,519	$24,350	$50,168
31		E391 - Office Furniture, Equipment		40,722	13,307	27,415
32		E392 - Transportation Equipment		114,663	37,468	77,195
33		E393 - Stores Equipment		540	176	363
34		E394 - Tools, Shop, Garage Equipmnt		1,312	429	883
35		E396 - Power Operated Equipment		325	106	219
36		E397 - Communication Equipment		56,170	18,355	37,815
37		E398 - Miscellaneous Equipment		683	223	460
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(384)	(125)	(258)
40		Sub Total - General Plant	SUM L30 to L39	$288,548	$94,289	$194,259
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$492,678	$160,992	$331,686
42						
43		Net Common Plant	L20 - L41	**$874,943**	**$285,905**	**$589,038**
44						
45						
46		Common Plant in Service to Utility	L20	$1,367,621	$446,898	$920,724
47		Common Plant Accum Depreciation to Utility	L41	492,678	160,992	331,686
48		Net Common Plant to Utility	L46 - L47	$874,943	$285,905	$589,038

Line No.	Description	(1) Reference	(2) Total
1	HTY 13-Month Average		
2	December		$8,256
3	January		10,444
4	February		8,761
5	March		7,609
6	April		7,944
7	May		7,480
8	June		8,730
9	July		13,442
10	August		12,482
11	September		11,891
12	October		12,405
13	November		12,916
14	December		13,718
15			
16	13-Month Total	SUM L2 to L14	$136,078
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$10,468**

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$51,593	$0	$51,593
3	January		53,064	(535)	52,530
4	February		55,613	(319)	55,294
5	March		55,645	(560)	55,085
6	April		57,445	(2,433)	55,012
7	May		56,753	(911)	55,842
8	June		55,119	(1,049)	54,070
9	July		56,000	(1,747)	54,253
10	August		52,558	(2,066)	50,492
11	September		52,239	(2,581)	49,657
12	October		52,308	(2,857)	49,451
13	November		51,470	(2,421)	49,049
14	December		52,109	0	52,109
15					
16	Total	SUM L2 to L14	$701,915	($17,478)	$684,437
17					
18	Distribution Expense Allocation Factor		100.00%	67.32%	
19					
20	Allocation to Distribution	L16 * L18	$701,915	($11,767)	
21					
22	**Average Monthly Balance**	L20 / 13	**$53,993**	**($905)**	**$53,088**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$274,076	100.00%	$274,076	100.00%	$274,076
2		ADIT - CIAC			100.00%		100.00%	
3		Sub-total HTY	L1 + L2	274,076		274,076		274,076
4								
5	**FTY**	DIT - Distribution		($3,010)	100.00%	($3,010)	100.00%	($3,010)
6		DIT - CIAC			100.00%		100.00%	
7		Sub-total FTY	L5 + L6	($3,010)		($3,010)		($3,010)
8								
9		**Total**	L3 + L7 + L11	**$271,066**		**$271,066**		**$271,066**

Line No.	Category	Description	(1) Reference	(2) Pro Forma Adjusted at Present Rates	(3) Proposed Rate Increase	(4) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$2,087,225		$2,087,225
2		Residential - House Heating		454,706		454,706
3		C & I Small		553,710		553,710
4		C & I Large		315,038		315,038
5		Railroads & Railways		9,416		9,416
6		Street Lighting		25,102		25,102
7		Intercompany				
8		Transmission - All Classes		226,232		226,232
9		Forfeited Discounts		18,329	$1,059	19,388
10		Miscellaneous Service Revenues		3,923		3,923
11		Rent For Electric Property		27,040		27,040
12		Other Electric Revenues		3,659		3,659
13		Revenue Increase			$298,434	298,434
14		Total Operating Revenues	SUM L1 to L13	$3,724,380	$299,493	$4,023,874
15						
16	**Operating Expenses**	Power Supply		$1,418,435		$1,418,435
17		Transmission Expense		211,789		211,789
18		Distribution Expense		439,535		439,535
19		Customer Accounts Expense		163,266	$3,330	166,596
20		Customer Service and Information Expense		43,386		43,386
21		Sales Expense		698		698
22		Administrative & General		208,459	1,083	209,542
23		Sub-total O&M Expense	SUM L16 to L22	$2,485,568	$4,413	$2,489,981
24						
25		Depreciation & Amortization Expense		$370,202		$370,202
26		Amortization of Regulatory Expense		1,119		1,119
27		Taxes Other Than Income Taxes - Other		$243,845	$17,608	$261,452
28		Total Operating Expenses	SUM L23 to L27	$3,100,734	$22,020	$3,122,754
29						
30	**Net Operating Income - BIT**		L14 - L28	**$623,646**	**$277,473**	**$901,120**

Line No.	Category	Description	Reference	(1) FTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$2,106,536	($19,312)	$2,087,225
2		Residential - House Heating		458,665	(3,958)	454,706
3		C & I Small		568,314	(14,604)	553,710
4		C & I Large		342,004	(26,966)	315,038
5		Railroads & Railways		10,337	(921)	9,416
6		Street Lighting		25,264	(162)	25,102
7		Intercompany				
8		Transmission - All Classes		226,232		226,232
9		Forfeited Discounts		18,329		18,329
10		Miscellaneous Service Revenues		3,923		3,923
11		Rent For Electric Property		27,040		27,040
12		Other Electric Revenues		3,293	366	3,659
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$3,789,938	($65,557)	$3,724,380
15						
16	**Operating Expenses**	Power Supply		$1,418,435		$1,418,435
17		Transmission Expense		211,789		211,789
18		Distribution Expense		414,911	$24,625	439,535
19		Customer Accounts Expense		136,296	26,971	163,266
20		Customer Service and Information Expense		102,765	(59,380)	43,386
21		Sales Expense		682	15	698
22		Administrative & General		207,932	528	208,459
23		Sub-total O&M Expense	SUM L16 to L22	$2,492,809	($7,241)	$2,485,568
24						
25		Depreciation & Amortization Expense		$343,772	$26,430	$370,202
26		Amortization of Regulatory Expense		1,099	20	1,119
27		Taxes Other Than Income Taxes - Other		248,197	(4,352)	243,845
28		Total Operating Expenses	SUM L23 to L27	$3,085,877	$14,857	$3,100,734
29						
30	**Net Operating Income - BIT**		L14 - L28	**$704,061**	**($80,414)**	**$623,646**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-3 Adjustments to Net Operating Income

Line No.	Category	Description	Description	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
1	**Operating Revenues**	Residential	Elec Cost	$976,446							
2			Cust & Dist	1,130,090	2,330	(2,204)	(2,101)	(17,957)		622	
3			Sub-total Residential	$2,106,536	$2,330	($2,204)	($2,101)	($17,957)		$622	
4											
5		Residential - House Heating	Elec Cost	$241,229							
6			Cust & Dist	217,436	1,202	(272)	(465)	(4,605)		180	
7			Sub-total Residential - House Heating	$458,665	$1,202	($272)	($465)	($4,605)		$180	
8											
9		C & I Small	Elec Cost	$214,828							
10			Cust & Dist	353,486	569		(1,083)	(14,286)		196	
11			Sub-total C & I Small	$568,314	$569		($1,083)	($14,286)		$196	
12											
13		C & I Large	Elec Cost	$80,396							
14			Cust & Dist	261,609			(802)	(26,327)		163	
15			Sub-total C & I Large	$342,004			($802)	($26,327)		$163	
16											
17		Railroads & Railways	Cust & Dist	$10,337				(921)			
18			Sub-total Railroads & Railways	$10,337				($921)			
19											
20		Street Lighting	Elec Cost	$607							
21			Cust & Dist	24,657				(162)			
22			Sub-total Street Lighting	$25,264				($162)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes	$226,232							
29			Sub-total Transmission - All Classes	$226,232							
30											
31		Forfeited Discounts	Forfeited Discounts	$18,329							
32			Sub-total Forfeited Discounts	$18,329							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$3,923							
35			Sub-total Miscellaneous Service Revenues	$3,923							
36											
37		Rent For Electric Property	Rent For Electric Property	$27,040							
38			Sub-total Rent For Electric Property	$27,040							
39											
40		Other Electric Revenues	Other Electric Revenues	$3,293							
41			Sub-total Other Electric Revenues	$3,293							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$3,789,938**	**$4,101**	**($2,476)**	**($4,450)**	**($64,258)**		**$1,161**	
47											

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Description	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
48	**Operating Expenses**	Power Supply	Purchased Power	$1,418,435							
49			Sub-total Power Supply	$1,418,435							
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch	110,360							
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development	101,429							
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense	211,789							
71											
72		Distribution Expense	Operation & Supervision	$530							
73			Load Dispatching								
74			Station Expense	6,973							
75			Overhead Lines Expenses	17,302							
76			Underground Lines Expense	11,059							
77			Meter Expenses	6,216							
78			Customer Installations Expense	12,650							
79			Miscellaneous Expense	87,589							
80			Rents	4,215							
81			Maintenance of Structures	7,015							
82			Maintenance of Station Equipment	16,512							
83			Maintenance of Overhead Lines	188,602							
84			Maintenance of Underground Lines	34,508							
85			Maintenance of Line Transformers	2,663							
86			Maintenance of Street Lighting & Signal Systems	1,761							
87			Maintenance of Misc. Distribution	17,317							
88			Sub-total Distribution Expense	$414,911							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$245							
92			Customer Records and Collection	98,222							
93			Uncollectible Accounts.	34,396							
94			Miscellaneous Customer Accounts Expenses.	3,433							
95			Sub-total Total Customer Accounts	$136,296							

Line No.	Category	Description	Description	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
96											
97		Customer Service and Information	Customer Assistance	$99,468				(59,417)			
98			Informational & Instructional	2,389							
99			Miscellaneous Customer & Informational	908							
100			Sub-total Customer Service & Information	$102,765				($59,417)			
101											
102		Sales	Demonstrating & Selling	$682							
103			Miscellaneous Sales								
104			Sub-total Sales	$682							
105											
106		Administrative & General	Administrative and General Salaries	$37,084							
107			Office Supplies and Expenses	4,220							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	99,366							
110			Property Insurance	951							
111			Injuries & Damages	16,346							
112			Employee Pensions and Benefits	31,080							
113			Regulatory Commission Expenses	9,619							
114			Duplicate Charges-Credit	(2,026)							
115			Miscellaneous General Expenses	1,516							
116			Maintenance of General Plant	9,776							
117			Sub-total Administrative & General	$207,932							
118											
119			**Total O&M Expense**	$2,492,809				($59,417)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$343,772							
122			Sub-total Depreciation & Amortization Expense	$343,772							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$1,099							
125			Sub-total Amortization of Regulatory Expense	$1,099							
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$248,197							
128			Sub-total Taxes Other Than Income Taxes - Other	$248,197							
129											
130			**Total Operating Expenses**	**$3,085,877**				**($59,417)**			
131											
132	**Net Operating Income Before Income Tax**			**$704,061**	**$4,101**	**($2,476)**	**($4,450)**	**($4,841)**		**$1,161**	

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest
1	**Operating Revenues**	Residential	Elec Cost								
2			Cust & Dist								
3			Sub-total Residential								
4											
5		Residential - House Heating	Elec Cost								
6			Cust & Dist								
7			Sub-total Residential - House Heating								
8											
9		C & I Small	Elec Cost								
10			Cust & Dist								
11			Sub-total C & I Small								
12											
13		C & I Large	Elec Cost								
14			Cust & Dist								
15			Sub-total C & I Large								
16											
17		Railroads & Railways	Cust & Dist								
18			Sub-total Railroads & Railways								
19											
20		Street Lighting	Elec Cost								
21			Cust & Dist								
22			Sub-total Street Lighting								
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes								
29			Sub-total Transmission - All Classes								
30											
31		Forfeited Discounts	Forfeited Discounts								
32			Sub-total Forfeited Discounts								
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues								
35			Sub-total Miscellaneous Service Revenues								
36											
37		Rent For Electric Property	Rent For Electric Property								
38			Sub-total Rent For Electric Property								
39											
40		Other Electric Revenues	Other Electric Revenues	$366							
41			Sub-total Other Electric Revenues	$366							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$366**							
47											

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest
48	**Operating Expenses**	Power Supply	Purchased Power								
49			Sub-total Power Supply								
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch								
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development								
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense								
71											
72		Distribution Expense	Operation & Supervision	$13							
73			Load Dispatching								
74			Station Expense	10							
75			Overhead Lines Expenses	92							
76			Underground Lines Expense	96							
77			Meter Expenses	84							
78			Customer Installations Expense	202							
79			Miscellaneous Expense	240							
80			Rents								
81			Maintenance of Structures	49							
82			Maintenance of Station Equipment	260							
83			Maintenance of Overhead Lines	1,489							
84			Maintenance of Underground Lines	506							
85			Maintenance of Line Transformers	25							
86			Maintenance of Street Lighting & Signal Systems	5							
87			Maintenance of Misc. Distribution	106							
88			Sub-total Distribution Expense	$3,176							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	0							
92			Customer Records and Collection	1,116							
93			Uncollectible Accounts.						22,509		
94			Miscellaneous Customer Accounts Expenses.	31							3,315
95			Sub-total Total Customer Accounts	$1,147					$22,509		$3,315

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest
96											
97		Customer Service and Information	Customer Assistance		$37						
98			Informational & Instructional								
99			Miscellaneous Customer & Informational								
100			Sub-total Customer Service & Information		$37						
101											
102		Sales	Demonstrating & Selling		$15						
103			Miscellaneous Sales								
104			Sub-total Sales		$15						
105											
106		Administrative & General	Administrative and General Salaries		$1,387						
107			Office Supplies and Expenses								
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed								
110			Property Insurance								
111			Injuries & Damages		54						
112			Employee Pensions and Benefits		1		78	(1,069)			
113			Regulatory Commission Expenses			37					
114			Duplicate Charges-Credit								
115			Miscellaneous General Expenses		0						
116			Maintenance of General Plant		39						
117			Sub-total Administrative & General		$1,481	$37	$78	($1,069)			
118											
119			**Total O&M Expense**		$5,856	$37	$78	($1,069)	$22,509		$3,315
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense								
122			Sub-total Depreciation & Amortization Expense								
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense							20	
125			Sub-total Amortization of Regulatory Expense							$20	
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								
128			Sub-total Taxes Other Than Income Taxes - Other								
129											
130			**Total Operating Expenses**		**$5,856**	**$37**	**$78**	**($1,069)**	**$22,509**	**$20**	**$3,315**
131											
132	**Net Operating Income Before Income Tax**			**$366**	**($5,856)**	**($37)**	**($78)**	**$1,069**	**($22,509)**	**($20)**	**($3,315)**

Line No.	Category	Description	Description	(17) D-13 Storm	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Elec Cost							$976,446
2			Cust & Dist						($19,312)	1,110,778
3			Sub-total Residential						($19,312)	$2,087,225
4										
5		Residential - House Heating	Elec Cost							$241,229
6			Cust & Dist						($3,958)	213,478
7			Sub-total Residential - House Heating						($3,958)	$454,706
8										
9		C & I Small	Elec Cost							$214,828
10			Cust & Dist						($14,604)	338,882
11			Sub-total C & I Small						($14,604)	$553,710
12										
13		C & I Large	Elec Cost							$80,396
14			Cust & Dist						($26,966)	234,642
15			Sub-total C & I Large						($26,966)	$315,038
16										
17		Railroads & Railways	Cust & Dist						($921)	$9,416
18			Sub-total Railroads & Railways						($921)	$9,416
19										
20		Street Lighting	Elec Cost							$607
21			Cust & Dist						($162)	24,495
22			Sub-total Street Lighting						($162)	$25,102
23										
24		Intercompany	Elec Cost							
25			Cust & Dist							
26			Sub-total Interdepartmental							
27										
28		Transmission - All Classes	Transmission - All Classes							$226,232
29			Sub-total Transmission - All Classes							$226,232
30										
31		Forfeited Discounts	Forfeited Discounts							$18,329
32			Sub-total Forfeited Discounts							$18,329
33										
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues							$3,923
35			Sub-total Miscellaneous Service Revenues							$3,923
36										
37		Rent For Electric Property	Rent For Electric Property							$27,040
38			Sub-total Rent For Electric Property							$27,040
39										
40		Other Electric Revenues	Other Electric Revenues						$366	$3,659
41			Sub-total Other Electric Revenues						$366	$3,659
42										
43		Revenue Increase	Revenue Increase							
44			Sub-total Revenue Increase							
45										
46			**Total Operating Revenues**						**($65,557)**	**$3,724,380**
47										

Line No.	Category	Description	Description	(17) D-13 Storm	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
48	**Operating Expenses**	Power Supply	Purchased Power							$1,418,435
49			Sub-total Power Supply							$1,418,435
50										
51		Transmission Expense	Operation & Supervision							
52			Load Dispatching							
53			Scheduling, System Control & Dispatch							110,360
54			Transmission Service Studies							
55			Generation Service Studies							
56			Reliability, Planning & Standard Development							101,429
57			Station Expense							
58			Overhead Lines							
59			Underground Lines Expense							
60			Miscellaneous Expense							
61			Rents							
62			Maintenance of Structures							
63			Maintenance of Computer Hardware							
64			Maintenance of Computer Software							
65			Maintenance of Communication Equipment							
66			Maintenance of Station Equipment							
67			Maintenance of Overhead Lines							
68			Maintenance of Underground Lines							
69			Maintenance of Misc Transmission Plant							
70			Sub-total Transmission Expense							211,789
71										
72		Distribution Expense	Operation & Supervision					$13		$543
73			Load Dispatching							
74			Station Expense					10		6,983
75			Overhead Lines Expenses					92		17,394
76			Underground Lines Expense					96		11,155
77			Meter Expenses					84		6,300
78			Customer Installations Expense					202		12,852
79			Miscellaneous Expense					240		87,829
80			Rents							4,215
81			Maintenance of Structures					49		7,064
82			Maintenance of Station Equipment					260		16,772
83			Maintenance of Overhead Lines	6,562	14,887			22,937		211,539
84			Maintenance of Underground Lines					506		35,014
85			Maintenance of Line Transformers					25		2,688
86			Maintenance of Street Lighting & Signal Systems					5		1,765
87			Maintenance of Misc. Distribution					106		17,423
88			Sub-total Distribution Expense	$6,562	$14,887			$24,625		$439,535
89										
90		Customer Accounts	Supervision							
91			Meter Reading					$0		$245
92			Customer Records and Collection					1,116		99,338
93			Uncollectible Accounts.					22,509		56,905
94			Miscellaneous Customer Accounts Expenses.					3,346		6,778
95			Sub-total Total Customer Accounts					$26,971		$163,266

Line No.	Category	Description	Description	(17) D-13 Storm	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
96										
97		Customer Service and Information	Customer Assistance						($59,380)	$40,088
98			Informational & Instructional							2,389
99			Miscellaneous Customer & Informational							908
100			Sub-total Customer Service & Information						($59,380)	$43,386
101										
102		Sales	Demonstrating & Selling						$15	$698
103			Miscellaneous Sales							
104			Sub-total Sales						$15	$698
105										
106		Administrative & General	Administrative and General Salaries						$1,387	$38,472
107			Office Supplies and Expenses							4,220
108			Administrative Expenses Transferred-Credit							
109			Outside Service Employed							99,366
110			Property Insurance							951
111			Injuries & Damages						54	16,399
112			Employee Pensions and Benefits						(990)	30,090
113			Regulatory Commission Expenses						37	9,657
114			Duplicate Charges-Credit							(2,026)
115			Miscellaneous General Expenses						0	1,516
116			Maintenance of General Plant						39	9,815
117			Sub-total Administrative & General						$528	$208,459
118										
119			**Total O&M Expense**	$6,562	$14,887				($7,241)	$2,485,568
120										
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense					$26,430	$26,430	$370,202
122			Sub-total Depreciation & Amortization Expense					$26,430	$26,430	$370,202
123										
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense						$20	$1,119
125			Sub-total Amortization of Regulatory Expense						$20	$1,119
126										
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other				(4,352)		($4,352)	$243,845
128			Sub-total Taxes Other Than Income Taxes - Other				($4,352)		($4,352)	$243,845
129										
130			**Total Operating Expenses**	**$6,562**	**$14,887**		**($4,352)**	**$26,430**	**$14,857**	**$3,100,734**
131										
132	**Net Operating Income Before Income Tax**			**($6,562)**	**($14,887)**		**$4,352**	**($26,430)**	**($80,414)**	**$623,646**

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,418,435							
2			Sub-total Power Supply	$1,418,435							
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch	110,360							
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development	101,429							
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations	$211,789							
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE	$211,789							
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$530	$13						
30			581.0 Load Dispatching								
31			582.0 Station Expense	6,973	10						
32			583.0 Overhead Lines Expenses	17,302	92						
33			584.0 Underground Lines Expense	11,059	96						
34			586.0 Meter Expenses	6,216	84						
35			587.0 Customer Installations Expense	12,650	202						
36			588.0 Miscellaneous Expense	87,589	240						
37			589.0 Rents	4,215							
38			Sub-total Distribution Operations	$146,533	$737						
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$7,015	$49						
41			592.0 Maintenance of Station Equipment	16,512	260						
42			593.0 Maintenance of Overhead Lines	188,602	1,489						
43			594.0 Maintenance of Underground Lines	34,508	506						
44			595.0 Maintenance of Line Transformers	2,663	25						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,761	5						
46			598.0 Maintenance of Misc. Distribution	17,317	106						
47			Sub-total Distribution Maintenance	$268,377	$2,439						
48											

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
49			Sub-total DISTRIBUTION EXPENSE	$414,911		$3,176					
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading	$245		0					
53			903.0 Customer Records and Collection	98,222		1,116					
54			904.0 Uncollectible Accounts.	34,396						22,509	
55			905.0 Miscellaneous Customer Accounts Expenses.	3,433		31					
56			Sub-total Customer Accounts	$136,296		$1,147				$22,509	
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance	$99,468	($59,417)	$37					
59			909.0 Informational & Instructional	2,389							
60			910.0 Miscellaneous Customer & Informational	908							
61			Sub-total Customer Service & Information	$102,765	($59,417)	$37					
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling	$682		$15					
64			916.0 Miscellaneous Sales								
65			Sub-total Sales	$682		$15					
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries	$37,084		$1,387					
68			921.0 Office Supplies and Expenses	4,220							
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed	99,366							
71			924.0 Property Insurance	951							
72			925.0 Injuries & Damages	16,346		54					
73			926.0 Employee Pensions and Benefits	31,080		1		78	(1,069)		
74			928.0 Regulatory Commission Expenses	9,619			37				
75			929.0 Duplicate Charges-Credit	(2,026)							
76			930.2 Miscellaneous General Expenses	1,516		0					
77			Sub-total A&G Operations	$198,156		$1,442	$37	$78	($1,069)		
78											
79		A&G Maintenance	935.0 Maintenance of General Plant	$9,776		$39					
80											
81			Sub-total ADMINISTRATION & GENERAL	$207,932		$1,481	$37	$78	($1,069)		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$313,766							
84			404.0 Amort. Of Limited-Term Electric Plant.	30,006							
85			Sub-total Depreciation & Amortization Expense	$343,772							
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$1,099							$20
88			Sub-total Amortization of Regulatory Expense	$1,099							$20
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$248,197							
91			Sub-total Taxes Other Than Income Taxes - Other	$248,197							
92											
93			**Total**	**$3,085,877**	**($59,417)**	**$5,856**	**$37**	**$78**	**($1,069)**	**$22,509**	**$20**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.								$1,418,435
2			Sub-total Power Supply								$1,418,435
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch								110,360
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development								101,429
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations								$211,789
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE								$211,789
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision							$13	$543
30			581.0 Load Dispatching								
31			582.0 Station Expense							$10	$6,983
32			583.0 Overhead Lines Expenses							$92	$17,394
33			584.0 Underground Lines Expense							$96	$11,155
34			586.0 Meter Expenses							$84	$6,300
35			587.0 Customer Installations Expense							$202	$12,852
36			588.0 Miscellaneous Expense							$240	$87,829
37			589.0 Rents								$4,215
38			Sub-total Distribution Operations							$737	$147,270
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures							$49	$7,064
41			592.0 Maintenance of Station Equipment							260	16,772
42			593.0 Maintenance of Overhead Lines		6,562	14,887				22,937	211,539
43			594.0 Maintenance of Underground Lines							506	35,014
44			595.0 Maintenance of Line Transformers							25	2,688
45			596.0 Maintenance of Street Lighting & Signal Systems							5	1,765
46			598.0 Maintenance of Misc. Distribution							106	17,423
47			Sub-total Distribution Maintenance		$6,562	$14,887				$23,888	$292,265
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE		$6,562	$14,887				$24,625	$439,535
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading							$0	$245
53			903.0 Customer Records and Collection							$1,116	99,338
54			904.0 Uncollectible Accounts.							22,509	56,905
55			905.0 Miscellaneous Customer Accounts Expenses.	3,315						3,346	6,778
56			Sub-total Customer Accounts	$3,315						$26,971	$163,266
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance							($59,380)	$40,088
59			909.0 Informational & Instructional								2,389
60			910.0 Miscellaneous Customer & Informational								908
61			Sub-total Customer Service & Information							($59,380)	$43,386
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling							$15	$698
64			916.0 Miscellaneous Sales								
65			Sub-total Sales							$15	$698
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries							$1,387	$38,472
68			921.0 Office Supplies and Expenses								4,220
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed								99,366
71			924.0 Property Insurance								951
72			925.0 Injuries & Damages							54	16,399
73			926.0 Employee Pensions and Benefits							(990)	30,090
74			928.0 Regulatory Commission Expenses							37	9,657
75			929.0 Duplicate Charges-Credit								(2,026)
76			930.2 Miscellaneous General Expenses							0	1,516
77			Sub-total A&G Operations							$489	$198,645
78											
79		A&G Maintenance	935.0 Maintenance of General Plant							$39	$9,815
80											
81			Sub-total ADMINISTRATION & GENERAL							$528	$208,459
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$20,263	$20,263	$334,028
84			404.0 Amort. Of Limited-Term Electric Plant.						6,167	6,167	36,174
85			Sub-total Depreciation & Amortization Expense						$26,430	$26,430	$370,202
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.							$20	$1,119
88			Sub-total Amortization of Regulatory Expense							$20	$1,119
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					($4,352)		($4,352)	$243,845
91			Sub-total Taxes Other Than Income Taxes - Other					($4,352)		($4,352)	$243,845
92											
93			**Total**	**$3,315**	**$6,562**	**$14,887**		**($4,352)**	**$26,430**	**$14,857**	**$3,100,734**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-5 Revenue Adjustment Summary

Line No.	Category	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) D-5H Other Adjustments	(10) Adjustments Sub-total	(11) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$1,130,090	$2,330	($2,204)	($2,101)	($17,957)		$622			($19,312)	$1,110,778
2			Residential - House Heating	440.1	217,436	1,202	(272)	(465)	(4,605)		180			(3,958)	213,478
3			C & I Small	442.0	353,486	569	-	(1,083)	(14,286)		196			(14,604)	338,882
4			C & I Large	442.1	261,609		-	(802)	(26,327)		163			(26,966)	234,642
5			Railroads & Railways	446.0	10,337		-	-	(921)					(921)	9,416
6			Street Lighting	444.0	24,657		-		(162)					(162)	24,495
7			Intercompany	448.0											
8			Transmission - All Classes		226,232										226,232
9			Sub-total - Customer & Distribution Revenues		$2,223,847	$4,101	($2,476)	($4,450)	($64,258)		$1,161			($65,923)	$2,157,924
10															
11		**Electric Cost Revenue**	Residential	440.0	$976,446										$976,446
12			Residential - House Heating	440.1	241,229										241,229
13			C & I Small	442.0	214,828										214,828
14			C & I Large	442.1	80,396										80,396
15			Railroads & Railways	446.0											
16			Street Lighting	444.0	607										607
17			Intercompany	448.0											
18			Sub-total - Electric Cost Revenue		$1,513,506										$1,513,506
19															
20			**Total OPERATING REVENUE**		$3,737,353	$4,101	($2,476)	($4,450)	($64,258)		$1,161			($65,923)	$3,671,430
21															
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$27,040										$27,040
23			Other Electric Revenues	456.0	3,293								366	$366	3,659
24			Transmission of Electricity for Others	456.1											
25			Sub-total - Other electric Revenue		$30,333								$366	$366	$30,698
26															
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$18,329										$18,329
28			Miscellaneous Service Revenues	451.0	3,923										3,923
29			Sub-total - Other Operating Revenue		$22,252										$22,252
30															
31			**Total OTHER REVENUE**		$52,584								$366	$366	$52,950
32															
33			**Total REVENUE**		**$3,789,938**	**$4,101**	**($2,476)**	**($4,450)**	**($64,258)**		**$1,161**		**$366**	**($65,557)**	**$3,724,380**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Total FTY Revenues		$2,229,131	$488,916	$608,736	$373,619	$982,355
2	Commodity Billings in Revenues		(1,099,041)	(271,480)	(255,251)	(112,010)	(367,261)
3	Weather Adjustment						
4	Total Reconcilable Surcharge in Revenues		(12,231)	(3,158)	(9,838)	(18,034)	(27,872)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$1,117,859	$214,278	$343,648	$243,574	$587,222
6							
7	Average Monthly Customers in FTY		1,343,164	207,443	155,189	3,156	158,345
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.832	$1.033	$2.214	$77.178	$3.708
10							
11	Number of Customers at end of FTY		1,345,963	208,607	155,446	3,156	158,602
12							
13	Increase in Customers during FTY	L11 - L7	2,799	1,164	257		257
14							
15	**Annualization of Revenue**	L9 * L13	**$2,330**	**$1,202**	**$569**		**$569**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3)
1	CAP Discount		($181,456)	($22,364)	
2					
3					
4	**ANNUALIZATION TO YEAR END CUSTOMERS**				
5					
6	Annual CAP Customers		1,486,971	186,977	
7	Average Monthly CAP Customers		123,914	15,581	
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.464)	($1.435)	
9					
10	CAP Customers at End of FPFTY		125,623	15,796	
11	Increase of CAP Customers	L10 - L7	1,709	215	
12					
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($2,502)	($308)	
14	Write-Offs & Working Capital Factor		11.9%	11.9%	
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$298	$37	
16					
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($2,204)**	**($272)**	

Line No.	Description	Reference	(1) 2026 Revenue Loss	(2) 2027 Revenue Loss	(3) 2027 Revenue Loss Over 2026	(4) Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2026 - Included in FTY Year Budget**					
2	Residential		($4,482)			
3	Residential Heaing		(991)			
4	Small C&I		(1,810)			
5	Large C&I		(2,022)			
6	Total	SUM L2 to L5	($9,305)			
7						
8	**Target Revenue Impact in 2027**					
9	Residential			($8,684)		
10	Residential Heaing			(1,920)		
11	Small C&I			(3,975)		
12	Large C&I			(3,627)		
13	Total	SUM L9 to L12		($18,206)		
14						
15	**Incremental Revenue Impact Over FTY Budget**					
16	Residential	L9 - L2			($4,203)	
17	Residential Heaing	L10 - L3			(929)	
18	Small C&I	L11 - L4			(2,165)	
19	Large C&I	L12 - L5			(1,604)	
20	Total	SUM L16 to L19			($8,901)	
21						
22	**Average Annual Incremental Revenue Not in FTY Budget**					
23	Residential	L16 / 2				($2,101)
24	Residential Heaing	L17 / 2				(465)
25	Small C&I	L18 / 2				(1,083)
26	Large C&I	L19 / 2				(802)
27	**Total**	SUM L23 to L26				**($4,450)**

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($17,957)
2	440001: Residential Heating Sales		(4,605)
3	442001: C&I Sales-Small		(14,286)
4	442002: C&I Sales-Large		(26,327)
5	444000: Public Street/Highway Lighting		(162)
6	446000: Sales-Railroad/Railway		(921)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($64,258)**
8			
9	O&M Expense		($59,417)

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
D-5F Leap Year Revenue Normalization

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Revenue in February of FTY		$69,631	$20,196	$21,929	$18,239	$40,167
2	Days in February of FTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$2,487	$721	$783	$651	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$622**	**$180**	**$196**	**$163**	**$359**

Line No.	Account	(1) Total
1	Residental Sales	
2	Residental Heating Sales	
3	C&I Sales-Small	
4	C&I Sales-Large	
5		
6	**Total**	

Line No.	Description	(1) Reference	(2) Total
1	Final Incremental COVID-19 Uncollectible Surcharge (ICUS) Reconciliation		
2	Residential		$935
3	Small C&I		(32)
4	Large C&I		(17)
5	Street Lighting		(11)
6	Sub-total ICUS Under Refund	SUM L2 to L5	$876
7	Final Fiber Affiliate Revenue Surcharge (FARS) Reconciliation		
8	Residential		($168)
9	Small C&I		(9)
10	Street Lighting		371
11	Large C&I & Railroads		(50)
12	Sub-total FARS Over Refund	SUM L8 to L11	$145
13	Total ICUS and FARS	L6 - L12	$731
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	$366

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,106	1,191
2	Number of Employees @ HTY - Total		2,297	2,297
3	Percentage of Employees @ HTY	L1 / L2	48.14%	51.86%
4	Distribution of Budget S&W Expense		$81,871	$88,186
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$441
10		L4 + L9	$81,871	$88,627
11				
12	**Annualize January 1 and March 1, 2028 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$2,047	$2,659
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$83,918**	**$91,286**

Line No.	Description	(1) Reference	(2) Amount
1	Distribution of S&W Expense		$170,057
2			
3	Annualized S&W Including Wage Increases		$175,203
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		76.67%
8	Union Contract Payment for Utility	L6 * L7	$999
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$167
11			
12	Adjusted S&W for Employees in FTY	L3 + L10	$175,370
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FTY		2,382
16	Average Number of Employees in FTY - Total		2,375
17	Annualization for Number of Employees	L15 - L16	7
18	Annual S&W per Employee	L12 / L16	$73.9
19	Annualization of S&W for New Employees	L17 * L18	$543
20			
21	Pro Forma FPFTY S&W	L12 + L19	$175,913
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$5,856**
24			
25	S&W Pro Forma Factor	L23 / L1	3.44%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$382	$13	$396
26			581.0 Load Dispatching			
27			582.0 Station Expense	296	10	306
28			583.0 Overhead Lines Expenses	2,668	92	2,760
29			584.0 Underground Lines Expense	2,797	96	2,894
30			586.0 Meter Expenses	2,436	84	2,520
31			587.0 Customer Installations Expense	5,861	202	6,063
32			588.0 Miscellaneous Expense	6,960	240	7,200
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,433	49	1,482
35			592.0 Maintenance of Station Equipment	7,547	260	7,806
36			593.0 Maintenance of Overhead Lines	43,238	1,489	44,727
37			594.0 Maintenance of Underground Lines	14,684	506	15,189
38			595.0 Maintenance of Line Transformers	732	25	757
39			596.0 Maintenance of Street Lighting & Signal Systems	134	5	138
40			598.0 Maintenance of Misc. Distribution	3,072	106	3,178
41			Sub-total Distribution Operations	$92,240	$3,176	$95,416
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	$0	$0	$0
45			903.0 Customer Records and Collection	32,402	1,116	33,518
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	892	31	923
48			Sub-total Customer Accounts	$33,294	$1,147	$34,441
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,075	$37	$1,112
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational			
53			Sub-total Customer Service & Information	$1,075	$37	$1,112
54						
55	**Sales**		912.0 Demonstrating & Selling	$446	$15	$462
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$446	$15	$462
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$40,286	$1,387	$41,673
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,562	54	1,616
65			926.0 Employee Pensions and Benefits	31	1	32
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	3	0	3
69			935.0 Maintenance of General Plant	1,120	39	1,158
70			Sub-total Administration & General	$43,001	$1,481	$44,482
71						
72			**Total**	**$170,057**	**$5,856**	**$175,913**
73						
74	**Percent Increas**		**Percent Increase**			3.44%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$111
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		$31
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$142
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,740
8	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		366
9	Total Expenditure Expected in FTY	SUM L7 to L8	$3,106
10			
11	Total Rate Case Expense	L4 + L9	$3,248
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,624
15			
16	Annual Amortization Amount Included in Budget		$1,587
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$37**

Line No.	Description	(1) Reference	(2) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,335
3	Employees at Ten Months Prior		2,343
4	Employees at Nine Months Prior		2,340
5	Employees at Eight Months Prior		2,362
6	Employees at Seven Months Prior		2,382
7	Employees at Six Months Prior		2,388
8	Employees at Five Months Prior		2,387
9	Employees at Four Months Prior		2,392
10	Employees at Three Months Prior		2,400
11	Employees at Two Months Prior		2,395
12	Employees at One Month Prior		2,390
13	Employees at End of FPFTY		2,382
14			
15	Average Monthly Employees in FTY	AVERAGE L2 to L13	2,375
16	Additional Employees in FTY		7
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$25,277
20	Number of Employees for Budget		2,375
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	7
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$78**

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to FTY		$15,222
2	Pension Contribution for Three Years Prior to FTY		1,408
3	Pension Contribution for Two Years Prior to FTY		3,690
4	Pension Contribution for One Year Prior to FTY		11,760
5	Pension Contribution for FTY		10,374
6			
7	Average Pension Contribution	Average L1 to L5	$8,491
8			
9	Percent to Electric Distribution		76.67%
10	Total Amount to Electric Distribution	L7 * L9	$6,510
11	Pension Capitalization Factor		48.37%
12	Pension Contribution To Be Capitalized	L10 * L11	$3,149
13	Pension Contribution To Be Expensed	L10 - L12	$3,361
14	FPFTY Distribution Pension Expense		4,430
15	**Additional Pension Expense**	L13 - L14	**($1,069)**

Line No.	Description	Reference	Reference	Charge Off Amounts	InPA Charge Off Amounts	Net Charge Off Amounts	Billed Revenue	Percent	Totals
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$42,650	$17	$42,632	$3,880,008	1.0988%	
2		One Year Prior to HTY		28,792	2	28,791	4,036,898	0.7132%	
3		HTY		68,853		68,853	4,655,348	1.4790%	
4		Three Year Average	SUM L1 to L3 / 3	$46,765	$6	$46,759	$4,190,751	1.1158%	
5									
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FTY					$3,671,430		
7									
8	Tariff Revenue - Non Shopping Revenue	FTY	L6				$3,671,430		
9									
10	Tariff Revenue - Shopping Revenue	FTY					1,428,686		
11									
12	Tariff Revenue - Including Shopping Revenue	FTY	L8 + L10				$5,100,116		
13									
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12						$56,905
15									
16	Uncollectible Accounts (904)	FTY							$34,396
17									
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16						**$22,509**

Line No.	Description	(1) Reference	(2) Total
1	Actual IIJA Related Incremental Costs in 2024 and 2025		$451
2	Amortization Years		2
3	Total Pro Forma Adjustment Amount	L1 / L2	$226
4	Annual Amortization Amount Included in Budget		$206
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**$20**

Line No.	Description	Description	(1) Reference	(2) Interest Rate	(3) Deposit Amount	(4) Interest on Deposit Amount	(5) Interest Sub Total	(6) Interest Total
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				22,580	132		
4	February				23,154	135		
5	March				24,246	141		
6	April				25,771	150		
7	May				26,839	157		
8	June				27,171	158		
9	July				27,725	162		
10	August				28,297	165		
11	September				29,109	170		
12	October				29,946	175		
13	November				30,524	178		
14	December				30,889	180		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,903	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				35,889	105		
20	February				36,470	106		
21	March				37,775	110		
22	April				39,113	114		
23	May				39,833	116		
24	June				39,865	116		
25	July				40,669	119		
26	August				40,986	120		
27	September				41,497	121		
28	October				43,006	125		
29	November				43,769	128		
30	December				45,192	132		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,412	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,315**

Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
		(1)	(2)	(3)	(4)	(5)	(6)
1	2021		-	1.23871	$54,400	$67,386	
2	2022		0.07799	1.23871	$22,457	$27,818	
3	2023		0.04436	1.14909	$41,173	$47,312	
4	2024		0.03550	1.10028	$54,149	$59,579	
5	2025		0.03283	1.06256	$42,147	$44,784	
6	2026		0.02879	1.02879			
7							
8	Average Storm Restoration Expense at 2027 cost levels	Avg. Col 5, L1 to L5					$49,376
9							
10	FTY Budget						$42,814
11							
12	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$6,562**

Line No.	Description	(1) Reference	(2) Total
1	Deferred Storm Expense		$74,434
2	Amortization Years		5
3	Total Pro Forma Adjustment Amount	L1 / L7	$14,887
4	Annual Amortization Amount Included in Budget		
5	**Pro Forma Adjustment for Annual Amortization**		**$14,887**

Line No.	Description	Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
		(1)	(2)	(3)	(4)	(5)	(6)
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$8,306	($1,443)	$6,863		$6,863
2	Use Tax Accrued	17.372%	2,848	(495)	2,353		2,353
3	Real Estate Tax Accrued	17.372%	7,421	(1,289)	6,132		6,132
4	Miscellaneous TOTI	12.545%		-			
5	Payroll Tax Accrued	12.545%	15,650	(1,963)	13,686	471	14,158
6	Sub-total TOTI - Other	SUM L1 to L5	$34,225	($5,190)	$29,035	$471	$29,506
7							
8	Gross Receipt Tax		$219,162		$219,162	($4,823)	$214,338
9							
10	**Total**	L6 + L8	**$253,387**	**($5,190)**	**$248,197**	**($4,352)**	**$243,845**

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$170,057
2	Payroll Tax Expense		$13,686
3	Payroll Tax Expense - Percent	L2 / L1	8.05%
4	Pro Forma Increase in S&W		$5,856
5	**Payroll Tax Pro Forma**	L3 * L4	**$471**

Line No.	Description	(1) Reference	(2) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		
2			
3	Residential		$2,087,225
4	Residential Heating		454,706
5	Small C&I		553,710
6	Large C&I		315,038
7	Railroads & Railways		9,416
8	Street Lighting & Highway		25,102
9	Interdepartmental Sales - Electric		
10	Transmission		226,232
11	Sub-total	SUM L3 to L10	$3,671,430
12			
13	Forfeited Discounts - Electric		$18,329
14	Uncollectible Accounts		(56,905)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($38,576)
17			
18	Total FPFTY at Present Rates	L11 + L16	$3,632,854
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$214,338
23			
24	FPFTY Budget		$219,162
25			
26	**Net Adjustment**	L22 - L24	**($4,823)**

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$3,814	$599	$3,215	$599	$4,413
2			PECO Elec 3650 PA LTIIP	4,883	583	4,301	583	5,466
3			PECO Elec 3660 PA LTIIP	4,905	1,042	3,863	1,042	5,947
4			PECO Elec 3670 PA LTIIP	9,040	1,523	7,516	1,523	10,563
5			PECO Elec 3705 SM UD RES PA	7,734		7,734		7,734
6			PECO Elec 3706 Non DOE Rcv PA	1,785		1,785		1,785
7			PECO Elec 3707 SM RES PA	8,051	188	7,863	188	8,239
8			PECO Elec 3708 SM SCI PA	742	4	738	4	747
9			PECO Elec 3709 SM LCI PA	1,417	28	1,389	28	1,445
10			PECO Electric 3611 PA	1,528	128	1,400	128	1,657
11			PECO Electric 3612 PA	3,822	318	3,505	318	4,140
12			PECO Electric 3613 PA	184	0	184	0	184
13			PECO Electric 3620 PA	23,023	725	22,298	725	23,748
14			PECO Electric 3631 PA	5,110	57	5,053	57	5,167
15			PECO Electric 3632 PA	29,082	343	28,739	343	29,424
16			PECO Electric 3633 PA	8,459	405	8,055	405	8,864
17			PECO Electric 3640 PA	33,854	2,708	31,146	2,708	36,562
18			PECO Electric 3650 PA	48,182	2,668	45,514	2,668	50,849
19			PECO Electric 3660 PA	11,949	1,086	10,862	1,086	13,035
20			PECO Electric 3670 PA	40,097	2,181	37,916	2,181	42,278
21			PECO Electric 3680 PA	22,969	1,747	21,221	1,747	24,716
22			PECO Electric 3691 PA	3,802	159	3,643	159	3,961
23			PECO Electric 3692 PA	4,463	29	4,434	29	4,492
24			PECO Electric 3701 PA	194	10	184	10	204
25			PECO Electric 3710 PA	4		4		4
26			PECO Electric 3730 PA	604		604		604
27			PECO Electric 3731 PA	56	0	56	0	56
28			PECO Electric 3732 PA	890	14	875	14	904
29			PECO Electric 3733 PA	24		24		24
30			Sub-total Electric - Distribution	$280,666	$16,546	$264,120	$16,546	$297,211
31			Sub-total Electric - Distribution	$280,666	$16,546	$264,120	$16,546	$297,211
32								

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
33		Electric - General Plant	PECO Common 3901 PA	$4,635	$112	$4,523	$112	$4,747
34			PECO Common 3902 IL	16		16		16
35			PECO Common 3902 PA	4,473	728	3,745	728	5,201
36			PECO Common 3903 PA	176	43	134	43	219
37			PECO Common 3911 PA	13		13		13
38			PECO Common 3912 PA	2,203	34	2,169	34	2,237
39			PECO Common 3913 IL	3,345	417	2,928	417	3,762
40			PECO Common 3913 PA	10,070	3,002	7,068	3,002	13,072
41			PECO Common 3930 PA	127	7	121	7	134
42			PECO Common 3941 PA	0		0		0
43			PECO Common 3942 PA	68	0	68	0	68
44			PECO Common 3970 PA	6,142	181	5,961	181	6,324
45			PECO Elec 3949 SM Tools PA	5		5		5
46			PECO Elec 3979 SM Comm Equip PA	22	22	0	22	45
47			PECO Electric 3901 PA	1,385	167	1,219	167	1,552
48			PECO Electric 3902 PA	346	5	341	5	350
49			PECO Electric 3903 PA	6		6		6
50			PECO Electric 3911 PA	0		0		0
51			PECO Electric 3912 PA	76	3	73	3	79
52			PECO Electric 3913 PA	238	238	0	238	476
53			PECO Electric 3930 PA	4		4		4
54			PECO Electric 3940 PA	4,606	201	4,405	201	4,806
55			PECO Electric 3951 PA	4		4		4
56			PECO Electric 3952 PA	0		0		0
57			PECO Electric 3971 PA	1,416	12	1,404	12	1,429
58			PECO Electric 3972 PA	3,931	59	3,872	59	3,990
59			PECO Electric 3973 PA	1,556	49	1,508	49	1,605
60			PECO Electric 3980 PA	181	12	169	12	193
61			Sub-total Electric - General Plant	$45,046	$5,291	$39,755	$5,291	$50,337
62			Sub-total Electric - General Plant	$45,046	$5,291	$39,755	$5,291	$50,337
63								

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
64		Electric - Transmission	PECO Electric 3511 PA	$3,143	$10	$3,133	$10	$3,153
65			PECO Electric 3512 PA	581	67	514	67	648
66			PECO Electric 3513 PA	1,337	44	1,293	44	1,381
67			PECO Electric 3521 PA	1,512	218	1,295	218	1,730
68			PECO Electric 3522 MD	1		1		1
69			PECO Electric 3522 NJ	0		0		0
70			PECO Electric 3522 PA	2,426	210	2,215	210	2,636
71			PECO Electric 3523 NJ	0		0		0
72			PECO Electric 3523 PA	86		86		86
73			PECO Electric 3530 NJ	63		63		63
74			PECO Electric 3530 PA	19,846	501	19,345	501	20,348
75			PECO Electric 3540 DE	87		87		87
76			PECO Electric 3540 MD	49		49		49
77			PECO Electric 3540 NJ	207		207		207
78			PECO Electric 3540 PA	3,311	38	3,273	38	3,350
79			PECO Electric 3550 PA	585	41	544	41	626
80			PECO Electric 3560 DE	5		5		5
81			PECO Electric 3560 MD	12		12		12
82			PECO Electric 3560 NJ	558	58	500	58	616
83			PECO Electric 3560 PA	3,061	134	2,927	134	3,194
84			PECO Electric 3570 PA	938	150	787	150	1,088
85			PECO Electric 3580 PA	2,487	161	2,327	161	2,648
86			PECO Electric 3590 MD	2	0	1	0	2
87			PECO Electric 3590 NJ	4		4		4
88			PECO Electric 3590 PA	22		22	-	22
89			Sub-total Electric - Transmission	$40,323	$1,633	$38,690	$1,633	$41,955
90								
91			Sub-total 403.0 Depreciation Expense	$366,034	$23,470	$342,564	$23,470	$389,504
92			Sub-total Electric - Transmission	$40,323	$1,633	$38,690	$1,633	$41,955
93								
95	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	$152		$152		$152

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$3,814	$599	$3,215	$599	$4,413
2			PECO Elec 3650 PA LTIIP	1.0000	$4,883	583	4,301	583	$5,466
3			PECO Elec 3660 PA LTIIP	1.0000	$4,905	1,042	3,863	1,042	$5,947
4			PECO Elec 3670 PA LTIIP	1.0000	$9,040	1,523	7,516	1,523	$10,563
5			PECO Elec 3705 SM UD RES PA	1.0000	$7,734		7,734		$7,734
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$1,785		1,785		$1,785
7			PECO Elec 3707 SM RES PA	1.0000	$8,051	188	7,863	188	$8,239
8			PECO Elec 3708 SM SCI PA	1.0000	$742	4	738	4	$747
9			PECO Elec 3709 SM LCI PA	1.0000	$1,417	28	1,389	28	$1,445
10			PECO Electric 3611 PA	1.0000	$1,528	128	1,400	128	$1,657
11			PECO Electric 3612 PA	1.0000	$3,822	318	3,505	318	$4,140
12			PECO Electric 3613 PA	1.0000	$184	0	184	0	$184
13			PECO Electric 3620 PA	1.0000	$23,023	725	22,298	725	$23,748
14			PECO Electric 3631 PA	1.0000	$5,110	57	5,053	57	$5,167
15			PECO Electric 3632 PA	1.0000	$29,082	343	28,739	343	$29,424
16			PECO Electric 3633 PA	1.0000	$8,459	405	8,055	405	$8,864
17			PECO Electric 3640 PA	1.0000	$33,854	2,708	31,146	2,708	$36,562
18			PECO Electric 3650 PA	1.0000	$48,182	2,668	45,514	2,668	$50,849
19			PECO Electric 3660 PA	1.0000	$11,949	1,086	10,862	1,086	$13,035
20			PECO Electric 3670 PA	1.0000	$40,097	2,181	37,916	2,181	$42,278
21			PECO Electric 3680 PA	1.0000	$22,969	1,747	21,221	1,747	$24,716
22			PECO Electric 3691 PA	1.0000	$3,802	159	3,643	159	$3,961
23			PECO Electric 3692 PA	1.0000	$4,463	29	4,434	29	$4,492
24			PECO Electric 3701 PA	1.0000	$194	10	184	10	$204
25			PECO Electric 3710 PA	1.0000	$4		4		$4
26			PECO Electric 3730 PA	1.0000	$604	-	$604	-	$604
27			PECO Electric 3731 PA	1.0000	$56	0	56	0	$56
28			PECO Electric 3732 PA	1.0000	$890	14	875	14	$904
29			PECO Electric 3733 PA	1.0000	$24		24		$24
30			Sub-total Electric - Distribution		$280,666	$16,546	$264,120	$16,546	$297,211
31			Sub-total Electric - Distribution		$280,666	$16,546	$264,120	$16,546	$297,211
32									

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
33		Electric - General Plant	PECO Common 3901 PA	0.7698	$3,568	$86	$3,482	$86	$3,654
34			PECO Common 3902 IL	0.7698	12		$12		12
35			PECO Common 3902 PA	0.7698	3,443	$560	$2,883	$560	4,003
36			PECO Common 3903 PA	0.7698	136	$33	$103	$33	169
37			PECO Common 3911 PA	0.7698	10		$10		10
38			PECO Common 3912 PA	0.7698	1,696	$26	$1,670	$26	1,722
39			PECO Common 3913 IL	0.7698	2,575	$321	$2,254	$321	2,896
40			PECO Common 3913 PA	0.7698	7,752	$2,311	$5,441	$2,311	10,063
41			PECO Common 3930 PA	0.7698	98	$5	$93	$5	103
42			PECO Common 3941 PA	0.7698	0		$0		0
43			PECO Common 3942 PA	0.7698	52	$0	$52	$0	52
44			PECO Common 3970 PA	0.7698	4,728	$140	$4,589	$140	4,868
45			PECO Elec 3949 SM Tools PA	1.0000	5		$5		5
46			PECO Elec 3979 SM Comm Equip PA	1.0000	22	$22	$0	$22	45
47			PECO Electric 3901 PA	1.0000	1,385	$167	$1,219	$167	1,552
48			PECO Electric 3902 PA	1.0000	346	$5	$341	$5	350
49			PECO Electric 3903 PA	1.0000	6		$6		6
50			PECO Electric 3911 PA	1.0000	0		$0		0
51			PECO Electric 3912 PA	1.0000	76	$3	$73	$3	79
52			PECO Electric 3913 PA	1.0000	238	$238	$0	$238	476
53			PECO Electric 3930 PA	1.0000	4		$4		4
54			PECO Electric 3940 PA	1.0000	4,606	$201	$4,405	$201	4,806
55			PECO Electric 3951 PA	1.0000	4		$4		4
56			PECO Electric 3952 PA	1.0000	0		$0		0
57			PECO Electric 3971 PA	1.0000	1,416	$12	$1,404	$12	1,429
58			PECO Electric 3972 PA	1.0000	3,931	$59	$3,872	$59	3,990
59			PECO Electric 3973 PA	1.0000	1,556	$49	$1,508	$49	1,605
60			PECO Electric 3980 PA	1.0000	181	$12	$169	$12	193
61			Sub-total Electric - General Plant		$37,848	$4,250	$33,598	$4,250	$42,098
62			Sub-total Electric - General Plant		$37,848	$4,250	$33,598	$4,250	$42,098
63									

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
64		Electric - Transmission	PECO Electric 3511 PA	1.0000	$3,143	$10	$3,133	$10	$3,153
65			PECO Electric 3512 PA	1.0000	581	67	514	67	648
66			PECO Electric 3513 PA	1.0000	1,337	44	1,293	44	1,381
67			PECO Electric 3521 PA	1.0000	1,512	218	1,295	218	1,730
68			PECO Electric 3522 MD	1.0000	1		1		1
69			PECO Electric 3522 NJ	1.0000	0		0		0
70			PECO Electric 3522 PA	1.0000	2,426	210	2,215	210	2,636
71			PECO Electric 3523 NJ	1.0000	0		0		0
72			PECO Electric 3523 PA	1.0000	86		86		86
73			PECO Electric 3530 NJ	1.0000	63		63		63
74			PECO Electric 3530 PA	1.0000	19,846	501	19,345	501	20,348
75			PECO Electric 3540 DE	1.0000	87		87		87
76			PECO Electric 3540 MD	1.0000	49		49		49
77			PECO Electric 3540 NJ	1.0000	207		207		207
78			PECO Electric 3540 PA	1.0000	3,311	38	3,273	38	3,350
79			PECO Electric 3550 PA	1.0000	585	41	544	41	626
80			PECO Electric 3560 DE	1.0000	5		5		5
81			PECO Electric 3560 MD	1.0000	12		12		12
82			PECO Electric 3560 NJ	1.0000	558	58	500	58	616
83			PECO Electric 3560 PA	1.0000	3,061	134	2,927	134	3,194
84			PECO Electric 3570 PA	1.0000	938	150	787	150	1,088
85			PECO Electric 3580 PA	1.0000	2,487	161	2,327	161	2,648
86			PECO Electric 3590 MD	1.0000	2	0	1	0	2
87			PECO Electric 3590 NJ	1.0000	4		4		4
88			PECO Electric 3590 PA	1.0000	22	-	22	-	22
89			Sub-total Electric - Transmission		$40,323	$1,633	$38,690	$1,633	$41,955
90									
91			Sub-total 403.0 Depreciation Expense		$358,836	$22,428	$336,408	$22,428	$381,264
92			Sub-total Electric - Transmission		$40,323	$1,633	$38,690	$1,633	$41,955
93									
95	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.7698	$117		$117		$117

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$3,814	$599	$3,215	$599	$4,413
2			PECO Elec 3650 PA LTIIP	1.0000	$4,883	$583	$4,301	$583	$5,466
3			PECO Elec 3660 PA LTIIP	1.0000	$4,905	$1,042	$3,863	$1,042	$5,947
4			PECO Elec 3670 PA LTIIP	1.0000	$9,040	$1,523	$7,516	$1,523	$10,563
5			PECO Elec 3705 SM UD RES PA	1.0000	$7,734		$7,734		$7,734
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$1,785		$1,785		$1,785
7			PECO Elec 3707 SM RES PA	1.0000	$8,051	$188	$7,863	$188	$8,239
8			PECO Elec 3708 SM SCI PA	1.0000	$742	$4	$738	$4	$747
9			PECO Elec 3709 SM LCI PA	1.0000	$1,417	$28	$1,389	$28	$1,445
10			PECO Electric 3611 PA	1.0000	$1,528	$128	$1,400	$128	$1,657
11			PECO Electric 3612 PA	1.0000	$3,822	$318	$3,505	$318	$4,140
12			PECO Electric 3613 PA	1.0000	$184	$0	$184	$0	$184
13			PECO Electric 3620 PA	1.0000	$23,023	$725	$22,298	$725	$23,748
14			PECO Electric 3631 PA	1.0000	$5,110	$57	$5,053	$57	$5,167
15			PECO Electric 3632 PA	1.0000	$29,082	$343	$28,739	$343	$29,424
16			PECO Electric 3633 PA	1.0000	$8,459	$405	$8,055	$405	$8,864
17			PECO Electric 3640 PA	1.0000	$33,854	$2,708	$31,146	$2,708	$36,562
18			PECO Electric 3650 PA	1.0000	$48,182	$2,668	$45,514	$2,668	$50,849
19			PECO Electric 3660 PA	1.0000	$11,949	$1,086	$10,862	$1,086	$13,035
20			PECO Electric 3670 PA	1.0000	$40,097	$2,181	$37,916	$2,181	$42,278
21			PECO Electric 3680 PA	1.0000	$22,969	$1,747	$21,221	$1,747	$24,716
22			PECO Electric 3691 PA	1.0000	$3,802	$159	$3,643	$159	$3,961
23			PECO Electric 3692 PA	1.0000	$4,463	$29	$4,434	$29	$4,492
24			PECO Electric 3701 PA	1.0000	$194	$10	$184	$10	$204
25			PECO Electric 3710 PA	1.0000	$4		$4		$4
26			PECO Electric 3730 PA	1.0000	$604		$604		$604
27			PECO Electric 3731 PA	1.0000	$56	$0	$56	$0	$56
28			PECO Electric 3732 PA	1.0000	$890	$14	$875	$14	$904
29			PECO Electric 3733 PA	1.0000	$24		$24		$24
30			Sub-total Electric - Distribution		$280,666	$16,546	$264,120	$16,546	$297,211
31			Sub-total Electric - Distribution		$280,666	$16,546	$264,120	$16,546	$297,211
32									

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
33		Electric - General Plant	PECO Common 3901 PA	0.8746	$3,121	$75	$3,045	$75	$3,196
34			PECO Common 3902 IL	0.8746	11		11		11
35			PECO Common 3902 PA	0.8746	3,011	490	2,521	490	3,501
36			PECO Common 3903 PA	0.8746	119	29	90	29	148
37			PECO Common 3911 PA	0.8746	8		8		8
38			PECO Common 3912 PA	0.8746	1,483	23	1,460	23	1,506
39			PECO Common 3913 IL	0.8746	2,252	281	1,971	281	2,533
40			PECO Common 3913 PA	0.8746	6,779	2,021	4,758	2,021	8,800
41			PECO Common 3930 PA	0.8746	86	4	81	4	90
42			PECO Common 3941 PA	0.8746	0		0		0
43			PECO Common 3942 PA	0.8746	46	0	46	0	46
44			PECO Common 3970 PA	0.8746	4,135	122	4,013	122	4,257
45			PECO Elec 3949 SM Tools PA	0.8746	4		4		4
46			PECO Elec 3979 SM Comm Equip PA	0.8746	20	20	0	20	39
47			PECO Electric 3901 PA	0.8746	1,212	146	1,066	146	1,357
48			PECO Electric 3902 PA	0.8746	302	4	298	4	306
49			PECO Electric 3903 PA	0.8746	6		6		6
50			PECO Electric 3911 PA	0.8746	0		0		0
51			PECO Electric 3912 PA	0.8746	66	2	64	2	69
52			PECO Electric 3913 PA	0.8746	208	208	0	208	417
53			PECO Electric 3930 PA	0.8746	3		3		3
54			PECO Electric 3940 PA	0.8746	4,028	176	3,852	176	4,204
55			PECO Electric 3951 PA	0.8746	4		4		4
56			PECO Electric 3952 PA	0.8746	0		0		0
57			PECO Electric 3971 PA	0.8746	1,239	11	1,228	11	1,250
58			PECO Electric 3972 PA	0.8746	3,438	51	3,386	51	3,489
59			PECO Electric 3973 PA	0.8746	1,361	43	1,319	43	1,404
60			PECO Electric 3980 PA	0.8746	158	10	148	10	169
61			Sub-total Electric - General Plant		$33,100	$3,717	$29,383	$3,717	$36,817
62			Sub-total Electric - General Plant		$33,100	$3,717	$29,383	$3,717	$36,817
63									

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
64		Electric - Transmission	PECO Electric 3511 PA						
65			PECO Electric 3512 PA						
66			PECO Electric 3513 PA						
67			PECO Electric 3521 PA						
68			PECO Electric 3522 MD						
69			PECO Electric 3522 NJ						
70			PECO Electric 3522 PA						
71			PECO Electric 3523 NJ						
72			PECO Electric 3523 PA						
73			PECO Electric 3530 NJ						
74			PECO Electric 3530 PA						
75			PECO Electric 3540 DE						
76			PECO Electric 3540 MD						
77			PECO Electric 3540 NJ						
78			PECO Electric 3540 PA						
79			PECO Electric 3550 PA						
80			PECO Electric 3560 DE						
81			PECO Electric 3560 MD						
82			PECO Electric 3560 NJ						
83			PECO Electric 3560 PA						
84			PECO Electric 3570 PA						
85			PECO Electric 3580 PA						
86			PECO Electric 3590 MD						
87			PECO Electric 3590 NJ						
88			PECO Electric 3590 PA						
89			Sub-total Electric - Transmission						
90									
91			Sub-total 403.0 Depreciation Expense		$313,766	$20,263	$293,503	$20,263	$334,028
92			Sub-total Electric - Transmission						
93									
95	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.8746	$102		$102		$102

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$3,724,380	$299,493	$4,023,874
2	Operating Expenses		3,100,734	22,020	3,122,754
3	OIBIT	L1 - L2	$623,646	$277,473	$901,120
4					
5	Rate Base		$9,960,123		$9,960,123
6	Weighted Cost of Debt		2.180%		2.180%
7	Synchronized Interest Expense	L5 * L6	$217,131		$217,131
8	Base Taxable Income	L3 - L7	$406,516	$277,473	$683,989
9					
10	State Accelerated Tax Depreciation		$338,817		$338,817
11	Pro Forma Book Depreciation		370,202		370,202
12	State Tax Depreciation (Over) Under Book	L11 - L10	$31,385		$31,385
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(498)		(498)
14	Other Property Basis Adjustments (CIAC/ICM)		(89,188)		(89,188)
15	Removal Costs/Software		(10,120)		(10,120)
16	AFUDC Equity		-		-
17	Permanent Adjustments		4,202		4,202
18	Repair Deduction		(368,000)		(368,000)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($25,703)	$277,473	$251,770
21					
22	State Income Tax Rate		7.49%	7.49%	7.49%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$1,925	($20,783)	($18,858)
24	Net Operating Loss Utilization %		50.00%	50.00%	50.00%
25	Net Operating Loss Utilization	- L24 * L23	(963)	10,391	9,429
26	State Income Tax Benefit / (Expense)	L23 + L25	$963	($10,391)	($9,429)
27					
28	Federal Accelerated Tax Depreciation		$344,672		$344,672
29	Pro Forma Book Depreciation		370,202		370,202
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$25,530		$25,530
31	Regulatory Asset Programs M-1		(498)		(498)
32	Other Property Basis Adjustments (CIAC/ICM)		(89,188)		(89,188)
33	Removal Costs/Software		(10,120)		(10,120)
34	AFUDC Equity		-		-
35	Permanent Adjustments		4,202		4,202
36	Repair Deduction		(368,000)		(368,000)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($30,596)	$267,082	$236,486
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	-	$6,425	($56,087)	($49,662)
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$7,388	($66,479)	($59,091)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($14,389)	$2,182	($12,207)
47	Deferred Taxes on Timing Differences- State		(6,718)		(6,718)
48	Deferred Taxes on State NOL		963	(10,391)	(9,429)
49	Excess Deferred Amortization		6,781		6,781
50	Excess Deferred Amortization - State (Net of Federal)		552		552
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(21,193)		(21,193)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	($34,005)	($8,209)	($42,214)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	($26,617)	($74,688)	($101,305)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		($17)		($17)
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	($26,634)	($74,688)	($101,322)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	($22,393)	($53,905)	($76,298)
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	($4,241)	($20,783)	($25,023)
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**($26,634)**	**($74,688)**	**($101,322)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		18,329
4	Total Customer Revenue		3,737,353
5	Shopping Revenue		1,428,686
6	LPC REVENUE	L3 / (L4 + L5)	0.003548
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.011158)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003628)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.929762
13			
14	STATE INCOME TAX RATE		7.490%
15			
16	STATE INCOME TAX FACTOR	-	(0.069639)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.860123
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.180626)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.679497
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.471676
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	25.027%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.490%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.074900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.925100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.194271)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.730829
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.368309
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	26.917%

PECO Exhibit MJT-3:
Principal Accounting Exhibit
Historic Test Year ending 2025

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
A-1 Overall Summary

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$11,083,080		$11,083,080
3	Accumulated Depreciation	C-3	2,072,414		2,072,414
4	Common Plant - Net of Accum Depr	C-8	492,441		492,441
5	Net Plant in service	L2 - L3 + L4	$9,503,107		$9,503,107
6					
7	Working Capital	C-1	$290,366		$290,366
8	Pension Assets / (Liability)	C-1	163,722		163,722
9	Accum Deferred Income Taxes	C-1	(562,995)		(562,995)
10	Customer Deposits	C-1	(66,853)		(66,853)
11	Customer Advances for Construction	C-1	(10,468)		(10,468)
12	Materials and Supplies	C-1	53,088		53,088
13	Accum Deferred Income Taxes - Reg Liability	C-1	(274,076)		(274,076)
14					
15	TOTAL RATE BASE	SUM L5 to L13	$9,095,891		$9,095,891
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$2,087,494	$82,204	$2,169,697
19	Electric Cost Revenue	D-5	$1,290,152		1,290,152
20	Other Operating Revenues	D-5	$60,823	378	61,201
21	Total Revenues	SUM L18 to L20	$3,438,469	$82,581	$3,521,050
22					
23	Operating Expenses	D-1	$2,740,289	$6,065	$2,746,354
24					
25	OIBIT	L21 - L23	$698,180	$76,516	$774,696
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	($29,765)		($29,765)
28	Income Taxes @ Statutory Rates	D-18		(20,898)	(20,898)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$668,415	$55,618	$724,033
31					
32	RATE OF RETURN	L30 / L15	7.35%		7.96%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	7.35%		
36					
37	Rate of Return Required	B-7	7.96%		
38					
39	Change in ROR	L37 - L35	0.61%		
40					
41	Change in Operating Income	L15 * L39	$55,618		
42					
43	Gross Revenue Conversion Factor	D-19	1.478		
44					
45	Change in Revenues	L41 * L43	$82,204		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	53.50%		
49	Common Equity Rate Base	L15 * L48	$4,866,302		
50	NET OPERATING INCOME	L30 / L15	$668,415		
51	Synchronized Interest Expense	D-18	$191,014		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$477,401		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	9.81%		

Line No.	Description	Reference	Total - PECO
		(1)	(2)
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$19,247,007
3	Construction Work In Progress (107)		838,974
4	Total Utility Plant	L2 + L3	$20,085,981
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,153,619
6	Net Utility Plant	L4 - L5	$15,932,362
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,465
11	Invest in Assoc Company (123)		16,388
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$67,729
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$107,349
17	Customer Accounts Receivable (142)		533,708
18	Other Accounts Receivable (143)		146,860
19	Accum. Prov. for Uncollectible (144)		(155,196)
20	Receivables from Assoc. Comp. (146)		447
21	Fuel Stock (151)		1,693
22	Plant Materials & Supplies (154)		82,402
23	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)		336
24	Gas Stored Underground - Current (164.1)		37,749
25	Liquefied Natural Gas stored (164.2)		3,774
26	Prepayments (165)		71,882
27	Interest and Dividends Receivable (171)		10
28	Accrued Utility Revenues (173)		278,063
29	Miscellaneous Current & Accrued Assets (174)		2,500
30	Total Current and Accrued Assets	SUM L16 to L29	$1,111,575
31			
32	**Deferred Debits**		
33	Unamortized Debt Expense (181)		$54,815
34	Unrecovered Plant and Regulatory Study Costs (182.2)		741
35	Other Regualtory Assets (182.3)		1,346,571
36	Miscellaneous Deferred Debits (186)		905,479
37	Unamortized Loss on Reacquired Debt (189)		
38	Accumulated Deferred Income Taxes (190)		541,926
39	Total Deferred Debits	SUM L33 to L38	$2,849,533
40			
41	**TOTAL ASSETS**	L6+L13+L30+L39	$19,961,199
42			

		(1)	(2)
Line No.	Description	Reference	Total - PECO
43	**Proprietary Capital**		
44	Common Stock Issued (201)		$1,423,004
45	Preferred Stock Issued (204)		
46	Other Paid-In Capital (208-211)		3,799,345
47	Capital Stock Expense (214)		(87)
48	Retained Earnings (215, 215.2, 216)		5,947,074
49	Unappropriated Undistributed Subsidiary Earnings (216.1)		(3,512,588)
50	Accum Other Comprehensive Income (219)		3,163
51	Total Propriety Capital & Margins	SUM L44 to L50	$7,659,911
52			
53	**Long Term Debt**		
54	Bonds (221)		$6,475,000
55	Advances from Associated Companies (223)		184,419
56	Other Long-Term Debt (224)		
57	Unamortized Premium on LTD (225)		
58	Unamortized Discount on LTD (226)		(24,980)
59	Total Long-Term Debt	SUM L54 to L58	$6,634,438
60			
61	**Other Non-Current Liabilities**		
62	Obligations under Capital Leases (227)		
63	Accum. Prov for Injuries & Damages (228.2)		$62,513
64	Accum. Prov for Pensions & Benefits (228.3)		300,327
65	Accum. Miscellaneous Operating Prov (228.4)		11,729
66	Asset Retirement Obligation (230)		25,838
67	Total Other Non-Current Liabilities	SUM L62 to L66	$400,407
68			
69	**Current and Accrued Liabilities**		
70	Notes Payable (231)		
71	Accounts Payable (232)		$814,817
72	Notes Payable to Assoc. Companies (233)		
73	Accounts Payable to Assoc. Companies (234)		36,173
74	Customer Deposits (235)		93,432
75	Taxes Accrued (236)		311,493
76	Interest Accrued (237)		76,903
77	Dividends Declared (238)		
78	Tax Collections Payable (241)		92
79	Misc Current & Accrued Liabilities (242)		192,665
80	Total Current & Accrued Liabilities	SUM L70 to L79	$1,525,574
81			
82	**Other Deferred Credits**		
83	Customer Advances for Construction (252)		$15,732
84	Other Deferred Credits (253)		1,420
85	Other Regulatory Liabilities (254)		587,580
86	Deferred Investment Tax Credit (255)		286
87	Unamortized Gain on Reacquired Debt (257)		618
88	Accumulated Deferred Income Taxes (281-283)		3,135,233
89	Total Other Deferred Credits	SUM L83 to L88	$3,740,869
90			
91	**TOTAL LIABILITIES AND OTHER CREDITS**	L51+L59+L67+L80+L89	$19,961,199

Line No.	Category	Description	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,971,791		$1,971,791
2		Electric Cost Revenue	1,290,271		1,290,271
3		Transmission - All Classes	233,615		233,615
4		Other Revenues	332,198	$271,741	60,458
5		Total Operating Revenues	$3,827,875	$271,741	$3,556,135
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,436,476	$92,498	$2,343,978
8		Depreciation & Amortization Expense	353,809	48,111	305,698
9		Amortization of Regulatory Expense	1,459		1,459
10		Taxes Other Than Income Taxes - Other	231,390	4,346	227,045
11		Total Operating Expenses	$3,023,135	$144,955	$2,878,180
12					
13	**Net Utility Operating Income Before Income Tax**		**$804,740**	**$126,786**	**$677,954**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$1,099,108		$1,099,108
2			Residential - House Heating	440.1	215,945		215,945
3			C & I Small	442.0	370,920		370,920
4			C & I Large	442.1	252,807		252,807
5			Street Lighting	444.0	23,231		23,231
6			Railroads & Railways	446.0	9,426		9,426
7			Intercompany	448.0	354		354
8			Transmission - All Classes		233,615		233,615
9			Sub-total - Customer & Distribution Revenues		$2,205,406		$2,205,406
10							
11		Electric Cost Revenue	Residential	440.0	$824,223		$824,223
12			Residential - House Heating	440.1	203,033		203,033
13			C & I Small	442.0	212,006		212,006
14			C & I Large	442.1	49,781		49,781
15			Street Lighting	444.0	890		890
16			Sales for Resale	447.0	120		120
17			Intercompany	448.0	218		218
18			Sub-total - Electric Cost Revenue		$1,290,271		$1,290,271
19							
20		Other Operating Revenues	Forfeited Discounts	450.0	$21,431		$21,431
21			Miscellaneous Service Revenues	451.0	5,189		5,189
22			Rent For Electric Property	454.0	37,546	$11,872	25,675
23			Other Electric Revenues	456.0	8,163		8,163
24			Transmission of Electricity for Others	456.1	259,869	259,869	
25			Sub-total - Other Operating Revenues		$332,198	$271,741	$60,458
26							
27			**TOTAL OPERATING REVENUES**		$3,827,875	$271,741	$3,556,135
28							
29	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,133,435		$1,133,435
30			Bundled Environmental Credits	555.2	$85,487		85,487
31			Unbundled Environmental Credits	555.3	$669		669
32			Other expenses	557.0	$1,113		1,113
33			Operation & Supervision	560.0	10,549	$10,549	
34			Load Dispatching	561.0			
35			Scheduling, System Control & Dispatch	561.4	112,785		112,785
36			Transmission Service Studies	561.6	284	284	
37			Generation Service Studies	561.7			
38			Reliability, Planning & Standard Development	561.8	103,657		103,657

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
39			Station Expense	562.0	1,183	1,183	
40			Overhead Lines	563.0	409	409	
41			Underground Lines Expense	564.0			
42			Miscellaneous Expense	566.0	16,657	16,657	
43			Rents	567.0	12,217	12,217	
44			Maintenance of Structures	569.0	1,365	1,365	
45			Maintenance of Computer Hardware	569.1	90	90	
46			Maintenance of Computer Software	569.2	249	249	
47			Maintenance of Communication Equipment	569.3	90	90	
48			Maintenance of Station Equipment	570.0	7,389	7,389	
49			Maintenance of Overhead Lines	571.0	12,510	12,510	
50			Maintenance of Underground Lines	572.0	921	921	
51			Maintenance of Misc Transmission Plant	573.0	5,558	5,558	
52			Market Facilitation, Monitoring and Compliance Services	575.7	58	58	
53			Maint Energy Storage Equipment & Structures	578.2	23	23	
54			Operation & Supervision	580.0	554		554
55			Load Dispatching	581.0			
56			Station Expenses	582.0	5,825		5,825
57			Overhead Lines Expenses	583.0	17,811		17,811
58			Underground Lines Expense	584.0	10,648		10,648
59			Meter Expenses	586.0	6,002		6,002
60			Customer Installations Expense	587.0	12,490		12,490
61			Miscellaneous Expense	588.0	87,504		87,504
62			Rents	589.0	3,793		3,793
63			Maintenance of Structures	591.0	6,042		6,042
64			Maintenance of Station Equipment	592.0	17,236		17,236
65			Maintenance of Computer Hardware	592.2	1		1
66			Maintenance of Overhead Lines	593.0	173,935		173,935
67			Maintenance of Underground Lines	594.0	36,353		36,353
68			Maintenance of Line Transformers	595.0	2,851		2,851
69			Maintenance of Street Lighting & Signal Systems	596.0	1,691		1,691
70			Maintenance of Misc. Distribution	598.0	17,266		17,266
71			Supervision	901.0			
72			Meter Reading	902.0	203		203
73			Customer Records and Collection	903.0	95,368		95,368
74			Uncollectible Accounts	904.0	90,777		90,777
75			Miscellaneous Customer Accounts	905.0	3,509		3,509
76			Customer Assistance	908.0	101,387		101,387

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
77			Informational & Instructional	909.0	1,977		1,977
78			Miscellaneous Customer & Informational	910.0	822		822
79			Demonstrating & Selling	912.0	612		612
80			Miscellaneous Sales	916.0			
81			Administrative and General Salaries	920.0	31,019	4,994	26,024
82			Office Supplies and Expenses	921.0	5,000	558	4,442
83			Administrative Expenses Transferred-Credit	922.0			
84			Outside Service Employed	923.0	118,949	12,986	105,963
85			Property Insurance	924.0	1,185	147	1,037
86			Injuries & Damages	925.0	29,187		29,187
87			Employee Pensions and Benefits	926.0	30,109	2,752	27,357
88			Regulatory Commission Expenses	928.0	10,681	13	10,668
89			Duplicate Charges-Credit	929.0	(2,468)	(133)	(2,335)
90			Miscellaneous General Expenses	930.2	1,110	395	715
91			Maintenance of General Plant	935.0	10,351	1,232	9,118
92				Sub-total - O&M Expenses	$2,436,476	$92,498	$2,343,978
93							
94		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$326,842	$44,728	$282,114
95				404.0	26,967	3,383	23,584
96				Sub-total - Depreciation & Amortization Expense	$353,809	$48,111	$305,698
97							
98		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3	$1,459		$1,459
99				Sub-total - Amortization of Regulatory Expense	$1,459		$1,459
100							
101		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$231,390	$4,346	$227,045
102				Sub-total -Taxes Other Than Income Taxes - Other	$231,390	$4,346	$227,045
103							
104				**TOTAL OPERATING EXPENSES**	$3,023,135	$144,955	$2,878,180
105							
106				**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**	**$804,740**	**$126,786**	**$677,954**
107							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$1,099,108		$1,099,108
2			Residential - House Heating	440.1	215,945		215,945
3			C & I Small	442.0	370,920		370,920
4			C & I Large	442.1	252,807		252,807
5			Railroads & Railways	446.0	9,426		9,426
6			Street Lighting	444.0	23,231		23,231
7			Intercompany	448.0	354		354
8			Transmission - All Classes		233,615		233,615
9			Sub-total - Customer & Distribution Revenue		$2,205,406		$2,205,406
10							
11		**Electric Cost Revenue**	Residential	440.0	$824,223		$824,223
12			Residential - House Heating	440.1	203,033		203,033
13			C & I Small	442.0	212,006		212,006
14			C & I Large	442.1	49,781		49,781
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	890		890
17			Sales for Resale	447.0	120		120
18			Intercompany	448.0	218		218
19			Sub-total - Electric Cost Revenue		$1,290,271		$1,290,271
20							
21			**TOTAL OPERATING REVENUE**		$3,495,677		$3,495,677
22							
23	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$21,431		$21,431
24			Miscellaneous Service Revenues	451.0	5,189		5,189
25			Sub-total - Other Operating Revenue		$26,620		$26,620
26							
27		**Other Electric Revenue**	Rent For Electric Property	454.0	$37,546	$11,872	$25,675
28			Other Electric Revenues	456.0	8,163		8,163
29			Transmission of Electricity for Others	456.1	259,869	259,869	
30			Sub-total - Other Electric Revenue		$305,578	$271,741	$33,837
31							
32			**TOTAL OTHER REVENUE**		$332,198	$271,741	$60,458
33							
34			**TOTAL REVENUE**		**$3,827,875**	**$271,741**	**$3,556,135**

					(1)	(2)	(3)
Line No.	Category	Description	Account	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,133,435		$1,133,435
2			Bundled Environmental Credits	555.2	85,487		85,487
3			Unbundled Environmental Credits	555.3	669		669
4			Other expenses	557.0	1,113		1,113
5			**TOTAL POWER SUPPLY EXPENSES**		$1,220,704		$1,220,704
6							
7	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$10,549	$10,549	
8			Load Dispatching	561.0			
9			Scheduling, System Control & Dispatch	561.4	112,785		112,785
10			Transmission Service Studies	561.6	284	284	
11			Generation Service Studies	561.7			
12			Reliability, Planning & Standard Development	561.8	103,657		103,657
13			Station Expense	562.0	1,183	1,183	
14			Overhead Lines	563.0	409	409	
15			Underground Lines Expense	564.0			
16			Miscellaneous Expense	566.0	16,657	16,657	
17			Rents	567.0	12,217	12,217	
18			Sub-total Transmission Operations	SUM L4 to L14	$257,741	$41,299	$216,442
19							
20		Transmission Maintenance	Maintenance of Structures	569.0	$1,365	$1,365	
21			Maintenance of Computer Hardware	569.1	90	90	
22			Maintenance of Computer Software	569.2	249	249	
23			Maintenance of Communication Equipment	569.3	90	90	
24			Maintenance of Station Equipment	570.0	7,389	7,389	
25			Maintenance of Overhead Lines	571.0	12,510	12,510	
26			Maintenance of Underground Lines	572.0	921	921	
27			Maintenance of Misc Transmission Plant	573.0	5,558	5,558	
28			Market Facilitation, Monitoring and Compliance Serv	575.7	58	58	
29			Maint Energy Storage Equipment & Structures	578.2	23	23	
30			Sub-total Transmission Maintenance	SUM L17 to L24	$28,253	$28,253	
31							
32			**TOTAL TRANSMISSION EXPENSE**	L15 + L25	$285,994	$69,552	$216,442
33							
34	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$554		$554
35			Load Dispatching	581.0			
36			Station Expenses	582.0	5,825		5,825
37			Overhead Lines Expenses	583.0	17,811		17,811
38			Underground Lines Expense	584.0	10,648		10,648
39			Meter Expenses	586.0	6,002		6,002
40			Customer Installations Expense	587.0	12,490		12,490
41			Miscellaneous Expense	588.0	87,504		87,504
42			Rents	589.0	3,793		3,793
43			Sub-total Distribution Operations	SUM L29 to L37	$144,627		$144,627
44							
45		Distribution Maintenance	Maintenance of Structures	591.0	$6,042		$6,042
46			Maintenance of Station Equipment	592.0	17,236		17,236
47			Maintenance of Computer Hardware	592.2	1		1
48			Maintenance of Overhead Lines	593.0	173,935		173,935

Line No.	Category	Description	Account	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
49			Maintenance of Underground Lines	594.0	36,353		36,353
50			Maintenance of Line Transformers	595.0	2,851		2,851
51			Maintenance of Street Lighting & Signal Systems	596.0	1,691		1,691
52			Maintenance of Misc. Distribution	598.0	17,266		17,266
53			Sub-total Distribution Maintenance	SUM L40 to L46	$255,374		$255,374
54							
55			**TOTAL DISTRIBUTION EXPENSE**	L38 + L47	$400,001		$400,001
56							
57	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
58			Meter Reading	902.0	$203		$203
59			Customer Records and Collection	903.0	95,368		95,368
60			Uncollectible Accounts	904.0	90,777		90,777
61			Miscellaneous Customer Accounts	905.0	3,509		3,509
62			**TOTAL CUSTOMER ACCOUNTS**	SUM L51 to L55	$189,857		$189,857
63							
64	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$101,387		$101,387
65			Informational & Instructional	909.0	1,977		1,977
66			Miscellaneous Customer & Informational	910.0	822		822
67			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L58 to L60	$104,186		$104,186
68							
69	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$612		$612
70			Advertising Expenses	913.0			
71			Miscellaneous Sales	916.0			
72			**TOTAL SALES EXPENSE**	SUM L63 to L64	$612		$612
73							
74	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$31,019	$4,994	$26,024
75			Office Supplies and Expenses	921.0	5,000	$558	4,442
76			Administrative Expenses Transferred-Credit	922.0			
77			Outside Service Employed	923.0	118,949	$12,986	105,963
78			Property Insurance	924.0	1,185	$147	1,037
79			Injuries & Damages	925.0	29,187		29,187
80			Employee Pensions and Benefits	926.0	30,109	$2,752	27,357
81			Regulatory Commission Expenses	928.0	10,681	$13	10,668
82			Duplicate Charges-Credit	929.0	(2,468)	(133)	(2,335)
83			Miscellaneous General Expenses	930.2	1,110	$395	715
84			Sub-total A&G Operations	SUM L67 to L76	$224,772	$21,714	$203,058
85							
86		A&G Maintenance	Maintenance of General Plant	935.0	10,351	1,232	9,118
87							
88			TOTAL ADMINISTRATION & GENERAL	L77 + L79	$235,123	$22,946	$212,177
89							
90			**TOTAL O&M EXPENSE**	L2+L27+L49+L56+L61+L65+L81	$2,436,476	$92,498	$2,343,978
91							
92			TOTAL OPERATIONS EXPENSE		$2,152,850	$64,245	$2,088,604
93			TOTAL MAINTENANCE EXPENSE		283,627	28,253	255,374
94			**TOTAL O&M EXPENSE**	L85 + L86	**$2,436,476**	**$92,498**	**$2,343,978**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
B-4 O+M Expenses - A+G Detail

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$26,025	0.0000%		$26,025
2			Office Supplies and Expenses	921.0	4,442	0.0000%		4,442
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	105,963	0.0000%		105,963
5			Property Insurance	924.0	1,037	0.0000%		1,037
6			Injuries and Damages	925.0	29,187	0.0000%		29,187
7			Employee Pensions and Benefits	926.0	27,357	0.0000%		27,357
8			Regulatory Commission Expenses	928.0	10,668	0.0000%		10,668
9			Duplicate Charges-Credit	929.0	(2,335)	0.0000%		(2,335)
10			Miscellaneous General Expenses	930.2	715	0.0000%		715
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$203,059			$203,059
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,118	0.0000%		$9,118
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$212,177			$212,177
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	$4,994	100.0000%	$4,994	
17			Office Supplies and Expenses	921.0	558	100.0000%	558	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	12,986	100.0000%	12,986	
20			Property Insurance	924.0	147	100.0000%	147	
21			Injuries and Damages	925.0		100.0000%		
22			Employee Pensions and Benefits	926.0	2,752	100.0000%	2,752	
23			Regulatory Commission Expenses	928.0	13	100.0000%	13	
24			Duplicate Charges-Credit	929.0	(133)	100.0000%	(133)	
25			Miscellaneous General Expenses	930.2	395	100.0000%	395	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$21,714		$21,714	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0	$1,232	100.0000%	$1,232	
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$22,946		$22,946	
30								

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
B-4 O+M Expenses - A+G Detail

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0	($1)	12.5447%	($0)	($1)
32			Office Supplies and Expenses	921.0	0	12.5447%	0	0
33			Administrative Expenses Transferred-Credit	922.0		12.5447%		
34			Outside Service Employed	923.0		12.5447%		
35			Property Insurance	924.0		12.5447%		
36			Injuries and Damages	925.0		12.5447%		
37			Employee Pensions and Benefits	926.0	(0)	12.5447%	(0)	(0)
38			Regulatory Commission Expenses	928.0		12.5447%		
39			Duplicate Charges-Credit	929.0		12.5447%		
40			Miscellaneous General Expenses	930.2	(0)	12.5447%	(0)	(0)
41			Sub-total A&G Operations - General	SUM L31 to L40	($1)		($0)	($1)
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0		12.5447%		
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	($1)		($0)	($1)
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$31,019		$4,994	$26,024
47			Office Supplies and Expenses	921.0	5,000		558	4,442
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	118,949		12,986	105,963
50			Property Insurance	924.0	1,185		147	1,037
51			Injuries & Damages	925.0	29,187			29,187
52			Employee Pensions and Benefits	926.0	30,109		2,752	27,357
53			Regulatory Commission Expenses	928.0	10,681		13	10,668
54			Duplicate Charges-Credit	929.0	(2,468)		(133)	(2,335)
55			Miscellaneous General Expenses	930.2	1,110		395	715
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$224,772		$21,714	$203,058
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$10,351		$1,232	$9,118
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	$235,123		$22,946	$212,177

Line No.	Description	(1) Percentage	(2) Total	(3) Transmission Elimination	(4) Distribution
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$9,061	($1,574)	$7,487
2	Use Tax Accrued	17.372%	(495)	86	(409)
3	Real Estate Tax Accrued	17.372%	5,898	(1,025)	4,873
4	Miscellaneous TOTI	12.545%	52	(7)	46
5	Payroll Tax Accrued	12.545%	14,088	(1,767)	12,321
6	Gross Receipt Tax		202,445		202,445
7	**Total**		**$231,049**	**($4,286)**	**$226,763**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%		
2					8.63%		0.43%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.13%		0.07%	
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%		
6					7.88%		0.39%	
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
8					4.51%		0.27%	
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
10					2.63%		0.15%	
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
12					3.75%		0.18%	
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%		
14					4.51%		0.19%	
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
16					4.88%		0.18%	
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%		
18					4.88%		0.19%	
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%		
20					4.88%		0.20%	
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
22					4.88%		0.15%	
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
24					5.26%		0.15%	
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%		
26					5.63%		0.18%	
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%		
28					5.63%		0.16%	
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%		
30					5.26%		0.25%	
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%		
32					6.38%		0.28%	
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%		
34					8.63%		0.46%	
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%		
36					7.88%		0.45%	
37								
38		Sub-total Mortgage Bonds	SUM L1 to L37	$6,475,000	97.23%		4.33%	
39								
40	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%		
41					1.21%		0.09%	
42		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%		
43					0.01%			
44		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
45					1.55%		0.09%	
46								
47		Sub-total Capital Securities	SUM L40 to L46	$184,419	2.77%		0.18%	
48								
49		Total Long-Term Debt	L38 + L47	$6,659,419	100.00%		4.51%	
50								
51		Adjustments for Tenders & Calls		(521)				
52								
53		Net Long-Term Debt	L49 + L51	$6,658,898				
54								
55		Annualized Cost		300,340				
56								
57		Adjustment for Tenders & Calls Reacquired		68				
58								
59		**Total**	L55 + L57	$300,408				4.51%

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$6,658,898	46.50%	4.51%	2.10%
3					
4	Common Equity	$7,659,911	53.50%	10.95%	5.86%
5					
6	Total	$14,318,809	100.00%		7.96%

Line No.	Description	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
		(1)	(2)	(3)	(4)
1	Utility Plant	C-2	$13,322,798	$2,239,718	$11,083,080
2	Accumulated Depreciation	C-3	2,754,375	681,961	2,072,414
3	Common Plant	C-8	492,441		492,441
4	**Net Plant in Service**	L1 - L2 + L3	$11,060,864	$1,557,757	$9,503,107
5					
6	Working Capital	C-4	$290,366		$290,366
7	Pension Assets / (Liability)	C-5	163,722		163,722
8	Accumulated Deferred Income Taxes	C-6	(562,995)		(562,995)
9	Customer Deposits	C-7	(66,853)		(66,853)
10	Customer Advances for Construction	C-9	(10,468)		(10,468)
11	Material & Supplies	C-11	53,088		53,088
12	ADIT - Reg Liability	C-12	(274,076)		(274,076)
13	**Total Measures of Value**	SUM L4 to L12	$10,653,648	$1,557,757	$9,095,891

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$142
3		E303 - Misc Intangible Plant		6,914		6,914
4		Sub-total Intangible Plant	SUM L1 to L3	$7,077	$20	$7,056
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$92,459	$92,459	
7		E351.1 - Computer Hardware		$10,089	$10,089	
8		E351.2 - Computer Software		$23,901	$23,901	
9		E351.3 - Communication Equipment		27,762	27,762	
10		E352 - Structures and Improvements		190,292	190,292	
11		E353 - Station Equipment		1,101,199	1,101,199	
12		E354 - Towers and Fixtures		299,463	299,463	
13		E355 - Poles and Fixtures		34,860	34,860	
14		E356 - Overhead Conductors, Devices		235,660	235,660	
15		E357 - Underground Conduit		51,144	51,144	
16		E358 - Undergrnd Conductors, Devics		143,306	143,306	
17		E359 - Roads and Trails		2,643	2,643	
18		E359.1 - ARO Costs Transmission Plt		679	679	
19		Sub-total Transmission Plant	SUM L6 to L18	$2,213,457	$2,213,457	
20						
21	**Distribution Plant**	E360 - Land and Land Rights		$56,497		$56,497
22		E361 - Structures and Improvements		254,986		254,986
23		E362 - Station Equipment		1,319,714		1,319,714
24		E363.1 - Computer Hardware		19,321		19,321
25		E363.2 - Computer Software		188,081		188,081
26		E363.3 - Communication Equipment		135,890		135,890
27		E364 - Poles, Towers and Fixtures		1,520,587		1,520,587
28		E365 - Overhead Conductors, Devices		2,297,101		2,297,101
29		E366 - Underground Conduit		1,036,480		1,036,480
30		E367 - Undergrnd Conductors, Devics		2,188,469		2,188,469
31		E368 - Line Transformers		922,346		922,346
32		E369 - Services		488,871		488,871
33		E370 - Meters		377,824		377,824
34		E371 - Installs on Customer Premiss		13,772		13,772
35		E373 - Street Lighting,Signal Systm		69,602		69,602
36		E374 - ARO Costs Distribution Plt		3,554		3,554
37		Sub-total Distribution Plant	SUM L21 to L36	$10,893,096		$10,893,096
38						
39	**General Plant**	E389 - Land and Land Rights		$1,063	$133	$930
40		E390 - Structures and Improvements		68,748	8,624	60,124
41		E391 - Office Furniture, Equipment		1,115	140	976
42		E393 - Stores Equipment		45	6	39
43		E394 - Tools, Shop, Garage Equipmnt		68,030	8,534	59,496
44		E395 - Laboratory Equipment		97	12	85
45		E397.1 - Computer Hardware		6,976	875	6,101
46		E397.2 - Computer Software		24,675	3,095	21,579
47		E397.3 - Communication Equipment		34,012	4,267	29,745
48		E398 - Miscellaneous Equipment		1,987	249	1,738
49		E399.1 - ARO Costs General Plt		2,420	304	2,116
50		Sub-total General Plant	SUM L39 to L49	$209,169	$26,240	$182,929
51						
52		**Total**	L4+L19+L37+L50	**$13,322,798**	**$2,239,718**	**$11,083,080**

Line No.	Category	Account	(1) Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E350 - Land and Land Rights	
5		E351.1 - Computer Hardware	
6		E351.2 - Computer Software	
7		E351.3 - Communication Equipment	
8		E352 - Structures and Improvements	
9		E353 - Station Equipment	
10		E354 - Towers and Fixtures	
11		E355 - Poles and Fixtures	
12		E356 - Overhead Conductors, Devices	
13		E357 - Underground Conduit	
14		E358 - Undergrnd Conductors, Devics	
15		E359 - Roads and Trails	
16		E359.1 - ARO Costs Transmission Plt	
17		Sub-total Transmission Plant	
18			
19	**Distribution Plant**	E360 - Land and Land Rights	
20		E361 - Structures and Improvements	
21		E362 - Station Equipment	
22		E363.1 - Computer Hardware	
23		E363.2 - Computer Software	
24		E363.3 - Communication Equipment	
25		E364 - Poles, Towers and Fixtures	
26		E365 - Overhead Conductors, Devices	
27		E366 - Underground Conduit	
28		E367 - Undergrnd Conductors, Devics	
29		E368 - Line Transformers	
30		E369 - Services	
31		E370 - Meters	
32		E371 - Installs on Customer Premiss	
33		E373 - Street Lighting,Signal Systm	
34		E374 - ARO Costs Distribution Plt	
35		Sub-total Distribution Plant	
36			
37	**General Plant**	E389 - Land and Land Rights	
38		E390 - Structures and Improvements	
39		E391 - Office Furniture, Equipment	
40		E393 - Stores Equipment	
41		E394 - Tools, Shop, Garage Equipmnt	
42		E395 - Laboratory Equipment	
43		E397.1 - Computer Hardware	
44		E397.2 - Computer Software	
45		E397.3 - Communication Equipment	
46		E398 - Miscellaneous Equipment	
47		E399.1 - ARO Costs General Plt	
48		Sub-total General Plant	
49			
50		**Total**	

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E352 - Structures and Improvements	
5		E353 - Station Equipment	
6		E354 - Towers and Fixtures	
7		E355 - Poles and Fixtures	
8		E356 - Overhead Conductors, Devices	
9		E357 - Underground Conduit	
10		E358 - Undergrnd Conductors, Devics	
11		E359.1 - ARO Costs Transmission Plt	
12		Sub-total Transmission Plant	
13			
14	**Distribution Plant**	E361 - Structures and Improvements	
15		E362 - Station Equipment	
16		E363.1 - Computer Hardware	
17		E363.2 - Computer Software	
18		E363.3 - Communication Equipment	
19		E364 - Poles, Towers and Fixtures	
20		E365 - Overhead Conductors, Devices	
21		E366 - Underground Conduit	
22		E367 - Undergrnd Conductors, Devics	
23		E368 - Line Transformers	
24		E369 - Services	
25		E370 - Meters	
26		E373 - Street Lighting,Signal Systm	
27		E374 - ARO Costs Distribution Plt	
28		Sub-total Distribution Plant	
29			
30	**General Plant**	E390 - Structures and Improvements	
31		E391 - Office Furniture, Equipment	
32		E393 - Stores Equipment	
33		E394 - Tools, Shop, Garage Equipmnt	
34		E395 - Laboratory Equipment	
35		E397.1 - Computer Hardware	
36		E397.2 - Computer Software	
37		E397.3 - Communication Equipment	
38		E398 - Miscellaneous Equipment	
39		E399.1 - ARO Costs General Plt	
40		Sub-total General Plant	
41			
42		**Total**	

Line No.	Description	Account	(1) HTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs						
2								
3		E302 - Franchises and Consents	$163	100.00%	$163	87.46%	$142	$20
4			$163		$163		$142	$20
5								
6		E303 - Misc Intangible Plant	$6,914	100.00%	$6,914	100.00%	$6,914	
7			$6,914		$6,914		$6,914	
8								
9		Sub-total Intangible Plant	$7,077		$7,077		$7,056	$20
10								
11	**Transmission Plant**	E350 - Land and Land Rights	$92,459	100.00%	$92,459			$92,459
12			$92,459		$92,459			$92,459
13								
14		E351.1 - Computer Hardware - Transmissio	$10,089	100.00%	$10,089			$10,089
15			$10,089		$10,089			$10,089
16								
17		E351.2 - Computer Software- Transmission	$23,901	100.00%	$23,901			$23,901
18			$23,901		$23,901			$23,901
19								
20		E351.3 - Communication Equipment- Trans	$27,762	100.00%	$27,762			$27,762
21			$27,762		$27,762			$27,762
22								
23		E352 - Structures and Improvements	$190,292	100.00%	$190,292			$190,292
24			$190,292		$190,292			$190,292
25								
26		E353 - Station Equipment	$1,101,199	100.00%	$1,101,199			$1,101,199
27			$1,101,199		$1,101,199			$1,101,199
28								
29		E354 - Towers and Fixtures	$299,463	100.00%	$299,463			$299,463
30			$299,463		$299,463			$299,463
31								
32		E355 - Poles and Fixtures	$34,860	100.00%	$34,860			$34,860
33			$34,860		$34,860			$34,860
34								
35		E356 - Overhead Conductors, Devices	$235,660	100.00%	$235,660			$235,660
36			$235,660		$235,660			$235,660
37								
38		E357 - Underground Conduit	$51,144	100.00%	$51,144			$51,144
39			$51,144		$51,144			$51,144
40								
41		E358 - Undergrnd Conductors, Devics	$143,306	100.00%	$143,306			$143,306
42			$143,306		$143,306			$143,306
43								
44		E359 - Roads and Trails	$2,643	100.00%	$2,643			$2,643
45			$2,643		$2,643			$2,643
46								
47		E359.1 - ARO Costs Transmission Plt	$679	100.00%	$679			$679
48			$679		$679			$679
49								
50		Sub-total Transmission Plant	$2,213,457		$2,213,457			$2,213,457
51								

Line No.	Description	Account	(1) HTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
52	**Distribution Plant**	E360 - Land and Land Rights	$56,497	100.00%	$56,497	100.00%	$56,497	
53			$56,497		$56,497		$56,497	
54								
55		E361 - Structures and Improvements	254,986	100.00%	254,986	100.00%	254,986	
56			254,986		254,986		254,986	
57								
58		E362 - Station Equipment	1,319,714	100.00%	1,319,714	100.00%	1,319,714	
59			1,319,714		1,319,714		1,319,714	
60								
61		E363.1 - Computer Hardware	19,321	100.00%	19,321	100.00%	19,321	
62			19,321		19,321		19,321	
63								
64		E363.2 - Computer Software	188,081	100.00%	188,081	100.00%	188,081	
65			188,081		188,081		188,081	
66								
67		E363.3 - Communication Equipment	135,890	100.00%	135,890	100.00%	135,890	
68			135,890		135,890		135,890	
69								
70		E364 - Poles, Towers and Fixtures	1,520,587	100.00%	1,520,587	100.00%	1,520,587	
71			1,520,587		1,520,587		1,520,587	
72								
73		E365 - Overhead Conductors, Devices	2,297,101	100.00%	2,297,101	100.00%	2,297,101	
74			2,297,101		2,297,101		2,297,101	
75								
76		E366 - Underground Conduit	1,036,480	100.00%	1,036,480	100.00%	1,036,480	
77			1,036,480		1,036,480		1,036,480	
78								
79		E367 - Undergrnd Conductors, Devics	2,188,469	100.00%	2,188,469	100.00%	2,188,469	
80			2,188,469		2,188,469		2,188,469	
81								
82		E368 - Line Transformers	922,346	100.00%	922,346	100.00%	922,346	
83			922,346		922,346		922,346	
84								
85		E369 - Services	488,871	100.00%	488,871	100.00%	488,871	
86			488,871		488,871		488,871	
87								
88		E370 - Meters	377,824	100.00%	377,824	100.00%	377,824	
89			377,824		377,824		377,824	
90								
91		E371 - Installs on Customer Premiss	13,772	100.00%	13,772	100.00%	13,772	
92			13,772		13,772		13,772	
93								
94		E373 - Street Lighting,Signal Systm	69,602	100.00%	69,602	100.00%	69,602	
95			69,602		69,602		69,602	
96								
97		E374 - ARO Costs Distribution Plt	3,554	100.00%	3,554	100.00%	3,554	
98		Electric Nonrecoverable 100%						
99			3,554		3,554		3,554	
100								
101		Sub-total Distribution Plant	$10,893,096		$10,893,096		$10,893,096	
102								

Line No.	Description	Account	(1) HTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
103	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.46%	$930	$133
104			$1,063		$1,063		$930	$133
105								
106		E390 - Structures and Improvements	68,748	100.00%	68,748	87.46%	60,124	8,624
107			68,748		68,748		60,124	8,624
108								
109		E391 - Office Furniture, Equipment	1,115	100.00%	1,115	87.46%	976	140
110			1,115		1,115		976	140
111								
112		E393 - Stores Equipment	45	100.00%	45	87.46%	39	6
113			45		45		39	6
114								
115		E394 - Tools, Shop, Garage Equipmnt	68,030	100.00%	68,030	87.46%	59,496	8,534
116			68,030		68,030		59,496	8,534
117								
118		E395 - Laboratory Equipment	97	100.00%	97	87.46%	85	12
119			97		97		85	12
120								
124		E397.1 - Computer Hardware	6,976	100.00%	6,976	87.46%	6,101	875
125			6,976		6,976		6,101	875
126								
127		E397.2 - Computer Software	24,675	100.00%	24,675	87.46%	21,579	3,095
128			24,675		24,675		21,579	3,095
129								
130		E397.3 - Communication Equipment	34,012	100.00%	34,012	87.46%	29,745	4,267
131			34,012		34,012		29,745	4,267
132								
133		E398 - Miscellaneous Equipment	1,987	100.00%	1,987	87.46%	1,738	249
134			1,987		1,987		1,738	249
135								
136		E399.1 - ARO Costs General Plt	2,420	100.00%	2,420	87.46%	2,116	304
137			2,420		2,420		2,116	304
138								
139		Sub-total General Plant	$209,169		$209,169		$182,929	$26,240
140								
141								
142		**Total**	**$13,322,798**		**$13,322,798**		**$11,083,081**	**$2,239,717**

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	HTY Amount	Non- Jurisdictional	Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant				
4		Sub-total Intangible Plant	SUM L1 to L3			
5						
6	**Transmission Plant**	E350 - Land and Land Rights				
7		E351.1 - Computer Hardware		$3,269	$3,269	
8		E351.2 - Computer Software		22,214	22,214	
9		E351.3 - Communication Equipment		14,468	14,468	
10		E352 - Structures and Improvements		20,574	20,574	
11		E353 - Station Equipment		265,264	265,264	
12		E354 - Towers and Fixtures		177,667	177,667	
13		E355 - Poles and Fixtures		7,219	7,219	
14		E356 - Overhead Conductors, Devices		98,002	98,002	
15		E357 - Underground Conduit		6,759	6,759	
16		E358 - Undergrnd Conductors, Devices		53,255	53,255	
17		E359 - Roads and Trails		2,250	2,250	
18		E359.1 - ARO Costs Transmission Plt		162	162	
19		Sub-total Transmission Plant	SUM L6 to L18	$671,102	$671,102	
20						
21	**Distribution Plant**	E360 - Land and Land Rights		$310		$310
22		E361 - Structures and Improvements		50,936		$50,936
23		E362 - Station Equipment		492,177		$492,177
24		E363.1 - Computer Hardware		8,321		$8,321
25		E363.2 - Computer Software		49,977		$49,977
26		E363.3 - Communication Equipment		59,009		$59,009
27		E364 - Poles, Towers and Fixtures		28,047		$28,047
28		E365 - Overhead Conductors, Devices		296,907		$296,907
29		E366 - Underground Conduit		197,833		$197,833
30		E367 - Undergrnd Conductors, Devices		159,645		159,645
31		E368 - Line Transformers		155,531		155,531
32		E369 - Services		212,161		212,161
33		E370 - Meters		235,486		235,486
34		E371 - Installs on Customer Premises		11,738		11,738
35		E373 - Street Lighting, Signal Systems		36,323		36,323
36		E374 - ARO Costs Distribution Plant		2,312		2,312
37		Sub-total Distribution Plant	SUM L21 to L36	$1,996,714		$1,996,714
38						
39	**General Plant**	E389 - Land and Land Rights				
40		E390 - Structures and Improvements		$17,634	$2,212	$15,421
41		E391 - Office Furniture, Equipment		420	53	367
42		E393 - Stores Equipment		33	4	29
43		E394 - Tools, Shop, Garage Equipmnt		25,496	3,198	22,297
44		E395 - Laboratory Equipment		89	11	77
45		E397.1 - Computer Hardware		3,920	492	3,428
46		E397.2 - Computer Software		18,579	2,331	16,248
47		E397.3 - Communication Equipment		19,027	2,387	16,640
48		E398 - Miscellaneous Equipment		(555)	(70)	(485)
49		E399.1 - ARO Costs General Plt		1,918	241	1,677
50		Sub-total General Plant	SUM L39 to L49	$86,559	$10,859	$75,700
51						
52		**Total**	L4+L19+L37+L50	**$2,754,375**	**$681,961**	**$2,072,414**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant		100.00%				
5				100.00%				
6								
7		Sub-total Intangible Plant						
8								
9	**Transmission Plant**	E350 - Land and Land Rights		100.00%				
10								
11								
12		E351.1 - Computer Hardware	$3,269	100.00%	$3,269			$3,269
13			$3,269		$3,269			$3,269
14								
15		E351.2 - Computer Software	$22,214	100.00%	$22,214			$22,214
16			$22,214		$22,214			$22,214
17								
18		E351.3 - Communication Equipment	$14,468	100.00%	$14,468			$14,468
19			$14,468		$14,468			$14,468
20								
21		E352 - Structures and Improvements	20,574	100.00%	20,574			20,574
22			20,574		20,574			20,574
23								
24		E353 - Station Equipment	265,264	100.00%	265,264			265,264
25			265,264		265,264			265,264
26								
27		E354 - Towers and Fixtures	177,667	100.00%	177,667			177,667
28			177,667		177,667			177,667
29								
30		E355 - Poles and Fixtures	7,219	100.00%	7,219			7,219
31			7,219		7,219			7,219
32								
33		E356 - Overhead Conductors, Devices	98,002	100.00%	98,002			98,002
34			98,002		98,002			98,002
35								
36		E357 - Underground Conduit	6,759	100.00%	6,759			6,759
37			6,759		6,759			6,759
38								
39		E358 - Undergrnd Conductors, Devices	53,255	100.00%	53,255			53,255
40			53,255		53,255			53,255
41								
42		E359 - Roads and Trails	2,250	100.00%	2,250			2,250
43			2,250		2,250			2,250
44								
45		E359.1 - ARO Costs Transmission Plt	162	100.00%	162			162
46			162		162			162
47								
48		Sub-total Transmission Plant	$671,102		$671,102			$671,102
49								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
50	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
51			310		310		310	
52								
53		E361 - Structures and Improvements	$50,936	100.00%	$50,936	100.00%	$50,936	
54			$50,936		$50,936		$50,936	
55								
56		E362 - Station Equipment	492,177	100.00%	492,177	100.00%	492,177	
57			492,177		492,177		492,177	
58								
59		E363.1 - Computer Hardware	8,321	100.00%	8,321	100.00%	8,321	
60			8,321		8,321		8,321	
61								
62		E363.2 - Computer Software	49,977	100.00%	49,977	100.00%	49,977	
63			49,977		49,977		49,977	
64								
65		E363.3 - Communication Equipment	59,009	100.00%	59,009	100.00%	59,009	
66			59,009		59,009		59,009	
67								
68		E364 - Poles, Towers and Fixtures	28,047	100.00%	28,047	100.00%	28,047	
69			28,047		28,047		28,047	
70								
71		E365 - Overhead Conductors, Devices	296,907	100.00%	296,907	100.00%	296,907	
72			296,907		296,907		296,907	
73								
74		E366 - Underground Conduit	197,833	100.00%	197,833	100.00%	197,833	
75			197,833		197,833		197,833	
76								
77		E367 - Undergrnd Conductors, Devices	159,645	100.00%	159,645	100.00%	159,645	
78			159,645		159,645		159,645	
79								
80		E368 - Line Transformers	155,531	100.00%	155,531	100.00%	155,531	
81			155,531		155,531		155,531	
82								
83		E369 - Services	212,161	100.00%	212,161	100.00%	212,161	
84			212,161		212,161		212,161	
85								
86		E370 - Meters	235,486	100.00%	235,486	100.00%	235,486	
87			235,486		235,486		235,486	
88								
89		E371 - Installs on Customer Premises	11,738	100.00%	11,738	100.00%	11,738	
90			11,738		11,738		11,738	
91								
92		E373 - Street Lighting, Signal Systems	36,323	100.00%	36,323	100.00%	36,323	
93			36,323		36,323		36,323	
94								
95		E374 - ARO Costs Distribution Plant	2,312	100.00%	2,312	100.00%	2,312	
96								
97			2,312		2,312		2,312	
98								
99		Sub-total Distribution Plant	$1,996,714		$1,996,714		$1,996,714	
100								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
101	**General Plant**	E389 - Land and Land Rights						
102								
103								
104		E390 - Structures and Improvements	$17,634	100.00%	$17,634	87.46%	$15,422	$2,212
105			$17,634		$17,634		$15,422	$2,212
106								
107		E391 - Office Furniture, Equipment	420	100.00%	420	87.46%	367	53
108			420		420		367	53
109								
110		E393 - Stores Equipment	33	100.00%	33	87.46%	29	4
111			33		33		29	4
112								
113		E394 - Tools, Shop, Garage Equipmnt	25,496	100.00%	25,496	87.46%	22,297	3,198
114			25,496		25,496		22,297	3,198
115								
116		E395 - Laboratory Equipment	89	100.00%	89	87.46%	77	11
117			89		89		77	11
118								
119		E397.1 - Computer Hardware	3,920	100.00%	3,920	87.46%	3,428	492
120			3,920		3,920		3,428	492
121								
122		E397.2 - Computer Software	18,579	100.00%	18,579	87.46%	16,248	2,331
123			18,579		18,579		16,248	2,331
124								
125		E397.3 - Communication Equipment	19,027	100.00%	19,027	87.46%	16,640	2,387
126			19,027		19,027		16,640	2,387
127								
128		E398 - Miscellaneous Equipment	(555)	100.00%	(555)	87.46%	(485)	(70)
129			(555)		(555)		(485)	(70)
130								
131		E399.1 - ARO Costs General Plt	1,918	100.00%	1,918	87.46%	1,677	241
132			1,918		1,918		1,677	241
133								
134		Sub-total General Plant	$86,559		$86,559		$75,700	$10,859
135								
136		**Total**	**$2,754,375**		**$2,754,375**		**$2,072,414**	**$681,961**

Line No.	Category	Account	Reference	(1) HTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		
2		Sub-total Electric - Intangible Plant		
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		
5		E351.1 - Computer Hardware		
6		E351.2 - Computer Software		
7		E351.3 - Communication Equipment		
8		E352 - Structures and Improvements		
9		E353 - Station Equipment		
10		E354 - Towers and Fixtures		
11		E355 - Poles and Fixtures		
12		E356 - Overhead Conductors, Devices		
13		E357 - Underground Conduit		
14		E358 - Undergrnd Conductors, Devices		
15		E359 - Roads and Trails		
16		Sub-total Electric - Transmission	SUM L4 to L15	
17				
18	**Electric - Distribution**	E360 - Land and Land Rights		
19		E361 - Structures and Improvements		
20		E362 - Station Equipment		
21		E363.1 - Computer Hardware		
22		E363.2 - Computer Software		
23		E363.3 - Communication Equipment		
24		E364 - Poles, Towers and Fixtures		
25		E365 - Overhead Conductors, Devices		
26		E366 - Underground Conduit		
27		E367 - Undergrnd Conductors, Devices		
28		E368 - Line Transformers		
29		E369 - Services		
30		E370 - Meters		
31		E371 - Installs on Customer Premises		
32		E373 - Street Lighting, Signal Systems		
33		Sub-total Electric - Distribution	SUM L18 to L32	
34				
35	**Electric - General Plant**	E389 - Land and Land Rights		
36		E390 - Structures and Improvements		
37		E391 - Office Furniture, Equipment		
38		E393 - Stores Equipment		
39		E394 - Tools, Shop, Garage Equipmnt		
40		E395 - Laboratory Equipment		
41		E397.1 - Computer Hardware		
42		E397.2 - Computer Software		
43		E397.3 - Communication Equipment		
44		E398 - Miscellaneous Equipment		
45		Sub-total Electric - General Plant	SUM L35 to L44	
46				
47		**Total**	Lines 2+16+33+45	

Line No.	Description	(1) Reference	(2) HTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			57.60	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$182,452	13.56	$2,474,506
7	Pension Expense		3,907	(167.00)	(652,481)
8	Commodity Purchased - [A]		1,123,769	35.71	40,127,918
9	Commodity Purchased - [B]		9,666	12.50	120,831
10	PJM Transmission Purchased - By-passable		111,746	12.50	1,396,824
11	PJM Transmission Purchased - Non By-passable		104,754	12.50	1,309,425
12	Other Expenses		600,083	43.21	25,927,509
13	Sub-Total O&M	SUM L6 to L12	$2,136,378		$70,704,531
14					
15	Payment to Suppliers		$1,167,600	37.90	$44,253,131
16					
17	Total O&M and POR Payments	L13 + L15	$3,303,977		$114,957,662
18					
19	O&M Expense / POR Payment Lag Days			34.79	
20					
21	Net Lead/(Lag) Days	L3 - L19		22.80	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$9,052		
26					
27	Working Capital for O&M Expense		$206,424		
28					
29	Average Prepayments		$8,432		
30	Accrued Taxes		93,098		
31	Interest Payments		(17,587)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$290,366**		
34					
35	Pro Forma O&M Expense		$2,187,092		
36	Uncollectible Expense		50,714		
37	Pro Forma Cash O&M Expense	L35 - L36	$2,136,378		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$441,873			
4	January		511,639	$416,118		
5	February		536,250	394,707		
6	March		520,942	364,969		
7	April		498,684	325,032		
8	May		477,882	316,108		
9	June		518,591	365,739		
10	July		619,727	508,393		
11	August		625,228	489,153		
12	September		552,426	394,187		
13	October		521,995	365,223		
14	November		503,475	288,094		
15	December		533,971	427,625		
16						
17	Total	SUM L3 to L15	$6,862,683	$4,655,348		
18						
19	Average A/R Balance		13			
20						
21	Factor		$527,899	$4,655,348	8.82	41.39
22						
23	Collection Days Lag					41.39
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12 * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**57.60**

Line No.	Category	Description	(1) Reference	(2) Payment Date	(3) Mid-point of Service Period	(4) Expense Amount	(5) (Lead)/Lag Days	(6) Dollar Days
1	PAYROLL	Union & Non-Union Payroll				$172,832		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$2,344,027
4								
5		**Payroll Lag**	SUM L1 to L3			$172,832	**13.56**	$2,344,027
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$11,760	(167.00)	($1,963,934)
12								
13		Sub-total	SUM L7 to L11			$11,760		($1,963,934)
14								
15		**Lag Days for Pension Payment**					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.71**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.90**	
20								
21								
22	OTHER O & M EXPENSES	March				$15,875		$656,144
23		June				18,479		697,875
24		September				36,511		1,651,476
25		December				35,501		1,590,220
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$106,366	**43.21**	$4,595,716

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643	-	
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705	-	
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,894	$106,366	$4,595,716	**43.21**

Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**FEDERAL INCOME TAX**	First Payment	4/15/2025	7/1/2025	77	$14,632	25.00%	$3,658	$281,663
2		Second Payment	6/16/2025	7/1/2025	15	14,632	25.00%	3,658	54,869
3		Third Payment	9/15/2025	7/1/2025	(76)	14,632	25.00%	3,658	(278,005)
4		Fourth Payment	12/15/2025	7/1/2025	(167)	14,632	25.00%	3,658	(610,880)
5		Sub-total FEDERAL INCOME TAX					100.00%	$14,632	($552,353)
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	$2,252	25.00%	$563	$59,689
8		Second Payment	6/16/2025	7/1/2025	15	2,252	25.00%	563	8,447
9		Third Payment	9/15/2025	7/1/2025	(76)	2,252	25.00%	563	(42,796)
10		Fourth Payment	12/15/2025	7/1/2025	(167)	2,252	25.00%	563	(94,039)
11		Sub-total STATE INCOME TAX					100.00%	$2,252	($68,699)
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$7,487	100.00%	$7,487	$456,708
14		Subtotal PURTA					100.00%	$7,487	$456,708
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2025	7/1/2025	29	$4,873	100.00%	$4,873	$141,328
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$4,873	$141,328
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/17/2025	7/1/2025	106	$197,553	100.00%	$197,553	$20,940,664
27		Sub-total GROSS RECEIPTS TAX					100.00%	$197,553	$20,940,664

Line No.	Description	(1) Total Payment Amount	(2) Weighted Dollar Days	(3) Payment Lead/(Lag) Days	(4) Revenue Lag Days	(5) Net Payment Lead/(Lag) Days	(6) Net Payment Lead/(Lag) Dollars Days	(7) Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$14,632	($552,353)	(37.75)	57.60	19.85	$290,412	$796
2	STATE INCOME TAX	$2,252	($68,699)	(30.50)	57.60	27.10	$61,036	$167
3	PURTA	$7,487	$456,708	61.00	57.60	118.60	$887,945	$2,433
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$4,873	$141,328	29.00	57.60	86.60	$422,025	$1,156
6	GROSS RECEIPTS TAX	$197,553	$20,940,664	106.00	57.60	163.60	$32,319,334	$88,546

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of HTY		$9,095,891
2	Long-Term Debt Ratio		46.50%
3	Embedded Cost of Long-Term Debt		4.51%
4	Pro Forma Interest Expense	L1 * L2 * L3	$190,754
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$523
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	57.60
9	Interest Payment Lag Days	L8 - L7	(33.65)
10	**Total Interest for Working Capital**	L6 * L9	**($17,587)**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Line No.	Description	Reference	EPRI Dues	EEI Dues	EAP Membership Dues	Prepaid Rents & Pole Attachments	PUC Assessment Electric	Land Leasing	Maintenance	IT License & Maintenance	Business Support Systems	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December				$285	$230	$4,323	$143	$117	$148	$599	$3,449	$0	$27	$478	$172	$112	$566	
2	January			530	262	702	3,742		78	98	558	3,449	(16)	14	498	166	232	580	
3	February			482	238	666	2,993		78	80	462	3,449	(32)	0	500	110	198	554	
4	March		217	434	214	481	2,245	136	78	62	519	2,376	150	0	503	82	439	538	
5	April		217	386	190	330	1,497		78	50	422	2,376	134	0	528	136	378	540	
6	May		217	337	166	298	748		78	37	325	2,376	117	0	527	237	340	489	
7	June		126	289	143	121	0	130	78	25	454	1,888	100	0	530	484	302	499	
8	July		126	241	119	603	4,605		78	164	614	1,888	84	0	562	405	264	445	
9	August		126	193	95	423	3,893		78	163	506	1,888	67	0	445	356	226	520	
10	September		117	145	71	601	8,182	123	78	203	475	2,231	50	0	471	306	188	655	
11	October		36	96	48	449	7,273		78	176	457	2,231	33	0	470	256	150	748	
12	November		36	48	24	282	6,364		78	149	339	2,231	17	0	500	318	112	748	
13	December		(54)	570		238	5,455	117	78	122	297	2,048	0	0	505	271	74	942	
14																			
15	Total	SUM L1 to L13	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																			
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.32%	67.32%	67.32%	67.32%	74.52%	74.52%	74.52%	
18																			
19	Distribution Amount	L15 * L17	$1,164	$3,751	$1,855	$5,424	$51,321	$648	$1,053	$1,477	$6,026	$21,465	$474	$28	$4,387	$2,458	$2,248	$5,831	
20																			
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																			
23	Monthly Average	L19 / L21	$90	$289	$143	$417	$3,948	$50	$81	$114	$464	$1,651	$36	$2	$337	$189	$173	$449	
24																			
25	**Rate Case Amount**																		**$8,432**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in HTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.00	19.00	1.00	34.00	
5	April	15.50	19.00	2.00	36.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	1.00	35.50	
8	July	15.00	19.00	2.00	36.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	3.00	37.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	3.00	37.00	
14	**Payment Lag - Contract Purchases**					**35.71**
15						
16	**Spot Market Purchases in HTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	34%	8.46		
30	Nonresidential	20.00	66%	13.23		
31	Weighted Lag Days				21.69	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.90**

Line No.	Description	(1) Reference	(2) Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Allocation % to Utility		76.67%
3	Utility Amount	L4 * L5	$338,501
4	Allocation % to Distribution Capital		48.37%
5	Balance at End of HTY - Distribution Capital	L6 * L7	$163,722

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($12,383)	100.00%	($12,383)	100.00%	($12,383)
2		ADIT - Common Plant		106,546	100.00%	106,546	67.32%	71,730
3		ADIT - Electric Common Plant		24,741	100.00%	24,741	87.46%	21,638
4		ADIT - Electric Distribution		665,968	100.00%	665,968	100.00%	665,968
5		ADIT - Corp. Alternative Minimum Tax		(183,957)	100.00%	(183,957)	100.00%	(183,957)
6		**Total**	SUM L1 to L5	$600,915		$600,915		$562,995

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$22,499	$36,282	$58,780
2	January		22,580	35,889	58,469
3	February		23,154	36,470	59,623
4	March		24,246	37,775	62,021
5	April		25,771	39,113	64,884
6	May		26,839	39,833	66,672
7	June		27,171	39,865	67,035
8	July		27,725	40,669	68,394
9	August		28,297	40,986	69,283
10	September		29,109	41,497	70,606
11	October		29,946	43,006	72,952
12	November		30,524	43,769	74,292
13	December		30,889	45,192	76,081
14					
15	Total	SUM L1 to L13	$348,750	$520,343	$869,092
16					
17	Average Monthly Balance	L15 / 13	$26,827	$40,026	$66,853
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$26,827
21	Small C&I				33,270
22	Large C&I				6,746
23	Other				11
24					
25	**Total**	SUM L20 to L23			**$66,853**

Line No.	Category	Account	(1) Reference	(2) HTY Amount	(3) Allocated to Non Jurisdiction	(4) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$288,498	$94,272	$194,225
6						
7		E389 - Land and Land Rights		$6,770	$2,212	$4,558
8						
9		E390 - Structures and Improvements		$424,901	$138,845	$286,056
10		E391 - Office Furniture, Equipment		85,851	28,054	57,798
11		E392 - Transportation Equipment		229,264	74,916	154,347
12		E393 - Stores Equipment		1,758	574	1,183
13		E394 - Tools, Shop, Garage Equipmnt		2,880	941	1,939
14		E396 - Power Operated Equipment		870	284	586
15		E397 - Communication Equipment		127,674	41,720	85,954
16		E398 - Miscellaneous Equipment		852	278	573
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		337	110	227
19		Sub Total - General Plant	SUM L9 to L18	$874,386	$285,723	$588,663
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,170,330	$382,429	$787,902
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$173,818	$56,799	$117,020
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$73,945	$24,163	$49,782
31		E391 - Office Furniture, Equipment		33,550	10,963	22,587
32		E392 - Transportation Equipment		104,912	34,282	70,630
33		E393 - Stores Equipment		479	156	322
34		E394 - Tools, Shop, Garage Equipmnt		1,223	400	824
35		E396 - Power Operated Equipment		268	88	181
36		E397 - Communication Equipment		50,163	16,392	33,771
37		E398 - Miscellaneous Equipment		872	285	587
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(360)	(118)	(242)
40		Sub Total - General Plant	SUM L30 to L39	$265,053	$86,611	$178,441
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$438,871	$143,410	$295,461
42						
43		Net Common Plant	L20 - L41	$731,460	$239,019	$492,441
44						
45						
46		Common Plant in Service to Utility	L20	$1,170,330	$382,429	$787,902
47		Common Plant Accum Depreciation to Utility	L41	438,871	143,410	295,461
48		Net Common Plant to Utility	L46 - L47	$731,460	$239,019	$492,441

Line No.	Description	(1) Reference	(2) Total
1	HTY 13-Month Average		
2	December		$8,256
3	January		10,444
4	February		8,761
5	March		7,609
6	April		7,944
7	May		7,480
8	June		8,730
9	July		13,442
10	August		12,482
11	September		11,891
12	October		12,405
13	November		12,916
14	December		13,718
15			
16	13-Month Total	SUM L2 to L14	$136,078
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$10,468**

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$51,593	$0	$51,593
3	January		53,064	(535)	52,530
4	February		55,613	(319)	55,294
5	March		55,645	(560)	55,085
6	April		57,445	(2,433)	55,012
7	May		56,753	(911)	55,842
8	June		55,119	(1,049)	54,070
9	July		56,000	(1,747)	54,253
10	August		52,558	(2,066)	50,492
11	September		52,239	(2,581)	49,657
12	October		52,308	(2,857)	49,451
13	November		51,470	(2,421)	49,049
14	December		52,109	0	52,109
15					
16	Total	SUM L2 to L14	$701,915	($17,478)	$684,437
17					
18	Distribution Expense Allocation Factor		100.00%	67.32%	
19					
20	Allocation to Distribution	L16 * L18	$701,915	($11,767)	
21					
22	**Average Monthly Balance**	L20 / 13	$53,993	($905)	**$53,088**

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - Distribution		$274,076	100.00%	$274,076	100.00%	$274,076
2		ADIT - CIAC			100.00%		100.00%	
3		**Total**	L1 + L2	274,076		274,076		274,076

Line No.	Category	Description	Reference	(1) Pro Forma Adjusted at Present Rates	(2) Proposed Rate Increase	(3) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$1,880,273		$1,880,273
2		Residential - House Heating		411,519		411,519
3		C & I Small		546,408		546,408
4		C & I Large		272,686		272,686
5		Railroads & Railways		8,551		8,551
6		Street Lighting		24,022		24,022
7		Intercompany		572		572
8		Transmission - All Classes		233,615		233,615
9		Forfeited Discounts		21,431	$378	21,809
10		Miscellaneous Service Revenues		5,189		5,189
11		Rent For Electric Property		25,675		25,675
12		Other Electric Revenues		8,528		8,528
13		Revenue Increase			$82,204	82,204
14		Total Operating Revenues	SUM L1 to L13	$3,438,469	$82,581	$3,521,050
15						
16	**Operating Expenses**	Power Supply		$1,133,435		$1,133,435
17		Transmission Expense		216,442		216,442
18		Distribution Expense		444,229		444,229
19		Customer Accounts Expense		154,845	$917	155,762
20		Customer Service and Information Expense		18,841		18,841
21		Sales Expense		634		634
22		Administrative & General		218,665	298	218,964
23		Sub-total O&M Expense	SUM L16 to L22	$2,187,092	$1,215	$2,188,307
24						
25		Depreciation & Amortization Expense		$328,879		$328,879
26		Amortization of Regulatory Expense		1,479		1,479
27		Taxes Other Than Income Taxes - Other		$222,839	$4,850	$227,689
28		Total Operating Expenses	SUM L23 to L27	$2,740,289	$6,065	$2,746,354
29						
30	**Net Operating Income - BIT**		L14 - L28	**$698,180**	**$76,516**	**$774,696**

Line No.	Category	Description	Reference	(1) HTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$1,923,331	($43,058)	$1,880,273
2		Residential - House Heating		418,979	(7,460)	411,519
3		C & I Small		582,927	(36,518)	546,408
4		C & I Large		302,588	(29,903)	272,686
5		Railroads & Railways		9,426	(874)	8,551
6		Street Lighting		24,121	(99)	24,022
7		Intercompany		572		572
8		Transmission - All Classes		233,615		233,615
9		Forfeited Discounts		21,431		21,431
10		Miscellaneous Service Revenues		5,189		5,189
11		Rent For Electric Property		25,675		25,675
12		Other Electric Revenues		8,163	366	8,528
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$3,556,015	($117,546)	$3,438,469
15						
16	**Operating Expenses**	Power Supply		$1,133,435		$1,133,435
17		Transmission Expense		216,442		216,442
18		Distribution Expense		400,000	$44,228	444,229
19		Customer Accounts Expense		189,857	(35,012)	154,845
20		Customer Service and Information Expense		104,186	(85,345)	18,841
21		Sales Expense		612	23	634
22		Administrative & General		212,177	6,489	218,665
23		Sub-total O&M Expense	SUM L16 to L22	$2,256,709	($69,617)	$2,187,092
24						
25		Depreciation & Amortization Expense		$305,698	$23,181	$328,879
26		Amortization of Regulatory Expense		1,459	20	1,479
27		Taxes Other Than Income Taxes - Other		227,045	(4,206)	222,839
28		Total Operating Expenses	SUM L23 to L27	$2,790,911	($50,622)	$2,740,289
29						
30	**Net Operating Income - BIT**		L14 - L28	**$765,105**	**($66,924)**	**$698,180**

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
1	**Operating Revenues**	Residential	Elec Cost	$824,223							
2			Cust & Dist	1,099,108	1,531	(3,487)	(2,241)	(25,187)		638	(14,313)
3			Sub-total Residential	$1,923,331	$1,531	($3,487)	($2,241)	($25,187)		$638	($14,313)
4											
5		Residential - House Heating	Elec Cost	$203,033							
6			Cust & Dist	215,945	1,085	(529)	(495)	(5,622)		176	(2,074)
7			Sub-total Residential - House Heating	$418,979	$1,085	($529)	($495)	($5,622)		$176	($2,074)
8											
9		C & I Small	Elec Cost	$212,006							
10			Cust & Dist	370,920	11		(905)	(33,043)		195	(2,775)
11			Sub-total C & I Small	$582,927	$11		($905)	($33,043)		$195	($2,775)
12											
13		C & I Large	Elec Cost	$49,781							
14			Cust & Dist	252,807	86		(1,011)	(27,636)		139	(1,480)
15			Sub-total C & I Large	$302,588	$86		($1,011)	($27,636)		$139	($1,480)
16											
17		Railroads & Railways	Cust & Dist	$9,426				(874)			
18			Sub-total Railroads & Railways	$9,426				($874)			
19											
20		Street Lighting	Elec Cost	$890							
21			Cust & Dist	23,231				(99)			
22			Sub-total Street Lighting	$24,121				($99)			
23											
24		Intercompany	Elec Cost	$218							
25			Cust & Dist	354							
26			Sub-total Interdepartmental	$572							
27											
28		Transmission - All Classes	Transmission - All Classes	$233,615							
29			Sub-total Transmission - All Classes	$233,615							
30											
31		Forfeited Discounts	Forfeited Discounts	$21,431							
32			Sub-total Forfeited Discounts	$21,431							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$5,189							
35			Sub-total Miscellaneous Service Revenues	$5,189							
36											
37		Rent For Electric Property	Rent For Electric Property	$25,675							
38			Sub-total Rent For Electric Property	$25,675							
39											
40		Other Electric Revenues	Other Electric Revenues	$8,163							
41			Sub-total Other Electric Revenues	$8,163							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$3,556,015**	**$2,712**	**($4,016)**	**($4,652)**	**($92,462)**		**$1,148**	**($20,642)**

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,133,435							
49			Sub-total Power Supply	$1,133,435							
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch	112,785							
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development	103,657							
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense	216,442							
71											
72		Distribution Expense	Operation & Supervision	$554							
73			Load Dispatching								
74			Station Expense	5,825							
75			Overhead Lines Expenses	17,811							
76			Underground Lines Expense	10,648							
77			Meter Expenses	6,002							
78			Customer Installations Expense	12,490							
79			Miscellaneous Expense	87,504							
80			Rents	3,793							
81			Maintenance of Structures	6,042							
82			Maintenance of Station Equipment	17,236							
83			Maintenance of Overhead Lines	173,935							
84			Maintenance of Underground Lines	36,353							
85			Maintenance of Line Transformers	2,851							
86			Maintenance of Street Lighting & Signal Systems	1,691							
87			Maintenance of Misc. Distribution	17,266							
88			Sub-total Distribution Expense	$400,000							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$203							
92			Customer Records and Collection	95,368							

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
93			Uncollectible Accounts.	90,777							
94			Miscellaneous Customer Accounts Expenses.	3,509							
95			Sub-total Total Customer Accounts	$189,857							
96											
97		Customer Service and Information	Customer Assistance	$101,387				(85,400)			
98			Informational & Instructional	1,977							
99			Miscellaneous Customer & Informational	822							
100			Sub-total Customer Service & Information	$104,186				($85,400)			
101											
102		Sales	Demonstrating & Selling	$612							
103			Miscellaneous Sales								
104			Sub-total Sales	$612							
105											
106		Administrative & General	Administrative and General Salaries	$26,024							
107			Office Supplies and Expenses	4,442							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	105,963							
110			Property Insurance	1,037							
111			Injuries & Damages	29,187							
112			Employee Pensions and Benefits	27,357							
113			Regulatory Commission Expenses	10,668							
114			Duplicate Charges-Credit	(2,335)							
115			Miscellaneous General Expenses	715							
116			Maintenance of General Plant	9,118							
117			Sub-total Administrative & General	$212,177							
118											
119			**Total O&M Expense**	$2,256,709				($85,400)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$305,698							
122			Sub-total Depreciation & Amortization Expense	$305,698							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$1,459							
125			Sub-total Amortization of Regulatory Expense	$1,459							
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$227,045							
128			Sub-total Taxes Other Than Income Taxes - Other	$227,045							
129											
130			**Total Operating Expenses**	**$2,790,911**				**($85,400)**			
131											
132	**Net Operating Income Before Income Tax**			**$765,105**	**$2,712**	**($4,016)**	**($4,652)**	**($7,062)**		**$1,148**	**($20,642)**

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost									
2			Cust & Dist									
3			Sub-total Residential									
4												
5		Residential - House Heating	Elec Cost									
6			Cust & Dist									
7			Sub-total Residential - House Heating									
8												
9		C & I Small	Elec Cost									
10			Cust & Dist									
11			Sub-total C & I Small									
12												
13		C & I Large	Elec Cost									
14			Cust & Dist									
15			Sub-total C & I Large									
16												
17		Railroads & Railways	Cust & Dist									
18			Sub-total Railroads & Railways									
19												
20		Street Lighting	Elec Cost									
21			Cust & Dist									
22			Sub-total Street Lighting									
23												
24		Intercompany	Elec Cost									
25			Cust & Dist									
26			Sub-total Interdepartmental									
27												
28		Transmission - All Classes	Transmission - All Classes									
29			Sub-total Transmission - All Classes									
30												
31		Forfeited Discounts	Forfeited Discounts									
32			Sub-total Forfeited Discounts									
33												
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues									
35			Sub-total Miscellaneous Service Revenues									
36												
37		Rent For Electric Property	Rent For Electric Property									
38			Sub-total Rent For Electric Property									
39												
40		Other Electric Revenues	Other Electric Revenues	$366								
41			Sub-total Other Electric Revenues	$366								
42												
43		Revenue Increase	Revenue Increase									
44			Sub-total Revenue Increase									
45												
46			**Total Operating Revenues**	**$366**								

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
47												
48	**Operating Expenses**	Power Supply	Purchased Power									
49			Sub-total Power Supply									
50												
51		Transmission Expense	Operation & Supervision									
52			Load Dispatching									
53			Scheduling, System Control & Dispatch									
54			Transmission Service Studies									
55			Generation Service Studies									
56			Reliability, Planning & Standard Development									
57			Station Expense									
58			Overhead Lines									
59			Underground Lines Expense									
60			Miscellaneous Expense									
61			Rents									
62			Maintenance of Structures									
63			Maintenance of Computer Hardware									
64			Maintenance of Computer Software									
65			Maintenance of Communication Equipment									
66			Maintenance of Station Equipment									
67			Maintenance of Overhead Lines									
68			Maintenance of Underground Lines									
69			Maintenance of Misc Transmission Plant									
70			Sub-total Transmission Expense									
71												
72		Distribution Expense	Operation & Supervision		$20							
73			Load Dispatching									
74			Station Expense		15							
75			Overhead Lines Expenses		177							
76			Underground Lines Expense		163							
77			Meter Expenses		130							
78			Customer Installations Expense		322							
79			Miscellaneous Expense		373							
80			Rents									
81			Maintenance of Structures		75							
82			Maintenance of Station Equipment		428							
83			Maintenance of Overhead Lines		2,708							23,794
84			Maintenance of Underground Lines		900							
85			Maintenance of Line Transformers		43							
86			Maintenance of Street Lighting & Signal Systems		8							
87			Maintenance of Misc. Distribution		188							
88			Sub-total Distribution Expense		$5,548							$23,794
89												
90		Customer Accounts	Supervision									
91			Meter Reading		0							
92			Customer Records and Collection		1,691							

Line No.	Category	Description	Description	(9) D-5H Other Adjustments	(10) D-6 Salary & Wages	(11) D-7 Rate Case Expense	(12) D-8 Adjustments for Employee Benefits	(13) D-9 Adjustments for Pension	(14) D-10 Uncollectible Accounts	(15) D-11 IIJA Reg Asset	(16) D-12 Customer Deposit Interest	(17) D-13 Storm
93			Uncollectible Accounts.						(40,063)			
94			Miscellaneous Customer Accounts Expenses.		45						3,315	
95			Sub-total Total Customer Accounts		$1,737				($40,063)		$3,315	
96												
97		Customer Service and Information	Customer Assistance		$55							
98			Informational & Instructional									
99			Miscellaneous Customer & Informational									
100			Sub-total Customer Service & Information		$55							
101												
102		Sales	Demonstrating & Selling		$23							
103			Miscellaneous Sales									
104			Sub-total Sales		$23							
105												
106		Administrative & General	Administrative and General Salaries		$2,115							
107			Office Supplies and Expenses									
108			Administrative Expenses Transferred-Credit									
109			Outside Service Employed									
110			Property Insurance									
111			Injuries & Damages		80							
112			Employee Pensions and Benefits		2		494	2,112				
113			Regulatory Commission Expenses			1,624						
114			Duplicate Charges-Credit									
115			Miscellaneous General Expenses		0							
116			Maintenance of General Plant		62							
117			Sub-total Administrative & General		$2,259	$1,624	$494	$2,112				
118												
119			**Total O&M Expense**		$9,620	$1,624	$494	$2,112	($40,063)		$3,315	$23,794
120												
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense									
122			Sub-total Depreciation & Amortization Expense									
123												
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense							20		
125			Sub-total Amortization of Regulatory Expense							$20		
126												
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other									
128			Sub-total Taxes Other Than Income Taxes - Other									
129												
130			**Total Operating Expenses**		**$9,620**	**$1,624**	**$494**	**$2,112**	**($40,063)**	**$20**	**$3,315**	**$23,794**
131												
132	**Net Operating Income Before Income Tax**			**$366**	**($9,620)**	**($1,624)**	**($494)**	**($2,112)**	**$40,063**	**($20)**	**($3,315)**	**($23,794)**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-3 Adjustments to Net Operating Income

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Elec Cost						$824,223
2			Cust & Dist					(43,058)	1,056,050
3			Sub-total Residential					($43,058)	$1,880,273
4									
5		Residential - House Heating	Elec Cost						$203,033
6			Cust & Dist					(7,460)	208,485
7			Sub-total Residential - House Heating					($7,460)	$411,519
8									
9		C & I Small	Elec Cost						$212,006
10			Cust & Dist					(36,518)	334,402
11			Sub-total C & I Small					($36,518)	$546,408
12									
13		C & I Large	Elec Cost						$49,781
14			Cust & Dist					(29,903)	222,904
15			Sub-total C & I Large					($29,903)	$272,686
16									
17		Railroads & Railways	Cust & Dist					(874)	$8,551
18			Sub-total Railroads & Railways					($874)	$8,551
19									
20		Street Lighting	Elec Cost						$890
21			Cust & Dist					(99)	23,132
22			Sub-total Street Lighting					($99)	$24,022
23									
24		Intercompany	Elec Cost						$218
25			Cust & Dist						354
26			Sub-total Interdepartmental						$572
27									
28		Transmission - All Classes	Transmission - All Classes						$233,615
29			Sub-total Transmission - All Classes						$233,615
30									
31		Forfeited Discounts	Forfeited Discounts						$21,431
32			Sub-total Forfeited Discounts						$21,431
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$5,189
35			Sub-total Miscellaneous Service Revenues						$5,189
36									
37		Rent For Electric Property	Rent For Electric Property						$25,675
38			Sub-total Rent For Electric Property						$25,675
39									
40		Other Electric Revenues	Other Electric Revenues					366	$8,528
41			Sub-total Other Electric Revenues					$366	$8,528
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($117,546)**	**$3,438,469**

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,133,435
49			Sub-total Power Supply						$1,133,435
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						112,785
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						103,657
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						216,442
71									
72		Distribution Expense	Operation & Supervision					$20	$573
73			Load Dispatching						
74			Station Expense					15	5,840
75			Overhead Lines Expenses					177	17,988
76			Underground Lines Expense					163	10,810
77			Meter Expenses					130	6,132
78			Customer Installations Expense					322	12,813
79			Miscellaneous Expense					373	87,877
80			Rents						3,793
81			Maintenance of Structures					75	6,116
82			Maintenance of Station Equipment					428	17,663
83			Maintenance of Overhead Lines	14,887				41,388	215,323
84			Maintenance of Underground Lines					900	37,253
85			Maintenance of Line Transformers					43	2,893
86			Maintenance of Street Lighting & Signal Systems					8	1,699
87			Maintenance of Misc. Distribution					188	17,454
88			Sub-total Distribution Expense	$14,887				$44,228	$444,229
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$203
92			Customer Records and Collection					1,691	97,059

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-3 Adjustments to Net Operating Income

Line No.	Category	Description	Description	(18) D-13A Storm Deferral	(19) D-15 OPEN	(20) D-16 Taxes Other Than Income	(21) D-17 Depreciation Annualization	(22) Adjustments Sub-total	(23) Pro Forma Adjusted at Present Rates
93			Uncollectible Accounts.					(40,063)	50,714
94			Miscellaneous Customer Accounts Expenses.					3,360	6,869
95			Sub-total Total Customer Accounts					($35,012)	$154,845
96									
97		Customer Service and Information	Customer Assistance					($85,345)	$16,042
98			Informational & Instructional						1,977
99			Miscellaneous Customer & Informational						822
100			Sub-total Customer Service & Information					($85,345)	$18,841
101									
102		Sales	Demonstrating & Selling					$23	$634
103			Miscellaneous Sales						
104			Sub-total Sales					$23	$634
105									
106		Administrative & General	Administrative and General Salaries					$2,115	$28,139
107			Office Supplies and Expenses						4,442
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						105,963
110			Property Insurance						1,037
111			Injuries & Damages					80	29,267
112			Employee Pensions and Benefits					2,607	29,964
113			Regulatory Commission Expenses					1,624	12,292
114			Duplicate Charges-Credit						(2,335)
115			Miscellaneous General Expenses					0	715
116			Maintenance of General Plant					62	9,180
117			Sub-total Administrative & General					$6,489	$218,665
118									
119			**Total O&M Expense**	$14,887				($69,617)	$2,187,092
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense				$23,181	$23,181	$328,879
122			Sub-total Depreciation & Amortization Expense				$23,181	$23,181	$328,879
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					$20	$1,479
125			Sub-total Amortization of Regulatory Expense					$20	$1,479
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			(4,206)		($4,206)	$222,839
128			Sub-total Taxes Other Than Income Taxes - Other			($4,206)		($4,206)	$222,839
129									
130			**Total Operating Expenses**	**$14,887**		**($4,206)**	**$23,181**	**($50,622)**	**$2,740,289**
131									
132	**Net Operating Income Before Income Tax**			**($14,887)**		**$4,206**	**($23,181)**	**($66,924)**	**$698,180**

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset	(9) D-12 Customer Deposit Interest
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,133,435								
2			Sub-total Power Supply	$1,133,435								
3												
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision									
5			561.0 Load Dispatching									
6			561.4 Scheduling, System Control & Dispatch	112,785								
7			561.6 Transmission Service Studies									
8			561.7 Generation Service Studies									
9			561.8 Reliability, Planning & Standard Development	103,657								
10			562.0 Station Expense									
11			563.0 Overhead Lines									
12			564.0 Underground Lines Expense									
13			566.0 Miscellaneous Expense									
14			567.0 Rents									
15			Sub-total Transmission Operations	$216,442								
16												
17		**Transmission Maintenance**	569.0 Maintenance of Structures									
18			569.1 Maintenance of Computer Hardware									
19			569.2 Maintenance of Computer Software									
20			569.3 Maintenance of Communication Equipment									
21			570.0 Maintenance of Station Equipment									
22			571.0 Maintenance of Overhead Lines									
23			572.0 Maintenance of Underground Lines									
24			573.0 Maintenance of Misc Transmission Plant									
25			Sub-total Transmission Maintenance									
26												
27			Sub-total TRANSMISSION EXPENSE	$216,442								
28												
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$554		$20						
30			581.0 Load Dispatching									
31			582.0 Station Expense	5,825		15						
32			583.0 Overhead Lines Expenses	17,811		177						
33			584.0 Underground Lines Expense	10,648		163						
34			586.0 Meter Expenses	6,002		130						
35			587.0 Customer Installations Expense	12,490		322						
36			588.0 Miscellaneous Expense	87,504		373						
37			589.0 Rents	3,793								
38			Sub-total Distribution Operations	$144,627		$1,199						
39												
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$6,042		$75						
41			592.0 Maintenance of Station Equipment	17,236		428						
42			593.0 Maintenance of Overhead Lines	173,935		2,708						
43			594.0 Maintenance of Underground Lines	36,353		900						
44			595.0 Maintenance of Line Transformers	2,851		43						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,691		8						
46			598.0 Maintenance of Misc. Distribution	17,266		188						
47			Sub-total Distribution Maintenance	$255,373		$4,349						

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset	(9) D-12 Customer Deposit Interest
48												
49			Sub-total DISTRIBUTION EXPENSE	$400,000		$5,548						
50												
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision									
52			902.0 Meter Reading	$203		0						
53			903.0 Customer Records and Collection	95,368		1,691						
54			904.0 Uncollectible Accounts.	90,777						(40,063)		
55			905.0 Miscellaneous Customer Accounts Expenses.	3,509		45						3,315
56			Sub-total Customer Accounts	$189,857		$1,737				($40,063)		$3,315
57												
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance	$101,387	(85,400)	$55						
59			909.0 Informational & Instructional	1,977								
60			910.0 Miscellaneous Customer & Informational	822								
61			Sub-total Customer Service & Information	$104,186	($85,400)	$55						
62												
63	**SALES**	**Sales**	912.0 Demonstrating & Selling	$612		23						
64			916.0 Miscellaneous Sales									
65			Sub-total Sales	$612		$23						
66												
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries	$26,024		$2,115						
68			921.0 Office Supplies and Expenses	4,442								
69			922.0 Administrative Expenses Transferred-Credit									
70			923.0 Outside Service Employed	105,963								
71			924.0 Property Insurance	1,037								
72			925.0 Injuries & Damages	29,187		80						
73			926.0 Employee Pensions and Benefits	27,357		2		494	2,112			
74			928.0 Regulatory Commission Expenses	10,668			1,624					
75			929.0 Duplicate Charges-Credit	(2,335)								
76			930.2 Miscellaneous General Expenses	715		0						
77			Sub-total A&G Operations	$203,058		$2,197	$1,624	$494	$2,112			
78												
79		A&G Maintenance	935.0 Maintenance of General Plant	$9,118		62						
80												
81			Sub-total ADMINISTRATION & GENERAL	$212,177		$2,259	$1,624	$494	$2,112			
82												
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$282,114								
84			404.0 Amort. Of Limited-Term Electric Plant.	23,584								
85			Sub-total Depreciation & Amortization Expense	$305,698								
86												
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$1,459							$20	
88			Sub-total Amortization of Regulatory Expense	$1,459							$20	
89												
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$227,045								
91			Sub-total Taxes Other Than Income Taxes - Other	$227,045								
92												
93			**Total**	**$2,790,911**	**($85,400)**	**$9,620**	**$1,624**	**$494**	**$2,112**	**($40,063)**	**$20**	**$3,315**

Line No.	Category	Description	Account	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.							$1,133,435
2			Sub-total Power Supply							$1,133,435
3										
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision							
5			561.0 Load Dispatching							
6			561.4 Scheduling, System Control & Dispatch							112,785
7			561.6 Transmission Service Studies							
8			561.7 Generation Service Studies							
9			561.8 Reliability, Planning & Standard Development							103,657
10			562.0 Station Expense							
11			563.0 Overhead Lines							
12			564.0 Underground Lines Expense							
13			566.0 Miscellaneous Expense							
14			567.0 Rents							
15			Sub-total Transmission Operations							$216,442
16										
17		**Transmission Maintenance**	569.0 Maintenance of Structures							
18			569.1 Maintenance of Computer Hardware							
19			569.2 Maintenance of Computer Software							
20			569.3 Maintenance of Communication Equipment							
21			570.0 Maintenance of Station Equipment							
22			571.0 Maintenance of Overhead Lines							
23			572.0 Maintenance of Underground Lines							
24			573.0 Maintenance of Misc Transmission Plant							
25			Sub-total Transmission Maintenance							
26										
27			Sub-total TRANSMISSION EXPENSE							$216,442
28										
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision						$20	$573
30			581.0 Load Dispatching							
31			582.0 Station Expense						$15	$5,840
32			583.0 Overhead Lines Expenses						$177	$17,988
33			584.0 Underground Lines Expense						$163	$10,810
34			586.0 Meter Expenses						$130	$6,132
35			587.0 Customer Installations Expense						$322	$12,813
36			588.0 Miscellaneous Expense						$373	$87,877
37			589.0 Rents							$3,793
38			Sub-total Distribution Operations						$1,199	$145,826
39										
40		**Distribution Maintenance**	591.0 Maintenance of Structures						$75	$6,116
41			592.0 Maintenance of Station Equipment						428	17,663
42			593.0 Maintenance of Overhead Lines	23,794	14,887				41,388	215,323
43			594.0 Maintenance of Underground Lines						900	37,253
44			595.0 Maintenance of Line Transformers						43	2,893
45			596.0 Maintenance of Street Lighting & Signal Systems						8	1,699
46			598.0 Maintenance of Misc. Distribution						188	17,454
47			Sub-total Distribution Maintenance	$23,794	$14,887				$43,029	$298,403

Line No.	Category	Description	Account	(10) D-13 Storm	(11) D-13A Storm Deferral	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
48										
49			Sub-total DISTRIBUTION EXPENSE	$23,794	$14,887				$44,228	$444,229
50										
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision							
52			902.0 Meter Reading						$0	$203
53			903.0 Customer Records and Collection						$1,691	97,059
54			904.0 Uncollectible Accounts.						(40,063)	50,714
55			905.0 Miscellaneous Customer Accounts Expenses.						3,360	6,869
56			Sub-total Customer Accounts						($35,012)	$154,845
57										
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance						($85,345)	$16,042
59			909.0 Informational & Instructional							1,977
60			910.0 Miscellaneous Customer & Informational							822
61			Sub-total Customer Service & Information						($85,345)	$18,841
62										
63	**SALES**	**Sales**	912.0 Demonstrating & Selling						$23	$634
64			916.0 Miscellaneous Sales							
65			Sub-total Sales						$23	$634
66										
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries						$2,115	$28,139
68			921.0 Office Supplies and Expenses							4,442
69			922.0 Administrative Expenses Transferred-Credit							
70			923.0 Outside Service Employed							105,963
71			924.0 Property Insurance							1,037
72			925.0 Injuries & Damages						80	29,267
73			926.0 Employee Pensions and Benefits						2,607	29,964
74			928.0 Regulatory Commission Expenses						1,624	12,292
75			929.0 Duplicate Charges-Credit							(2,335)
76			930.2 Miscellaneous General Expenses						0	715
77			Sub-total A&G Operations						$6,427	$209,485
78										
79		A&G Maintenance	935.0 Maintenance of General Plant						$62	$9,180
80										
81			Sub-total ADMINISTRATION & GENERAL						$6,489	$218,665
82										
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.					$19,547	$19,547	$301,661
84			404.0 Amort. Of Limited-Term Electric Plant.					3,634	3,634	27,218
85			Sub-total Depreciation & Amortization Expense					$23,181	$23,181	$328,879
86										
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.						$20	$1,479
88			Sub-total Amortization of Regulatory Expense						$20	$1,479
89										
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.				($4,206)		($4,206)	$222,839
91			Sub-total Taxes Other Than Income Taxes - Other				($4,206)		($4,206)	$222,839
92										
93			**Total**	**$23,794**	**$14,887**		**($4,206)**	**$23,181**	**($50,622)**	**$2,740,289**

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-5 Revenue Adjustment Summary

Line No.	Category	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) D-5H Other Adjustments	(10) Adjustments Sub-total	(11) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$1,099,108	$1,531	($3,487)	($2,241)	($25,187)		$638	($14,313)		($43,058)	$1,056,050
2			Residential - House Heating	440.1	215,945	1,085	(529)	(495)	(5,622)		176	(2,074)		(7,460)	208,485
3			C & I Small	442.0	370,920	11	-	(905)	(33,043)		195	(2,775)		(36,518)	334,402
4			C & I Large	442.1	252,807	86	-	(1,011)	(27,636)		139	(1,480)		(29,903)	222,904
5			Railroads & Railways	446.0	9,426		-	-	(874)			-		(874)	8,551
6			Street Lighting	444.0	23,231		-		(99)			-		(99)	23,132
7			Intercompany	448.0	354							-			354
8			Transmission - All Classes		233,615										233,615
9			Sub-total - Customer & Distribution Revenues		$2,205,406	$2,712	($4,016)	($4,652)	($92,462)		$1,148	($20,642)		($117,912)	$2,087,494
10															
11		**Electric Cost Revenue**	Residential	440.0	$824,223										$824,223
12			Residential - House Heating	440.1	203,033										203,033
13			C & I Small	442.0	212,006										212,006
14			C & I Large	442.1	49,781										49,781
15			Railroads & Railways	446.0											
16			Street Lighting	444.0	890										890
17			Intercompany	448.0	218										218
18			Sub-total - Electric Cost Revenue		$1,290,152										$1,290,152
19															
20			**Total OPERATING REVENUE**		$3,495,558	$2,712	($4,016)	($4,652)	($92,462)		$1,148	($20,642)		($117,912)	$3,377,646
21															
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$25,675										$25,675
23			Other Electric Revenues	456.0	8,163								366	$366	8,528
24			Transmission of Electricity for Others	456.1											
25			Sub-total - Other electric Revenue		$33,837								$366	$366	$34,203
26															
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$21,431										$21,431
28			Miscellaneous Service Revenues	451.0	5,189										5,189
29			Sub-total - Other Operating Revenue		$26,620										$26,620
30															
31			**Total OTHER REVENUE**		$60,458								$366	$366	$60,823
32															
33			**Total REVENUE**		**$3,556,015**	**$2,712**	**($4,016)**	**($4,652)**	**($92,462)**		**$1,148**	**($20,642)**	**$366**	**($117,546)**	**$3,438,469**

Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
		(1)	(2)	(3)	(4)	(5)	(6)
1	Total HTY Revenues		$2,045,411	$448,959	$627,135	$338,697	$965,832
2	Commodity Billings in Revenues		(946,303)	(233,014)	(256,215)	(85,890)	(342,105)
3	Weather Adjustment		(14,313)	(2,074)	(2,775)	(1,480)	(4,255)
4	Total Reconcilable Surcharge in Revenues		(20,791)	(4,542)	(28,687)	(19,739)	(48,427)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$1,064,004	$209,329	$339,457	$231,588	$571,045
6							
7	Average Monthly Customers in HTY		1,335,280	203,713	158,636	3,154	161,790
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.797	$1.028	$2.140	$73.431	$3.530
10							
11	Number of Customers at end of HTY		1,337,201	204,769	158,641	3,155	161,796
12							
13	Increase in Customers during HTY	L11 - L7	1,921	1,056	5	1	6
14							
15	**Annualization of Revenue**	L9 * L13	**$1,531**	**$1,085**	**$11**	**$86**	**$96**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3)
1	CAP Discount		($164,539)	($24,973)	
2					
3					
4	**ANNUALIZATION TO YEAR END CUSTOMERS**				
5					
6	Annual CAP Customers		1,433,214	173,274	
7	Average Monthly CAP Customers		119,435	14,439	
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.378)	($1.729)	
9					
10	CAP Customers at End of HTY		122,307	14,787	
11	Increase of CAP Customers	L10 - L7	2,873	347	
12					
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($3,958)	($601)	
14	Write-Offs & Working Capital Factor		11.9%	11.9%	
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$471	$71	
16					
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($3,487)**	**($529)**	

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-5C Act 129 - Lost Revenue Due to Load Reduction

Line No.	Description	Reference	(1) 2025 Revenue Loss	(2) 2026 Revenue Loss	(3) 2026 Revenue Loss Over 2025	(4) Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2025 - Included in HTY Year Budget**					
2	Residential		($6,467)			
3	Residential Heaing		(1,430)			
4	Small C&I		(3,160)			
5	Large C&I		(1,468)			
6	Total	SUM L2 to L5	($12,524)			
7						
8	**Target Revenue Impact in 2025**					
9	Residential			($10,948)		
10	Residential Heaing			(2,420)		
11	Small C&I			(4,970)		
12	Large C&I			(3,490)		
13	Total	SUM L9 to L12		($21,829)		
14						
15	**Incremental Revenue Impact Over HTY Budget**					
16	Residential	L9 - L2			($4,482)	
17	Residential Heaing	L10 - L3			(991)	
18	Small C&I	L11 - L4			(1,810)	
19	Large C&I	L12 - L5			(2,022)	
20	Total	SUM L16 to L19			($9,305)	
21						
22	**Average Annual Incremental Revenue Not in HTY Budget**					
23	Residential	L16 / 2				($2,241)
24	Residential Heaing	L17 / 2				(495)
25	Small C&I	L18 / 2				(905)
26	Large C&I	L19 / 2				(1,011)
27	**Total**	SUM L23 to L26				**($4,652)**

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($25,187)
2	440001: Residential Heating Sales		(5,622)
3	442001: C&I Sales-Small		(33,043)
4	442002: C&I Sales-Large		(27,636)
5	444000: Public Street/Highway Lighting		(99)
6	446000: Sales-Railroad/Railway		(874)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($92,462)**
8			
9	O&M Expense		($85,400)

PECO Electric Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-5F Leap Year Revenue Normalization

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Revenue in February of HTY		$71,458	$19,749	$21,818	$15,580	$37,398
2	Days in February of HTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$2,552	$705	$779	$556	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$638**	**$176**	**$195**	**$139**	**$334**

Line No.	Account	(1) Total
1	Residental Sales	($14,313)
2	Residental Heating Sales	(2,074)
3	C&I Sales-Small	(2,775)
4	C&I Sales-Large	(1,480)
5		
6	**Total**	**($20,642)**

Line No.	Description	(1) Reference	(2) Total
1	Final Incremental COVID-19 Uncollectible Surcharge (ICUS) Reconciliation		
2	Residential		$935
3	Small C&I		(32)
4	Large C&I		(17)
5	Street Lighting		(11)
6	Sub-total ICUS Credit	SUM L2 to L5	$876
7	Final Fiber Affiliate Revenue Surcharge (FARS) Reconciliation		
8	Residential		($168)
9	Small C&I		(9)
10	Street Lighting		371
11	Large C&I & Railroads		(50)
12	Sub-total FARS Credit	SUM L8 to L11	$145
13	Total ICUS and FARS	L6 - L12	$731
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	$366

Line No.	Description	(1) Reference	(2) Union	(3) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,106	1,191
2	Number of Employees @ HTY - Total		2,297	2,297
3	Percentage of Employees @ HTY	L1 / L2	48.14%	51.86%
4	Distribution of Budget S&W Expense		$83,207	$89,625
5				
6	**Annualize March 1 Wage Increase for HTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$448
10		L4 + L9	$83,207	$90,073
11				
12	**Annualize January 1 and March 1, 2025 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		3.00%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$2,496	$2,702
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$85,703**	**$92,775**

Line No.	Description	(1) Reference	(2) Amount
1	Distribution of S&W Expense		$172,832
2			
3	Annualized S&W Including Wage Increases		$178,478
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		76.67%
8	Union Contract Payment for Utility	L6 * L7	$999
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$167
11			
12	Adjusted S&W for Employees in HTY	L3 + L10	$178,645
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ HTY		2,335
16	Average Number of Employees in HTY - Total		2,286
17	Annualization for Number of Employees	L15 - L16	49
18	Annual S&W per Employee	L12 / L16	$78.1
19	Annualization of S&W for New Employees	L17 * L18	$3,807
20			
21	Pro Forma HTY S&W	L12 + L19	$182,452
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$9,620**
24			
25	S&W Pro Forma Factor	L23 / L1	5.57%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$351	$20	$371
26			581.0 Load Dispatching			
27			582.0 Station Expense	278	15	294
28			583.0 Overhead Lines Expenses	3,173	177	3,349
29			584.0 Underground Lines Expense	2,919	163	3,082
30			586.0 Meter Expenses	2,338	130	2,469
31			587.0 Customer Installations Expense	5,788	322	6,111
32			588.0 Miscellaneous Expense	6,694	373	7,067
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,340	75	1,415
35			592.0 Maintenance of Station Equipment	7,682	428	8,109
36			593.0 Maintenance of Overhead Lines	48,641	2,708	51,349
37			594.0 Maintenance of Underground Lines	16,163	900	17,063
38			595.0 Maintenance of Line Transformers	767	43	809
39			596.0 Maintenance of Street Lighting & Signal Systems	144	8	152
40			598.0 Maintenance of Misc. Distribution	3,385	188	3,574
41			Sub-total Distribution Operations	$99,665	$5,548	$105,212
42						

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	$0	$0	$0
45			903.0 Customer Records and Collection	30,385	1,691	32,076
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	813	45	859
48			Sub-total Customer Accounts	$31,198	$1,737	$32,935
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$982	$55	$1,037
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational			
53			Sub-total Customer Service & Information	$982	$55	$1,037
54						
55	**Sales**		912.0 Demonstrating & Selling	$407	$23	$429
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$407	$23	$429
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$37,992	$2,115	$40,107
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,444	80	1,524
65			926.0 Employee Pensions and Benefits	28	2	30
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	5	0	6
69			935.0 Maintenance of General Plant	1,110	62	1,172
70			Sub-total Administration & General	$40,579	$2,259	$42,838
71						
72			**Total**	**$172,832**	**$9,620**	**$182,452**
73						
74	**Percent Increas**		**Percent Increase**			5.57%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$111
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		$31
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$142
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,740
8	Materials, IT Costs, Travel, Copies, etc.		366
9	Total Expenditure Expected in FTY	SUM L7 to L8	$3,106
10			
11	Total Rate Case Expense	L4 + L9	$3,248
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,624
15			
16	Annual Amortization Amount Included in Budget		
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$1,624**

Line No.	Description	(1) Reference	(2) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,237
3	Employees at Ten Months Prior		2,245
4	Employees at Nine Months Prior		2,251
5	Employees at Eight Months Prior		2,251
6	Employees at Seven Months Prior		2,251
7	Employees at Six Months Prior		2,251
8	Employees at Five Months Prior		2,315
9	Employees at Four Months Prior		2,315
10	Employees at Three Months Prior		2,315
11	Employees at Two Months Prior		2,335
12	Employees at One Month Prior		2,335
13	Employees at End of HTY		2,335
14			
15	Average Monthly Employees in HTY	AVERAGE L2 to L13	2,286
16	Additional Employees in HTY		49
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$23,174
20	Number of Employees for Budget		2,286
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	49
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$494**

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to HTY		$17,267
2	Pension Contribution for Three Years Prior to HTY		15,222
3	Pension Contribution for Two Years Prior to HTY		1,408
4	Pension Contribution for One Year Prior to HTY		3,690
5	Pension Contribution for HTY		11,760
6			
7	Average Pension Contribution	Average L1 to L5	$9,869
8			
9	Percent to Electric Distribution		76.67%
10	Total Amount to Electric Distribution	L7 * L9	$7,567
11	Pension Capitalization Factor		48.37%
12	Pension Contribution To Be Capitalized	L10 * L11	$3,660
13	Pension Contribution To Be Expensed	L10 - L12	$3,907
14	HTY Distribution Pension Expense		1,795
15	**Additional Pension Expense**	L13 - L14	**$2,112**

Line No.	Description	(1) Reference	(2) Reference	(3) Charge Off Amounts	(4) InPA Charge Off Amounts	(5) Net Charge Off Amounts	(6) Billed Revenue	(7) Percent	(8) Totals
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$42,650	$17	$42,632	$3,880,008	1.0988%	
2		One Year Prior to HTY		28,792	2	28,791	4,036,898	0.7132%	
3		HTY		68,853		68,853	4,655,348	1.4790%	
4		Three Year Average	SUM L1 to L3 / 3	$46,765	$6	$46,759	$4,190,751	1.1158%	
5									
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	HTY					$3,377,646		
7									
8	Tariff Revenue - Non Shopping Revenue	HTY	L6				$3,377,646		
9									
10	Tariff Revenue - Shopping Revenue	HTY					1,167,600		
11									
12	Tariff Revenue - Including Shopping Revenue	HTY	L8 + L10				$4,545,245		
13									
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12						$50,714
15									
16	Uncollectible Accounts (904)	HTY							$90,777
17									
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16						**($40,063)**

Line No.	Description	(1) Reference	(2) Total
1	Actual IIJA Related Incremental Costs in 2024 and 2025		$451
2	Amortization Years		2
3	Total Pro Forma Adjustment Amount	L1 / L2	$226
4	Annual Amortization Amount Included in Budget		$206
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**$20**

Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub-Total	Interest Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				22,580	132		
4	February				23,154	135		
5	March				24,246	141		
6	April				25,771	150		
7	May				26,839	157		
8	June				27,171	158		
9	July				27,725	162		
10	August				28,297	165		
11	September				29,109	170		
12	October				29,946	175		
13	November				30,524	178		
14	December				30,889	180		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,903	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				35,889	105		
20	February				36,470	106		
21	March				37,775	110		
22	April				39,113	114		
23	May				39,833	116		
24	June				39,865	116		
25	July				40,669	119		
26	August				40,986	120		
27	September				41,497	121		
28	October				43,006	125		
29	November				43,769	128		
30	December				45,192	132		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,412	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,315**

Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
		(1)	(2)	(3)	(4)	(5)	(6)
1	2021		-	1.23871	$54,400	$67,386	
2	2022		0.07799	1.23871	$22,457	$27,818	
3	2023		0.04436	1.14909	$41,173	$47,312	
4	2024		0.03550	1.10028	$54,149	$59,579	
5	2025		0.03283	1.06256	$42,147	$44,784	
7							
8	Average Storm Restoration Expense at 2025 cost levels	Avg. Col 5, L1 to L5					$49,376
9							
10	HTY Budget						$25,582
11							
12	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$23,794**

Line No.	Description	(1) Reference	(2) Total
1	Deferred Storm Expense		$74,434
2	Amortization Years		5
3	Total Pro Forma Adjustment Amount	L1 / L7	$14,887
4	Annual Amortization Amount Included in Budget		
5	**Pro Forma Adjustment for Annual Amortization**		**$14,887**

Line No.	Description	Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
		(1)	(2)	(3)	(4)	(5)	(6)
1	Public Utility Real Tax (PURTA) Total Expense	17.372%	$9,061	($1,574)	$7,487		$7,487
2	Capital Stock & Franchise Tax	17.372%	$341	($59)	$282		$282
3	Use Tax Accrued	17.372%	(495)	86	(409)		(409)
4	Real Estate Tax Accrued	17.372%	5,898	(1,025)	4,873		4,873
5	Miscellaneous TOTI	12.545%	52	(7)	46		46
6	Payroll Tax Accrued	12.545%	14,088	(1,767)	12,321	686	13,006
7	Sub-total TOTI - Other	SUM L1 to L6	$28,945	($4,346)	$24,599	$686	$25,285
8							
9	Gross Receipt Tax		$202,445		$202,445	($4,892)	$197,553
10							
11	**Total**	L7 + L9	**$231,390**	**($4,346)**	**$227,045**	**($4,206)**	**$222,839**

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$172,832
2	Payroll Tax Expense		$12,321
3	Payroll Tax Expense - Percent	L2 / L1	7.13%
4	Pro Forma Increase in S&W		$9,620
5	**Payroll Tax Pro Forma**	L3 * L4	**$686**

Line No.	Description	(1) Reference	(2) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		
2			
3	Residential		$1,880,273
4	Residential Heating		411,519
5	Small C&I		546,408
6	Large C&I		272,686
7	Railroads & Railways		8,551
8	Street Lighting & Highway		24,022
9	Interdepartmental Sales - Electric		572
10	Transmission		233,615
11	Sub-total	SUM L3 to L10	$3,377,646
12			
13	Forfeited Discounts - Electric		$21,431
14	Uncollectible Accounts		(50,714)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($29,282)
17			
18	Total HTY at Present Rates	L11 + L16	$3,348,363
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$197,553
23			
24	HTY Budget		$202,445
25			
26	**Net Adjustment**	L22 - L24	**($4,892)**

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$2,860	$428	$2,432	$428	$3,289
2			PECO Elec 3650 PA LTIIP	4,003	447	3,556	447	$4,449
3			PECO Elec 3660 PA LTIIP	3,637	503	3,134	503	$4,141
4			PECO Elec 3670 PA LTIIP	6,890	1,116	5,773	1,116	$8,006
5			PECO Elec 3705 SM UD RES PA	8,807		8,807		$8,807
6			PECO Elec 3706 Non DOE Rcv PA	2,032		2,032		$2,032
7			PECO Elec 3707 SM RES PA	7,154	977	6,176	977	$8,131
8			PECO Elec 3708 SM SCI PA	792	21	771	21	$812
9			PECO Elec 3709 SM LCI PA	1,311	133	1,178	133	$1,444
10			PECO Electric 3611 PA	1,469		1,469		$1,469
11			PECO Electric 3612 PA	3,120		3,120		$3,120
12			PECO Electric 3613 PA	189	38	152	38	$227
13			PECO Electric 3620 PA	22,823		22,823		$22,823
14			PECO Electric 3631 PA	4,473	907	3,566	907	$5,380
15			PECO Electric 3632 PA	24,994	447	24,547	447	$25,441
16			PECO Electric 3633 PA	6,854	2,499	4,355	2,499	$9,353
17			PECO Electric 3640 PA	28,746	685	28,060	685	$29,431
18			PECO Electric 3650 PA	42,608	2,412	40,196	2,412	$45,019
19			PECO Electric 3660 PA	10,136	1,908	8,229	1,908	$12,044
20			PECO Electric 3670 PA	36,703	576	36,127	576	$37,280
21			PECO Electric 3680 PA	20,780	1,252	19,528	1,252	$22,031
22			PECO Electric 3691 PA	3,694	1,851	1,843	1,851	$5,545
23			PECO Electric 3692 PA	4,689	131	4,558	131	$4,820
24			PECO Electric 3701 PA	177	21	156	21	$198
25			PECO Electric 3710 PA	4	6	(2)	6	$10
26			PECO Electric 3730 PA	697		697		$697
27			PECO Electric 3731 PA	65	22	43	22	$86
28			PECO Electric 3732 PA	911	0	911	0	$911
29			PECO Electric 3733 PA	29	27	2	27	$55
30			Sub-total Electric - Distribution	$250,646	$16,406	$234,239	$16,406	$267,052
31			Sub-total Electric - Distribution	$250,646	$16,406	$234,239	$16,406	$267,052
32								
33		Electric - General Plant	PECO Common 3901 PA	4,522		$4,522		$4,522
34			PECO Common 3902 IL	16		16		16
35			PECO Common 3902 PA	3,367	677	2,691	677	4,044
36			PECO Common 3903 PA	310		310		310
37			PECO Common 3911 PA	13		13		13
38			PECO Common 3912 PA	2,278	41	2,237	41	2,318
39			PECO Common 3913 IL	3,026	1,980	1,046	1,980	5,005
40			PECO Common 3913 PA	7,501		7,501		7,501
41			PECO Common 3930 PA	116	10	107	10	126

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
42			PECO Common 3941 PA	0		0		0
43			PECO Common 3942 PA	66	0	66	0	67
44			PECO Common 3970 PA	5,948		5,948		5,948
45			PECO Common 3980 PA	139		139		139
46			PECO Elec 3919 SM Comp Equip ID	3		3		3
47			PECO Elec 3919 SM Comp Equip IL	6		6		6
48			PECO Elec 3919 SM Comp Equip MD	2		2		2
49			PECO Elec 3919 SM Comp Equip NC	1		1		1
50			PECO Elec 3919 SM Comp Equip PA	2		2		2
51			PECO Elec 3949 SM Tools PA	6		6		6
52			PECO Elec 3979 SM Comm Equip PA	216		216		216
53			PECO Electric 3901 PA	1,069	289	780	289	1,358
54			PECO Electric 3902 PA	394	0	394	0	394
55			PECO Electric 3903 PA	7		7		7
56			PECO Electric 3911 PA	0		0		0
57			PECO Electric 3912 PA	70	6	64	6	76
58			PECO Electric 3913 PA	743		743		743
59			PECO Electric 3930 PA	4		4		4
60			PECO Electric 3940 PA	4,351	380	3,971	380	4,731
61			PECO Electric 3951 PA	11		11		11
62			PECO Electric 3952 PA	0		0		0
63			PECO Electric 3971 PA	1,215	121	1,093	121	1,336
64			PECO Electric 3972 PA	4,489	449	4,040	449	4,938
65			PECO Electric 3973 PA	2,232	223	2,009	223	2,455
66			PECO Electric 3980 PA	158	39	119	39	197
67			Sub-total Electric - General Plant	$42,281	$4,215	$38,065	$4,215	$46,496
68			Sub-total Electric - General Plant	$42,281	$4,215	$38,065	$4,215	$46,496
69								
70		Electric - Transmission	PECO Electric 3511 PA	$2,331		$2,331		$2,331
71			PECO Electric 3512 PA	3,673		3,673		3,673
72			PECO Electric 3513 PA	1,263		1,263		1,263
73			PECO Electric 3521 PA	1,333	$360	973	360	1,693
74			PECO Electric 3522 MD	1		1		1
75			PECO Electric 3522 NJ	0		0		0
76			PECO Electric 3522 PA	2,185	$242	1,943	242	2,427
77			PECO Electric 3523 NJ	0		0		0
78			PECO Electric 3523 PA	94	$3	92	3	97
79			PECO Electric 3530 NJ	64		64		64
80			PECO Electric 3530 PA	19,360	$1,276	18,084	1,276	20,635
81			PECO Electric 3540 DE	90		90		90
82			PECO Electric 3540 MD	51		51		51

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
83			PECO Electric 3540 NJ	213		213		213
84			PECO Electric 3540 PA	3,327	$206	3,121	206	3,534
85			PECO Electric 3550 PA	422		422		422
86			PECO Electric 3560 DE	4		4		4
87			PECO Electric 3560 MD	11		11		11
88			PECO Electric 3560 NJ	340	$155	185	155	495
89			PECO Electric 3560 PA	2,666		2,666	-	2,666
90			PECO Electric 3570 PA	789	$7	782	7	795
91			PECO Electric 3580 PA	1,967	$54	1,913	54	2,021
92			PECO Electric 3590 MD	1	$1		1	2
93			PECO Electric 3590 NJ	4		4		4
94			PECO Electric 3590 PA	24		24	-	24
95			Sub-total Electric - Transmission	$40,214	$2,303	$37,911	$2,303	$42,517
96								
97			Sub-total 403.0 Depreciation Expense	$333,141	$22,925	$310,216	$22,925	$356,066
98			Sub-total Electric - Transmission	$40,214	$2,303	$37,911	$2,303	$42,517
99								
100	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	$69	$69		69	139
101			PECO Com 303-CFP MEU SW	135		135		135
102			PECO Com 303-CFP MMA SW	40	40		40	80
103			PECO Com 303-DSS Platform Enhanc SW	67	67		67	135
104			PECO Com 303-EU Custom Hardening SW	85	85		85	170
105			PECO Com 303-EU EAM SW	59	59		59	118
106			PECO Com 303-EU EAM Transformation	22	22		22	45
107			PECO Com 303-EU GIS Core SW	560	560		560	1,119

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,860	$428	$2,432	$428	$3,289
2			PECO Elec 3650 PA LTIIP	1.0000	4,003	447	3,556	447	4,449
3			PECO Elec 3660 PA LTIIP	1.0000	3,637	503	3,134	503	4,141
4			PECO Elec 3670 PA LTIIP	1.0000	6,890	1,116	5,773	1,116	8,006
5			PECO Elec 3705 SM UD RES PA	1.0000	8,807		8,807		8,807
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,032		2,032		2,032
7			PECO Elec 3707 SM RES PA	1.0000	7,154	977	6,176	977	8,131
8			PECO Elec 3708 SM SCI PA	1.0000	792	21	771	21	812
9			PECO Elec 3709 SM LCI PA	1.0000	1,311	133	1,178	133	1,444
10			PECO Electric 3611 PA	1.0000	1,469		1,469		1,469
11			PECO Electric 3612 PA	1.0000	3,120		3,120		3,120
12			PECO Electric 3613 PA	1.0000	189	38	152	38	227
13			PECO Electric 3620 PA	1.0000	22,823		22,823		22,823
14			PECO Electric 3631 PA	1.0000	4,473	907	3,566	907	5,380
15			PECO Electric 3632 PA	1.0000	24,994	447	24,547	447	25,441
16			PECO Electric 3633 PA	1.0000	6,854	2,499	4,355	2,499	9,353
17			PECO Electric 3640 PA	1.0000	28,746	685	28,060	685	29,431
18			PECO Electric 3650 PA	1.0000	42,608	2,412	40,196	2,412	45,019
19			PECO Electric 3660 PA	1.0000	10,136	1,908	8,229	1,908	12,044
20			PECO Electric 3670 PA	1.0000	36,703	576	36,127	576	37,280
21			PECO Electric 3680 PA	1.0000	20,780	1,252	19,528	1,252	22,031
22			PECO Electric 3691 PA	1.0000	3,694	1,851	1,843	1,851	5,545
23			PECO Electric 3692 PA	1.0000	4,689	131	4,558	131	4,820
24			PECO Electric 3701 PA	1.0000	177	21	156	21	198
25			PECO Electric 3710 PA	1.0000	4	6	(2)	6	10
26			PECO Electric 3730 PA	1.0000	697		697		697
27			PECO Electric 3731 PA	1.0000	65	22	43	22	86
28			PECO Electric 3732 PA	1.0000	911	0	911	0	911
29			PECO Electric 3733 PA	1.0000	29	27	2	27	55
30			Sub-total Electric - Distribution		$250,646	$16,406	$234,239	$16,406	$267,052
31			Sub-total Electric - Distribution		$250,646	$16,406	$234,239	$16,406	$267,052
32									
33		Electric - General Plant	PECO Common 3901 PA	0.7693	$3,479		$3,479		$3,479
34			PECO Common 3902 IL	0.7693	12		12		12
35			PECO Common 3902 PA	0.7693	2,590	521	2,070	521	3,111
36			PECO Common 3903 PA	0.7693	238		238		238
37			PECO Common 3911 PA	0.7693	10		10		10
38			PECO Common 3912 PA	0.7693	1,752	31	1,721	31	1,784
39			PECO Common 3913 IL	0.7693	2,328	1,523	805	1,523	3,851
40			PECO Common 3913 PA	0.7693	5,771		5,771		5,771
41			PECO Common 3930 PA	0.7693	90	7	82	7	97

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
42			PECO Common 3941 PA	0.7693	0		0		0
43			PECO Common 3942 PA	0.7693	51	0	51	0	51
44			PECO Common 3970 PA	0.7693	4,576		4,576		4,576
45			PECO Common 3980 PA	0.7693	107		107		107
46			PECO Elec 3919 SM Comp Equip ID	1.0000	3		3		3
47			PECO Elec 3919 SM Comp Equip IL	1.0000	6		6		6
48			PECO Elec 3919 SM Comp Equip MD	1.0000	2		2		2
49			PECO Elec 3919 SM Comp Equip NC	1.0000	1		1		1
50			PECO Elec 3919 SM Comp Equip PA	1.0000	2		2		2
51			PECO Elec 3949 SM Tools PA	1.0000	6		6		6
52			PECO Elec 3979 SM Comm Equip PA	1.0000	216		216		216
53			PECO Electric 3901 PA	1.0000	1,069	289	780	289	1,358
54			PECO Electric 3902 PA	1.0000	394	0	394	0	394
55			PECO Electric 3903 PA	1.0000	7		7		7
56			PECO Electric 3911 PA	1.0000	0		0		0
57			PECO Electric 3912 PA	1.0000	70	6	64	6	76
58			PECO Electric 3913 PA	1.0000	743		743		743
59			PECO Electric 3930 PA	1.0000	4		4		4
60			PECO Electric 3940 PA	1.0000	4,351	380	3,971	380	4,731
61			PECO Electric 3951 PA	1.0000	11		11		11
62			PECO Electric 3952 PA	1.0000	0		0		0
63			PECO Electric 3971 PA	1.0000	1,215	121	1,093	121	1,336
64			PECO Electric 3972 PA	1.0000	4,489	449	4,040	449	4,938
65			PECO Electric 3973 PA	1.0000	2,232	223	2,009	223	2,455
66			PECO Electric 3980 PA	1.0000	158	39	119	39	197
67			Sub-total Electric - General Plant		$35,982	$3,591	$32,391	$3,591	$39,573
68			Sub-total Electric - General Plant		$35,982	$3,591	$32,391	$3,591	$39,573
69									
70		Electric - Transmission	PECO Electric 3511 PA	1.0000	$2,331		$2,331		$2,331
71			PECO Electric 3512 PA	1.0000	3,673		3,673		3,673
72			PECO Electric 3513 PA	1.0000	1,263		1,263		1,263
73			PECO Electric 3521 PA	1.0000	1,333	360	973	360	1,693
74			PECO Electric 3522 MD	1.0000	1		1		1
75			PECO Electric 3522 NJ	1.0000	0		0		0
76			PECO Electric 3522 PA	1.0000	2,185	242	1,943	242	2,427
77			PECO Electric 3523 NJ	1.0000	0		0		0
78			PECO Electric 3523 PA	1.0000	94	3	92	3	97
79			PECO Electric 3530 NJ	1.0000	64		64		64
80			PECO Electric 3530 PA	1.0000	19,360	1,276	18,084	1,276	20,635
81			PECO Electric 3540 DE	1.0000	90		90		90
82			PECO Electric 3540 MD	1.0000	51		51		51

Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
				(6)	(7)	(8)	(9)	(10)	(11)
83			PECO Electric 3540 NJ	1.0000	213		213		213
84			PECO Electric 3540 PA	1.0000	3,327	206	3,121	206	3,534
85			PECO Electric 3550 PA	1.0000	422		422		422
86			PECO Electric 3560 DE	1.0000	4		4		4
87			PECO Electric 3560 MD	1.0000	11		11		11
88			PECO Electric 3560 NJ	1.0000	340	155	185	155	495
89			PECO Electric 3560 PA	1.0000	2,666	-	2,666	-	2,666
90			PECO Electric 3570 PA	1.0000	789	7	782	7	795
91			PECO Electric 3580 PA	1.0000	1,967	54	1,913	54	2,021
92			PECO Electric 3590 MD	1.0000	1	1		1	2
93			PECO Electric 3590 NJ	1.0000	4		4		4
94			PECO Electric 3590 PA	1.0000	24	-	24	-	24
95			Sub-total Electric - Transmission		$40,214	$2,303	$37,911	$2,303	$42,517
96									
97			Sub-total 403.0 Depreciation Expense		$326,842	$22,301	$304,541	$22,301	$349,142
98			Sub-total Electric - Transmission		$40,214	$2,303	$37,911	$2,303	$42,517
99									
100	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.7693	53	53		53	107
101			PECO Com 303-CFP MEU SW	0.7693	104		104		104
102			PECO Com 303-CFP MMA SW	0.7693	31	31		31	62
103			PECO Com 303-DSS Platform Enhanc SW	0.7693	52	52		52	104
104			PECO Com 303-EU Custom Hardening SW	0.7693	65	65		65	131
105			PECO Com 303-EU EAM SW	0.7693	46	46		46	91
106			PECO Com 303-EU EAM Transformation	0.7693	17	17		17	35
107			PECO Com 303-EU GIS Core SW	0.7693	431	431		431	861

					(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,860	$428	$2,432	$428	$3,289
2			PECO Elec 3650 PA LTIIP	1.0000	4,003	447	3,556	447	4,449
3			PECO Elec 3660 PA LTIIP	1.0000	3,637	503	3,134	503	4,141
4			PECO Elec 3670 PA LTIIP	1.0000	6,890	1,116	5,773	1,116	8,006
5			PECO Elec 3705 SM UD RES PA	1.0000	8,807		8,807		8,807
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,032		2,032		2,032
7			PECO Elec 3707 SM RES PA	1.0000	7,154	977	6,176	977	8,131
8			PECO Elec 3708 SM SCI PA	1.0000	792	21	771	21	812
9			PECO Elec 3709 SM LCI PA	1.0000	1,311	133	1,178	133	1,444
10			PECO Electric 3611 PA	1.0000	1,469		1,469		1,469
11			PECO Electric 3612 PA	1.0000	3,120		3,120		3,120
12			PECO Electric 3613 PA	1.0000	189	38	152	38	227
13			PECO Electric 3620 PA	1.0000	22,823		22,823		22,823
14			PECO Electric 3631 PA	1.0000	4,473	907	3,566	907	5,380
15			PECO Electric 3632 PA	1.0000	24,994	447	24,547	447	25,441
16			PECO Electric 3633 PA	1.0000	6,854	2,499	4,355	2,499	9,353
17			PECO Electric 3640 PA	1.0000	28,746	685	28,060	685	29,431
18			PECO Electric 3650 PA	1.0000	42,608	2,412	40,196	2,412	45,019
19			PECO Electric 3660 PA	1.0000	10,136	1,908	8,229	1,908	12,044
20			PECO Electric 3670 PA	1.0000	36,703	576	36,127	576	37,280
21			PECO Electric 3680 PA	1.0000	20,780	1,252	19,528	1,252	22,031
22			PECO Electric 3691 PA	1.0000	3,694	1,851	1,843	1,851	5,545
23			PECO Electric 3692 PA	1.0000	4,689	131	4,558	131	4,820
24			PECO Electric 3701 PA	1.0000	177	21	156	21	198
25			PECO Electric 3710 PA	1.0000	4	6	(2)	6	10
26			PECO Electric 3730 PA	1.0000	697		697		697
27			PECO Electric 3731 PA	1.0000	65	22	43	22	86
28			PECO Electric 3732 PA	1.0000	911	0	911	0	911
29			PECO Electric 3733 PA	1.0000	29	27	2	27	55
30			Sub-total Electric - Distribution		$250,646	$16,406	$234,239	$16,406	$267,052
31			Sub-total Electric - Distribution		$250,646	$16,406	$234,239	$16,406	$267,052
32									
33		Electric - General Plant	PECO Common 3901 PA	0.8746	$3,043		$3,043		$3,043
34			PECO Common 3902 IL	0.8746	11		11		11
35			PECO Common 3902 PA	0.8746	2,265	455	1,810	455	2,721
36			PECO Common 3903 PA	0.8746	209		209		209
37			PECO Common 3911 PA	0.8746	8		8		8
38			PECO Common 3912 PA	0.8746	1,532	27	1,505	27	1,560
39			PECO Common 3913 IL	0.8746	2,036	1,332	704	1,332	3,368
40			PECO Common 3913 PA	0.8746	5,047		5,047		5,047
41			PECO Common 3930 PA	0.8746	78	6	72	6	85

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
42			PECO Common 3941 PA	0.8746	0		0		0
43			PECO Common 3942 PA	0.8746	45	0	44	0	45
44			PECO Common 3970 PA	0.8746	4,002		4,002		4,002
45			PECO Common 3980 PA	0.8746	94		94		94
46			PECO Elec 3919 SM Comp Equip ID	0.8746	3		3		3
47			PECO Elec 3919 SM Comp Equip IL	0.8746	5		5		5
48			PECO Elec 3919 SM Comp Equip MD	0.8746	2		2		2
49			PECO Elec 3919 SM Comp Equip NC	0.8746	1		1		1
50			PECO Elec 3919 SM Comp Equip PA	0.8746	2		2		2
51			PECO Elec 3949 SM Tools PA	0.8746	5		5		5
52			PECO Elec 3979 SM Comm Equip PA	0.8746	189		189		189
53			PECO Electric 3901 PA	0.8746	935	253	682	253	1,188
54			PECO Electric 3902 PA	0.8746	344	0	344	0	344
55			PECO Electric 3903 PA	0.8746	7		7		7
56			PECO Electric 3911 PA	0.8746	0		0		0
57			PECO Electric 3912 PA	0.8746	61	5	56	5	67
58			PECO Electric 3913 PA	0.8746	650		650		650
59			PECO Electric 3930 PA	0.8746	3		3		3
60			PECO Electric 3940 PA	0.8746	3,805	333	3,473	333	4,138
61			PECO Electric 3951 PA	0.8746	9		9		9
62			PECO Electric 3952 PA	0.8746	0		0		0
63			PECO Electric 3971 PA	0.8746	1,062	106	956	106	1,169
64			PECO Electric 3972 PA	0.8746	3,926	393	3,533	393	4,318
65			PECO Electric 3973 PA	0.8746	1,952	195	1,757	195	2,147
66			PECO Electric 3980 PA	0.8746	138	34	104	34	173
67			Sub-total Electric - General Plant		$31,468	$3,141	$28,328	$3,141	$34,609
68			Sub-total Electric - General Plant		$31,468	$3,141	$28,328	$3,141	$34,609
69									
70		Electric - Transmission	PECO Electric 3511 PA						
71			PECO Electric 3512 PA						
72			PECO Electric 3513 PA						
73			PECO Electric 3521 PA						
74			PECO Electric 3522 MD						
75			PECO Electric 3522 NJ						
76			PECO Electric 3522 PA						
77			PECO Electric 3523 NJ						
78			PECO Electric 3523 PA						
79			PECO Electric 3530 NJ						
80			PECO Electric 3530 PA						
81			PECO Electric 3540 DE						
82			PECO Electric 3540 MD						

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
83			PECO Electric 3540 NJ						
84			PECO Electric 3540 PA						
85			PECO Electric 3550 PA						
86			PECO Electric 3560 DE						
87			PECO Electric 3560 MD						
88			PECO Electric 3560 NJ						
89			PECO Electric 3560 PA						
90			PECO Electric 3570 PA						
91			PECO Electric 3580 PA						
92			PECO Electric 3590 MD						
93			PECO Electric 3590 NJ						
94			PECO Electric 3590 PA						
95			Sub-total Electric - Transmission						
96									
97			Sub-total 403.0 Depreciation Expense		$282,114	$19,547	$262,567	$19,547	$301,661
98			Sub-total Electric - Transmission						
99									
100	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 303-CFP B&P SW	0.8746	47	47		47	93
101			PECO Com 303-CFP MEU SW	0.8746	91		91		91
102			PECO Com 303-CFP MMA SW	0.8746	27	27		27	54
103			PECO Com 303-DSS Platform Enhanc SW	0.8746	45	45		45	91
104			PECO Com 303-EU Custom Hardening SW	0.8746	57	57		57	114
105			PECO Com 303-EU EAM SW	0.8746	40	40		40	80
106			PECO Com 303-EU EAM Transformation	0.8746	15	15		15	30
107			PECO Com 303-EU GIS Core SW	0.8746	377	377		377	753

Line No.	Description	(1) Reference	(2) Present Rates	(3) Rate Increase	(4) Proposed Rates
1	Revenue		$3,438,469	$82,581	$3,521,050
2	Operating Expenses		2,740,289	6,065	2,746,354
3	OIBIT	L1 - L2	$698,180	$76,516	$774,696
4					
5	Rate Base		$9,095,891		$9,095,891
6	Weighted Cost of Debt		2.100%		2.100%
7	Synchronized Interest Expense	L5 * L6	$191,014		$191,014
8	Base Taxable Income	L3 - L7	$507,167	$76,516	$583,682
9					
10	State Accelerated Tax Depreciation		$327,027		$327,027
11	Pro Forma Book Depreciation		328,879		328,879
12	State Tax Depreciation (Over) Under Book	L11 - L10	$1,852		$1,852
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(27,182)		(27,182)
14	Other Property Basis Adjustments (CIAC/ICM)		(62,660)		(62,660)
15	Removal Costs/Software		(12,537)		(12,537)
16	AFUDC Equity				-
17	Permanent Adjustments		3,458		3,458
18	Repair Deduction		(439,629)		(439,629)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($29,532)	$76,516	$46,984
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$2,360	($6,114)	($3,754)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- L24 * L23	(944)	2,445	1,502
26	State Income Tax Benefit / (Expense)	L23 + L25	$1,416	($3,668)	($2,252)
27					
28	Federal Accelerated Tax Depreciation		$312,809		$312,809
29	Pro Forma Book Depreciation		328,879		328,879
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$16,070		$16,070
31	Regulatory Asset Programs M-1		(27,182)		(27,182)
32	Other Property Basis Adjustments (CIAC/ICM)		(62,660)		(62,660)
33	Removal Costs/Software		(12,537)		(12,537)
34	AFUDC Equity		-		-
35	Permanent Adjustments		3,458		3,458
36	Repair Deduction		(439,629)		(439,629)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($13,898)	$72,848	$58,950
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	-	$2,919	($15,298)	($12,379)
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$4,334	($18,966)	($14,632)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($16,816)	$514	($16,302)
47	Deferred Taxes on Timing Differences- State		(7,178)		(7,178)
48	Deferred Taxes on State NOL		944	(2,445)	(1,502)
49	Excess Deferred Amortization		7,183		7,183
50	Excess Deferred Amortization - State (Net of Federal)		552		552
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(18,766)		(18,766)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	(34,082)	($1,932)	(36,014)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	($29,748)	($20,898)	($50,646)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		(17)	-	(17)
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	($29,765)	($20,898)	($50,663)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	($25,498)	($14,784)	($40,282)
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	($4,267)	($6,114)	($10,381)
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**($29,765)**	**($20,898)**	**($50,663)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		21,431
4	Total Customer Revenue		3,495,558
5	Shopping Revenue		1,167,600
6	LPC REVENUE	L3 / (L4 + L5)	0.004596
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.011158)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003628)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.930810
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	-	(0.074372)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.856439
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.179852)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.676586
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.478008
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	25.422%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.079900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.920100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.193221)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.726879
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.375745
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.312%

PECO Exhibit MJT-4:
PECO Historical Storm Restoration Expense

PECO Historical Storm Restoration Expense ($ millions)

	A	B	C	D = A+B+C	E = A+B
Year	**Minor Storms**	**Non-Extraordinary Major Storms**	**Extraordinary Major [(a)] Storms**	**Total Storm Expense**	**Minor + Non-Extraordinary Major Storm Expense**
2010	$ 30.0	$ -	$ -	$ 30.0	$ 30.0
2011	20.3	-	22.9	43.1	20.3
2012	5.3	-	46.3	51.6	5.3
2013	3.8	-	-	3.8	3.8
2014	10.2	20.2	58.1	88.6	30.5
2015	3.0	-	18.3	21.3	3.0
2016	9.1	6.9	-	16.1	16.1
2017	9.0	-	-	9.0	9.0
2018	11.2	4.5	48.1	63.8	15.7
2019	35.9	-	-	35.9	35.9
2020	27.5	-	87.4	114.9	27.5
2021	33.4	-	21.0	54.4	33.4
2022	22.5	-	-	22.5	22.5
2023	41.2	-	-	41.2	41.2
2024	20.3	11.1	22.7	54.1	31.5
2025	25.6	-	51.7	77.3	25.6
Total	**$ 308.3**	**$ 42.8**	**$ 376.6**	**$ 727.6**	**$ 351.0**
Avg.	$ 19.3	$ 2.7	$ 23.5	$ 45.5	$ 21.9

[(a)] Storms damage costs exceeding 5% of PECO's income at the time of the storm event.