PECO Statement No. 1:

Direct Testimony of
Amy E. Hamilton

PECO ENERGY COMPANY
STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: AMY E. HAMILTON

SUBJECT: PECO'S GAS OPERATIONS; OVERVIEW OF PECO'S RATE FILING; PECO'S CAPITAL INVESTMENT PROCESS; SYSTEM SAFETY AND RELIABILITY; MANUFACTURED GAS PLANT REMEDIATION PROGRAM; CUSTOMER SERVICE AND PROGRAMS; SAFETY SECURITY, AND ENVIRONMENTAL PROGRAMS; FULFILLMENT OF 2022 RATE CASE COMMITMENTS; ECONOMIC DEVELOPMENT, COMMUNITY SUPPORT, AND DIVERSITY; MANAGEMENT PERFORMANCE

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
AMY E. HAMILTON

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Amy E. Hamilton. 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 the Vice President, Gas Operations. In that capacity, I am responsible for the administration of PECO's gas system construction and maintenance, engineering, plant operations and system control, new business and regulatory compliance. I have been performing these functions since 2022.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts degree from Gettysburg College and a Juris Doctorate from Widener University Delaware School of Law. I have been employed by PECO, or affiliates of Exelon Corporation ("Exelon"), since December 1999. I started as a regulatory attorney in the legal department and have held various positions of increasing responsibility in the Exelon corporate family since. I worked in PECO's gas supply and transportation department, Exelon Generation's government regulatory and public policy organization, served as the Chief of Staff to both the Chief Executive Officer ("CEO") of Exelon Generation and the CEO of Exelon Utilities, and was the Vice President of

PECO's Support Services organization before transferring into my current role in July 2022.

4. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) generally describe PECO's gas operations; (2) provide an overview of PECO's request for rate relief and the testimony filed in support of that relief; (3) explain PECO's capital investment process and identify, by major plant category, PECO's claimed future test year ("FTY") and fully projected future test year ("FPFTY") plant additions; (4) discuss the Company's actions to ensure the safety and reliability of PECO's gas distribution system; (5) support the Company's claim for manufactured gas plant ("MGP") remediation expense; (6) discuss PECO's customer service operations and additional programs to help our customers save energy; (7) describe measures taken by the Company with respect to safety, security, and its environmental impact; (8) discuss PECO's fulfillment of obligations from the Company's most recent gas base rate proceeding at Docket No. R-2022-3031113 ("2022 Gas Rate Case"); (9) describe PECO's community work and support for economic and workforce development and diversity, equity and inclusion; and (10) address PECO's overall management performance in relation to the factors identified in Section 523 of the Public Utility Code.

II. DESCRIPTION OF GAS OPERATIONS

5. Q. Please provide an overview of PECO's gas 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 natural gas service region is located throughout a 1,900 square-mile area in southeastern Pennsylvania adjacent to, but exclusive of, the City of Philadelphia. The Company's gas service territory comprises all or portions of Bucks, Chester, Delaware, Montgomery, and Lancaster counties and includes a total population served of approximately 2.6 million people.

6. Q. What services does PECO offer its gas customers?

A. PECO makes available both bundled and unbundled natural gas service. Most of our customers have elected a bundled service, whereby PECO procures and delivers gas to their home or place of business. With the advent of transportation service in the 1980s and the passage of the Natural Gas Choice and Competition Act in 1999, customers also have the option to procure their own gas supply and pay PECO for delivery service only. In addition, and as set forth in our gas tariff, qualifying customers can avail themselves of a variety of firm, interruptible and temperature-controlled services.

7. Q. How does PECO's customer base break down by major customer classification?

A. As of December 31, 2023, PECO served approximately 507,197 residential customers; approximately 45,001 small commercial and industrial customers; and 636 large commercial and industrial customers (retail and transportation). Residential customers account for nearly 92% of total metered volume.

8. Q. What are the major assets and facilities that PECO utilizes to provide gas service to its customers?

A. The natural gas PECO delivers to its customers is procured through contracts with third-party suppliers. PECO transports and stores gas for its customers on six interstate pipelines. PECO has direct interconnects on its distribution system with three of these interstate pipelines. To supplement that supply on an as-needed basis during peak-demand periods, PECO operates a liquefied natural gas ("LNG") plant in West Conshohocken and a propane-air peaking plant in Chester.

In the last 10 years, PECO has invested in two new portable vaporizers, three LNG transport trailers, two portable storage tanks, and off-loading facilities built to handle LNG transport trailers that are located at the West Conshohocken gas plant, East Greenville Gate Station, and Parkesburg Gate Station. PECO has also commissioned two new boil off compressors at the West Conshohocken gas plant that increase the reliability and efficiency of the boil off system and were in service as of January 2022. In 2023, PECO completed the construction and commissioning of new vaporization equipment at the LNG plant, replacing assets from the 1970s. This new equipment provides PECO with the ability to vaporize at a higher pressure and has a 100% built-in redundancy.

In addition to its supply and storage facilities, PECO operates approximately 7,300 miles of low, medium, high, and over-high-pressure gas mains, 480,000 gas services and 28 gate stations that feed its distribution system. PECO's purchased gas costs are recovered through a separate Section 1307(f) rate mechanism, which is reviewed and reconciled annually. Those costs are not part of the increase

requested by this filing.

III. OVERVIEW OF RATE FILING

9. Q. Please summarize the relief that PECO is requesting through this rate filing.

A. PECO has requested an overall natural gas rate increase of approximately $111 million per year. The filing also includes a request for approval of a Weather Normalization Adjustment ("WNA") as an alternative rate mechanism in accordance with 66 Pa. C.S. § 1330. The WNA would adjust certain customers' bills to reflect normalized weather conditions. 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 27, 2024, but we recognize that our filing will likely be suspended and investigated.

10. Q. Why is PECO requesting a rate increase at this time?

A. Since rates were established in the Company's last base rate case, PECO has continued to make substantial investments in new and replacement utility plant to ensure that our customers can continue to receive the safe and reliable service they have come to expect. Indeed, between January 1, 2024 and December 31, 2025, the end of the FPFTY, PECO will have invested $786 million in additional gas distribution plant.

Much of this investment is focused on maintaining and improving our distribution system and adding new distribution plant to meet the increasing demand for reliable natural gas service throughout our service territory as well as the necessary investment in PECO's information technology and communication

systems, which all have positive benefits for customers.

As discussed by Company witness Marissa Humphrey in PECO Statement No. 2, a large portion of the increase in our operation and maintenance ("O&M") expenses has been caused by inflationary pressures experienced by PECO since the last rate case. Moreover, the Company's continued focus on the reliability and safety of the system, the increased costs associated with our expanded leak surveys and management of "One Call" requests for location of utility facilities, and the deployment of additional resources in our Customer Care center to help ensure continued high levels of customer service and satisfaction have driven increases in O&M expense.

As Ms. Humphrey, and Company witness Jacqueline F. Golden in PECO Statement No. 10 detail, despite the rate increase we are proposing, customer affordability remains a critical priority for PECO and we are continuing to expand our customer assistance programs to minimize the impact of higher rates. The Company is also proposing a WNA mechanism, which will provide customers with greater predictability in billing, better enabling customers to budget and pay their bills, and mitigate the impact of higher bills during severely cold months. The WNA mechanism is described in further detail in the testimony of Company witness Michael J. Trzaska in PECO Statement No. 3.

11. Q. What has PECO done to control expenses?

A. As in past years, we have continued to carefully manage our expenses. As Ms. Humphrey explains, PECO's projected annual gas O&M growth rate since 2023

is nearly 30% lower than the recent average inflation rate of 6.25% in the Consumer Price Index. While higher than in prior years, customers have benefitted from PECO's efforts to keep the growth well below the inflation rate since our last rate case filing.

PECO also leverages new and existing technologies to drive efficiencies. For example, we use directional drilling equipment and camera equipment to eliminate the need to open trenches and to increase overall productivity, reducing both the number of street openings required and cost of restoration. We also utilize a bolt-on tee removal tool to eliminate the need to replace whole sections of main when a potentially hazardous bolt-on tee is identified, and facility locating equipment such as vacuum excavation to further assist in pinpointing our facilities and reducing the potential for damage while excavating. The techniques and technologies PECO deploys also minimize disruption to local roads and properties and thereby reduce restoration cost and the time required to restore roads to full service.

In addition to these technologies, PECO has implemented a regional work model for all contractors. While our contractor costs have risen since our last rate case, this regional approach creates greater efficiencies by allowing one specific contractor to work all different types of construction work within a geographical region, rather than multiple contractors performing various types of work within that region.

12. Q. Please identify the other 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:

Marissa Humphrey (PECO Statement No. 2) is Senior Vice President, Chief Financial Officer and Treasurer of PECO. Ms. Humphrey discusses PECO's need for rate relief and our efforts to minimize both customer costs and PECO's own costs. Ms. Humphrey also 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. 3) 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, 2025, FTY ending December 31, 2024, and historic test year ("HTY") ended December 31, 2023, respectively. He specifically supports PECO's measures of value, revenue, operating expense and tax claims, and the Company's proposed WNA mechanism.

Caroline Fulginiti (PECO Statement No. 4) is the Vice President and Assistant Controller at Exelon. Ms. Fulginiti 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.

Paul R. Moul (PECO Statement No. 5) is the Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents testimony concerning the rate of return that PECO should be afforded an opportunity to earn on its measures of value. He supports PECO's claimed capital structure ratios, its embedded costs of debt, and its requested equity allowance.

Jiang Ding (PECO Statement No. 6) 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. 7) 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.

Megan A. McDevitt (PECO Statement No. 8) is a Senior Manager, Retail Rates at PECO. Ms. McDevitt discusses proposed changes and clarifications to PECO's gas service tariff.

Doreen L. Masalta (PECO Statement No. 9) is the Director of Energy and Marketing Services at PECO. Ms. Masalta describes the Company's proposed enhancements to its residential and low-income gas energy efficiency programs and our proposed extension of PECO's Neighborhood Gas Pilot Rider.

Jacqueline F. Golden (PECO Statement No. 10) is the Director, Customer & Financial Operations at PECO. Ms. Golden addresses Company proposals regarding Customer Assistance Program ("CAP") cost recovery, other universal service programs, the operation of PECO's Matching Energy Assistance Fund ("MEAF"), gas customer safety program, and its small business grant program.

IV. PECO'S CAPITAL INVESTMENT PROCESS

13. 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 ("LRP") development process. A key goal of that process is to integrate and align capital investments with PECO's strategic operational, 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 that 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 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, and customer service goals as well as achieve an optimal operational efficiency.

14. Q. What are PECO's primary categories of investment for its gas operations?

A. Annual capital investment requirements are evaluated on a functional level and are primarily placed into categories of system performance, capacity improvement, facility relocation, new business, information technology ("IT"), and customer operations.

System performance projects are evaluated based upon factors specific to the appropriate replacement program and then prioritized for replacement in a given year. These projects target aging infrastructure based on field observations and a review of program-specific performance metrics. Projects are ranked within their respective programs based on certain criteria including, but not limited to, age of main, repaired leaks/breaks, main pressures, active leaks, customer complaints, cost to replace versus cost to repair, condition of main, and environmental factors.

Capacity improvement projects prevent system pressure from dropping below design standards and relieve capacity constrained areas that prevent the addition of new customers. Facility relocation projects move gas facilities away from conflicting township and state road improvements, while new business projects support residential and commercial customer requests for new gas service, an upgrade of existing service and the relocation of gas facilities.

In the area of IT infrastructure, many of our capital projects drive operational improvements and efficiencies, reduce risk, increase reliability, and strengthen cyber security. For example, our Enterprise Asset Management replacement will enable improved asset management, work order development, and work management, as well as upgrades to its gas supervisory control and data acquisition ("SCADA") system.

A primary area of our capital investment relating to customer operations covers the design, development, implementation, lifecycle upgrades and replacements, and security of customer facing systems, as well as the development and implementation of web tools, such as outage tools and mobile app technologies, so customers can easily access PECO customer systems and information through multiple channels. These are individual projects that help the Company create and improve the technology PECO customers use to access account and outage information; enroll in assistance programs; make start, stop, and move requests; receive usage data, and receive and pay bills, which I will describe later in my testimony.

We are also investing in Customer Flight Path ("CFP") projects, that improve the availability of customer products and the reliability of the underlying platforms. These projects consist of enhancing digital self-service options and offering personalized solutions that meet customer needs, improve communications during power outages, and help promote and maintain affordability. Associated with these capital projects are O&M costs in order to put these investments into service for customer benefit.

15. Q. How do capital investments in gas system infrastructure relate to PECO's Long-Term Infrastructure Improvement Plan ("LTIIP")?

A. Many of the capital investments in this case are included in the requirements of PECO's LTIIP for 2023-2027, which the Commission approved on December 8, 2022. In that proceeding, the Commission reviewed and approved PECO's plans to spend an additional $1.002 billion above the Company's expected baseline and facility relocation expenditures to continue PECO's accelerated replacement programs for the retirement of aging mains, services, and district regulator stations.

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 FTY and FPFTY plant additions are itemized by functional area and by FERC account in PECO Statement No. 3, the direct testimony of Mr. Trzaska, Exhibit MJT-2, Schedule C-2, and MJT-1, Schedule C-2, for the FTY and FPFTY, respectively.

In summary, PECO's capital budget calls for overall gas distribution plant additions of approximately $345 million during the 12 months ending December 31, 2024 and $429 million during the 12 months ending December 31, 2025. These investments will target reliability projects and other infrastructure improvements.

V. SYSTEM SAFETY AND RELIABILITY

17. Q. How does PECO ensure the safety and reliability of its gas distribution system?

A. PECO manages its natural gas distribution system in a safe and responsible manner to ensure pipeline reliability while meeting or exceeding all requirements of the federal pipeline safety regulations (49 C.F.R. Part 192) and the applicable provisions of the Pennsylvania Code (Title 52, Chapter 59).

The Company's Distribution Integrity Management Program ("DIMP") provides a rigorous framework for analyzing, ranking and mitigating threats to PECO's entire distribution system. Data obtained via preventative and corrective maintenance tasks are incorporated into the DIMP, allowing PECO to assess which asset categories are in need of threat mitigation. PECO analyzes data throughout the year for emerging threats and incorporates the analysis results and corresponding increased mitigative actions.

PECO's preventative maintenance programs are designed to identify when an asset is not operating as intended and either needs corrective maintenance or replacement. Although many of these tasks are required by federal regulations (49 C.F.R. Part 192), PECO exceeds these federal requirements to better identify emerging issues, minimize impacts to customers, and provide sufficient lead time to address an emerging issue before it becomes detrimental to safety.

For example, PECO's mobile leak survey intervals for outmoded mains and services, plastic and coated steel services, and transmission and OHP lines, all

exceed the federally required intervals for each of those categories.

Preventative maintenance helps ensure that PECO's gas system continues to operate safely and reliably. When emergent situations are uncovered, PECO is able to provide a rapid response to address the situation. If a permanent solution is not immediately available, corrective maintenance tasks make the situation safe and allow for the proper time to plan and implement a permanent solution.

PECO's safety and reliability programs are consistent with many of the elements of the Pipeline Safety Management System ("PSMS") we are implementing per the recommendation of the American Gas Association and the American Petroleum Institute ("API") Recommended Practice 1173. PECO's PSMS includes ten essential elements directly tied to safe operating principles: (1) Leadership and Management Commitment; (2) Stakeholder Engagement; (3) Risk Management; (4) Operational Controls; (5) Incident Investigation and Lessons Learned; (6) Safety Assurance; (7) Management Review and Continuous Improvement; (8) Emergency Preparedness and Response; (9) Competence, Awareness, and Training; and (10) Documentation and Record Keeping.

Many of these elements were already in place prior to our adoption of PSMS, but we continue to enhance and add new programs in accordance with the PSMS principles. For example, PECO implemented a best practice Management of Control system to better identify and track changes to standards, practices, and procedures, as well as ensure that the required stakeholders are fully engaged in the process from beginning to implementation. Additionally, PECO is enhancing

its Public Safety Awareness program consistent with recommendations under PSMS's Stakeholder Engagement element and recommendations from API. In order to enhance existing practices under the Emergency Preparedness and Response element, the Company instituted comprehensive table drill exercises with its operations leadership four times a year, and implemented experiential learning exercises in regional operations' safety meetings.

18. Q. Can you describe the various programs associated with PECO's long-term threat management?

A. PECO has long-term threat mitigation programs associated with gas services and gas mains. PECO has approximately 480,000 total gas services on its system and, as of the end of 2023, all known bare steel services[1] were replaced with plastic or coated steel.

Out of PECO's 7,300 miles of gas main on its system as of the end of 2023, 177 are composed of bare steel and 473 are composed of cast, ductile, or wrought iron. Of those mains composed of bare steel, PECO has committed to replacing all mains that are 8" in diameter or less by the end of 2030 while replacing all bare steel mains greater than 8" in diameter and all cast, ductile and wrought iron mains by the end of 2035. PECO's baseline main replacement programs account for approximately 12 miles of main replacement each year. These programs are driven by field observations obtained during routine preventative maintenance as

[1] All known bare steel services that were identified in 2007 have been replaced and the Company is working to replace any newly identified bare steel services.

well as from feedback from corrective maintenance of specific assets.

PECO's accelerated main replacement programs are geared toward assets with a history of field indications suggesting that asset replacement will soon be necessary but where an individual asset has not been identified as needing replacement under PECO's regular maintenance programs. The accelerated main replacement programs are prioritized by a number of factors, including field observations, asset class DIMP scoring, customer satisfaction, third party construction, municipal coordination, and proposed paving/paving moratorium. PECO's annual plans include replacing approximately 45 miles of main under accelerated programs that, when combined with PECO's baseline programs, total approximately 60 miles of main replacement annually.

19. Q. What recent enhancements has PECO implemented to improve the safety and reliability of its gas distribution operations?

A. PECO has implemented a number of important initiatives and technological improvements focused on safety and reliability.

Post Construction Quality Audits for all Contractors. Since 2018, the Company has conducted post construction quality audits and random dig ups of all line of work for all PECO contractors. The post construction quality audits are overseen by PECO personnel for new work completed in the previous 30 days. Any identified defects are repaired immediately by the contractor and at the contractor's expense. In 2022, we conducted 6,904 inspections and increased our inspections to 7,342 in 2023.

Dispatch and Field Reporting. PECO Gas utilizes LocusView software to capture high accuracy GPS locations of assets and other key data attributes through digitized forms. In 2022, we upgraded the LocusView platform to Generation 3, the newest version available. This helped streamline operational workflows, improved data quality, enhanced security, and position PECO for digital as-builting in the future. In 2024, PECO will be deploying improvements to the field user experience when completing the digitized Pipe Inspection Leak Repair Report ("PILRR") form to increase efficiency and accuracy of data being collected. In addition, PECO's OneMDS will streamline the Company's operational workflow dispatch, field reporting capabilities via a mobile experience accessible on secure mobile device, improve data records through electronic data capture, and provide an interactive mapping tool with the functionality to create work orders, leading to an overall reduction in O&M expenses.

PON System: The Gas Planned Outage Notification ("PON") is a system used to notify customers of a planned outage. The benefits to using the Gas 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.

Marker Ball Utilization. PECO utilizes marker balls, which are buried alongside underground facilities, to provide an accurate, convenient and long-lasting means to identify specific locations on PECO's gas distribution system, including valves, dead ends, leaks, or places where pipe changes directions. In

2023, PECO installed approximately 171,000 marker balls on its system for use in assisting with locating of various facilities.

Prevention of Cross-Boring. As part of projects that utilize trenchless technologies, PECO has implemented improved measures to avoid occurrences of incidental cross-boring with another existing utility. The Company locates and exposes all utility facilities within the boring pathway, including laterals, prior to initiating boring activity. PECO also performs a camera inspection of relevant sewer laterals before and after boring activity, as appropriate.

Public Awareness. As discussed in Ms. Golden's direct testimony, in 2023, PECO started its Gas Customer Safety Program, in which all new residential gas customers who move into an existing home and sign up for gas service along an existing gas main (referred to as "gas along the main service") receive a PECO "Safety Package" that includes printed educational materials and a gas safety device. The educational materials include, at a minimum: (1) mercaptan "scratch n sniff" information so that customers understand how to recognize natural gas odor leaks; and (2) pamphlets or brochures illustrating where gas detectors should be placed in the home and explaining the importance of installing and maintaining smoke detectors in the home. Additionally, all residential customers who receive a gas odor response visit (i.e., a home visit in response to a gas odor complaint) are provided with the educational material component of the Safety Package.

PECO expanded its outreach to emergency officials in 2023 by offering annual gas plant familiarization tours to police, fire, and emergency management

organizations with jurisdiction in areas around its gas plants. PECO also created a new reference guide for local public officials that covers its gas safety, reliability, and emergency response measures, and distributed the guide to municipal and state officials in April and May 2023. We will further enhance our outreach to local public officials and emergency management officials as well as residents and places of congregation along the transmission right-of-way. PECO also created a new informational brochure on reporting odors, recognizing potential hazards, and calling 811, and will be partnering with municipalities in its gas service territory to make these brochures available to the public at licensing and inspection offices in 2024.

Ongoing Reliability Project. As part of the ongoing natural gas reliability project in Delaware and Montgomery counties to meet the growing needs and demands of our customers, PECO installed 11.5 miles of over high-pressure gas main and upgraded PECO's natural gas plant infrastructure in West Conshohocken. This project was delayed due to an appeal of a Commission ruling permitting PECO to utilize its proposed project location for the construction of a reliability station in Marple Township in Delaware County. The Commonwealth Court remanded the matter to the Commission for an environmental review of the placement of two buildings associated with the Marple reliability station, and hearings were held in December 2023. The Company is awaiting the initial decision of the administrative law judge presiding over the remand proceedings.

Regional Energy Access ("REA") Additional Capacity Gate Station Modification. The Transco REA Project is now scheduled to be placed fully into service in December 2024. Once complete, the REA project will provide PECO with increased firm capacity from the Leidy Pennsylvania Marcellus Shale production area to PECO's City gate. Transco was able to bring the REA project online earlier than expected, giving PECO 32,922 Dth/day of capacity in October 2023. The additional 67,078 Dth/day will come online in the fourth quarter of 2024. The capacity will provide PECO with a least-cost, reliable, source of supply enabling the Company to meet its firm demand by reducing the delivered supply needed to eliminate the peak-day supply gap, while providing deliveries to PECO gate stations and further eliminating exposure to market area price volatility.

Southeast Reliability Project. Starting in 2024, PECO will begin a reliability project in Southeastern Bucks County to resolve immediate pressure concerns. This section of PECO's high-pressure distribution system is projected to drop below defined system minimum pressures on a design day, which is the coldest day that PECO's service territory could reasonably be expected to experience. This project would alleviate the constraint and mitigate the reliability risk through the installation of 1.56 miles of new large diameter gas main feeding the southeastern part of Bucks County.

Sonix IQ Ultrasonic Residential Gas Meter. In 2024, PECO will be piloting the Sonix IQ Ultrasonic Residential Gas Meter. This meter potentially offers several advantages and benefits over traditional mechanical gas meters, including

built-in pressure sensing and remote shut-off functionality to enable remote monitoring, as well as the ability to automatically or remotely shut off gas flow. The meter may also allow PECO to integrate continuous meter health checks and provide alerts and alarms to improve customer service. With a compact footprint as well as an internal battery designed for a 20-year service life, this meter has significant potential benefits for our customers that we expect to deliver in the future.

20. Q. In your opinion, has PECO been successful in ensuring system safety and reliability?

A. Yes. Between preventative maintenance activities, the accelerated investment in the replacement of potentially hazardous capital assets and the utilization of the enhancements mentioned above, PECO continues to improve on its performance in both safety and reliability. In addition to the bare steel services replacement I have already discussed, several key additional metrics demonstrate the extent of our success.

Incoming Leak Reduction. PECO has also been replacing outmoded (i.e., cast iron and unprotected bare steel) mains on an accelerated basis in coordination with the Company's LTIIP and has seen a 40% reduction in incoming 1, 2A, and 2B leaks since 2019.

Gas Odor Call Reduction. As a result of PECO's mains and services replacement programs, gas odor calls have decreased in the last 15 years from approximately 33,000 to under 19,000 gas odor calls annually, with an additional

2,000 less since the last rate case. PECO's odor response rate has remained in the top decile for the last 16 years among similar gas utilities per industry benchmarking.

Gas Damage Rate. Within the last five years, 2019 through 2023, PECO has experienced a general decline in damage occurrences with respect to the number of One Call locate tickets received, each of which is a potential damage case. Gas underground damages per 1,000 requests decreased from a rate of 2.15 in 2019 to 1.57 in 2023. Similarly, the third-party damage rate decreased from 1.82 in 2019 to 1.33 in 2023 and gas damages due to print error (i.e., mapping error) have dropped from 0.83 in 2019 to 0.44 in 2023. All of these positive trends are attributed to PECO's increased focus on its damage prevention program and on PECO's Gas Mapping Program initiative.

VI. MANUFACTURED GAS PLANT REMEDIATION PROGRAM

21. Q. Please discuss the Company's program to remediate former manufactured gas plant sites and its FTY and FPFTY claims for the cost of that program.

A. PECO has undertaken positive efforts to eliminate potential environmental concerns at its former MGP sites. Historically, these sites were used to manufacture gas from coal for distribution to customers for heating, cooking, and lighting purposes. Following the construction of the interstate natural gas pipeline system, MGP became obsolete and were no longer necessary. Currently, PECO has 26 former MGP sites geographically dispersed around its service territory. To date, 20 of the 26 sites have been actively remediated to standards established by

the Pennsylvania Department of Environmental Protection's ("PADEP") Land Recycling Program (Act 2). Four of the six remaining sites are currently enrolled in the Act 2 Program and are undergoing active remediation. Once remediated, the sites will no longer pose a threat to human health or the environment and could be used for various beneficial land-use purposes that otherwise would not be permitted.

Since 2011, we have spent, on average, $4.6 million per year for MGP remediation. The Company expects to spend approximately $24.3 million over the next 10 years (2024-2033) and a total of $24.7 million through 2042 on MGP remediation. Of the $24.7 million, $24.3 million has been reserved for the remaining six sites, with three sites (Bristol, Langhorne, and Coatesville) accounting for approximately $20.5 million in projected remediation costs. Post-2033, PECO estimates that approximately $400,000 in Operations and Maintenance costs will be required to maintain environmental covenant requirements through 2042 on the closed MGP sites.

VII. CUSTOMER SERVICE AND PROGRAMS

22. Q. What efforts have been made by the Company in recent years to enhance the quality of its customer service?

A. The Company has undertaken several initiatives to improve its customer service. For example, PECO made many customer orientated enhancements to its mobile application and its website, www.peco.com, to make it easier for customers to sign up or move service, pay their bill with slide-to-pay by credit card or e-check,

monitor usage, and enroll in electronic billing, automatic payments, or budget billing. As of the end of 2023, PECO now has 373,000 gas customers enrolled in "MyAccounts" which is a 10% increase from 335,000 in 2022 and directly reduces our customer operations costs.

PECO upgraded the overall look and feel of its website and, consistent with applicable Web Content Accessibility Guidelines, updated its website's content to be accessible to people with disabilities. Customers now also have the option to view webpages in English, Spanish or Simplified Chinese. This feature provides multi-lingual customers the ability to quickly locate information about PECO's products and offerings.

We also added a variety of other features and capabilities, including a two-step customer verification process to improve customer account security and a "Welcome Back" feature for returning customers to access their program recommendations without re-entering information. We also added an "Assistance Finder" feature to aid customers with determining their eligibility to participate in energy assistance, financial, or energy efficiency programs. In the seven months since the launch of Assistance Finder in May 2023, nearly 1,000 customers have enrolled online in payment arrangements, budget billing, and due date extensions.

To enhance the quality of service and improve customer experiences, PECO shifted its focus to an approach we call "First Contact Resolution" ("FCR") so customers receive all the assistance they need on their first contact with the Company. Other initiatives include integrating the management of our

outsourced call center into PECO's Customer Care Center (PECO's internal call center) to provide better alignment of quality guidelines, accountability, and leadership support. The Company also deployed a "Universal Agent" strategy whereby PECO customer service representatives ("CSRs") are trained to handle virtually all types of calls instead of targeted skill handling. This strategy enables CSRs to provide a more comprehensive call experience to customers and address each of the issues that led the customer to call PECO.

23. Q. How does the Company plan to continue improvement in customer satisfaction?

A. PECO recognizes its responsibilities to customers and seeks to invest in maintaining and improving how the Company provides premier customer service and how it interfaces with customers. Customer Operations has focused on improving the customer service component of this score through continuous improvement training of PECO's Customer Service Representatives, as well as incorporating more customer requested needs into the Company's interactive voice response system, web portal, My Account, and mobile apps.

24. Q. What direct customer benefits will PECO's additional investments in customer operations provide?

A. The CFP projects are designed to enhance the customer's online experience in areas such as billing and payments, managed account services, and start, stop, and move. Addressing critical customer information systems and expanding digital products and services can help meet customer expectations for reliable and personalized experiences.

25. Q. Please describe PECO's energy efficiency customer programs.

A. As Ms. Masalta explains in PECO Statement No. 9, PECO currently offers its residential customers a mix of rebates to encourage them to upgrade to high-efficiency furnaces, boilers and water heaters, and direct install measures, and to receive discounts on smart thermostats purchased through PECO's online marketplace. In addition, PECO's Safe and Efficient Heating Program ("SEHP") provides qualifying low-income customers no-cost direct installation measures through the Low-Income Usage Reduction Program ("LIURP") and as part of free home energy assessments to improve the efficiency and safety of natural gas heating in their homes. SEHP also provides program recipients with education on maintenance and energy efficiency tips at no cost. We have seen consistent growth in customer participation and energy savings since 2018.

VIII. SAFETY, SECURITY AND ENVIRONMENTAL PROGRAMS

26. Q. What is PECO's record with respect to the safety of its employees?

A. In the last two years, PECO has made many enhancements to the way it categorizes and addresses employee injuries to be more effective at developing programs that will eliminate serious injuries and fatalities ("SIF"). PECO, along with the other Exelon utilities, adopted a best in class hazard recognition tool known as the Energy Hazard Wheel, and also adopted the EEI Safety Classification ("SCL") model that places emphasis on high energy hazards in our industry that have the potential to result in SIFs. In 2023, PECO Gas had its best employee safety record since 2018. PECO Gas ended the year with four OSHA recordable incidents, all of which were classified as low severity under the SCL

model and three of which were identified as "no fault" of the employee.

27. Q. Does the Company have a program to address cybersecurity and physical security risks?

A. Yes. In addition to the Company's IT investments, PECO has programs to address cybersecurity risks and, along with its Exelon sister utilities, implemented an Operational Technologies ("OT") Security Governance Program ("OTSGP") to enhance existing cybersecurity measures. In accordance with this program, we properly identify and categorize OT assets and have developed an associated inventory of OT assets currently on our systems. OTSGP has also developed procedures to identify the specific cyber threat vulnerability to our asset inventory and the associated data connections, as well as remediation and mitigation strategies to protect PECO's interconnected system. Procedures have also been developed to manage access administration, data at rest and in transit between devices, and the sanitation and decommissioning of OT assets at their end of life. Safeguards have been put into effect for firewall utilization and malicious code detection. As part of this OTSGP, PECO will be implementing a transient cyber asset in 2024 – a disconnected system that scans and validates that new data intended to integrate with internal systems is free of malicious code, allowing PECO's OT assets to remain in a completely disconnected environment.

Our gas operations are also subject to the cybersecurity directives issued by the Department of Homeland Security's Transportation Security Administration ("TSA"). New security control programs have been developed to ensure compliance with TSA's requirements, and our efforts have been successful. In

2023, PECO's implementation of TSA's new requirements was inspected by TSA and found to be in compliance, with four "smart security practices" cited for specific recognition.

The ever-evolving threat landscape is of concern to our entire industry. In response, PECO has also 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. For gas, this includes critical system valves, gate stations, the LNG and propane plants, and the control rooms. 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 a defense in depth strategy. Both programs use a risk-based approach and tiering methodologies that analyze the criticality of each type of asset (Electric, Gas, and O& SF) in order to prioritize investment. PECO tiers our assets based on factors such as, but not limited to, system impact, customer count, critical customers served, feeder number, etc. While the tier dictates the protections implemented at each site, the protections are designed for the threats within the service territory that PECO operates.

28. Q. Ms. Hamilton, 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 ("EMS") based on standards set forth in International Organization for Standardization ("ISO") 14001, which supports the development of performance-improvement goals and targets. With respect to land quality, PECO has obtained Conservation Certification from the Wildlife Habitat Council and/or the National Wildlife Federation for eighteen sites (155 acres).

PECO is also focused on being a low-carbon company. 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. PECO is looking to exceed this goal with our 2030 Path to Clean initiative that aims to reduce Exelon's operational emissions by 50% from 2015 levels by 2030.

The Company's investments in 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 gas distribution utility replaces an outmoded main, residual gas is released into the atmosphere. Through ZEVAC, PECO teams are able to 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), that was built on an existing building at its headquarters in Philadelphia, which was recently 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 97% (2023), and the Company recently launched an innovative pilot-study using cameras in bulk waste containers to optimize waste pickup and disposal.

29. Q. Please describe the Company's efforts to support the use of alternative fuel vehicles and related technologies.

A. PECO operates its own fleet of 1,452 hybrid, electric, flex fuel, and biodiesel vehicles including 56 plug-in hybrid trucks, nine battery electric vehicles, and 108 Job Energy Management system worksite electrification plug-in aerial trucks. These vehicle numbers will continue to grow in furtherance of PECO's goal to electrify 50% of its fleet by 2030. Between 2020-2023, the Company's electrified fleet has saved approximately 91,603 gallons of fuel. The Company also encourages sustainable practices with employees by providing over 100 EV charging stations, rebate programs, and bike racks at most Company locations.

IX. FULFILLMENT OF 2022 GAS RATE CASE COMMITMENTS

30. Q. In the Joint Petition for Settlement of Rate Investigation ("Settlement Agreement") that the Commission approved in the 2022 Gas Rate Case, the Company made a number of commitments. Has PECO fulfilled or taken steps to satisfy those commitments?

A. Yes, it has.

31. Q. In the Settlement Agreement, the Company 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 ("TUS"), the Commission's Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA") with an update on its Gas Division's actual capital expenditures, plant additions, and plant retirements by month for the twelve months ending December 31, 2022. Second, the Company agreed to provide a similar update on or before April 1, 2024 to include actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2023. 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, 2023 to its projections in the 2022 gas base rate proceeding. PECO met each of these reporting requirements. PECO witness Ms. Humphrey describes the Company's 2023 actual expenditures further in her testimony.

32. Q. The Company also agreed to (a) accelerate its gas mapping program and (b) continue its comprehensive analysis of the Company's DIMP threat rankings, create additional threat categories, and hold a collaborative to update I&E Safety on new threat categories. Has PECO satisfied these commitments?

Yes. We accelerated our gas mapping program plan and 31,030 services have

now been field-located out of approximately 145,000 services initially identified. In addition, 3,252 mains have been located out of 9,500 identified. In 2022 and 2023, the team met or exceeded the annual number of locates versus our targeted number. The accuracy of our service sketches, which are audited by a third party, have increased from 64% to 80% due to improved dimensioning and land base alignment.

In accordance with our commitment, we continued our comprehensive analysis of our DIMP threat rankings. In order to provide more granularity regarding risk rankings of various types and sizes of pipelines in the PECO gas distribution system, our pipe diameters are now categorized by small (8" & smaller) and large (greater than 8"). The resulting risk rankings were analyzed and shared in a collaborative meeting with Commission staff on February 23, 2023, along with our current DIMP model risk categories. At the same meeting, we reviewed our Primary Threat Table with Commission staff, which contained a chart of the highest risk categories per 100 miles of pipe, as well as an analysis of various pipeline risk data utilizing Power BI and the risk model outputs.

As planned, we replaced 45,000 known bare steel services by the end of 2023 and our on-going outmoded pipe replacement programs will remove all wrought iron, cast iron and ductile iron pipe from the system by 2035.

33. Q. Please summarize PECO's compliance with other commitments in the Settlement Agreement directly affecting rates, customer programs, and assistance to low-income customers.

A. ***General Service ("Rate GC") Rate Design (Paragraph No. 21)***. In this filing, PECO is proposing to eliminate declining block distribution charge differentials and to establish differentiated customer charges for Rate GC, as discussed by Mr. Bisti in PECO Statement No. 7.

Gas Transportation Customers (Paragraph No. 22). PECO has prepared a cost analysis of the relative cost to serve gas transportation customers in the TS-F and TS-I rate classes with annual usage above and below 18,000 Mcf, which is described by Mr. Bisti.

Cost-of-Service Study (Paragraph No. 23). In addition to the cost-of-service study presented by Ms. Ding in PECO Statement No. 6, PECO has provided a good faith calculation of the costs to serve negotiated gas service customers whose rates are set by contract.

Gas Energy Efficiency and Conservation ("EE&C") Program (Paragraph No. 31). The Company performed a cost-effectiveness analysis of its residential and small commercial natural gas EE&C measures. Ms. Masalta describes the key findings and recommendations that PECO is considering for future measure implementations.

Universal Service Programs (Paragraph Nos. 33 through 43). With respect to PECO's LIURP, PECO has accomplished all settlement commitments, including

increasing the annual budget, implementing a three-year pilot to support health and safety remediation for LIURP-eligible customers who are deferred due to health and safety issues within the home, and establishing a multifamily working group. PECO's low-income programs brochure, which describes CAP and LIURP in both English and Spanish, is being provided at outreach events and upon request to customers, community partners, and other interested parties. The brochure is also provided to all new residential gas customers as part of the customer welcome packet.

With respect to PECO's MEAF, the Company has permitted customers to remain eligible for MEAF assistance even if they use a medical certificate or enter into a payment arrangement after receiving MEAF assistance. The Company has also fulfilled its commitments regarding our annual shareholder contribution and allocating funds to MEAF agencies for which the Company has not received a customer match. In addition, PECO has initiated collaborative meetings to discuss possible avenues for reducing CAP defaults due to failure to recertify and solicited feedback from its Universal Service Advisory Committee on the Company's low-income programs brochure.

X. ECONOMIC DEVELOPMENT, COMMUNITY SUPPORT, AND DIVERSITY

34. 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.

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 a Gas Mechanics School ("School") to develop a hiring pool for gas operations personnel and in 2022, the Company held two Schools and hired all 39 graduating individuals. In 2023, the Company held another School in May, and hired all 22 graduates. Interest in gas mechanic positions is high, with the Company receiving at least 500 applications for each School. The Company intends to host another School in October 2024 and to hire 20 additional individuals.

In early 2020, PECO created a team dedicated to workforce development to attract talented candidates and support our region by providing opportunities to individuals from underserved communities. Since 2020, PECO in partnership with community partners has supported the placement of nearly 200 individuals in jobs throughout the region. The Company also implemented a variety of other workforce development programs to train individuals for opportunities at PECO, including annual Infrastructure Academies where attendees are introduced to various departments within the Company.

35. Q. Please discuss PECO's commitment to diversity, equity, and inclusion.

A. PECO has a strong commitment to diversity, equity, and inclusion both among its workforce and in the communities it serves. PECO supports diverse suppliers who represent the diverse customer communities we serve, and we contract with minority-owned, women-owned and other diverse businesses, contractors, and vendors in our communities and maintain business relationships with local banks. In 2023, PECO expenditures with diversity-certified suppliers totaled $597 million, an increase of approximately $48 million over the previous year. PECO's supply personnel are also active members of numerous supplier diversity-focused organizations locally and nationally.

In 2017, Exelon became the first utility/energy services company to join the exclusive group of U.S.-based corporations that have achieved $1 billion or more in annual, direct spending with minority and women owned businesses. Exelon's annual spending with diversity certified suppliers totals more than three billion. Other Billion Dollar Roundtable member companies include Comcast, IBM, Walmart and Microsoft.

Exelon has also been named to the 2022 Forbes list of "America's Best Large Employers;" Fortune Magazine's "World's Most Admired Companies;" U.S. Veterans Magazine's "Best of the Best;" U.S. Black Engineer & Information Technology magazine as a "Top Supporter of Historically Black Colleges and Universities;" The Philadelphia Inquirer's "2023 Top Workplaces;" and received the highest honor by the Center for Energy Workforce Development for excellence in establishing diversity, equity and inclusion in workforce

development to attract and retain a skilled diverse workforce.

36. Q. Are there other ways in which PECO and its employees support their communities?

A. Yes. PECO also has a strong and continuing tradition of community involvement. The Company's corporate citizenship efforts are designed to improve the quality of life for the people who live and work in PECO's service territory and include sponsorships, employee volunteer activities, and executive and employee involvement on outside nonprofit boards. 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. PECO employees have also volunteered nearly 60,000 hours with a wide variety of community organizations. Additionally, 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.

XI. MANAGEMENT PERFORMANCE

37. Q. Ms. Hamilton, based on the factors you discussed above, how do you characterize PECO's record with regard to the performance factor considerations of efficiency, effectiveness and adequacy of service identified in Section 523 of the Public Utility Code?

A. My assessment is based on PECO's demonstrated excellence with regard to the quality and reliability of its service, its continuing substantial investment and careful management of expenses, its commitment to energy efficiency, its use of cost-effective new technologies, its vigilance in protecting the safety of its workers, and its strong promotion of community and economic development, all of which I have discussed above. It is also based on PECO's significant and successful efforts to manage and control its operating expenses since its last base rate case in 2022, as discussed by Ms. Humphrey in PECO Statement No. 2. Based on all of those factors, PECO has exhibited, and continues to exhibit, superior management performance, which fully supports Mr. Moul's recommendation that PECO receive a return on equity enhancement.

XII. CONCLUSION

38. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: AMY E. HAMILTON

SUBJECT: DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM; LEAKS AND EXCAVATION DAMAGE; SYSTEM SAFETY AND WORKFORCE; OPERATING EXPENSE ADJUSTMENTS; MANAGEMENT PERFORMANCE

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
AMY E. HAMILTON

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Amy E. Hamilton. I am employed by PECO Energy Company ("PECO" or the "Company") as the Vice President, Gas Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 1. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following areas:

PECO's Distribution Integrity Management Program, Leak Management, and Facility Excavation Damage. I will respond to the direct testimony of Martin Salamonski on behalf of the Pennsylvania Public Utility Commission ("Commission") Bureau of Investigation and Enforcement ("I&E") concerning (i) PECO's compliance with system integrity management requirements set forth in the Commission's final order in PECO's 2020 gas base rate case proceeding (Docket No. R-2020-3018929) and the Settlement Agreement in PECO's 2022 gas base rate case proceeding (Docket No. R-2022-3031113); (ii) the effectiveness of the Company's mapping program and continued analysis of its

Distribution Integrity Management Program ("DIMP") plan; and (iii) the Company's progress with respect to leak management and reducing facility excavation damage on its gas distribution system.

System Safety and Workforce Planning. I will respond to the direct testimony of James Glenn on behalf of the Local Union 614 of the International Brotherhood of Electrical Workers ("IBEW") regarding PECO's actions to ensure system safety for both customers and employees alike and his proposed "workforce planning report."

Operating Expense Adjustments. I will respond to the direct testimony of Mr. Defever on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") and the direct testimony of Mr. Keller on behalf of I&E regarding justification for recovery of operating expense related to Employee Recognition and Service Awards, Employee Volunteer Activities, Employee Activity Costs, Employee Cafeteria, and Industry and Non-Industry Dues.

Management Performance. I will respond to the direct testimony of Anthony Spadaccio on behalf of I&E, Roger D. Colton, David J. Garrett, and Nicholas A. DeMarco on behalf of the OCA, and Lisa V. Perry on behalf of Walmart Inc. regarding justification for PECO's proposed fifteen (15) basis point management performance adder to the Company's proposed return on equity.

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes, I have prepared PECO Exhibit AEH-1, PECO Exhibit AEH-2, PECO Exhibit AEH-3, PECO Exhibit AEH-4 and PECO Exhibit AEH-5, each of which I describe later in my testimony.

II. PECO'S DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

[redacted] [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[

[redacted] [END CONFIDENTIAL]

[redacted] **Mr. Salamonski testifies that PECO met requirements of the 2022 Settlement Agreement by (i) including threat categories based on size and (ii) holding a collaborative meeting with I&E safety staff on February 23, 2023. [BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

7. Q. How do you respond to Mr. Salamonski's claim that PECO's new pipeline diameter categories do not add more granularity regarding risk ranking?

A. I disagree. Our ability to analyze which diameters of main are more susceptible to certain threats adds granularity that allows for more targeted risk mitigation. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] [**END CONFIDENTIAL**]

8. Q. Do you agree with Mr. Salamonski that PECO's current threat categories lack granularity sufficient to allow PECO to make an informed decision about pipeline replacement?

A. No. As I explained in detail in my direct testimony at pages 14-23, pipeline replacement is an accelerated action for asset classes with a higher risk for time-dependent threats. [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]

9. Q. How do you respond to Mr. Salamonski's contention that it is "very important to consider size, age, pressure of a facility, cathodic protection status, or coating type in order to mitigate risks through pipeline

replacement."

A. I agree. As I described above, [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]

[redacted] **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

11. Q. How do you respond to Mr. Salamonski's recommendation that PECO include appurtenance failure in its DIMP risk ranking?

A. I do not believe that it is necessary to add a separate failure category for each type of appurtenance within the DIMP risk model because [**BEGIN CONFIDENTIAL**] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [END CONFIDENTIAL]

III. LEAKS AND EXCAVATION DAMAGE

12. Q. [BEGIN CONFIDENTIAL] [redacted]

A. [redacted]

[END CONFIDENTIAL]

13. Q. Mr. Salamonski goes on to state that "asset classes should be further filtered to include pressure, diameter, coating and year of installation, and a new, more granular top 10 threats would be generated." How do you respond?

A. I agree. In fact, the Company's DIMP risk model and program is capable of that level of granularity and that filtering is done today when reviewing results of the DIMP risk model.

14. Q. Please explain your understanding of Mr. Salamonski's concern with leaks and excavation damage on PECO's gas distribution system.

A. [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]

[redacted] [**BEGIN CONFIDENTIAL**] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [**END CONFIDENTIAL**]

17. Q. Mr. Salamonski recommends, among other things, that PECO implement a data review process to eliminate data errors regarding service line leak repair reports. How do you respond?

A. PECO has several checks in place to ensure the quality and reliability of our distribution system's data. Specifically, when performing any excavation that exposes a gas service that remains in service, PECO completes a Pipe Inspection/ Leak Repair Report in accordance with GO-PE-111-4001, the procedure which governs how PECO documents leak repairs. Any changes to service records are documented in accordance with GO-PE-301-1001 – Gas Facilities Record (GFR), the procedure which governs how PECO documents information related to service assets.

Further, Mr. Salamonski's assertion on page 20 of his direct testimony that there were "332 leaks reported to be repaired on cast iron, ductile iron, and wrought iron services" is incorrect. The service leak data submitted in PECO's response to discovery question IE-GS-49 corrects the previously inaccurate data that was provided in PECO's response to discovery question IE-GS-3 which appears to be the basis of Mr. Salamonski's assertion. The corrected data demonstrates that no

service leaks between 2019 and 2023 were repaired on cast iron, ductile iron, or wrought iron services. I submit PECO Exhibit AEH-2, which is the response to IE-GS-49.

18. Q. [BEGIN CONFIDENTIAL] [redacted]

A. [redacted]

[**END CONFIDENTIAL**]

19. Q. On page 26 of his testimony, Mr. Salamonski notes PECO's efforts to increase excavation damage awareness by updating its existing public awareness brochure but suggests the updated version is not different from the previous version. How do you respond?

A. While some of the information included in the new public awareness brochure is the same because that information has not changed, the new public awareness brochure has been improved because it provides more information on how the 811 process works and the steps to take for safe excavation. In addition, PECO recently updated its "Call 811 Before You Dig" webpage (https://www.peco.com/safety-community/safety/call-before-you-dig) to provide

more detailed information on how to understand the location marks for each type of buried utility by providing a chart showing "Color" and "Utility Type." The updated webpage also includes a link to Pennsylvania Act (50) 2021, which is the law requiring notification by excavators who are planning to disturb the ground in Pennsylvania.

Perhaps more importantly, in addition to the updated brochure and webpage, we also distribute excavation damage reminders to the most "frequent offenders." The list of frequent offenders is updated twice each year and these companies receive multiple emails with brochure reminders from our marketing department throughout the year. Finally, I note that April is "national safe digging month" and this April the Company sent new flyers to approximately 9,800 licensed contractors in PECO's service territory the first week of April 2024. These same flyers and reminders are scheduled to be sent again to the same list of contractors in recognition of "811 day" (i.e., on August 11, 2024). I have attached the new flyers here as PECO Exhibit AEH-4.

20. Q. Mr. Salamonski notes improvement to the gas mapping program appear to be "working well" but recommends continued efforts to increase overall captured GPS locations with Locusview to continue to decrease facility damages cause by inaccurate maps and records?

A. PECO agrees with the assertion that the gas mapping program has been successful. PECO has a commitment to continued use of Locusview, which is being utilized by PECO crews and contractors and, as the mapping program continues, more assets will be captured with high accuracy GPS locations.

21. Q. How do you respond to Mr. Salamonski's claim that the post construction quality audit reporting produces "mixed result" and his recommendations on tracking audits containing failed observations and hiring additional Senior Contractor Coordinators?

A. Post-construction quality audits, whether satisfactory or failed observations, are submitted using the Locusview tool and can be retrieved and tracked in a variety of ways. For example, PECO can run a report to see how many job sites were audited and how many of those observations noted failures. Thus, despite Mr. Salamonski's claims to the contrary, PECO can track whether the number of job sites not meeting standards is increasing or decreasing.

Additionally, the Company utilizes a data dashboard in Locusview to analyze the post construction audit observations by different categories such as classification of failure and responsible contractor. For example, the dashboard allows us to categorize deficient observations to see if there is either a trend for failure type (e.g., not wearing PPE, improper shoring, inadequate backfill compaction, etc.) or a trend for increasing deficiencies in a particular month. Tracking this data allows PECO to have targeted performance conversations with each of the Gas contractors based upon any trends identified around deficiency type or seasonality.

The Company regularly evaluates the ratio of Senior Contract Coordinators ("SCCs") to contractor crews by considering the complexity of the work being performed, the geographical area being covered, and the amount of installation miles by program in the annual workplan. The Company modified gas contracts

with its primary contractors beginning in 2023 to move to regional contractor assignments, by geographical area, to better manage SCC oversight and windshield time. The number of SCCs assigned to oversee large diameter projects increased in response to the total large diameter installation miles in the workplan increasing. Additionally in 2023, the Company added an additional SCC FTE to maintain or exceed the oversight ratio desired with the new contractor regional approach. Accordingly, PECO believes the SCC coverage today is adequate.

22. Q. On pages 28-34 of his testimony, Mr. Salamonski questions the efficacy of PECO's use of new and existing technology to drive efficiencies and he makes certain recommendations for areas of improvement. Do you agree with his assessment and recommendations?

A. No. First, on page 29 of his direct testimony, Mr. Salamonski commends the Company for using "camera equipment daily for trouble locates, mapping improvements, locating water intrusions, verifying branch services, and for locating and verifying tap locations." He also acknowledges PECO's prudent use of tools to remove potentially hazardous bolt-on tees.

Second, in response to Mr. Salamonski's concern that PECO has not invested in vacuum trucks, I note that PECO does in fact own vacuum trucks which our crews utilize for main line replacement work. This equipment maximizes efficiencies and reduces impact to the customers while the project is being completed. However, I want to reiterate our belief that it can also be more efficient to contract with vendors for the use of the vacuum trucks for the gas mapping program and for damage prevention rather than to purchase the

equipment. Contracting for these services provides flexibility to scale up or down as needed since vacuum trucks can be less efficient during the winter months. Moreover, the use of these tools through contracted work is meeting the needs of the mapping program and is just one example of how the company is leveraging technologies to drive efficiencies.

Third, since 2022, PECO has doubled the number of horizontal directional drills it uses for capital construction from two (2) to four (4), which allow us to further decrease the impact on restoration needs and expenses and significantly reduce the time needed to complete a job. Additionally, PECO initiated a three (3) year program to install remote rectifier monitor equipment on its 800+ recitfiers reducing the need for mechanics to drive out and manually read the units every other month. This new program will reduce O&M expenses and free up the corrosion mechanics to work on backlog maintenance tasks.

Fourth, I would also like to respond to Mr. Salamonski's disagreement with my statement that "PECO has seen a 40% reduction in incoming 1, 2A, and 2B leaks since 2019" and correct the record. The DOT Annual Report for 2023 included above ground leaks for the first time and therefore should not be compared to prior reported DOT reports (as described in PECO's response to IE-GS-53). It should also be noted that the DOT report also asked for number of *repaired leaks* which does not always align to *incoming leaks*. For example, there could be multiple incoming leaks that are resolved with a single repair. The data that the Company shared in response to discovery question IE-GS-6 supports a finding of

a 40% decrease in overall incoming leaks which include a 34% decrease in Grade 1 Leaks from 2019 to 2023.

Finally, I note that PECO continues to focus investment in new technologies designed to increase system safety and efficiency. In addition to the new technologies acquired since 2022 as referenced in response to interrogatory request IE-GS-38, PECO currently is studying additional investment in leak detection and repair technologies such as the Timberline Expert Tool for plastic repairs, Kobus Pipe Puller, and other advanced leak detection systems. Given the Company's demonstrated commitment to investment in new leak detection technologies, I do not believe there is a need to expend additional resources to conduct a study as recommended by Mr. Salamonski.

23. Q. Do you agree with Mr. Salamonski's claim that system improvement projects, which are performance projects meant to retire aging mains and service, are different from DIMP projects, which are meant to reduce system risk and improve safety?

A. No. All projects regardless of whether they are done to improve system performance or address safety concerns are influenced by the results of the risk analysis review which is done within the DIMP risk model and program. In my experience, the Company has found that aging mains and services typically are higher risk assets and through execution of replacement projects, this risk is reduced. As shown in attachment IE-GS-15 attached as PECO Exhibit AEH-5, the DIMP risk model monitors the effectiveness of the program and year over year PECO's DIMP risk model has shown a decrease in risk across the threat

categories. While the primary objective is to address leak-prone infrastructure and to preserve public safety and reliability of the PECO gas system, the Company considers other objectives such as managing construction costs, township commitments and customer fatigue when developing the annual infrastructure replacement plans.

IV. SYSTEM SAFETY AND WORKFORCE PLANNING

24. Q. In his direct testimony, Mr. Glenn agrees that PECO has met safety and reliability metrics for its customers. However, he is concerned that the Company has not sufficiently addressed safety and reliability with respect to its employees. Do you agree?

A. I do not agree. PECO has a mature employee safety management system that is constantly evolving and improving based on industry best practices. There is a myriad of tools utilized by PECO employees, leaders, and the safety professionals with a strong focus on the elimination of serious injuries and fatalities ("SIFs"). Many of these tools have been in place for years, such as, but not limited to: the event free performance tool book; investigation and corrective action programs; safety best practice program; regularly held safety meetings at a local, regional, and companywide level; safety plans developed at a team level; and employee led safety teams department and companywide. In the past five years, PECO Gas, in coordination with Exelon, has been on a journey to implement energy-based safety tools recognized as a best practice by the Edison Electric Institute and being implemented by over fifty (50) other electric and natural gas utilities across the nation. Energy-based safety has introduced new hazard recognition tools for

all our employees, significantly enhanced training protocols, and enhanced management safety observation tools. Last, but certainly not least, as discussed in my direct testimony, the Company is also implementing the Pipeline Safety Management System ("PSMS"), an American Petroleum Institute ("API")-recommended best practice specific to the natural gas and oil industry. In late 2023, API conducted an audit of PECO's conformance with all ten (10) elements of the PSMS and PECO Gas received a scored 2.8 out of a possible 3.0. PECO continues to implement the final elements of the PSMS program and is working to enhance its effectiveness. Safety for our employees and customers is a never-ending journey and will always be PECO's highest priority as a gas utility service provider in the state.

25. Q. Do you agree with Mr. Glenn's request that Union representatives be included in future discussions related to any potential changes to standards, practices and procedures of the Company's pipeline safety management system?

A. PECO Gas already considers input from represented employees with respect to critical standards and procedure changes. In fact, the changes are often made in specific response to feedback from represented and management employees received at the many safety forums attended by engineers responsible for compliance with standards and procedures. Additionally, all changes are reviewed with represented employees in multiple ways, including, Procedure Change Notifications, review at safety meetings, and through the advertisement of changes on the television slides located at every service building, which are

updated weekly. All employees, including represented employees, are welcome at any time to raise a concern about a standard or procedure change, just as they have multiple channels to raise any safety concerns.

26. Q. How do you respond to Mr. Glenn's contention that Union members should have been involved in the installation of high-pressure gas main and upgrades at PECO's natural gas plant infrastructure in West Conshohocken?

A. I do not agree. PECO's natural gas crews are organized across our natural gas service territory to allow for optimal response and repair of leaks, maintenance of our infrastructure throughout the region, completion of smaller main and service replacements and retirements, and completion of installations for new customers. The construction of the 11-mile OHP main associated with this project would have required at least six (6) crews (compromised of seven (7) members each) for two and one half (2.5) years. PECO would not have been able to complete this work and cover requirements associated with day-to-day operations of the utility gas business if it had used represented employees. Additionally, this type of large diameter, high pressure pipeline construction project requires specific experience that PECO Gas does not possess within the Company.

27. Q. Mr. Glenn recommends that PECO be required to file an annual workforce planning report that identifies "challenges" PECO faces, with specific requirements for the number and age of employees in various job classifications, the anticipated hiring and attrition levels for those positions, and the specific actions PECO is taking to address these "challenges." Do

you agree with this proposal?

A. No, I do not. As a threshold matter, I do not agree with his premise that PECO faces any "challenges" in its workforce planning, and he has not provided any specific evidence to support his concerns regarding the current or future lack of availability of highly skilled workers. As Ms. Humphrey discusses in more detail in her rebuttal testimony the Company is on track with hiring. For example, the Company is hosting our Gas Mechanic school for the FTY (October 2024) and the FPFTY (October 2025) and expects to have thirty-five (35) graduates (i.e., FTEs) hired into the Company's Field Ops by the end of the FPFTY. Nevertheless, while I appreciate the coordination and collaborative working relationship between PECO Gas and the Union, the Company's detailed hiring plans should remain within the managerial discretion of PECO.

V. OPERATING EXPENSE ADJUSTMENTS

28. Q. Mr. Defever proposes to reduce the Company's recovery of dues associated with industry groups, including the American Gas Association ("AGA"), by fifty percent (50%) or $361,333. Is this justified?

A. No. Mr. Defever wrongly classifies AGA's primary purpose as lobbying and political advertising. The primary value to PECO of AGA membership is the work they do leading a coordinated effort to shape energy regulation and policy impacting natural gas distribution members at the federal agency level (FERC, DOE, DOT/PHMSA, DHS) – not on Capitol Hill. Moreover, AGA has multiple committees that PECO participates in to share best practices in all areas impacting our business, including but not limited to, safety and security (including a separate PSMS executive committee); climate and sustainability; state and federal

regulatory affairs; customer service; risk management; cybersecurity; distribution and transmission integrity management; engineering standards; damage prevention, and many more. Even if PECO does not have an active participant on one or more of the committees, we have access to all the learnings and recommendations from these committees (including legal resources) which is an invaluable resource to improve all aspects of our service to our customers.

29. Q. Do you agree with Mr. Defever's proposal to reduce the Company's proposed allowance for non-industry dues by $20,073?

A. A. No. While I agree that Commission precedent does not permit charitable contributions to be recovered from ratepayers, I disagree that that non-industry membership dues paid to such organizations as the "chamber of commerce, Economy League of Greater Philadelphia and World Trade Center of Greater Philadelphia" that are referenced in Mr. Defever's testimony are comparable to charitable contributions. As Mr. Defever acknowledges, Commission precedent has supported membership in chambers of commerce and PECO explained in discovery that membership in these additional organizations "promotes the interests of PECO's commercial and industrial customers, and the residents of PECO's service territory overall" by engaging with the business community and promoting partnerships to grow the local economy. I do not believe there are simply "the possibility of benefits," as Mr. Defever suggests. For example, PECO partners with Economy League of Greater Philadelphia because we support their more macro efforts to have a positive impact on businesses in the region. This focus aligns with PECO's utility economic development mission to work with

partners to attract businesses to the region and while also helping existing businesses grow and expand here. We believe that working to make the region a better place to do business directly impacts companies' decisions to locate to Philadelphia and the surrounding areas.

The World Trade Center Greater Philadelphia (WTCGP) is the region's leading non-profit international trade services organization that assist companies in Southeastern Pennsylvania. The WTCGP provides resources to local businesses for them to expand their businesses internationally. This allows these companies to expand their customer base therefore supporting regional economic development, tax base, and creating local jobs. WTCGP focuses also on minority and women-owned business enterprises and programs that reach underserved communities in our territory which has always been a part of PECO's priorities.

Additionally, other organizations that PECO participates in provide valuable resources and programs to attract new businesses and to help businesses expand their operations or stay within PECO's service territory, thereby generating new jobs or protecting existing jobs, which benefits PECO and its customers directly. Expanding the Company's customer base also provides direct benefits to existing customers through a lower distribution revenue requirement.

30. Q. Mr. Defever recommends that the Commission disallow the Company's request to recover $45,966 for employee recognition and service awards claiming that this type of expenditure should be recovered from shareholders not ratepayers. Similarly, Mr. Keller recommends adjustment to the recovery of employee activity costs by ($144,001) to $48,529 to reflect

removal of the costs of an employee townhall, picnic, employee compact expenses, and other employee celebrations. Do you agree?

A. No. PECO's claim for employee recognition and service awards and the cost of several employee events, including an employee town hall and picnic, have real benefits in terms of employee morale and productivity. Counsel has informed me that the Commission has recognized the importance of employee recognition costs and events in contributing to a utility's workplace environment. I believe our celebration of employees and recognition of employee service is an appropriate expense that help make PECO an attractive workplace for its many talented professionals. Employee engagement-related activities and associated costs are a means to increase employee engagement and celebrate our workforce, their accomplishments, and strategic goals and initiatives. Employee engagement is a combination of the extent to which employees take pride in the company, are willing to exercise discretionary effort to improve the operations of the business and the customer experience, and the ability of the Company to attract and retain the talent we need to perform at an exceptional level. This directly benefits the Company's customers, as hiring and retaining top-level talent is imperative to continuing to provide PECO's customers with excellent service.

31. Q. Mr. Defever similarly recommends that the Commission disallow the Company's request to recover $23,244 related to the employee cafeteria claiming that the costs are not related to, or necessary for, the safe or reliable provision of service, and ratepayers receive no benefit. Do you agree?

A. No. PECO has an employee cafeteria to support the 1,300+ employees who are assigned to the Main Office Building daily. In addition to salaried employees at the Main Office Building, PECO also employs people in hourly positions such as Care Center Representatives, Clerical Support and Control Room Operators. People in these positions have limited time away from their work locations for meals/lunch due to the continuous attention required of their specific role. By offering an on-site cafeteria, employees are afforded the ability to purchase and eat their lunch within their allotted lunch time. PECO's employee cafeteria also provides food catering services to employees when working around the clock (24x7) in the Emergency Operations Center and prepares boxed lunches for crews who are going off system for mutual assistance support. This is a small cost paid by PECO to ensure our employees have quick and reliable access to meals in times of emergency support, as well as a convenient and quick option for breakfast and/or lunch when working in the Main Office Building. The employee cafeteria is a very cost-effective means to provide a quality benefit to all employees that ensures a timely return to work responsibilities, increases employee satisfaction/morale and potentially supports employee retention.

32. Q. Mr. Defever proposes to reduce by $98,985 the Company's proposed cost recovery associated with paid time off for employee volunteer activities, noting that the Company did not provide a cost estimate for FPFTY and that these costs are comparable to charitable donations, which should not be funded by ratepayers. Do you agree?

A. Volunteer events are an opportunity for PECO employees to directly interact with and serve customers in the community. Volunteers are often supporting PECO-led initiatives (e.g., summer fan distribution or tree giveaways) that benefit the entire community or general community projects. Volunteers also assist with projects that benefit the region's environment, including performing trail restoration and clean-up following major weather events. In addition to the obvious customer benefits of such direct assistance, affording employees the opportunity to help the communities PECO serves is a primary form of employee engagement and is beneficial to recruiting and maintaining employees.

VI. MANAGEMENT PERFORMANCE

33. Q. In your Statement, you support Mr. Moul's recommendation that PECO receive an enhanced return on equity. Why?

A. As set forth in my Statement and as supported by the direct testimony of other Company witnesses including Ms. Humphrey and Mr. Moul, the management performance adder accurately reflects PECO's demonstrated excellence providing safe, reliable natural gas service, as well as its deep commitment to and achievements in workplace safety, customer service, managing and controlling operating expenses, and investment in gas infrastructure and new technologies to promote efficient and clean gas operations.

34. Q. Did any parties oppose the Company's proposal to apply an exemplary management performance adder to the return on equity?

A. Yes. Mr. Spadaccio on behalf of I&E, contends that the Company's performance does not exceed the level of performance that is required by Pennsylvania public

utilities. Mr. Spadaccio claims that, if a Company is successful at controlling operating and maintenance costs, those cost savings would be offset by an increase in rates through an adjustment of return to reflect exemplary performance, thus defeating the purpose of cost cutting measures to benefit ratepayers. He also believes that any performance factor recognition should be awarded on a case-by-case basis and that existing precedent is distinguishable here.

Three witnesses from the OCA lodged similar objections. First, Mr. Garrett (at pages 50-53) raised concerns like those raised by Mr. Spadaccio that management performance generally does not have a material effect on the cost of equity and utilities should not be reward for operating systems in a prudent manner as required by law. He also raises a more specific concern that some of the claimed excellence of performance is related to actions taken by the diversified PECO Energy rather than PECO Gas. Second, Mr. Colton (at pages 95-103) testifies that the Company does not do enough with respect to the administration of its universal service programs, including program enrollment and communication with low-income customers, to warrant a management performance adder. He also disputes statements that the Company has invested in technology that supports assistance programs and affordability. Third, Mr. DeMarco's testimony argues that the Company is not entitled to a management performance adder because it has not provided more than the adequate and reasonable customer service it is obligated to provide as a public utility. In addition, Ms. Perry, on behalf of Walmart, objected to an award of management performance, contending

the Company has not provided evidence sufficient to support a clear and specific measure that excellence has been achieved.

35. Q. Do you agree with these objections?

A. No. Counsel has informed me that pursuant to 66 Pa C.S.A. §523, the Commission has the authority to consider a utility's performance to grand additional basis points to the ROE. As noted above, the evidence in this proceeding supports such an adjustment.

There is no question that PECO is required to deliver utility services efficiently and effectively to benefit our customers, and we have certainly done that. But what I have described goes well beyond "business as usual" as shown by our reliability and safety metrics, our continuing customer service improvements, and the other innovations I discuss in my direct testimony. In addition, I note the enhancements to the Company's universal service program and customer service initiatives described in Jaqueline F. Golden's rebuttal testimony, provide further support for the management performance adder. As support, I would also like to highlight Ms. Perry's direct testimony at pages 23-25 in which she applauds the Company for "the valuable service provided by the Company's key account management team" and provides a detailed account of the strong partnership between PECO and its large customers.

VII. CONCLUSION

36. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2024-3046932

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II - GS

Response Date: June 20, 2024

IE-II-GS-49

Reference attachment IE-I-GS-3(b). There are 0.5-inch, 0.75-inch, and 1.25-inch cast iron service lines reported. Are these in fact cast iron service lines, or is this due to inaccuracies in records?

RESPONSE:

Please see Attachment IE-II-GS-47(a).

The previously provided data for IE-I-GS-3(b) used incorrect data fields for some attribute information. The corrected data is attached in IE-GS-47 on the sheet titled “Services” which shows that PECO did not have any leaks on cast iron services.

Responsible Witness: Amy E. Hamilton

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15398509	9/21/2020	1988	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
15400695	4/23/2020	2017	2B	1.25	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
15400695	4/24/2020	2017	2B	1.25	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
15418005	8/8/2019			4	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15424244	9/3/2021	2005	2B	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
15427761	2/12/2022		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15433890	8/8/2019			1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15433983	5/21/2019	2003	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15434807	6/10/2019		2B	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15435625	12/18/2019		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15435801	1/18/2019		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15439580	1/2/2019		2B	4	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15444298	9/17/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15447853	8/19/2019		3	0.5	HIGH	CORROSION	STEEL	SOMASTIC	
15451050	4/18/2019	2008		0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15454585	8/16/2019	1964	2B	1	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
15454622	5/9/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15456802	4/18/2019			0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15456853	4/18/2019	1974		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15497525	1/28/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15498748	4/24/2019		3		HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15517725	1/30/2019		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15518221	6/11/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15518231	6/18/2021		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15518830	1/2/2019		3	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15524662	1/29/2019	1968	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
15524662	2/8/2019	1968	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
15526593	1/28/2019	1992	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15526642	4/10/2019	1984	2B	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
15531750	12/20/2021	1985	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15536249	1/8/2019	1974	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15537084	1/2/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15540249	1/28/2019	1981	2B	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15548642	1/4/2019		1	1	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
15548871	1/2/2019	1991	2A	0.75	HIGH	LEAKING JOINTS	STEEL	JALBOND	
15549785	1/4/2019	2018	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15550265	11/20/2020	1992	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15550389	1/10/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15551100	1/2/2019	1973	1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
15551126	1/8/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15554415	4/15/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15555178	1/14/2019		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15557211	1/7/2019	1993	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15567251	1/7/2019	1980		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15577050	1/2/2019		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15577094	1/7/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15577118	4/11/2019	2011	2A	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15577328	1/8/2019	1994	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
15590080	1/7/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15603278	1/7/2019		1	1	HIGH	CORROSION	STEEL	JALBOND	
15603297	1/3/2019			0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15603557	4/9/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15604922	1/18/2019		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15604925	2/9/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15604925	2/21/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15605256	1/8/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15605273	2/21/2019		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15605950	2/2/2019	1987	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15608580	1/24/2019			0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15608832	1/18/2019		1	1.25	HIGH	OTHER	STEEL	X-TRU	
15611241	1/16/2019	1971		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15613807	1/10/2019	1982	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15616453	1/16/2019	1981		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15616531	1/10/2019			1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15616611	6/26/2019	1968	2B	0.75	HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
15616670	1/29/2019			0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15616702	1/16/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15617995	1/29/2019			1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15618118	1/14/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15618184	1/14/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15618217	1/14/2019	1974		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15618333	1/14/2019			0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15619820	1/10/2020	2000	3	0.5	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
15620539	1/16/2019		1	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15621008	1/18/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15621026	1/15/2019	1980		1.25	HIGH	CORROSION	STEEL	PRITEC	
15621060	1/17/2019	2000		2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15621203	1/15/2019	1946	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15621864	1/16/2019	1961	1	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15621887	7/11/2019	2017	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
15622859	1/15/2019		1	0.5	MEDIUM	CORROSION	STEEL	SOMASTIC	
15623420	1/22/2019		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15624681	1/17/2019			0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15624834	1/18/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15626744	1/22/2019	1986	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15626744	1/22/2019	1986	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15626744	1/26/2019	1986	2A	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15798971	1/30/2019	2018	2B	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15799243	1/29/2019		3	1.25	HIGH	OTHER	STEEL	TAPE	
15799243	2/8/2019		3	1.25	HIGH	OTHER	STEEL	TAPE	
15799452	1/21/2019		1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15799514	1/28/2019		1		HIGH	MATERIAL DEFECT	PLASTIC		OTHER
15799642	1/28/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15799654	1/28/2019	1994	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15799754	1/28/2019		1	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15799772	1/28/2019	1994	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
15799867	1/28/2019	1982	1	1.25	MEDIUM	LEAKING JOINTS	STEEL	TAPE	
15799896	1/28/2019	1973	1	0.5	HIGH	CORROSION	PLASTIC		ALLIED
15800018	1/29/2019	1994	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15800018	1/29/2019	1994	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15800600	1/28/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15800979	1/29/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15802586	2/27/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15804331	3/20/2019		2B	0.5	HIGH	CORROSION	STEEL	SOMASTIC	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15804438	1/28/2019		2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15805636	1/30/2019	1993	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15805643	2/16/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15806945	5/8/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15807346	1/28/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15808195	3/11/2019	1970	2B	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15809777	1/31/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15811767	2/14/2019		1	0.5	MEDIUM	CORROSION	PLASTIC		ALLIED
15811973	2/14/2019	1993	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15812155	2/14/2019	1993	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15812937	2/4/2019		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15813105	1/31/2019		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15813153	3/25/2019	1993	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
15813409	2/14/2019	2019	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15816757	2/5/2019		2A	1	HIGH	LEAKING JOINTS	STEEL	X-TRU	
15816757	2/4/2019		2A	1	HIGH	LEAKING JOINTS	STEEL	X-TRU	
15818366	2/21/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15818734	2/8/2019	2000	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15819627	7/1/2019			1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15820592	8/21/2019		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15822571	2/12/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15824901	2/9/2019		2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15825389	2/14/2019	2003		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15825589	3/4/2019	1981		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15830954	2/14/2019	2017	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15831007	2/12/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15831082	2/14/2019	1968	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15831474	2/28/2019	1982	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15834538	2/14/2019	1959	1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15835828	2/19/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15835855	2/18/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15835855	2/21/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15835910	2/19/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15835910	2/22/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15835997	2/19/2019		1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15836013	2/22/2019	1987	2A	1	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
15836041	2/21/2019	2017	2B	1.25	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15836179	2/22/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15836489	2/21/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15837460	2/22/2019	2017	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15837826	2/21/2019	1977	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15838044	2/18/2019	1992	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15838136	2/25/2019		2B	1	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
15838236	2/21/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15838864	2/21/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15840844	3/7/2019		2A	0.5	MEDIUM	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
15840940	3/25/2019	1974	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15841214	2/19/2019	2007	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15842419	2/22/2019	1977	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15843840	7/10/2019		2B	0.5	HIGH	OTHER	STEEL	SCOTCH	
15846732	2/26/2019		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15846793	2/22/2019		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15846850	2/22/2019	2002	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15847613	3/25/2019	1964	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15847849	3/22/2019	2011	2B	0.5	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
15850902	3/5/2019	2018	3	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15852683	5/6/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15852954	3/18/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15854090	3/4/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15854228	3/4/2019	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15854703	3/6/2019	1994	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15855755	3/6/2019	1992	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15856555	5/2/2019	1971	3	0.75	HIGH	CORROSION	STEEL	JALBOND	
15858176	3/4/2019	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15861526	3/12/2019	1985	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15861849	4/15/2019			0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15861879	4/1/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15863124	3/6/2019	1986	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15864089	4/5/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15864143	8/15/2019	1971	2B	0.5	HIGH	LEAKING JOINTS	PLASTIC		ALLIED
15867111	3/14/2019	1988	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15867615	5/9/2019	1989	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15867939	3/25/2019	1953	1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15868164	3/23/2019	1968	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15868519	3/18/2019		3		MEDIUM	CONSTRUCTION DEFECT	PLASTIC		
15869942	3/11/2019		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15870152	3/25/2019	1994	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
15870781	3/12/2019	2015	2A	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15872167	3/18/2019			1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15878405	3/14/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15878483	3/18/2019	1963	1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15878621	3/25/2019	1969	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
15878623	3/12/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15878643	3/19/2019		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15879304	3/14/2019	1994	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15879568	3/14/2019	1994	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15879946	4/29/2019		1	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15880171	3/18/2019	2014	2A	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15881464	4/29/2019	2008		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15881464	4/29/2019	2008		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15882907	4/29/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15882907	4/29/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15882976	3/18/2019		1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15883226	4/29/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15883752	3/18/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15883752	3/18/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15884796	3/18/2019	2006	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15884847	3/18/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15885136	3/18/2019		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15885323	3/20/2019		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15886764	4/2/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15887187	3/20/2019		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15888367	4/5/2019	1970	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
15888394	3/19/2019	1981	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15889173	4/2/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15889347	3/20/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15889371	3/25/2019	1968	1	0.75	HIGH	MATERIAL DEFECT	PLASTIC		OTHER
15889418	3/27/2019	1980	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15889521	4/2/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15889730	3/19/2019		1	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15889794	1/22/2021		2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15890773	3/26/2019	2013	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15890773	3/28/2019	2013	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15891016	3/28/2019		2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15891128	3/28/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15891414	3/26/2019	1971	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15891723	4/13/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15892482	3/27/2019	2010	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15892726	3/28/2019	2011	1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15896158	3/25/2019	2006	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15896181	3/27/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15897704	3/28/2019		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
15897802	1/14/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15897813	4/8/2019		2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15898514	4/6/2019	1961	2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15898659	4/4/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15898891	3/28/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15900568	9/13/2019	1965	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15900616	4/4/2019		3	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15901279	4/4/2019	1989	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15902487	4/4/2019		1	0.5	HIGH	CORROSION	STEEL	X-TRU	
15902506	4/2/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15902563	3/28/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15902892	4/2/2019		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15902992	6/18/2019		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15904230	4/29/2019		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15904657	4/29/2019		1	1	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15904674	3/29/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15905682	4/4/2019		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15905682	4/4/2019		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15906011	4/4/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15906179	4/24/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15907206	4/4/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15907219	4/1/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15907336	4/29/2019		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15908350	4/12/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15908948	4/15/2019	2011	1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15910939	4/12/2019	2008	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15913111	4/9/2019	2018	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15913905	4/24/2019		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15915210	4/15/2019	1988	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
15915232	7/31/2019		2B	1	MEDIUM	CORROSION	STEEL	SCOTCH	
15915305	4/5/2019	2005	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15915329	4/15/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15915455	1/24/2020	1952	2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15916107	4/5/2019		1	0.5	HIGH	CORROSION	STEEL	SCOTCH	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
15916951	4/15/2019	2014		1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15917281	4/5/2019	1970	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15919473	4/9/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15919473	4/15/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15919825	4/9/2019	1		1.25	LOW	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
15921294	4/12/2019	1988	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15921439	4/10/2019	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15921519	4/10/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15921848	4/10/2019	1972	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALLIED
15923792	4/11/2019	1		1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15924566	4/12/2019	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15924649	4/15/2019	1		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15925030	4/29/2019	1985	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15928035	4/17/2019	1968	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15929232	4/26/2019	1981	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15930925	4/29/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15932693	4/22/2019	1992	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15932885	4/22/2019	2013	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15934361	6/10/2019		2B	1	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
15934534	4/22/2019	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15936407	4/29/2019	1975	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15936498	4/29/2019	1		1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15936498	4/29/2019	1		1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15938222	4/22/2019	1		0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15938791	4/23/2019	1		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15938862	4/23/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15938919	4/29/2019	1		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15938919	4/29/2019	1		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15938948	4/23/2019	1		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15938956	4/29/2019	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15939309	4/24/2019	1957	2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15939330	5/1/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15940538	4/24/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15940990	5/2/2019	1		3	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15942127	4/29/2019	1		1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15942127	4/29/2019	1		1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15942211	8/14/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15942304	4/17/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15942394	4/29/2019	2018	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
15942609	4/24/2019	1		1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15942848	5/22/2019	1		1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15943337	5/7/2019		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15943633	4/25/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15943808	4/25/2019	1924	1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15945424	5/2/2019	1995	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15946021	6/27/2019	2019	2B	0.5	HIGH	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
15948054	5/9/2019	1		0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15948158	4/30/2019	1968	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15948255	5/1/2019	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15948300	5/9/2019	1951	1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15948867	4/30/2019	1		1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15948890	5/1/2019		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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15948890	5/1/2019	2019	2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15948890	5/3/2019		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15949751	5/1/2019	1983	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
15949751	5/1/2019	1983	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15949772	5/1/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15950220	5/2/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15950421	5/2/2019	1995	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15950482	12/12/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15952584	5/3/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15953078	5/3/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15955442	5/3/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15955824	5/22/2019	2013	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15956002	5/2/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15956454	5/21/2019	1981	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15957598	5/6/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15957709	5/6/2019	1996	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15958142	5/4/2019		1	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15959199	5/8/2019	1991	2A	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15959199	5/10/2019	1991	2A	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
15959368	6/11/2019		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15960588	5/7/2019	1967	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		OTHER
15960699	5/8/2019	1969	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15962021	5/9/2019	1978	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15962089	5/15/2019		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15962245	5/23/2019		3	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15962417	5/22/2019	1991	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15962674	5/8/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15963820	5/13/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15964490	5/13/2019	1968	1	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15970029	5/13/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15971379	5/16/2019	1993	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15971613	5/22/2019	1967	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15971939	5/22/2019		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15972007	5/22/2019			1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15973469	5/17/2019	1991	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
15973487	5/22/2019	2014	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15973762	1/31/2020	1989	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
15973772	5/19/2019		2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		
15974893	5/16/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15974961	6/6/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15975222	5/19/2019		2A	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15975512	5/22/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15975526	6/22/2019		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15976997	5/20/2019	2008	1	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15979056	9/14/2019			0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15979090	5/22/2019		1	0.5	MEDIUM	CORROSION	STEEL	SCOTCH	
15979538	5/22/2019	1992	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15980926	5/22/2019	1982	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
15980926	5/22/2019	1982	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
15981027	6/10/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15981042	5/21/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15982485	5/23/2019	1987		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

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15985719	3/9/2020	2020	2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15987167	5/24/2019	1		0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15987167	5/28/2019	1		0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
15992227	8/12/2022		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15992642	6/11/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
15993116	6/26/2019		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15993850	5/30/2019	1984	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
15994745	6/3/2019	1969	1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15994745	6/17/2019	1969	1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15994972	6/10/2019	1		1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15995025	6/10/2019	1		1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15996323	5/31/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15999576	6/17/2019	1		0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15999587	6/3/2019	1971	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
15999688	6/11/2019	1990	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16002914	6/11/2019	1		0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16003234	7/2/2019	2019	2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16004727	6/7/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16004931	6/7/2019	1		1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16006845	6/10/2019	1969	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16007870	6/17/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16007903	6/14/2019	1993	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16007927	6/14/2019	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16008147	6/14/2019			0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16009238	6/10/2019	2018	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16009238	6/28/2019	2018	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16010928	6/17/2019	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16011064	6/13/2019	1987	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16011484	6/13/2019	1985	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16011486	6/13/2019	1		0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16012820	6/13/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16013243	7/9/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16016409	6/18/2019	1985	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16016534	6/22/2019		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	SOMASTIC	
16017143	7/1/2019	2018	1	1	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
16017218	7/1/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16018304	6/16/2019	1		1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16019173	6/24/2019	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16019478	4/19/2022	2005	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16021001	6/19/2019	1982	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16021571	6/21/2019	1		2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16021903	6/25/2019		2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16023411	6/19/2019	1		2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16024747	6/28/2019	2000	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16025310	6/24/2019	1998	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16026300	8/1/2019	1986	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16027387	6/22/2019	1		0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16027387	6/26/2019	1			HIGH	OTHER	PLASTIC		OTHER
16027528	6/26/2019	1		1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16028107	7/9/2019	1		1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16028721	6/26/2019	2018	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16028732	7/9/2019	1		1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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16030935	6/27/2019	1997	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16032536	2/19/2020		2B		MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16032599	7/1/2019	1999	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16036790	7/18/2019			1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16036838	8/2/2019	2019	2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16038073	7/30/2019		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16040005	7/22/2019	1985	1	1	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16041010	7/3/2019	1998	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16041056	7/2/2019		2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16041056	7/17/2019		2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16041109	7/3/2019	1998	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16041568	8/11/2020		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16041637	1/28/2020	1971	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16042164	7/2/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16043239	7/2/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16043284	7/9/2019	1969	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16045053	7/9/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16045255	7/10/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16048775	7/9/2019	1998	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16048775	8/29/2019	1998	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16050307	7/17/2020		3	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16055710	8/29/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16055777	8/29/2019	1928	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16055831	8/8/2019		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16056174	7/11/2019	1982	1	1	LOW	OTHER	PLASTIC		PLEXCO (YELLOW)
16057875	7/19/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16059449	3/4/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16060693	8/30/2019	2017	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16062115	7/17/2019	1991	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16062683	10/2/2019		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16062683	10/2/2019		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16063732	7/17/2019	1981	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16064636	8/8/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16064710	7/19/2019	1983	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
16064816	7/19/2019	1989	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16065175	7/17/2019	1984	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16065201	7/19/2019		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16065201	7/23/2019		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16065281	7/18/2019	1995	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16067165	7/19/2019		2A	0.5	MEDIUM	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
16067507	7/18/2019		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16068553	8/19/2019		2B		HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
16068592	7/30/2019	1975	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16068933	7/30/2019		1		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16071115	7/23/2019	1972	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16073082	7/30/2019	1983	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16073223	7/30/2019	1988	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16075381	7/30/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16075746	7/24/2019		1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16076588	7/25/2019		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16077558	7/30/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16078649	5/6/2021		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
16078855	7/29/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16080595	8/2/2019	2007		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16081561	7/31/2019	2016	1	1	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
16082452	7/31/2019	1973	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
16083787	7/30/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16083791	7/31/2019		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16084602	1/29/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16086414	10/10/2019	1974	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16086414	10/10/2019	1974	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16087711	8/5/2019	1973	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16088240	8/6/2019	1987	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16089603	8/8/2019		2A	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16092171	2/27/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16093174	2/12/2020		2B	0.5	HIGH	CORROSION	STEEL	SCOTCH	
16093680	10/2/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16093680	10/2/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16093787	8/6/2019	1980	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16095153	8/8/2019	2009	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16095265	8/13/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16095296	8/20/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16095324	2/8/2020	1996	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16097415	8/8/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16098979	8/8/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16099135	10/10/2019	1972	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16099357	8/13/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16101142	8/12/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16101186	8/12/2019	2014	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16103716	8/14/2019	1992	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16104019	8/13/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16104478	8/13/2019	2019	1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16105377	8/20/2019	1987	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16106387	1/16/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16108387	8/22/2019	1999	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16111995	8/19/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16112465	8/17/2019	2019	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
16114420	8/19/2019	2016	1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16114630	8/19/2019	2018	1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16114703	8/19/2019	2018	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16114703	8/19/2019	2018	1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16116227	8/21/2019	2016	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16116618	8/20/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16117158	8/27/2019		3	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16121607	8/23/2019	1972	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16122234	9/11/2019	2019	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16124674	8/26/2019	1996	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16126323	8/28/2019	2008	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16126388	10/2/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16127029	8/27/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16128917	8/28/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16129311	8/27/2019	1969	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16130554	7/3/2020		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16132059	8/30/2019		1	0.5	LOW	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
16134144	8/30/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16135981	7/8/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16135997	9/10/2019	2018	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16137159	9/3/2019		1	1	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16137257	2/15/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16137257	2/15/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16137257	2/15/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16137290	9/4/2019	1987	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16141193	9/10/2019		1		LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16142212	9/10/2019		1	1	MEDIUM	CORROSION	STEEL	SCOTCH	
16143215	9/6/2019	2019	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16145087	12/21/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16145230	9/11/2019		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16145273	6/14/2022		2A	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16147166	9/10/2019	1959	2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16147166	9/12/2019	1959	2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16150763	9/11/2019	1987	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16150973	10/2/2019	2012	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16150973	10/2/2019	2012	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16151757	1/22/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16152716	9/13/2019	1980	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16152778	9/13/2019	1997	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16154776	9/13/2019	1980	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16156569	9/26/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16157429	9/18/2019	1992	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16157748	9/18/2019	1968	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16158151	6/20/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16158928	9/24/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16158954	9/17/2019	1945	1	1.25	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
16160645	9/24/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16160651	9/26/2019		1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16162751	9/24/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16162868	9/20/2019	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16163065	10/23/2019	1994	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16163566	2/28/2020	2016	2B	1.25	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16164831	9/20/2019	1983	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16164854	9/20/2019	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16164943	9/20/2019	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16165210	9/26/2019		1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16165210	9/26/2019		1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16166751	10/10/2019	2017	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16166756	9/20/2019		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16168099	10/10/2019	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16168099	10/10/2019	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16168376	2/3/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16169525	9/24/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16169720	10/14/2019	1978	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16169720	10/14/2019	1978	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16169720	10/14/2019	1978	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16170454	9/27/2019	1996	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16170545	1/28/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16172283	10/10/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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16172324	10/10/2019	1979	1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16176593	10/10/2019	2017	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16176929	10/10/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16176929	10/10/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16176929	10/10/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16177465	1/11/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16178876	10/8/2019		1	1.25	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16179088	10/21/2019	1997	1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16182499	10/10/2019	2018	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16182911	10/10/2019	1989	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16182911	10/10/2019	1989	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16182911	10/10/2019	1989	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16183151	9/30/2019		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16183346	10/26/2019		2B	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16192557	10/4/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16192557	10/4/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16192557	10/4/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16192889	10/4/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16192889	10/4/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16192889	10/4/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16193086	10/8/2019	1994	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16193086	10/8/2019	1994	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16193086	10/8/2019	1994	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16193845	10/8/2019		2A	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16194763	10/10/2019		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16195255	10/14/2019	1987	1	1	MEDIUM	OTHER	PLASTIC		ALLIED
16195255	10/14/2019	1987	1	1	MEDIUM	OTHER	PLASTIC		ALLIED
16195398	10/15/2019	1980	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16195398	10/15/2019	1980	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16195398	10/15/2019	1980	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16197191	10/8/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16197630	10/21/2019	2013	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16197672	10/10/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16198020	10/14/2019	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16199488	10/21/2019	1989	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16200953	10/11/2019		1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16201121	11/7/2019		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16201685	10/11/2019		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16201724	10/10/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16203382	3/3/2020	2006	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16204250	10/12/2019		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16204366	3/2/2020		2A	4	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16206158	10/24/2019	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16206580	5/27/2020	1971	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
16208079	10/16/2019	1968	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16208324	10/24/2019	1999	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16209461	10/23/2019	1993	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16211271	10/24/2019	1964	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16211271	10/24/2019	1964	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16211674	10/21/2019	1967	2A	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16211771	10/24/2019	2019	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16213205	10/23/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
16215569	11/6/2019		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16216010	10/24/2019	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16217377	10/22/2019	1964	1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16217377	10/22/2019	1964	1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16217377	10/29/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16217377	11/15/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16219348	10/23/2019	1984	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16219348	10/23/2019	1984	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16219611	10/23/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16219611	10/23/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16220836	11/6/2019		1	2	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16222281	10/24/2019		1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16222997	10/24/2019		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16225071	10/1/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16225110	10/25/2019		1	1	HIGH	CORROSION	STEEL	SCOTCH	
16227325	10/29/2019			0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16227325	11/15/2019			0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16227458	3/5/2020	2019	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16228051	11/7/2019	2018	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16232154	11/7/2019	1995	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16233813	11/5/2019	1994	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16235538	11/15/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16236663	2/14/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16236663	2/14/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16236663	2/14/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16244166	11/6/2019	1961	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16244213	11/15/2019		1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16244253	11/7/2019		3	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16249189	11/6/2019		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16251571	11/8/2019	1989	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16251571	11/8/2019	1989	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16251693	11/13/2019			0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16251987	11/7/2019		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16252134	11/20/2019		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16262305	11/11/2019	1995	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16267090	11/19/2019	1971	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16273146	12/3/2019		1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16273225	2/17/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16273344	12/3/2019	2013	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16275486	3/11/2020		2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
16275664	11/22/2019	2016	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16275705	12/3/2019		1	1	MEDIUM	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
16276812	11/27/2019		1	0.5	HIGH	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16276846	4/20/2020	2003	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16280393	12/12/2019	1992	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16280595	11/22/2019		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16286153	2/21/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16296809	11/27/2019	1970	2A	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16296809	12/3/2019	1970	2A	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16297869	1/16/2020	1993	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16299010	11/27/2019		2A	0.5	HIGH	MATERIAL DEFECT	STEEL	PRITEC	
16299010	12/3/2019		2A	0.5	HIGH	MATERIAL DEFECT	STEEL	PRITEC	

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16299010	12/4/2019		2A	0.5	HIGH	MATERIAL DEFECT	STEEL	OTHER	
16300693	11/26/2019	1970	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16300775	12/3/2019	1978	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
16300789	12/12/2019		1	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16332861	12/5/2019	1968	2A	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16332861	12/6/2019	1968	2A	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16332861	7/28/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16333167	1/14/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16333657	12/9/2019	1970	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16333657	12/11/2019	1970	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16341241	12/3/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16346455	12/12/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16346455	12/18/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16346509	12/12/2019	1968	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16346521	12/18/2019		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16347930	12/19/2019	1982	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16348125	12/18/2019		1	1	MEDIUM	OTHER	PLASTIC		ALLIED
16348563	12/10/2019	1994	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16349171	12/12/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16349637	8/6/2020		2B	1	HIGH	CORROSION	STEEL	SOMASTIC	
16350629	12/18/2019		1	1	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16352374	12/19/2019	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16352670	12/10/2019		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16359847	12/12/2019		1	1.25	HIGH	LEAKING JOINTS	STEEL	SCOTCH	
16360561	12/19/2019		1	2	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16361467	12/13/2019		1	1.25	HIGH	LEAKING JOINTS	STEEL	PRITEC	
16361641	1/3/2020		2B	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16361696	1/22/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16362023	12/19/2019		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16363095	12/15/2019		1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16363137	12/16/2019	1980	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16363821	12/16/2019		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16364281	12/18/2019			1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16367851	12/31/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16367851	1/3/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16372825	7/21/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16372827	12/30/2019		1	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16372955	4/3/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16373041	1/22/2020		1	2	MEDIUM	MATERIAL DEFECT	STEEL	SCOTCH	
16373126	1/13/2020	1965	1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16374532	1/3/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16376075	1/13/2020		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16376302	1/2/2020		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16376469	1/10/2020	1967	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16376866	2/21/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16378269	6/10/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16378416	12/27/2019		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16381721	6/3/2020		2B	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16384222	1/8/2020	1986	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16384419	1/6/2020		1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16384488	3/9/2020		2B	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16384549	1/6/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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16384602	3/12/2020		2B	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16384602	3/13/2020		2B	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16384667	1/3/2020	2020		1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16392874	2/15/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16392874	2/15/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16393072	1/10/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16394642	1/10/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16395366	4/15/2020		2B	1.25	HIGH	CORROSION	STEEL	X-TRU	
16397991	11/2/2020		2B	1.25	HIGH	MATERIAL DEFECT	STEEL	TAPE	
16399162	1/6/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16401204	1/7/2020		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16401204	1/22/2020		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16402041	3/19/2020	1985	2B	1.25	HIGH	OTHER	STEEL	X-TRU	
16404260	1/8/2020		1	0.75	HIGH	CONSTRUCTION DEFECT	STEEL	SOMASTIC	
16404790	1/17/2020	1981	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16406400	1/22/2020	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
16406404	1/17/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16406433	2/13/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16407058	1/11/2020		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16407058	1/22/2020		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16408114	1/22/2020	1994	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16408945	1/11/2020	2001	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16409807	1/11/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16409837	1/11/2020	2019	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16409934	3/21/2020	1982	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16409959	1/22/2020	1971	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16410992	2/24/2020	1982	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16412614	1/27/2020	1981	2B	1.25	HIGH	LEAKING JOINTS	STEEL	JALBOND	
16412735	1/22/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16413261	5/18/2021	2020	2B	0.75	HIGH	LEAKING JOINTS	STEEL	JALBOND	
16413262	1/22/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16414677	1/24/2020	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16415282	1/27/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16415758	1/16/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16415758	1/22/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16418189	1/17/2020	2019	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16418189	1/24/2020	2019	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16419428	1/27/2020	1982	1	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16420674	4/1/2020	2020	2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16421048	2/3/2020		1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16422332	2/3/2020		1	0.5	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16422373	2/3/2020		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16422398	2/4/2020	1998	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16422504	1/29/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16422772	1/23/2020		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16426307	1/27/2020	1969	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16426485	1/28/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16426529	1/29/2020		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
16428960	7/27/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16428996	1/28/2020		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16429655	4/7/2020		2B	0.5	MEDIUM	CORROSION	PLASTIC		
16431159	2/5/2020		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

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16431789	1/24/2020	1982	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
16433574	1/29/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16433574	2/4/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16433993	10/28/2020	1965	2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16434429	1/27/2020		1	1.25	MEDIUM	CORROSION	STEEL	SCOTCH	
16434602	1/27/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16434776	5/20/2021	2020	1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16434913	2/6/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16438188	2/6/2020	1979	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16439967	2/7/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16439967	2/10/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16441331	1/31/2020	1990	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16442123	2/18/2020		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16442123	2/18/2020		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16442123	2/18/2020		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16442740	8/20/2020	1986	2A	0.5	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
16442796	2/14/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16443529	4/28/2020		2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16443928	12/13/2022	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16443956	2/21/2020		1	0.5	HIGH	CORROSION	PLASTIC		ALLIED
16444616	2/10/2020	2020	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
16445217	2/4/2020	1985	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16445225	5/5/2020	1985	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16445254	3/14/2020	2020	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16445255	2/25/2020		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16447320	8/10/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16449063	2/11/2020	2018	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16455275	4/29/2021	1968	2B	0.75	HIGH	CORROSION	STEEL	SCOTCH	
16455275	4/29/2021	1968	2B	0.75	HIGH	CORROSION	STEEL	SCOTCH	
16455630	2/7/2020	2015	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16455630	2/13/2020	2015	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16455892	2/17/2020	1963	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16455892	2/17/2020	1963	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16455892	2/26/2020	1963	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16456962	2/7/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16457092	2/7/2020		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16459272	2/10/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16460827	2/19/2020		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16465353	2/21/2020	1972	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16466755	2/21/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16468142	2/25/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16468142	3/4/2020		1	0.5	HIGH	CORROSION	STEEL	SOMASTIC	
16468414	2/24/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16468912	3/4/2020	1978	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469006	2/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16469142	3/9/2020		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16469330	2/25/2020	1957	1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
16469535	4/7/2020		3	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16469592	4/15/2020		2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
16470730	2/26/2020		1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	X-TRU	
16471105	3/6/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16472284	2/25/2020		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16472591	3/26/2020	1965	2B	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16475501	8/26/2020	1983	2B	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16478428	3/9/2020		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16478547	3/2/2020		2B	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16479299	3/5/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16479319	6/1/2021		1	0.5	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16479973	6/20/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16480158	3/4/2020	1949	2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16481679	2/25/2020	2020	1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16483691	3/4/2020		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16483691	3/9/2020		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16485201	3/3/2020		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16486445	2/28/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16488101	2/29/2020	2012	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16489655	3/4/2020	1993	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16489655	3/9/2020	1993	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16491183	6/15/2020		2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16491215	3/7/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16491399	3/18/2020		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16493021	3/18/2020	1948	1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16493872	3/5/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16495245	3/11/2020	1978	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16495280	3/12/2020	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16495280	3/16/2020	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16495655	3/18/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16497858	3/18/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16499350	3/10/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16499442	3/12/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16499442	3/16/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16499731	3/10/2020	1975	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16500871	3/18/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16501385	3/18/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16505517	6/10/2022		2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16506282	3/16/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16506408	3/16/2020		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16506437	3/16/2020	1989	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16508515	4/24/2020		2B	0.5	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16510048	3/18/2020	1995	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16510135	6/5/2020		2B	0.75	HIGH	MATERIAL DEFECT	STEEL	PRITEC	
16510235	3/20/2020		2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16514480	3/31/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16514718	3/24/2020		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)

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16517396	3/30/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16517440	3/25/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16517886	4/9/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16518870	5/13/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16521174	8/17/2020		2B	4	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16522453	4/15/2020		2B	1.25	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16522981	8/19/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16523864	4/10/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16523865	4/10/2020	2018	1	1	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16524472	4/6/2020		1	0.5	HIGH	CORROSION	PLASTIC		ALDYL A
16526815	5/28/2020	1925	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16526845	6/14/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16528091	4/1/2020		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16533297	10/27/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16534196	4/20/2020		1	4	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16535603	4/8/2020	2008	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16535674	4/20/2020		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16537062	4/17/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16537162	4/9/2020		2A	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16537162	4/14/2020		2A	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16537162	6/7/2021		2A	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16537162	6/7/2021		2A	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16540332	4/10/2020		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16540553	4/20/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16542324	4/17/2020		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16544438	4/16/2020	2018	2A	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16545346	4/24/2020		2A	1.25	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
16547272	4/20/2020	2020	2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16549421	5/4/2020		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16551621	4/24/2020		2B	0.5	HIGH	OTHER	PLASTIC		ALDYL A
16552799	4/21/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16554441	4/22/2020		1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16554751	4/22/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16554889	8/24/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16555609	7/21/2020		2B	0.5	MEDIUM	OTHER	STEEL	HILL HUBBEL/COAL TAR	
16555732	4/23/2020		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16555761	4/23/2020		1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16555761	4/23/2020		1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16558421	4/25/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16559481	4/27/2020			1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16561312	4/28/2020		1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16561811	4/29/2020		1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16562329	4/4/2022		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16563568	4/29/2020		1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16563585	6/18/2020		2B	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16563596	5/21/2020	1966	2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16563668	5/8/2020		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16563782	5/12/2020	1994	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16567595	5/8/2020		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16569506	5/8/2020		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16570303	5/19/2020		1		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16570658	5/5/2020	1981	2B	1	MEDIUM	OTHER	PLASTIC		ALDYL A

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16570658	5/27/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16572123	5/19/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16573159	10/6/2020	2020	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16573895	5/6/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16576035	5/8/2020		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16576035	5/12/2020		1	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16578374	5/19/2020	2017	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16579525	5/19/2020		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16581187	6/29/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16583164	7/20/2020	2020	2B	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16585325	9/14/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16586950	5/15/2020			1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16587338	7/21/2020		2B	1.25	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16588520	10/29/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16589793	5/19/2020	1967	1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16591094	5/19/2020	1967	1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16594555	6/23/2020		1	1.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16594928	6/13/2020	2003	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16594932	6/7/2021	2007	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16595454	8/25/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16598237	6/4/2020		2A	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16598237	5/25/2020		2A	2	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16599929	6/13/2020	1965	2B	0.5	HIGH	CORROSION	STEEL	SCOTCH	
16599929	6/13/2020	1965	2B	0.5	HIGH	CORROSION	STEEL	SCOTCH	
16601412	8/10/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16601586	5/28/2020	2019	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16608030	6/24/2020		2B	1	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16608125	6/26/2020	2019	2B	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16609058	6/1/2020	1967	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16609339	6/1/2020	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16609360	6/11/2020		2A	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16609360	7/3/2020	1964	2A	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16610119	6/15/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16610947	6/3/2020		2A	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16614083	6/10/2020		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16617190	10/26/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16617537	6/20/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16618359	6/10/2020		1	0.5	HIGH	OTHER	PLASTIC		ALLIED
16619565	6/8/2020		1	4	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
16620037	6/10/2020		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16621538	6/9/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16630051	6/17/2020		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16630291	6/15/2020		1	2	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16630373	6/27/2020		2A	0.5	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16633161	7/21/2020	1974	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16633819	6/17/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16638053	6/29/2020			0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16642136	8/12/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16642720	6/24/2020		2A		HIGH	MATERIAL DEFECT	PLASTIC		OTHER
16643206	7/1/2020	2016	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16643259	6/24/2020		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16644438	6/29/2020		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A

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16646018	6/29/2020	2019	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16649675	7/14/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16649675	7/21/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16650535	6/29/2020	2000	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16650585	7/8/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16651466	6/30/2020		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16655351	8/1/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16656149	7/2/2020	1936	1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16656149	7/2/2020	1936	1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16657049	7/10/2020	1983	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16660485	7/8/2020	1980	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16664094	7/8/2020		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16669726	7/25/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16670112	7/16/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16673592	7/14/2020	1992	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16673833	7/17/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16674475	7/29/2020	1964	2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16675990	8/28/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16677024	7/16/2020	2015	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16678967	7/17/2020			1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16679246	7/17/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SOMASTIC	
16681968	10/8/2020		2B	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16682324	7/20/2020			1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16683620	7/21/2020		1		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
16684175	8/10/2020		2A	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16685565	7/22/2020		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16686941	7/23/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16687047	7/23/2020	1978		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16689119	7/24/2020			0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16690758	7/30/2020	2017	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16691689	7/27/2020	1980		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16691959	7/28/2020			0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SCOTCH	
16697055	8/6/2020		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16698360	9/3/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16698396	8/20/2020	2020	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16700887	7/31/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16702512	10/1/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16704742	8/6/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16706991	8/13/2020		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16707830	8/17/2020		1	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
16709436	9/1/2020	1967	3	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16712396	8/9/2020		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16712563	9/12/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16712630	9/3/2020	2011	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16716929	8/17/2020	2003	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16717047	8/11/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16718353	8/15/2020	2008	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16718493	8/12/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16727289	9/15/2020	1994	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16729558	8/20/2020		1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
16729660	9/9/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16730870	8/20/2020	1992	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

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16732855	9/21/2020		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16734260	6/9/2021	1992	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16734595	10/14/2020	1987	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16735049	8/28/2020		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16735272	6/9/2021	1969	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16737523	8/25/2020			0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16740559	9/17/2020	1981	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
16740856	8/27/2020	1968	2A	1	MEDIUM	OTHER	PLASTIC		ALDYL A
16742556	9/3/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16746273	8/31/2020	1951	2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16747209	8/31/2020	1990	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16747412	9/16/2020		2B		MEDIUM	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
16747442	8/31/2020	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16748972	9/8/2020	1983	2A	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
16749325	9/1/2020		1	4	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16751546	9/9/2020		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16753981	9/15/2020	1995	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16756927	9/6/2020		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16758786	9/8/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16758962	9/8/2020		1	0.5	HIGH	CORROSION	STEEL	SCOTCH	
16758978	9/15/2020		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SCOTCH	
16761039	9/26/2020	1980	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16762932	6/10/2021		1	0.5	MEDIUM	CORROSION	STEEL	SCOTCH	
16763336	9/11/2020		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16765446	9/15/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16765990	9/12/2020		1		MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16766656	10/16/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16766782	9/12/2020	1993	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16769507	11/14/2020		2B	0.5	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16770655	9/15/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16771453	9/15/2020	1987	1	4	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16775423	9/17/2020	1972	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALLIED
16778940	10/28/2020	1961	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16782260	9/23/2020	2010	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16784970	9/23/2020	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16787084	9/30/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16788337	9/25/2020	2010	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16796702	9/30/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16797262	10/14/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16800152	6/9/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16800582	10/5/2020		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16810087	10/13/2020		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16812116	10/8/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16814647	4/2/2021	1980	2B	1.25	LOW	CORROSION	PLASTIC		ALDYL A
16814955	10/17/2020	1979	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16815783	10/10/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16821867	10/15/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16822233	10/14/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16823546	10/29/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16825901	10/29/2020	2015	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
16827607	11/5/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16828873	10/29/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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16829139	10/31/2020	1983	2B	0.5	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
16830414	6/8/2021		3		MEDIUM	LEAKING JOINTS	STEEL	TAPE	
16830915	10/29/2020		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16831291	10/29/2020		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
16832477	10/21/2020	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16832709	10/26/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16832830	10/29/2020		1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16834906	10/22/2020	1972	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16837392	10/24/2020		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16844272	6/8/2021	1968	2A	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16845423	11/3/2020		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16848121	10/29/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16856952	11/6/2020		1	1.25	HIGH	LEAKING JOINTS	STEEL	SCOTCH	
16857036	3/4/2022	2020	2B	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16857213	11/3/2020		1	4	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
16860607	11/3/2020		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16866687	11/24/2020	1971	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16867100	11/6/2020	1960	1	0.75	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16869386	11/24/2020	1985	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
16869390	11/13/2020		1	1.25	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
16869853	11/6/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16870909	11/18/2020	1975	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
16877694	11/12/2020		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16888684	11/13/2020		1	0.5	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
16902333	11/27/2020	2017	2B	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16911564	11/27/2020		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16916787	11/16/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16917708	11/23/2020	1980	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
16917841	11/16/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16924842	9/20/2021		2B	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16925334	6/18/2022	1985	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16925968	1/30/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16931146	11/24/2020	1972	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
16931221	12/16/2020	2007	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
16944991	12/10/2020		2B	2	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16945057	11/27/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16945581	11/28/2020	1971	1	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16949309	12/7/2020		1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16959469	12/12/2020	1953	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16959513	12/11/2020		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16961272	12/8/2020		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16961413	12/8/2020		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16967548	12/14/2020		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16967548	12/14/2020		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
16967642	4/8/2021	1989	2B	0.75	HIGH	MATERIAL DEFECT	STEEL	SCOTCH	
16971990	12/13/2020	2020	1	0.5	HIGH	CORROSION	STEEL	SCOTCH	
16983988	12/19/2020	1984	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
16984691	1/8/2021	2020	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16984724	11/22/2021	1981	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
16984974	1/25/2021	1992	1	0.5	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
16988432	12/29/2020		2A	1.25	HIGH	OTHER	STEEL	PRITEC	
16988990	12/23/2020		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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16989136	12/23/2020	1997	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
16990325	12/23/2020	1969	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALLIED
16992483	12/28/2020		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16993567	12/28/2020	1995	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
16994504	2/1/2021	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
16994550	1/14/2021		2B	2	MEDIUM	OTHER	STEEL	X-TRU	
16994669	12/28/2020		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
16995246	3/8/2021		2A	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		ALLIED
16996068	12/31/2020		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16999293	1/11/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
16999301	1/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17013725	1/6/2021		1	2	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17015355	1/5/2021	1988	1	0.75	HIGH	CORROSION	STEEL	X-TRU	
17016328	1/14/2021	1971	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17017360	2/15/2021		2B	0.5	HIGH	LEAKING JOINTS	STEEL	SOMASTIC	
17017475	2/8/2021		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17020701	1/12/2021		1	1.25	HIGH	CORROSION	STEEL	SCOTCH	
17020968	1/11/2021		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17022610	1/12/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17024728	1/11/2021	1992	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17025002	1/12/2021		2A	2	HIGH	CORROSION	STEEL	X-TRU	
17025380	1/25/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17027040	1/14/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17027139	6/3/2021	2018	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17027752	2/5/2021		1	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
17028731	1/13/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17030866	1/14/2021	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17031285	1/14/2021	1981	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17031519	1/19/2021	1987	1	1.25	HIGH	LEAKING JOINTS	STEEL	TAPE	
17035149	1/16/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17036363	9/29/2021		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17037460	2/1/2021		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17038407	2/1/2021		2B		HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
17038445	1/19/2021		1	1	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
17038517	2/4/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17042083	2/17/2021	1988	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17044062	2/1/2021		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17047106	2/1/2021	1989	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17047106	5/18/2021	1989	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17054842	2/17/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17055246	1/28/2021		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17057265	1/29/2021		1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17057640	2/10/2021		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17058321	5/18/2021	1993	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17059904	4/29/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17059978	3/17/2021		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17061573	4/22/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17062073	4/22/2021		1	1	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17063841	6/14/2021		2B	2	HIGH	CORROSION	PLASTIC		
17067191	4/23/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17069343	3/23/2021		2B	0.5	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
17069453	2/5/2021		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17075669	4/23/2021		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17077633	12/30/2022	1980	3	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17085276	2/12/2021	1988	2A	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17085959	2/11/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17087926	6/2/2021		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17089493	6/2/2021	1993	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17089563	2/12/2021		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17090256	2/12/2021	1993	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17092581	2/26/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17094171	2/26/2021	2021	2B	0.5	HIGH	CORROSION	STEEL	PRITEC	
17097425	2/16/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17098767	2/17/2021		2A	0.5	MEDIUM	LEAKING JOINTS	PLASTIC		ALDYL A
17101164	2/17/2021		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17102537	2/24/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17111616	4/14/2021		2B	0.5	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17113643	2/24/2021		2A	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17114731	2/23/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17114865	3/29/2021	2006	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17114976	2/23/2021	1993	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17115017	2/23/2021	1999	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17115591	2/23/2021	1982	1	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17117766	2/24/2021	2010		1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17118502	3/9/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17118681	3/6/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17119789	5/26/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17121986	5/27/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17121986	5/27/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17122102	2/26/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17122464	2/26/2021		1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17126772	5/20/2021	2009	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17126993	3/1/2021		1	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
17127506	3/2/2021		1	0.75	HIGH	CORROSION	STEEL	X-TRU	
17129300	3/3/2021	1996	2A	1	MEDIUM	OTHER	PLASTIC		ALDYL A
17131261	3/3/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17132813	3/4/2021		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17132850	3/4/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17133362	4/8/2021	1990	2B	1.25	HIGH	CORROSION	STEEL	SOMASTIC	
17135183	10/25/2021		2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17139658	3/9/2021	2015	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17140121	4/13/2021		2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17143883	3/11/2021	1983	1	0.5	HIGH	OTHER	PLASTIC		ALDYL A
17147327	3/16/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17148302	3/15/2021	1966	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17151422	11/27/2021	1982	2B	0.75	HIGH	LEAKING JOINTS	STEEL	SCOTCH	
17153580	4/21/2021	1997	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17153580	4/21/2021	1997	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17154036	9/7/2021		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17157548	3/19/2021		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17157548	3/19/2021		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17158066	3/22/2021		2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17158896	4/21/2021	1969	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
17159016	3/21/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17159035	3/20/2021	1982	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
17159035	3/20/2021	1982	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
17159261	3/21/2021	1979	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17159585	3/21/2021		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
17159585	3/21/2021		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
17162357	3/23/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17162357	3/23/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17165145	7/6/2021	1988	2B	2	HIGH	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17167179	2/23/2022		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17168411	3/26/2021	2021	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17171713	3/29/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17172359	3/29/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17173776	3/30/2021	1989	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17179361	4/2/2021		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17180210	4/3/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17181280	4/4/2021		1	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17183497	4/22/2021	2021	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17183759	4/6/2021		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17186268	4/21/2021	1996	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17188453	4/8/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17189876	4/14/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17190008	4/9/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17191287	9/9/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17192688	4/12/2021	1969	1	0.5	HIGH	OTHER	PLASTIC		ALLIED
17195147	4/13/2021			0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17195420	4/13/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17195427	4/13/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17196815	6/16/2021	2017	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17196903	4/14/2021	2002	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17197682	4/24/2021		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
17198797	4/15/2021	1975	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17198917	4/12/2022			1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17199032	5/8/2021	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17199330	7/19/2021		3	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17199330	7/19/2021		3	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17199330	7/19/2021		3	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17199330	7/19/2021		3	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17199434	5/15/2021	2019	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
17200073	9/7/2021		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17201123	4/16/2021		1	1	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17201946	4/17/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17203857	4/24/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17208971	4/22/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17209566	4/22/2021	2013	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17210755	4/23/2021	1991	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17210915	4/23/2021		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17210915	4/23/2021		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17212381	4/25/2021		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17216299	4/28/2021	1984	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17216299	4/27/2021	1984	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17216299	4/27/2021	1984	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17219011	4/28/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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17219011	4/28/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17225922	5/6/2021	1990	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17226491	5/3/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17234069	7/22/2021	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17234069	7/22/2021	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17234069	7/22/2021	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17234069	7/22/2021	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17234069	7/22/2021	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17234370	5/22/2021		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17235148	5/8/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17235662	5/29/2021		2B	2	HIGH	LEAKING JOINTS	PLASTIC		
17235771	5/15/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17236388	5/10/2021		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17236988	5/10/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17237419	12/6/2021	1990	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17237419	12/6/2021	1990	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17242371	6/15/2021	1993		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17244174	7/23/2021	1992	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17246935	5/17/2021	2008	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17247062	10/29/2022	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17247062	10/29/2022	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17247062	10/29/2022	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17248391	7/8/2021	1996	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17248898	5/29/2021		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
17248898	5/29/2021		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
17253836	5/21/2021	1979	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17256891	8/24/2021	1987	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17256891	12/6/2021	1987	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17256891	12/6/2021	1987	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17256891	12/6/2021	1987	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17257084	5/24/2021	1994	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17257119	5/25/2021		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17258819	5/25/2021	2000	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17261156	5/26/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17263965	8/24/2021	1970	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17263965	9/9/2021	1970	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17263990	5/27/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17264093	7/26/2021		1	1	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17264093	7/26/2021		1	1	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17264093	7/26/2021		1	1	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17264093	7/26/2021		1	1	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17264093	9/8/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17264646	5/27/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17264865	5/28/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17264865	8/13/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17265897	11/29/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17269177	6/14/2021		1	0.5	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17269177	9/9/2021		1	0.5	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17269466	6/1/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17269510	6/1/2021		1		LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17269590	9/8/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17269720	6/1/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17269779	6/14/2021	1992	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17271644	7/26/2021	1979	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271644	7/26/2021	1979	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271644	7/26/2021	1979	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271644	7/26/2021	1979	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271644	7/26/2021	1979	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271644	9/8/2021	1979	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17271767	6/15/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17272286	7/13/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17272491	7/6/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17273260	6/3/2021		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17273705	6/4/2021		2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17273902	6/3/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275052	6/4/2021	2020	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17275346	7/26/2021	1980	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275346	7/26/2021	1980	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275346	7/26/2021	1980	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275346	7/26/2021	1980	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275346	7/26/2021	1980	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17275346	9/8/2021	1980	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17277983	9/8/2021	1999	1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17278059	8/24/2021	1989	1	1.25	HIGH	MATERIAL DEFECT	PLASTIC		ALLIED
17278059	12/7/2021	1989	1	1.25	HIGH	MATERIAL DEFECT	PLASTIC		ALLIED
17278117	9/10/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17279788	6/8/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17279941	9/10/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17280279	9/10/2021	2016	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282281	6/9/2021	1979	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282339	7/22/2021	2021	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282339	7/22/2021	2021	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282339	7/22/2021	2021	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282339	7/22/2021	2021	1	0.5	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17282494	6/9/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17282741	7/22/2021		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17282741	7/22/2021		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17282741	7/22/2021		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17282741	7/22/2021		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17282741	7/22/2021		1	1	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17282938	6/9/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17284245	6/10/2021	1996	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17286084	6/11/2021		1	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17286272	7/22/2021	2007	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17286272	7/22/2021	2007	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17286272	7/22/2021	2007	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17286272	7/22/2021	2007	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
17289345	6/14/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17290309	7/22/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17291388	9/15/2021	1996	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17291862	7/22/2021	1988	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17291862	7/22/2021	1988	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17291862	7/22/2021	1988	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17291862	7/22/2021	1988	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17291862	7/22/2021	1988	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17291948	9/14/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17292357	6/26/2021	2011	2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17293185	8/13/2021		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
17293231	9/20/2021	1990	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17293480	6/16/2021			1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17293480	9/14/2021			1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17293822	6/16/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17299505	7/27/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17309021	7/1/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17312129	6/28/2021	2010	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17313796	6/29/2021		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17323181	8/7/2021	1979	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17323181	8/7/2021	1979	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17323181	8/7/2021	1979	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17323181	8/7/2021	1979	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17324766	7/15/2021		2B	1	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17328348	7/8/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17328509	7/13/2021	2014	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17330429	7/9/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17332024	7/10/2021	1986	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17332038	7/10/2021	1976	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17332194	7/10/2021		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/23/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17333821	7/26/2021	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17338652	7/17/2021		1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
17346562	7/19/2021	2016	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17348621	7/20/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17348621	7/20/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17349530	7/29/2021	1970	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17349530	7/29/2021	1970	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17349530	7/29/2021	1970	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17349530	7/29/2021	1970	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17349530	7/29/2021	1970	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17349657	8/14/2021	1997	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17352582	9/20/2021	1999	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17352582	12/6/2021	1999	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17352582	12/6/2021	1999	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17352582	12/6/2021	1999	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17355169	7/23/2021	1		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17355169	7/23/2021	1		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17355169	7/23/2021	1		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17355169	7/23/2021	1		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17355169	7/23/2021	1		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17358559	7/26/2021	1		0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17358559	7/26/2021	1		0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17358559	7/26/2021	1		0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17358559	7/26/2021	1		0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17358559	7/26/2021	1		0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17361809	7/28/2021	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17361809	7/28/2021	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17361809	7/28/2021	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17361809	7/28/2021	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17361809	7/28/2021	1		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17363177	8/9/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17369097	7/31/2021	1		2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17373058	8/13/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17375506	8/6/2021	1997	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17375506	8/6/2021	1997	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17377255	8/13/2021	1		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377452	8/5/2021	1		0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17377492	8/13/2021	1		1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17379227	8/19/2021	1977	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17382939	8/11/2021	1		1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17384741	8/10/2021	2016	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
17385884	8/19/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17387491	8/13/2021	1966	2A	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17388267	8/12/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17388267	8/12/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17388267	8/12/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17388267	8/12/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17388267	8/12/2021	2015	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17389558	8/12/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389558	8/12/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389558	8/12/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389558	8/12/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389558	8/12/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389621	8/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389621	8/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389621	8/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389621	8/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17389621	8/12/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17391427	8/19/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17392763	9/2/2021		1		MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
17392763	9/6/2021		1		MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
17393805	6/25/2022		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17393896	9/28/2021		2B	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17395381	8/16/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17396857	8/19/2021	2018	1	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17401674	9/6/2021	1971	2B	1	MEDIUM	OTHER	PLASTIC		ALLIED
17401674	9/1/2021	1971	2B	1	MEDIUM	OTHER	PLASTIC		ALLIED
17402224	8/20/2021	1970	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17407099	8/31/2021		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17412061	8/25/2021		1	0.5	HIGH	CORROSION	PLASTIC		ALLIED
17412061	8/25/2021		1	0.5	HIGH	CORROSION	PLASTIC		ALLIED
17413476	8/25/2021	2020	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17413513	9/16/2021		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17416474	8/26/2021	2018	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17419592	8/28/2021	1974	1	0.5	MEDIUM	CORROSION	PLASTIC		ALLIED
17424217	8/31/2021	1993	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17424229	8/31/2021		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17424260	9/17/2021	1972	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
17428729	9/2/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17439505	9/10/2021	2001	1	0.5	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17445444	9/11/2021	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17448989	9/13/2021		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17449022	9/15/2021		2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17449542	9/13/2021		1	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17452341	11/18/2021	2013	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17460348	9/17/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17461531	11/24/2021		2B	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17463792	9/23/2021		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17467655	9/22/2021	2007	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17471743	10/6/2021	1998	1	1	MEDIUM	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW)
17472033	12/2/2021	1972	1	1	MEDIUM	CORROSION	PLASTIC		ALDYL A
17474827	9/25/2021			1	HIGH	CORROSION	STEEL	SCOTCH	
17475043	11/11/2021		2B	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17475043	11/11/2021		2B	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17479145	10/1/2021	1983	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17479145	10/11/2021	1983	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17479222	10/13/2021		2B	0.5	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17480082	12/2/2021	1998	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17481498	10/1/2021	1981	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17484202	10/6/2021	1993	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17484379	10/6/2021	1996	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17489512	10/1/2021		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17491054	10/8/2021		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17494335	10/6/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17494335	10/18/2021		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17494497	10/4/2021	1970	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17496565	10/9/2021		2B		HIGH	MATERIAL DEFECT	PLASTIC		OTHER
17499107	10/21/2021	1949	2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17500899	10/7/2021		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17500952	10/7/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17503662	10/8/2021	1971	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17509082	10/12/2021	1990	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17509128	10/12/2021		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17511596	10/13/2021		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17512636	10/14/2021	1986	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17526292	10/12/2022	1965	2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17528574	10/22/2021	2021	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17529781	10/27/2021	1992	2A	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17531362	12/30/2022	1968	2B	1	MEDIUM	OTHER	PLASTIC		ALDYL A
17543012	10/29/2021		1	2	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17543612	10/29/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17548689	11/10/2021	1981	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17556128	12/3/2021	1987	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17559110	11/10/2021		1		MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
17559516	11/3/2021	1972	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALLIED
17559708	11/4/2021	2015	1	1.25	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
17562628	11/23/2021		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17565665	3/8/2022		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17566905	11/13/2021	1970	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17570234	11/10/2021	1984	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17571931	11/26/2021		2B	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17572031	11/10/2021	1996	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17572107	11/13/2021	1956	2B	0.75	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17572257	12/2/2021	2010	1	1	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17573121	11/9/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17575474	11/22/2021	1966	2B	0.75	HIGH	CORROSION	STEEL	PRITEC	
17577190	11/10/2021		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17727242	11/11/2021		1	1	MEDIUM	OTHER	PLASTIC		ALDYL A
17739578	11/20/2021		2A	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17740442	11/14/2021	1973	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
17744481	11/14/2021	1982	1	1	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17750249	11/15/2021	1972	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17750360	11/15/2021		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17750592	11/15/2021		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17751077	11/15/2021		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17764040	12/2/2021	1991	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17764292	11/17/2021		1	0.75	MEDIUM	CORROSION	PLASTIC		ALDYL A
17767457	11/18/2021	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17768077	11/24/2021	1983	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17771473	11/19/2021		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17788986	11/29/2021	1981	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17793768	1/11/2022	1970	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17794073	12/6/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17794073	12/6/2021		2A	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17795280	12/1/2021		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17795280	12/1/2021		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17795349	12/2/2021	1994	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17795419	12/1/2021		1	0.5	HIGH	OTHER	PLASTIC		ALLIED
17799645	12/3/2021		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17801339	12/14/2021	1959	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17801368	12/6/2021		1	1.25	LOW	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17804223	12/6/2021		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17804671	12/6/2021	1972	1	0.5	HIGH	OTHER	PLASTIC		ALLIED
17808078	9/13/2022	1988	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17811603	12/9/2021		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17811603	12/9/2021		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17813270	12/11/2021	1969	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
17813923	12/21/2021	1965	2A	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17813923	12/21/2021	1965	2A	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17813923	12/14/2021		2A	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17816686	12/21/2021	1971	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17818032	1/11/2022	2021		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17818056	5/25/2022	1995	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17818242	12/13/2021		1	0.75	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	X-TRU	
17820161	12/14/2021		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17824021	12/18/2021	1971	2A	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17836584	12/27/2021	1984	2A	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17841145	1/3/2022	1989	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17843659	3/22/2022		2B		HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17860964	1/7/2022		1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17861555	2/24/2022	1983	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17873452	2/7/2022	2020	2B	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17874627	1/13/2022			2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17874843	1/13/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17876826	1/14/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17876826	1/14/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17879342	1/18/2022	1993	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
17880713	1/26/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17882681	1/18/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17894365	1/24/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17895606	1/26/2022		2A	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
17896043	2/7/2022	1966	1	0.75	HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
17896046	7/11/2022	1980	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17898128	1/25/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17903384	1/27/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17905493	1/28/2022		1	1.25	HIGH	OTHER	STEEL	X-TRU	
17907405	2/7/2022	1993		0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17909563	2/1/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17913418	2/2/2022		1		LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17923984	2/26/2022		2B	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17925419	3/1/2022		2B	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

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17925792	2/7/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17925792	2/7/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17926968	3/5/2022	1998		0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17926997	2/12/2022	2019	2A	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17927800	2/8/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17929306	6/27/2022		2A	1.25	LOW	CORROSION	STEEL	TAPE	
17931330	2/10/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17931330	2/10/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
17931388	2/14/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17931388	2/10/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17931388	2/10/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17931633	2/10/2022		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17931633	2/10/2022		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
17931811	2/14/2022	1999	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALLIED
17932977	4/8/2022	1965	2B	0.75	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
17933064	2/12/2022		2A	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17934316	2/11/2022		1	1.25	HIGH	CORROSION	STEEL	SCOTCH	
17934745	2/11/2022		1	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
17936364	3/7/2022	1997	3	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17937451	2/14/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17937534	2/14/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17937534	2/14/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17937534	2/14/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17937842	2/16/2022	1982	3	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17941930	3/30/2022		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17942125	2/17/2022		2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17944159	3/1/2022	1971	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17944985	8/15/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17945596	2/18/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17946269	2/18/2022	1985	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17946312	2/18/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
17946469	2/18/2022	1972	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17946700	2/18/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17948055	2/25/2022	1983	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
17948757	2/21/2022	1977	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
17949539	3/31/2022		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17951588	2/25/2022	1986		0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17958695	5/23/2022	1972	2B	1	LOW	CORROSION	PLASTIC		ALLIED
17960387	2/28/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
17961091	2/28/2022	2006		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17961193	3/30/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17962063	3/1/2022	2019	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
17963793	4/1/2022	2006	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17963793	4/1/2022	2006	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17963856	3/3/2022	1969	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
17966347	3/3/2022		1	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17969324	3/4/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
17969792	3/4/2022		1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
17970205	3/23/2022	1981	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
17979997	3/9/2022		1	1	MEDIUM	OTHER	PLASTIC		ALDYL A
17981624	3/10/2022		1		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
17981902	4/15/2022		2B	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
17983852	4/9/2022		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17992441	3/16/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17992631	3/16/2022		1	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17992670	3/25/2022		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18000191	3/21/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18000191	3/21/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18000455	3/22/2022	2019		1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18005610	4/8/2022		2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18007653	6/30/2022		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18007709	3/25/2022	2004	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18009078	4/19/2022	1993	1	1.25	LOW	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18011037	3/31/2022		2B	1	MEDIUM	MATERIAL DEFECT	STEEL	SCOTCH	
18011037	4/4/2022		2B	0.75	MEDIUM	LEAKING JOINTS	STEEL	SCOTCH	
18014833	3/29/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18016585	3/30/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18017308	4/19/2022	2012	1	1	MEDIUM	OTHER	PLASTIC		OTHER
18017372	3/30/2022	1969	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18023868	4/8/2022	1994	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
18024356	4/4/2022	1986	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18033600	4/15/2022	2012	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18036701	4/11/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18039162	4/28/2022	1965	2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18039811	4/15/2022		2B	0.5	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
18042087	4/22/2022	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18043812	4/14/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18046688	4/16/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18053438	4/20/2022		1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18053504	4/20/2022	1998	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18054973	4/21/2022	2022	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18055774	4/27/2022	1989	2A	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
18056241	4/22/2022	1974	1	1	MEDIUM	CORROSION	PLASTIC		ALDYL A
18063200	8/3/2022		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18065036	4/27/2022		1	2	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18066770	5/6/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18067353	4/28/2022	2021	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18069033	5/6/2022	1971	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18069562	5/20/2022	1969	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
18070823	4/29/2022	2014	1	1.25	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
18070928	5/5/2022	1970	2A	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18071640	6/4/2022		2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18076605	5/4/2022		1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18077666	8/4/2022		2B	0.5	HIGH	CORROSION	STEEL	SCOTCH	
18077861	5/4/2022		1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18077880	5/11/2022	2021	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18079893	5/5/2022		2B	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18083572	5/12/2022	1995	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18083572	5/20/2022	1995	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18086364	5/10/2022	1969	1	0.75	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18088766	5/11/2022	1987	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18092972	5/16/2022	1983	1		MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18094983	5/16/2022	1973	1	0.5	HIGH	CORROSION	PLASTIC		ALDYL A
18095009	5/26/2022	1998	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)

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18095009	5/26/2022	1998	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18098037	5/18/2022	2012	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18099957	5/19/2022		2A	1	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
18103413	5/21/2022	1969	1	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
18103652	6/9/2022	2002	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18107361	5/23/2022	2019	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18111070	6/9/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18120519	5/31/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18122497	6/1/2022		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18122613	6/9/2022		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18123289	6/3/2022	2022	2A	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18124539	6/2/2022		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18124670	6/2/2022		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18124702	6/2/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18125242	6/18/2022	1972	2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
18128110	7/11/2022		2B	2	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18128613	6/23/2022	1971	3	1	MEDIUM	OTHER	PLASTIC		ALDYL A
18130823	6/6/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18134401	6/8/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136868	6/13/2022	2014	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136868	6/13/2022	2014	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136868	6/13/2022	2014	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136868	6/13/2022	2014	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136868	6/13/2022	2014	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18136887	6/9/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18138605	6/20/2022	2021	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18138616	6/17/2022	2022	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18140301	6/21/2022	1988	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18141415	6/17/2022		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18143831	7/1/2022		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18144173	6/22/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18145639	6/15/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18145942	6/15/2022		1		LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18147954	6/20/2022	2021	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18152094	6/20/2022		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18152436	6/22/2022	1964	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
18154327	6/21/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18154564	6/21/2022		1	0.75	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18154949	6/23/2022			1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18156269	6/22/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SCOTCH	
18156379	7/1/2022		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18156493	6/23/2022		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18163941	6/27/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18166823	7/1/2022	1971	2A	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18168760	7/11/2022	2014	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18168800	7/1/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18168975	6/29/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18170624	7/1/2022	1980	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18174649	7/6/2022		2A	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18175899	7/1/2022		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18178138	7/6/2022	1928	2A	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18178673	7/5/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	

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18181394	7/6/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18181665	7/7/2022		1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18183663	7/12/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18186764	7/20/2022		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18188636	8/1/2022	2022	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18189973	8/2/2022	2019	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18190169	7/11/2022		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18191940	7/13/2022	2022	1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18197576	7/13/2022	1970		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18197576	8/1/2022	1970		0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18198938	8/2/2022	1996	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18201522	7/13/2022		1	0.75	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	JALBOND	
18203321	8/1/2022	1975	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18205408	7/15/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18207180	7/23/2022			1	LOW	CORROSION	PLASTIC		PLEXCO (YELLOW)
18207848	7/19/2022	1971	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18208162	7/18/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18212146	7/20/2022		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18213831	8/9/2022	1976	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18213930	8/3/2022			1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SCOTCH	
18214499	7/21/2022	1980	1	0.5	HIGH	OTHER	PLASTIC		ALDYL A
18216641	7/26/2022		1		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
18216909	8/9/2022	1995	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18216929	8/9/2022	1995	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18216944	7/23/2022		1	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18219986	7/25/2022		1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18220088	8/3/2022	1971	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALLIED
18223609	7/30/2022	1998	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18225202	7/27/2022	1971	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18227131	7/28/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18227152	8/16/2022		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18232645	8/1/2022	1972	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18236719	8/3/2022	1995	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18237138	8/9/2022	1986	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18238412	8/15/2022	2021	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18241795	8/19/2022	2010	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18244068	8/12/2022	1979	2A	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18244162	8/9/2022	1989	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18244401	8/8/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18246568	8/11/2022	2016	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18249717	8/16/2022	2022	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18249740	8/16/2022	1970	2A	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18250282	8/11/2022		1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18254266	8/14/2022	1995	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18254972	8/15/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18257324	8/22/2022	2014	1	1	MEDIUM	LEAKING JOINTS	PLASTIC		OTHER
18257860	8/16/2022		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18259391	8/17/2022	1969	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18261393	8/19/2022		1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18261498	9/24/2022	1996	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18267270	8/22/2022		1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18272748	8/24/2022	1979	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
18276951	8/26/2022			0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18282375	8/30/2022	2013	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18284887	8/31/2022	2022	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18286823	9/1/2022	2005	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18287390	9/7/2022	1987	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18288649	9/7/2022	1979	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18290324	10/27/2022		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18294814	9/9/2022	2013		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18295253	9/7/2022	1982	1	2	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18296948	9/8/2022	1996	1	4	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18296965	9/9/2022	1976	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18297196	9/8/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18299954	10/27/2022		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18299954	10/27/2022		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18299954	10/27/2022		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18301970	10/3/2022			1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18304840	11/1/2022	1990	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18304840	11/1/2022	1990	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18310723	9/16/2022	2021		1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18314946	10/25/2022		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18314946	10/25/2022		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18314946	10/25/2022		1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18320544	11/14/2022		3	2	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18320544	11/14/2022		3	2	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18320544	11/14/2022		3	2	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18330658	11/1/2022	1985	2B	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
18330658	11/1/2022	1985	2B	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
18330658	11/1/2022	1985	2B	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
18335714	11/3/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18335714	11/3/2022		1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18335940	12/14/2022		1	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
18337456	12/14/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18343057	10/3/2022		1		HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
18343057	10/3/2022		1		HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
18343057	10/3/2022		1		HIGH	CONSTRUCTION DEFECT	PLASTIC		OTHER
18350183	10/5/2022		1	0.5	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
18350183	10/5/2022		1	0.5	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
18350183	10/5/2022		1	0.5	MEDIUM	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
18351737	11/9/2022	2000	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18351737	11/9/2022	2000	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18352293	10/6/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18352293	10/6/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18352293	10/6/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18352293	10/6/2022		1	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18353135	11/9/2022	1986	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18354291	10/12/2022	1995	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18354291	10/12/2022	1995	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18354291	10/12/2022	1995	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18359250	10/11/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18360875	11/11/2022	1973	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18365907	10/18/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18365907	10/18/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
18365907	10/18/2022		1	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18367329	11/3/2022		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18368132	10/18/2022	1983	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18368132	10/18/2022	1983	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18368132	10/18/2022	1983	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18369567	11/16/2022		1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18377397	10/21/2022	1978	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377397	10/21/2022	1978	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377397	10/21/2022	1978	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377426	11/3/2022	1973	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377426	11/3/2022	1973	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377698	10/28/2022	1981	1	2	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377698	10/28/2022	1981	1	2	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18377698	10/28/2022	1981	1	2	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18385918	11/3/2022		1	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18387842	11/3/2022	2018	1	2	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18388679	11/3/2022		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18391511	11/15/2022	1989	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18391511	11/15/2022	1989	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18394099	12/8/2022		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18394099	12/8/2022		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18394099	12/8/2022		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18412990	11/8/2022	2018	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18412990	11/8/2022	2018	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18412990	11/8/2022	2018	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18428469	11/11/2022		1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18448689	11/14/2022	2022	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18469363	11/17/2022	2022	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18477161	11/22/2022		1		MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
18485968	11/28/2022		1	2	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
18488243	12/2/2022		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18488243	12/2/2022		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18488243	12/2/2022		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18507543	12/8/2022		1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18516463	12/18/2022			2	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18517223	12/15/2022		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18522465	12/17/2022	2012	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18530330	12/22/2022		1	1.25	MEDIUM	CORROSION	STEEL	X-TRU	
18537353	12/28/2022		1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18541610	12/28/2022		1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
35M-3881-08	7/8/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
35M-4615-14	3/23/2020	1973	2B	0.5	MEDIUM	CORROSION	PLASTIC		ALLIED
35M-4839-14	1/30/2020		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
35M-4839-14	1/27/2020	2020	2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
35S-5356-15	7/26/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/26/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/26/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/27/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/27/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/27/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/27/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	
35S-5356-15	7/27/2021	1981	2B	2	HIGH	OTHER	STEEL	PRITEC	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
35T-3532-10	10/29/2019		2A	0.5	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
35T-3532-10	11/15/2019	2000	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
40M-1354-05	1/27/2021		2B	1	HIGH	CONSTRUCTION DEFECT	STEEL	PRITEC	
40M-2814-16	7/18/2020	1995	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
40M-2866-16	3/23/2021		2A	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40M-3234-16	3/25/2020		2B	0.5	HIGH	OTHER	STEEL	PRITEC	
40M-4246-08	8/18/2022	1988	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
40M-4456-17	2/1/2021	1965	2B	0.75	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
40M-4765-99	8/18/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40M-5749-11	8/24/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40M-5749-11	8/24/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40M-5804-11	9/30/2020		2B	0.5	HIGH	CONSTRUCTION DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
40M-6205-18	3/11/2019		2B	3	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40M-6715-12	8/15/2020	1980	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
40S-2116-06	8/3/2022		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	STEEL	SOMASTIC	
40S-8348-02	7/29/2020		2B	0.5	LOW	LEAKING JOINTS	STEEL	BARE (INCL. C.I. PIPE)	
40T-1461-90	10/14/2020				MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40T-4245-17	9/2/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
40T-4300-17	8/16/2022	1968	3	1	LOW	OTHER	PLASTIC		ALLIED
40T-4501-17	3/26/2022	1968	2B	0.75	HIGH	CORROSION	STEEL	SCOTCH	
40T-4947-17	3/18/2020	2020	3	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
40T-5792-18	4/24/2021		2B	0.5	MEDIUM	OTHER	PLASTIC		ALDYL A
40T-9981-14	11/13/2019		1	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
45T-5433-14	6/20/2020		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
45T-7463-17	1/29/2020	2011	2B	0.5	HIGH	MATERIAL DEFECT	STEEL	SOMASTIC	
45T-7626-17	2/18/2019	1976	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
45T-8083-18	3/11/2020		2A	0.5	HIGH	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
50M-0184-13	6/30/2022		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-0185-13	10/7/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-0393-18	2/15/2019		2B	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-0573-18	1/14/2020	2005	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
50M-0696-18	6/13/2020	1968	2B	0.75	HIGH	CORROSION	STEEL	SOMASTIC	
50M-1147-04	1/23/2020		2B	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-2239-06	3/4/2020		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-2262-92	6/3/2021		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
50M-2262-92	6/3/2021		2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
50M-2395-14	6/25/2019		2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
50M-2444-14	8/15/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-2461-14	6/28/2019	1970	2B	1	LOW	CORROSION	PLASTIC		ALLIED
50M-2999-98	9/9/2019			4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-3421-92	10/9/2021		2B		LOW	MATERIAL DEFECT	PLASTIC		
50M-3564-07	12/20/2022		3	0.5	HIGH	CONSTRUCTION DEFECT	STEEL	SOMASTIC	
50M-3821-93	6/9/2021		2B	0.75	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-3847-08	4/2/2021	2005	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
50M-3888-98	10/21/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-3993-93	10/21/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-4376-99	6/5/2019	1972	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
50M-4576-09	6/19/2019		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-5934-10	11/11/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-6300-11	5/20/2021	1977	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
50M-6368-11	5/11/2021		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-6940-16	6/30/2022		2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)

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50M-7297-11	10/5/2021		2B	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-8009-12	4/24/2021		2B	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
50M-8009-12	4/24/2021		2B	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
50M-8009-12	9/3/2021		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-8009-12	9/6/2021		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-8012-12	3/16/2020		2A	1	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
50M-8815-02	2/7/2019		2B		MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50M-9063-17	5/18/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50S-0469-18	6/8/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50S-1493-05	4/29/2019	1969	2B	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
50S-6734-16	3/2/2022		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50S-6821-16	11/11/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-0288-18	5/15/2019		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-0398-18	9/8/2020		2B	1	LOW	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
50T-0424-18	1/31/2019		2B	4	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-0424-18	2/8/2019		2B	4	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-0570-18	5/16/2019	2003	2B	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
50T-0629-18	7/1/2019		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-3506-09	3/30/2022		2B		MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
50T-4960-10	8/5/2019	1982	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
50T-6236-11	8/12/2019		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-7388-16	6/15/2022		2B	1	LOW	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
50T-7634-16	2/16/2019		2B	0.5	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-7801-16	9/12/2019		2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-7836-16	4/24/2019		3	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-8393-17	6/18/2020		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-8404-12	5/27/2021		2B	2	MEDIUM	CORROSION	PLASTIC		ALDYL A
50T-8404-12	5/27/2021		2B	2	MEDIUM	CORROSION	PLASTIC		ALDYL A
50T-8745-17	4/17/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-8808-17	11/3/2020		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-8845-17	7/22/2020	1926	2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-9007-17	7/1/2020		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
50T-9281-17	6/3/2019		2B	4	MEDIUM	OTHER	PLASTIC		
50T-9556-18	12/12/2019		1	4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19217419	12/3/2023	1982	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
19159538	11/30/2023	1967	2B	1	MEDIUM	CORROSION	PLASTIC		ALLIED
19201653	12/6/2023	1988	2A	0.5	LOW	MATERIAL DEFECT	PLASTIC		ALDYL A
19198617	12/3/2023	1989	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18911567	12/1/2023		2B		HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19186323	12/7/2023				HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
19188306	12/6/2023	1994	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
19186408	12/5/2023	1976	1	0.5	HIGH	NATURAL FORCES DAMAGE	PLASTIC		ALLIED
19166602	11/6/2023		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19127889	11/3/2023	2000	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
19104219	11/3/2023		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19104004	11/6/2023	2022	1	1.25	LOW	OTHER	PLASTIC		PLEXCO (YELLOW)
19103724	11/6/2023				MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
19090476	11/2/2023	2021	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
19080575	10/1/2023	1967	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
19075663	10/1/2023	1998	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
19080281	10/7/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19071770	10/4/2023	2005	2A	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
19051431	10/4/2023		1	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
19066949	9/30/2023	1971	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
19052734	10/1/2023	2023	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
19040930	10/4/2023	2023	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
15562575	10/4/2023			1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
19038611	10/3/2023	2018	1	0.5	MEDIUM	EQUIPMENT FAILURE	PLASTIC		PLEXCO (YELLOW)
19035721	10/2/2023		1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18823433	10/2/2023		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18773683	8/31/2023	1971	2B	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
19030652	9/9/2023	2023	1	0.5	HIGH	CONSTRUCTION DEFECT	STEEL	PRITEC	
18583731	9/8/2023				HIGH	CORROSION	STEEL	SCOTCH	
19022531	9/6/2023			1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
19022133	9/6/2023		1		HIGH	MATERIAL DEFECT	STEEL	BARE (INCL. C.I. PIPE)	
19017125	9/2/2023	1988	1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
19016680	9/2/2023	2020	1	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
19015257	9/1/2023	1990	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18911412	7/6/2023	1995	1	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
19000115	9/4/2023	2021	1	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18951873	9/5/2023	1980	2B	1.25	MEDIUM	OTHER	PLASTIC		ALDYL A
18962141	9/1/2023	1980	1	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18994542	9/1/2023	1970	1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18994375	9/1/2023	2021	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18966155	9/8/2023	1979	2B	0.5	MEDIUM	OTHER OUTSIDE FORCE DAMAGE	PLASTIC		ALDYL A
18976388	9/8/2023	1981	1	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18969335	9/6/2023	1981	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18983322	9/6/2023	1971		0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18969274	8/8/2023		1		MEDIUM	OTHER	PLASTIC		ALDYL A
17965545	8/8/2023	1989	2A	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18941594	8/5/2023	1969	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18918050	8/5/2023	2013	2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18849616	8/3/2023	1972	2B	4	MEDIUM	OTHER	PLASTIC		ALDYL A
18958678	8/3/2023	2023	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	SOMASTIC	
18956649	8/2/2023	2016	1	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18951911	8/1/2023	2016	2A	1.25	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18893652	8/5/2023	1967	1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18944228	8/5/2023	1986	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18930708	8/1/2023	1968	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18233236	8/4/2023	1971	2B	0.5	HIGH	CORROSION	STEEL	SCOTCH	
18468251	8/8/2023	1970	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18373523	8/8/2023	1974	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18703991	8/8/2023	1996	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18928462	8/7/2023	1985	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18738472	8/4/2023	2023	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18717328	8/4/2023	2011	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18926404	8/3/2023	2000	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18817516	7/1/2023	1987	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18911576	7/7/2023	2008	2A	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18759375	7/4/2023		2B	1	MEDIUM	EQUIPMENT FAILURE	PLASTIC		OTHER
18800479	7/2/2023	1962	2B	0.75	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18900393	7/9/2023	2023	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18887361	7/8/2023		2B		HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18887836	7/4/2023	2020	2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
16633603	7/3/2023	1994	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18870614	7/3/2023	1978	2B	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18887753	7/1/2023	1967	1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18062306	7/1/2023		2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18870546	5/31/2023	1971	1	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
18091088	5/31/2023	2023	2B	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18580675	6/2/2023	2012	2A	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18858387	6/3/2023		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18788664	5/31/2023				MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18751816	6/1/2023	2020	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18853990	6/1/2023	2009	1	1.25	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18808675	5/31/2023	2016	2B	1.25	LOW	OTHER	PLASTIC		PLEXCO (YELLOW)
16751204	5/31/2023	2019	2B	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18754608	6/9/2023	1989	2B	1.25	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18833066	6/8/2023	1971	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
18832973	6/8/2023		1	0.5	HIGH	CORROSION	STEEL	X-TRU	
18828449	6/7/2023		1		HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18811006	6/5/2023		2B	3	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18775921	6/5/2023	1995	2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18821319	6/1/2023	1991	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18819466	6/1/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18817178	4/30/2023	2011	1	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18803143	5/5/2023	2023	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18806625	5/3/2023	2023	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18751686	5/2/2023	1987	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18800585	5/9/2023	2002	1	1	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18427176	5/9/2023	2002	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18594002	5/9/2023	2023	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18371115	5/9/2023	1969	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18350027	5/8/2023	1978	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18654717	5/6/2023	1981	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18797374	5/7/2023	1996	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18797138	5/7/2023	1972	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18582162	4/30/2023		2B	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18788384	5/1/2023	1985	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALLIED
16152939	5/9/2023	1992	3	0.5	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)
18620231	5/8/2023	1994		0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18610672	5/8/2023		1		HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18540176	5/8/2023	1988	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
15184696	5/8/2023		1	1.25	HIGH	LEAKING JOINTS	STEEL	PRITEC	
18162987	5/8/2023	2016	2B	1	LOW	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18515141	5/5/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18369284	5/5/2023			4	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18380404	5/5/2023	2022	1	1.25	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
18141732	5/5/2023	1986	2B	2	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18368113	5/5/2023	1970	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18361074	5/5/2023	1978	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18335749	5/5/2023	2002	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18497611	5/5/2023	2013	1	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18746549	5/5/2023		2A	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18482006	5/4/2023	2022	1	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18468670	5/4/2023	2023	1	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW)

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18420711	5/4/2023		1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18501945	5/4/2023	2022	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18775254	5/3/2023		1	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
15800508	5/3/2023	1996	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18546751	5/3/2023	2022	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18620945	5/3/2023	1989	1	0.5	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18596216	5/2/2023	1998	2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
16658143	4/7/2023	2007	3	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18598890	4/7/2023	1969	1	1	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18611247	4/7/2023	1987	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18749571	4/6/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18570767	4/6/2023	1997	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18561309	4/5/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
17239050	4/5/2023	1997	3	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18537078	4/5/2023	1993	1	0.5	HIGH	CORROSION	PLASTIC		OTHER
18537212	4/5/2023	1993	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18537517	4/4/2023	1992	1	0.5	MEDIUM	CORROSION	PLASTIC		ALDYL A
18537291	4/4/2023	1994	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18542213	4/4/2023	2022	1	1	HIGH	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18525164	4/1/2023		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
15231316	4/1/2023	2010	3	1	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
18583318	3/31/2023	2023	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18564661	3/31/2023	2007	1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18598541	3/31/2023		1	2	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18712804	4/7/2023	1991	2B	0.5	HIGH	OTHER	PLASTIC		PLEXCO (YELLOW)
18742123	4/6/2023	1982	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18739935	4/4/2023	2013	1	1	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
18736430	4/2/2023	2002	1	1	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18689474	4/1/2023	1984	2B	1.25	HIGH	LEAKING JOINTS	STEEL	OTHER	
18708894	4/1/2023	1982	2A	2	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18722972	4/1/2023	2009	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		OTHER
18718017	4/1/2023	1962	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18581092	4/1/2023		1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18717676	4/1/2023	1969	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18629328	3/31/2023		1	1	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18728165	4/6/2023	2002	1	1.25	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18537147	4/6/2023	2021	1	1.25	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18726525	4/5/2023	1928	1	2	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18723073	4/3/2023	1930	1	2	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	STEEL	BARE (INCL. C.I. PIPE)	
18684319	2/28/2023	1974	1	0.5	MEDIUM	OTHER	STEEL	BARE (INCL. C.I. PIPE)	
18675975	2/28/2023	1973	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		ALDYL A
18261498	9/4/2022	1996	2B	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18666159	3/8/2023	2019	1	0.5	MEDIUM	INCORRECT OPERATIONS	PLASTIC		PLEXCO (YELLOW)
18485968	11/8/2022	2022	1	2	LOW	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
18497173	12/2/2022	1983	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18332643	11/30/2022	2010	1	0.5	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18566164	1/9/2023	2023	1	1	MEDIUM	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW STRIPE)
17970068	3/4/2023	1979	3	2	HIGH	EQUIPMENT FAILURE	PLASTIC		PLEXCO (YELLOW)
18669979	3/4/2023	1983	2A	0.5	MEDIUM	CORROSION	PLASTIC		PLEXCO (YELLOW)
18704065	3/2/2023		1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW STRIPE)
18701511	3/2/2023	2023	2B	1.25	LOW	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW STRIPE)
18123031	2/28/2023			0.75	HIGH	CORROSION	STEEL	SCOTCH	

LEAKNO	REPAIRDATE	INSTALL_YEAR	LASTCLASS	PIPESIZE	PRESSURE	LEAKCAUSE	PIPEMATL	COATTYPE	PLASTIC_TYPE
18689817	3/4/2023	1975	1	1.25	MEDIUM	OTHER	STEEL	PRITEC	
15348245	3/3/2023		2B	1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18668736	3/8/2023	1966	2B	0.75	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18644391	3/8/2023	1966	2B	1.25	HIGH	LEAKING JOINTS	STEEL	SCOTCH	
18677462	3/7/2023	1973	1	1.25	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18471959	11/30/2022		2B	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18530330	12/2/2022		1	1.25	MEDIUM	CORROSION	STEEL	X-TRU	
17531362	11/30/2022		2B		MEDIUM	OTHER	PLASTIC		ALDYL A
18670217	3/3/2023	2023	1	0.5	HIGH	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		PLEXCO (YELLOW)
18536979	3/2/2023	1994	1	0.5	HIGH	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18626138	3/2/2023	1986	2B	0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)
18634089	2/7/2023		2B		MEDIUM	OTHER	PLASTIC		ALDYL A
07963156	2/2/2023	1997	2B	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18646181	2/2/2023	1972	2A	0.5	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18543455	2/8/2023	1982		0.5	MEDIUM	NATURAL FORCES DAMAGE	PLASTIC		PLEXCO (YELLOW)
18290324	10/7/2022		2B	1	HIGH	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18360875	11/1/2022	1973	2A	0.5	MEDIUM	MATERIAL DEFECT	PLASTIC		ALDYL A
18594082	2/7/2023			1	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18596065	1/5/2023	1967	1	1	LOW	3RD PARTY (INCL. DAMAGE BY OTHERS)	PLASTIC		ALDYL A
18594526	1/31/2023	1968	2B	0.5	MEDIUM	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18133048	2/9/2023	1999	1	0.5	MEDIUM	NATURAL FORCES DAMAGE	STEEL	SOMASTIC	
18629355	2/9/2023	1988	1	0.75	HIGH	NATURAL FORCES DAMAGE	STEEL	PRITEC	
18554432	2/6/2023	2023	2B	1	MEDIUM	OTHER	PLASTIC		PLEXCO (YELLOW STRIPE)
16431270	2/1/2023	1993	3	0.75	HIGH	LEAKING JOINTS	STEEL	PRITEC	
18561340	1/1/2023	1979	2B	0.5	MEDIUM	NATURAL FORCES DAMAGE	PLASTIC		PLEXCO (YELLOW)
18601032	1/7/2023	2013	1	0.5	MEDIUM	OTHER	PLASTIC		ALLIED
17197039	1/6/2023	2022	3	1	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18596345	1/6/2023	2023	1	1	MEDIUM	EQUIPMENT FAILURE	PLASTIC		PLEXCO (YELLOW)
18581598	1/6/2023	1971		0.5	MEDIUM	NATURAL FORCES DAMAGE	PLASTIC		ALDYL A
18574681	1/3/2023	2023	1	0.5	HIGH	EQUIPMENT FAILURE	PLASTIC		PLEXCO (YELLOW)
18593946	1/4/2023	1964	1	1.25	LOW	CORROSION	STEEL	BARE (INCL. C.I. PIPE)	
18542349	12/31/2022	2023	2A	1	HIGH	LEAKING JOINTS	PLASTIC		PLEXCO (YELLOW STRIPE)
18566812	12/31/2022	1982	1	0.5	HIGH	EQUIPMENT FAILURE	PLASTIC		PLEXCO (YELLOW)
18559752	1/5/2023	1970		0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		ALDYL A
18521697	1/5/2023	1983	2B	2	MEDIUM	MATERIAL DEFECT	PLASTIC		PLEXCO (YELLOW)
18558907	1/4/2023	1969	1	0.5	HIGH	CORROSION	PLASTIC		PLEXCO (YELLOW)
18555010	1/3/2023	2004		0.5	MEDIUM	CONSTRUCTION DEFECT	PLASTIC		PLEXCO (YELLOW)

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2024-3046932

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set I-GS

Response Date: June 03, 2024

IE-I-GS-17

Reference PA One Call locate tickets on page 23 lines 4-12 of PECO Statement No. 1. For gas operations for each year, from 2019 through 2023, provide in Excel format the following:

A. The total tickets received;
B. The total tickets marked per KARL response;
C. The total number of line hits;
D. The total number of 1st party damages;
E. The total number of 2nd party damages;
F. The total number of 3rd party damages;
G. Number of damages due to print errors;
H. The total tickets cleared per KARL response.

RESPONSE:

Please see Attachment IE-I-GS-17.

Responsible Witness: Amy E. Hamilton

	2017	2018	2019	2020	2021	2022	2023
TOTAL TICKETS RECEIVED	186,473	207,583	237,964	221,612	262,140	259,906	218,306
TOTAL TICKETS MARKED PER KARL	126,114	133,116	147,132	137	151,761	140,689	126,675
TOTAL NUMBER OF LINE HITS	469	457	I-	501	508	469	344
TOTAL TICKETS CLEARED PER KARL RESPONSE	49,073	60,626	74,709	64,088	74,944	86,717	69,814
1st PARTY	-	4	2	3	3	7	1
2nd PARTY	68	65	76	72	74	84	52
3rd PARTY	401	388	434	426	431	378	291
PRINT ERRORS	177	162	198	194	175	176	113

Safety First: PECO wants you to call PA One Call *before* you dig.

POCS = 1800-242-1776



To the attention of: _((Enter or merge name here))____

Our records indicate you or someone working on your behalf either struck or damaged PECO's equipment in the past month.

Let's put safety first. Please call PA One Call at 8-1-1 at least three (3) business days prior to starting any digging project.

Coming into contact with any utilities' lines, pipes, or equipment could cause severe injury or even death. The legal and financial impacts could be devastating, too.

The PA Department of Labor & Industry enforces the Pennsylvania Underground Utility Line Protection Act. Accordingly, PECO is required to notify the department of any digging incident involving your striking or damaging our equipment

Please, always call PA One Call *before* you dig at 1-800-242-1776 or 8-1-1.

Cordially,

Patrick Dunham
Manager, Damage Prevention
T: 610-941-1809

peco℠
AN EXELON COMPANY

STOP!

Call PA One Call before you dig
Dial 811

Follow these steps when excavating to avoid utilities and other potential hazards beneath the surface.

	WHEN	WHERE	WHO
1	At least 3 days prior to dig date	All counties in PECO service area	PA One Call at **811** or **(800) 242-1776** *www.pa1call.org*
2	If you have questions about a mark-out or no marks	Counties of: Bucks, Chester, Delaware, Montgomery, Philadelphia, and York	USIC **(800) 811-7981** *www.usicinc.com*

If Steps 1 and 2 don't resolve the issue, contact the appropriate PECO specialist listed below.

3	Bucks County	PECO Inspector: **(267) 264-7185** (cell)
	Chester County	PECO Inspector: **(610) 721-8929** (cell)
	Delaware County	PECO Inspector: **(610) 721-6805** (cell)
	Montgomery County	PECO Inspector: **(267) 716-8405** (cell)
	Philadelphia County	PECO Inspector: **(267) 716-8406** (cell) PECO Inspector: **(610) 721-6807** (cell)
4	PECO facilities damages, electric or natural gas emergencies	**(800) 841-4141**, Option 1

Know what's below.
Call PA One toll-free at 811 or (800) 242-1776

811®
Know what's **below.**
Call before you dig.

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Safe and reliable service

PECO is a leader in the utility industry for rapid response to natural gas odor reports. We have consistently ranked as one of the best companies for natural gas odor response reliability, with the goal of responding in less than one hour. In a year, PECO receives more than 20,000 odor calls, and historically, we have had the best response times in Pennsylvania. Your safety is our priority. We will respond 24 hours a day, 7 days a week.

Committed to safety

We work hard to keep you safe. Nothing is more important than the safety of the people who live and work near our facilities.



We inspect and maintain pipelines and local service lines for more than 548,000 natural gas customers in Bucks, Chester, Delaware, Montgomery, and a portion of Lancaster counties. We use vehicle-mounted and handheld detectors to regularly patrol all of our lines to identify any issues.

It takes commitment and vigilance to maintain a safe and reliable system. We promote natural gas safety throughout the year, working with schools, businesses, first responders, and construction workers to help keep our communities safe.

Help us ensure safety and reliability by recognizing potential hazards, preventing pipeline damage, and reporting natural gas odors and leaks promptly.

Important information

- Report odors
- Recognize potential hazards
- Call 811 before you dig

To report an odor, potential natural gas leak, or other gas emergency:

- Call PECO's emergency number: **1-800-841-4141**

Before you dig:

- Call PA One Call: **811**

For non-emergency questions and concerns:

- Visit our website: **www.peco.com**
- Call PECO Customer Care: **1-800-494-4000**

For more on natural gas safety:

- PECO: **www.peco.com/GasSafety**
- U.S. Department of Transportation: **www.phmsa.dot.gov/pipeline**
- National Pipeline Mapping System: **www.npms.phmsa.dot.gov**
- American Gas Association: **www.aga.org**

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Natural Gas Safety for Everyone

Whether or not you have natural gas service, this important information is for you.

- Report odors
- Recognize potential hazards
- Call 811 before you dig



Call 811 before you dig

Through the PA One Call program, PECO works with contractors, builders, and excavators to prevent damage to underground facilities and promote safety.

Call 811. It's the law: Anyone digging around underground utility facilities must notify PA One Call at 811.* Homeowners, contractors, or anyone planning to dig anywhere must call before they dig—including yards, along streets, or in vacant fields or lots.

811
Know what's **below.**
Call before you dig.

Here's how it works: Call 811 three business days before you dig. PA One Call notifies PECO and other utilities so underground facilities can be marked before construction or digging activity. The service is free for residential customers.

Understanding natural gas markers: Look for brightly colored pipeline markers on above-ground posts or in the roadway. To locate natural gas mains and service lines on or near a property, you must call PA One Call at 811.



What to do if you smell natural gas

It smells like rotten eggs. Natural gas has no natural odor, so an odorant is added to help detect when a leak occurs.

If you smell natural gas or suspect a leak, go outside to where you do not smell gas and call PECO from a safe distance: **1-800-841-4141.**

Call PECO: **1-800-841-4141**



* The Federal Communications Commission approved the use of 811 as the national abbreviated telephone number for commercial and residential consumers to provide advanced notice of excavation activities.



Know what to do about:

A natural gas odor INSIDE: Evacuate immediately and call PECO from OUTSIDE.

- **DO NOT** open or close any windows
- **DO NOT** operate any electrical devices, including lights and appliances
- **DO NOT** use devices such as telephones, cell phones, radios, doorbells, or flashlights
- **DO NOT** smoke, strike a match, or use a lighter
- **DO NOT** start a motor vehicle near the building
- **DO NOT** try to shut off the natural gas service

A natural gas odor OUTSIDE: If you notice a natural gas odor outside, especially near a natural gas meter or around the sidewalk or street, call PECO.

Act quickly: Leaks can occur after nearby construction or ground movement during winter's deep freeze. Reporting a natural gas odor promptly plays a critical role in ensuring safety.

PECO ENERGY COMPANY
STATEMENT NO. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

SURREBUTTAL TESTIMONY

WITNESS: AMY E. HAMILTON

SUBJECT: RESPONDING TO OPPOSING PARTY TESTIMONY REGARDING CONSTRUCTION QUALITY AUDITS AND VACANCY FACTOR

DATED: AUGUST 2, 2024

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SURREBUTTAL TESTIMONY
OF
AMY E. HAMLITON

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Amy E. Hamilton. I am employed by PECO Energy Company ("PECO" or the "Company") as the Vice President, Gas Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 1 and 1-R, respectively.

3. Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the comment and recommendation made by James Glenn, witness for the Local 614 of the International Brotherhood of Electrical Workers, AFL-CIO, regarding the impact that the use of bargaining unit employees ("BUEs") may have on PECO's construction quality audits, as well as his testimony on PECO's vacancy factor.

II. CONSTRUCTION QUALITY AUDITS

4. Q. Please summarize Mr. Glenn's rebuttal testimony regarding the Company's construction quality audits.

A. In his response to Question 8, Mr. Glenn refers to the direct testimony and recommendations provided by Bureau of Investigation and Enforcement witness

Mr. Martin Salamonski regarding the Company's construction quality audits and the use of Senior Contractor Coordinators ("SCCs"). Specifically, Mr. Glenn makes two recommendations. First, he states that the Company should use BUEs rather than subcontractors to perform the work because then "PECO [would have] full control and supervision over the quality of the work done and the necessity and the costs associated with these audits [would be] avoided." Second, he agrees with Mr. Salamonski's recommendation to hire more SCCs "with one caveat." Specifically, Mr. Glenn states that PECO should hire "Senior Distribution Mechanics" and others "trusted with the maintenance of this infrastructure" for the role of SCCs.

5. Q. How does PECO Gas use BUEs today?

A. Primarily, the Company uses its "in-house" gas crews to proactively manage and maintain the distribution system, including by performing work to address leaks. As we continue to reduce the number of leaks on our system through our proactive replacement programs, the PECO Gas crews are doing more construction work that is primarily handled by subcontractors today. That will continue to increase as leaks continue to decrease, however, it is unlikely there will ever be a time when one hundred percent (100%) of the work will be handled in-house because it is not efficient or practical given the ebbs and flows of the number of projects throughout the year,, which can fluctuate depending on weather and competing demands. In other words, if PECO Gas used in-house crews only, it is likely that work force reductions would become necessary throughout the year when the number of planned projects in a given season do not

justify retention of full-time employees. The Company's continued use of subcontractors for a bulk of the construction work provides important flexibility and allows the Company to implement a balanced approach to staffing given the "lumpy" nature of this work.

6. Q. Do you agree with Mr. Glenn that the costs associated with construction quality audits would be "avoided" if the projects were staffed with BUEs?

I disagree. The use of in-house crews would increase labor costs due to the additional level of required supervisory support from foreman and first line supervisors who are responsible for the governance and oversight of the in-house crews. Thus, while the costs associated with performing audits on the subcontractors' work could be reduced, any savings likely would be offset by increased costs associated with staffing more foreman and supervisors.

7. Q. How do you respond to Mr. Glenn's recommendation that PECO should hire "Senior Distribution Mechanics" to fill the SCC role?

A. The SCC role is an open, posted position. In other words, anyone is welcome to apply, including Senior Distribution Mechanics, and any other qualified PECO employee.

III. PECO'S WORKFORCE

8. Q. Mr. Glenn states that IBEW would support PECO's vacancy factor of 2% if PECO can show it will change its hiring practices by offering more competitive wage and benefit packages and expanding its recruitment efforts. How do you respond?

A. As Ms. Humphrey explained in her rebuttal testimony (PECO Statement No. 2-R), PECO's vacancy rate of 2% is entirely correct. With respect to Mr. Glenn's proposal, there is no need to change PECO's hiring and recruitment practices, as they are clearly effective. PECO offers a highly competitive wage and benefits package for its employees. I note that the Company and IBEW have negotiated several collective bargaining agreements, each time reaching a mutual agreement on wages and benefits through good faith discussions. In fact, when gas mechanic schools are offered, PECO Gas receives hundreds of applications well above and beyond the number of available spots.

IV. CONCLUSION

9. Q. Does this complete your surrebuttal testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Amy E. Hamilton, hereby state that I am the Vice President, Gas 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 statements and exhibits listed below 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.

- PECO Statement No. 1

- PECO Statement No. 1-R (Public and Confidential Version)
- PECO Exhibit AEH-1 (Confidential)
- PECO Exhibit AEH-2
- PECO Exhibit AEH-3
- PECO Exhibit AEH-4
- PECO Exhibit AEH-5 (Confidential)

- PECO Statement No. 1-SR

Amy E. Hamilton

Dated: August 5, 2024 — Amy E. Hamilton

PECO Statement No. 2:

Direct Testimony of
Marissa Humphrey

PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: PECO'S NEED FOR RATE RELIEF; EFFORTS TO CONTROL CUSTOMER COSTS AND REDUCE CUSTOMER BILLS; OVERVIEW OF PECO'S ACCOUNTING EXHIBITS AND BUDGETING PROCESS; GAS SALES FORECAST; EXELON BUSINESS SERVICES COMPANY; AND THE CORPORATE ALTERNATIVE MINIMUM TAX

DATED: MARCH 28, 2024

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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) briefly explain PECO's need for rate relief; (2) summarize PECO's efforts to control costs and reduce customer bills since the Company's last approved gas base rate increase in 2022; (3) provide an overview of PECO's principal accounting exhibits, as well as its budgeting process; (4) describe PECO's gas sales forecast; (5) describe the nature and allocation of costs for services that PECO receives from EBSC; and (6) discuss the Corporate Alternative Minimum Tax.

II. NEED FOR RATE RELIEF

5. Q. Why is PECO seeking a rate increase at this time?

A. As detailed in the testimony of Company witness Amy E. Hamilton (PECO Statement No. 1), PECO is the largest combined natural gas and electric utility in the Commonwealth. PECO's gas operations serve a roughly 1,900 square-mile area in southeastern Pennsylvania. In addition to its supply and storage facilities, the Company's distribution system is comprised of over 7,300 miles of gas mains, approximately 480,000 gas services, and 28 gate stations. It takes considerable expertise and significant capital investment and operations and maintenance activities to provide PECO's customers with safe and reliable service. Further, PECO continuously strives to improve its system reliability and safety, customer service, and service offerings to meet evolving customer expectations and needs.

Since PECO last requested a base rate increase for its gas operations in March 2022, PECO has continued to make substantial investments in new and replacement utility plant. Between January 1, 2024 and December 31, 2025, the end of the fully projected future test year ("FPFTY") in this filing, PECO will have invested $786 million in additional gas distribution plant. Continued investment in PECO's gas distribution system is needed to safely and reliably serve customers. The cost of doing so, however, has increased significantly. As detailed further below, inflation and interest rates have risen at a historic pace, which has raised the cost of investment and continues to increase the Company's labor, contracting, and materials expense. The Company has actively worked to mitigate the impact of these increased costs, constraining controllable cost

increases below the rate of inflation. However, as explained in further detail below and in the testimony of Company witness Paul R. Moul (PECO Statement No. 5), without an increase in revenues, PECO's overall returns on capital and common equity will be inadequate, impairing the Company's ability to continue making the reasonable and prudent investments necessary to serve customers.

6. Q. Please provide an overview of the significant capital investments made by the Company since its prior rate request, and the investments planned through December 31, 2025.

A. As noted above, the Company is planning to invest $786 million in additional gas distribution plant between January 1, 2024 and December 31, 2025. These investments undergo a thorough review and approval process as further explained below in Section IV and in Ms. Hamilton's testimony regarding the Company's capital investment planning process.

As discussed in detail in Ms. Hamilton's testimony, the Company's capital investments are focused on system performance, capacity improvement, facility relocation, new business projects, information technology ("IT"), and customer operations. Many of these investments are made in coordination with the goals and requirements of PECO's Long-Term Infrastructure Improvement Plan.

7. Q. What is driving the increase in the Company's operating and maintenance ("O&M") costs since its last gas base rate case?

A. The increased O&M costs are driven in large part by historically high inflationary rates, which have caused a significant increase in the Company's labor, contracting, and materials expense. O&M costs have also grown as additional plant has been placed in service that requires ongoing maintenance. In addition, as described further in Ms. Hamilton's testimony, the Company is incurring additional O&M costs to enhance safety and reliability, address expanded leak surveys and management of "One Call requests," improve customer service, and conduct leak surveys.

8. Q. Please describe the inflationary pressures PECO is experiencing in greater detail.

A. Since the Company's last gas rate case filing in 2022, the United States has continued to experience a sustained and significantly elevated rate of inflation – the highest in forty years.[1] As a result, actual inflation has greatly exceeded the inflationary impacts assumed in the Company's prior gas rate case. The Company expected inflation to range from 2.0% to 2.1% over 2022-2023. Instead, inflation spiked significantly, reaching 7.8% in 2022 and averaging

[1] *See* Databases, Tables & Calculators by Subject, Consumer Price Index for All Urban Consumers (CPI-U), All items in Philadelphia-Camden-Wilmington, PA-NJ-DE-MD, all urban consumers, not seasonally adjusted, U.S. Bureau of Labor Statistics, https://data.bls.gov/timeseries/CUURS12BSA0?amp%253bdata_tool=XGtable&output_view=data&include_graphs=true.

6.25% over that two-year period.[2] As a result, PECO has faced steadily increasing costs, including material prices, contracting rates, and borrowing costs. The inflationary pressures have also significantly pushed up prevailing interest rates as shown by the increase in the thirty-year Treasury yield that serves as a risk-free benchmark rate in many financial products, including thirty-year maturity bonds that are typically issued by utility companies. From a low of 2.01% as of January 3, 2022 to 4.45% as of February 16, 2024, 30 Year Treasury rates have increased at one of the fastest paces in the past thirty years.[3]

9. Q. How has the high inflation environment impacted the Company's borrowing costs?

A. The rise in inflation has directly impacted the Company's borrowing costs. The cost to fund the Company's investments has increased significantly since the Company's last gas base rate case. As stated above, interest rates have increased since the Company's last rate case at one of the fastest paces in history, reaching the highest point in well over ten years.[4] These interest rate increases have pushed up the Company's average cost of borrowing from 3.92% in 2023, as documented in the Company's prior gas rate case filing, to 4.58% forecasted for

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[2] The average 6.25% inflation rate was calculated as the average of the inflation rates in 2022 through 2023 (7.8%, and 4.7%, respectively) per the Consumer Price Index for All Urban Consumers ("CPI-U") for Philadelphia, Pennsylvania.

[3] *See* 30 Year Treasury Rates listed at Daily Treasury Par Yield Curve Rates, U.S. Department of the Treasury, https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_yield_curve&field_tdr_date_value=all.

[4] *Id*.

2025. The Company's cost of debt is further detailed in the testimony of Mr. Moul.

10. Q. Please provide an overview of the Company's sales since its last gas base rate case.

A. Despite the need to incur increased costs to maintain safe and reliable service for its customers and, where possible, improve such service, the Company expects only a modest change in sales going forward. The Company's number of customers is forecasted to increase by an average of 0.8% per year between 2023 and 2025. Sales are forecasted to grow at 1.4% annually over the same period. The Company's modest growth in sales and customers does little to offset the necessary investments the Company must make in its system and the rising cost to operate and maintain it.

11. Q. How have the Company's increased expenditures impacted its rate of return in invested capital?

A. Without an increase in revenues, PECO's gas operations are projected to produce an overall return on investment capital of 5.80%, and a return on common equity of 6.87%, during the twelve months ending December 31, 2025.[5]

As explained by Mr. Moul, 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 to PECO's projected returns would

[5] *See* PECO Exhibit MJT-1, p. 1.

impair the Company's ability to make all of the reasonable and prudent investments in gas distribution infrastructure that are necessary to maintain and enhance the provision of safe and reliable natural gas 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 detailed below.

12. 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 $786 million in gas distribution plant between January 1, 2024 and December 31, 2025. 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 gas customers. Therefore, it is important that the Company maintain its favorable credit metrics in order to minimize customer costs.

III. PECO'S EFFORTS TO CONTROL CUSTOMER COSTS AND REDUCE CUSTOMER BILLS

13. Q. Please describe PECO's efforts to control customer costs and reduce customer bills.

A. PECO works to minimize financial impacts to customers in two ways. First, PECO diligently manages its own expenses to minimize costs for which customers will ultimately be responsible. Second, PECO has implemented customer programs and makes investments that result in customers incurring lower overall energy costs.

14. 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.

15. Q. What are some examples of PECO's efforts to control its costs?

A. The Company (i) actively works to minimize its O&M expenses, including by making investments in technology and equipment to reduce costly repairs on aging infrastructure and deliver other operational efficiencies; (ii) actively manages its employee-related expenses; (iii) works to reduce its financing costs to obtain the lowest rates available; (iv) pursues government funding opportunities to offset costs that customers would otherwise be responsible for; and (v) utilizes the EBSC to improve efficiencies and lower its costs. Indeed, as discussed further below, the Company benefits from the EBSC's procurement opportunities and

economies of scale in many specialized services. Additionally, and as discussed in Section IV below, PECO has rigorous cost-control processes that it performs on a monthly and annual basis to ensure that its spend is aligned with its operational plan.

16. Q. Please describe PECO's efforts to control its O&M expenses in further detail.

A. PECO actively manages its O&M expenses while maintaining, and, where possible, improving, high levels of reliability and customer service in the face of evolving customer expectations. PECO works proactively to identify initiatives to further improve productivity through best practices across the organization, leveraging new technologies, and improving efficiency through initiatives like regional work bundling for contractors. PECO also strives to make prudent investments that will minimize costs in the long-term. Accordingly, it is PECO's practice to prioritize the replacement of natural gas infrastructure partly on the basis of leak performance. This minimizes long-term O&M expenditures related to main repairs and surveying. As discussed in greater detail in Ms. Hamilton's testimony, PECO's replacement strategy has resulted in a significant reduction for incoming gas leaks since 2018. This reduction in leak volume has enabled the company to reduce the growth in costs associated with leak repair, a significant driver of overall O&M costs.

In addition, and as described in Section IV of my testimony, PECO actively manages the creation of its budget, taking reasonable and prudent steps to minimize its O&M expenses and mitigate inflationary impacts on its customers.

Notably, PECO's projected annual O&M growth rate since 2023 is nearly 30% lower than the recent average inflation rate of 6.25% in the Consumer Price Index. While higher than in recent years, customers continue to benefit from PECO's efforts to keep that growth rate well below increases in the Consumer Price Index.

17. Q. What steps has PECO taken to manage its employee benefit costs?

A. PECO actively manages its employee benefit costs to achieve savings to the maximum extent practicable. The Company does this by evaluating trends in benefits and identifying and implementing cost-reduction measures while maintaining competitive compensation and benefit packages to successfully attract and retain employees. As an example, the Company has actively taken initiatives to manage its healthcare costs, which nationally have been trending above the rate of inflation.

The Company has a self-insured healthcare program for employees. Therefore, the Company's projected cost increases are based on assumed employee participation, administrative costs, and actual claims experience trended to the next year based on projected medical-price inflation. The Company engages Willis Towers Watson, a national health plan consulting firm, to complete the actuarial underwriting for its health plans in order to set premiums and determine the cost projections.

PECO has undertaken several initiatives to manage its medical rates, i.e., medical cost per employee, including collaborating with our vendor partners to offer

population health management programs such as a diabetes program for high-risk members; promoting lower-cost care options, including behavioral telehealth visits and virtual physical therapy sessions; implementing utilization management guidelines for our prescription drug formulary; conducting plan audits to ensure contract compliance; and obtaining competitive contract renewals. For example, in 2023 the Company completed a detailed review of its pharmacy benefit manager (prescription drug benefit), as well as the pricing models and contract terms existing in the market, to ensure that the Company receives competitive coverage and pricing. This process resulted in projected premium savings that are being shared between the Company and its employees to help offset increases in medical plan rates. As a result of this initiative and other cost-management strategies, the Company expects its 2024 projected medical care cost trend of 5% to remain well below the 8.9% national-average increase projected by Willis Towers Watson and below the near 7% increase projected for the medical plans disclosed in the 2024 survey of health plan cost trends by The Segal Group, Inc.[6]

18. Q. What steps has PECO taken to minimize 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

[6] *See* 2024 Global Medical Trends Survey, Willis Towers Watson, https://www.wtwco.com/en-se/insights/2023/11/2024-global-medical-trends-survey; What Are the Projected Health Plan Cost Trends for 2024? The Segal Group, Inc., https://www.segalco.com/consulting-insights/2024-health-plan-cost-trend-survey#:~:text=Key%20health%20plan%20cost%20trend%20survey%20findings&text=Per%2Dperson%20cost%20trend%20for,drugs%20replacing%20lower%2Dcost%20therapies.

benefit of customers. In June 2023, PECO successfully priced a $575,000,000, ten-year first mortgage bond ("FMB") offering at a spread of 120 basis points over the ten-year U.S. Treasury for an all-in coupon rate of 4.90%. The deal was well received by investors and the strength of PECO's name and credit profile continue to drive strong investor demand, permitting PECO to tighten the credit spread from the initial launch. The transaction resulted in the third lowest credit spread (i.e., 120 basis points) and fifth lowest coupon for ten-year FMB utility transactions in 2023 at the time of issuance. Additionally, instead of issuing thirty-year bonds in 2023, in light of the unusually high Treasury rates, the Company opted for a ten-year bond to reduce interest expense borne by customers.

19. Q. How has PECO assisted customers in lowering their natural gas usage and energy costs?

A. The Company's gas energy efficiency and conservation programs offer residential customers a mix of rebates to encourage them to upgrade to high efficiency appliances. The Company's Safe and Efficient Heating Program further provides qualifying low-income customers no-cost direct installation measures, such as natural gas furnace and boiler tune-ups and replacements, after that customer has received a Low-Income Usage Reduction Program ("LIURP") audit or free energy check-up under PECO's Act 129 energy efficiency and conservation plan. In addition, the Company's neighborhood gas pilot seeks to reduce customer costs by enabling them to switch to less costly natural gas as a fuel choice. Over 2,000 homes have taken advantage of this program. Company witness Jacqueline F.

Golden (PECO Statement No. 10) discusses the LIURP program, and the neighborhood gas pilot and gas energy efficiency offerings are discussed in further detail in Company witness Doreen L. Masalta's testimony (PECO Statement No. 9).

20. Q. What other programs does PECO have to support its low-income customers?

A. In addition to its gas energy efficiency and conservation offerings, PECO has a suite of low-income-focused programs available to better support the Company's most vulnerable customers. As discussed in more detail in Ms. Golden's testimony, PECO has:

- Implemented a new CAP Percentage of Income Payment Plan program as of December 2022, providing eligible customers with a fixed maximum monthly bill equal to what the CAP customer can afford for utility service (subject to further program requirements). This program provides a substantially higher discount to customers than was previously available, thereby reducing CAP customers' bills.
- Proposed to change the maximum allowable Matching Energy Assistance Fund ("MEAF") grant in order to expand the impact of MEAF and increase the number of customers eligible for the program.
- Continued to conduct outreach and education to customers regarding the Low-Income Home Energy Assistance Program ("LIHEAP"), a Federally-funded grant program that provides supplemental payments to eligible customers' accounts, and supports its customers seeking LIHEAP grants.

IV. OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS

21. 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 Company witness Michael J. Trzaska (PECO Statement No. 3). 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.

22. 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 Pennsylvania Public Utility Commission ("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., Gas 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.

23. 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.

24. 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[7] basis) and related cost elements such as payroll, employee benefits, outside services, etc.

[7] GAAP stands for generally accepted accounting principles.

25. 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").[8] The Commission's auditors found no deficiencies or weaknesses in the way PECO prepares its budgets.

26. Q. Mr. Trzaska presents the budgeted data for the twelve months ending December 31, 2025 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, 2023 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.

27. 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

[8] *See* Focused Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (issued July 2022).

responses to the Commission's rate case filing requirements at 52 Pa. Code §§ 53.52, 53.53, 53.62, 53.64, and 56.56 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.

28. 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.

29. Q. In Paragraph 24 of the Joint Petition for Settlement of PECO's 2022 gas base rate case, PECO agreed that it would provide comparisons of its actual expenses and rate base additions for the twelve months ended December 21, 2023 to its projections in its 2022 case. Has PECO provided these comparisons?

A. Yes. PECO provided the Commission's Bureau of Technical Utility Services, the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate with an update on its Gas Division's actual capital expenditures, plant additions, and plant retirements by month for the twelve months ending December 31, 2023.[9] As described therein, the Company's actual capital expenditures, capital additions, and retirements were greater than its projections in the 2022 gas base rate proceeding.

With respect to O&M expense, PECO spent $149.8 million in 2023 in comparison to the 2023 budget of $143.8 million provided in the 2022 base rate case. The variance is primarily due to increased contractor costs and the volume of leak surveys, new security control programs to comply with cybersecurity directives issued by the Transportation Security Administration, and IT projects to enhance customer experience.

[9] *See* Docket No. R-2022-3031113.

V. GAS SALES FORECAST

30. Q. How does PECO develop its gas sales forecast, generally?

A. The natural gas forecasting process uses multiple regression-analysis models that determine the relationship between monthly gas sales and predictive variables, such as weather, economic indicators, usage trends, and time of year. The modeled results are evaluated using standard statistical criteria (e.g., the Adjusted R-Squared Score, Mean Absolute Percentage Error, t-statistics, and coefficients) to ensure that there are statistically significant relationships between the dependent and independent variables. Further detail is provided in the Company's responses to Commission filing requirements SDR-RR-9 and SDR-RR-10.

31. Q. How does PECO utilize historical weather data in developing its gas sales forecasts?

A. PECO's gas forecasts utilize "weather normal" assumptions based on weather averages from the prior thirty years. PECO's weather normal assumptions are re-calculated annually using the latest thirty-year period. The Company also utilizes weather normals to normalize historical sales results. The Company then analyzes that temperature-normalized historical usage to discern customer usage trends that result from factors other than weather. Out-of-Model adjustments are then made to the modeled forecasts to remain consistent with these trends and address any new growth drivers expected to impact future sales. The results of the forecast are then compared to prior forecasts for consistency and reviewed

with the Exelon Senior Manager of Load Forecasting, the PECO Director of Financial Planning and Business Analysis, and senior management for their approval.

32. Q. What is the economic outlook for the PECO service territory and how does this impact your sales growth expectations?

A. IHS Markit, which is an external vendor that provides economic data to the Company, projects that between 2022 and the end of the FPFTY, annual growth in gross metropolitan product ("GMP") and employment will be 1.8% and 0.8%, respectively.[10] The Philadelphia metropolitan area is coming out of a period of economic recovery, with GMP and employment growing faster than historical trends while facing record-high inflation. Efforts to reduce inflation are expected to slow the economy and ease labor markets in the coming years. This economic outlook is one of several drivers impacting the Company's forecasts.

33. Q. Please describe the results of the Company's sales forecast.

A. Between the HTY and the FPFTY, the Company forecasts total weather normal gas sales to grow 1.4% annually, with 1.3% annual growth in Residential sales and 1.5% annual growth in Commercial & Industrial sales. This modest growth in sales is expected to be driven by customer growth, economic growth, and lower gas prices.

[10] Data from IHS Markit for Philadelphia, PA categorized under "Metropolitan level" as of August 2023.

Over the same period, the number of PECO customers is forecasted to grow by 0.8% per year, with 0.8% annual growth in Residential customers and 0.8% annual growth in Commercial & Industrial customers. Based on the Company's sales and customer forecasts detailed above, use per customer ("UPC") during that same period is forecasted to see moderate growth.

VI. EXELON BUSINESS SERVICES COMPANY

34. 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.

35. 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; 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.

36. 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.

37. Q. What role does the EBSC play in PECO's natural gas 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 natural gas 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.

38. 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.

39. 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.

40. 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.

41. 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 review for reasonableness. This "Market Testing Analysis," developed in conjunction with the Commission's management auditors, is a formal approach for evaluating the cost effectiveness of using the EBSC's shared services. This analysis is performed on an annual basis, and, 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.[11] 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.

42. Q. What is PECO's claim in this proceeding for EBSC services?

A. PECO has included $32.6 million in its FPFTY expense claim for charges from EBSC. A breakdown of those costs is attached as PECO Exhibit MH-1.

[11] *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 (August 2017).

VII. CORPORATE ALTERNATIVE MINIMUM TAX

43. Q. How does the enactment of the Inflation Reduction Act ("IRA") impact PECO?

A. The IRA implemented a new corporate alternative minimum tax ("CAMT") beginning in 2023 that imposes a 15% tax on adjusted financial statement income ("AFSI") on "applicable corporations." Applicable corporations will now be required to pay the greater of 15% of their AFSI or their regular federal tax liability. Based on current tax guidance and forecasted projections, PECO is subject to the CAMT.

44. Q. Is PECO an "applicable corporation" under the CAMT?

A. Yes. The CAMT states that if a corporation's average annual AFSI exceeds $1 billion over the preceding three-year period, then the corporation and its subsidiaries are applicable corporations. Although PECO does not meet that $1 billion threshold on a standalone basis, PECO is a subsidiary of Exelon Corporation. Strictly for purposes of determining if Exelon exceeds the $1 billion in average profits, Exelon must include all of its subsidiaries, including PECO, because Exelon is considered a "single employer group" under the tax rules. If a single employer group in the aggregate exceeds the $1 billion profits threshold, each corporation that is part of that single employer group is considered an "applicable corporation" and separately subject to the CAMT. Under the tax rules, when a subsidiary ceases to be a member of an affiliated group of corporations, the departing subsidiary is entitled to its CAMT credit carryforward

and can utilize that credit in future tax years when its regular tax exceeds its CAMT liability.

45. Q. For CAMT purposes, how is AFSI determined?

A. For purposes of calculating AFSI, the starting point is financial statement net income under GAAP. The GAAP financial statement net income is then adjusted for federal income taxes, accelerated tax depreciation, pension and other postemployment benefits. As a result, for purposes of determining AFSI, federal income taxes, accelerated tax depreciation, pension, and other postemployment benefits are treated the same with respect to the calculation of the regular federal income tax liability.

46. Q. Why does PECO's CAMT liability exceed its regular tax liability?

A. Under tax law, certain expenditures capitalized for GAAP financial statement purposes qualify for accelerated tax deductions, such as tax repairs and certain overhead capitalization. As a result, these expenditures are expensed in the calculation of the regular tax liability sooner than for CAMT, which results in a lower regular tax liability than under the CAMT calculation.

47. Q. How does PECO calculate the CAMT?

A. The Company calculated the CAMT based on its standalone separate company books and records.

48. Q. How is the Company expected to account 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 tax credit equal to the amount by which the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when the regular tax liability exceeds the CAMT liability. The credits are not permitted to be carried back to prior years. For income tax accounting purposes, a deferred tax asset is established for the CAMT credit carryforward.

49. 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 rate making purposes, rate base is adjusted downward to reflect the lower cost of capital attributable to accelerated tax deductions. The CAMT has the effect of reducing the realization of the tax benefits associated with accelerated tax deductions, such as tax repairs and certain other overhead capitalization adjustments (tax repair and certain overhead capitalization deductions do not reduce 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.

VIII. CONCLUSION

50. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit MH-1:

BSC Operations & Maintenance Costs

PECO Energy Co. **PECO Exhibit MH-1**
BSC Operations & Maintenance Costs
Presentation Basis: PECO Gas

($ in millions)

		2025 Budget
1	Legal Governance	1.5
2	Executive Services	2.5
3	Security	2.0
4	Government and Regulatory Affairs & Public Policy	0.3
5	Exelon Utility Operations	1.9
6	Communications	0.4
7	Finance	3.8
8	Human Resources	1.6
9	Real Estate	0.2
10	Supply Services	0.2
11	**Subtotal of Non-IT EBSC**	**14.4**
12	**IT EBSC**	**18.4**
13	Charitable Contributions	0.1
14	Lobbying / Other	0.1
15	**Subtotal of Non-Recoverable Costs**	**0.2**
16	**Total EBSC Charges (excl. Non-Recoverable)**	**32.6**

PECO ENERGY COMPANY
STATEMENT NO. 2-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: RESPONDING TO CERTAIN PROPOSED REVENUE REQUIREMENT ADJUSTMENTS

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
MARISSA HUMPHREY

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Marissa Humphrey. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President, Chief Financial Officer and Treasurer. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 2. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address certain operating revenue and expense adjustments proposed by Bureau of Investigation and Enforcement ("I&E") witness Christopher Keller and Office of Consumer Advocate ("OCA") witness John Defever.

II. RESPONDING TO OPPOSING PARTY ADJUSTMENTS

A. <u>Payroll</u>

4. Q. Please describe Mr. Defever's and Mr. Keller's proposed adjustments to the Company's payroll expense.

A. The Company's proposed payroll expense was forecasted utilizing a 2% vacancy rate. Mr. Defever proposes applying a 4% vacancy rate. Mr. Defever and Mr.

Keller also proposed additional payroll-related adjustments that are addressed in the Rebuttal Testimony of Company witness Trzaska, PECO Statement No. 3-R.

5. Q. Do you agree with Mr. Defever's proposed vacancy rate?

A. No. Mr. Defever derived his proposed 4% vacancy rate by averaging actual vacancies over the five years 2019 through 2023. The Company's forecasted head count for the fully projected future test year ("FPFTY") utilizes a 2% vacancy rate, through which the Company is already taking into account the fact that there will always be a certain level of normal vacancies. It would be unreasonable to utilize a simple five-year average of actual vacancies when the Company's ability to hire and retain workers was significantly impacted in and around 2020-2022 by the COVID-19 pandemic.

Notably, it is also inconsistent with the Company's actual vacancy rate, which is only 1.9% through the first quarter of 2024, already below the 2% projected in the FPFTY. The Company currently has 682 full-time equivalent employees ("FTEs"), and there is a detailed hiring plan in place, putting PECO firmly on track to achieve its projected head count of 701 FTEs by December 31, 2024 and 705 FTEs by December 31, 2025.

A significant number of the Company's new hires in the future test year ("FTY") and FPFTY will be employees in our field operations ("Field Ops"), directly working on PECO's distribution system. These employees will be essential to completing the Company's planned distribution improvements, maintaining system reliability, and continuing to provide customers with top-quality service.

The Company's Field Ops employees are typically hired through PECO's "schools" described below.

The Company's Gas Mechanic school is held annually (with the exception of 2020 due to the COVID-19 pandemic). A Gas Mechanic school has been scheduled for the FTY (October 2024) and the FPFTY (October 2025). The Company has regularly met its hiring projections from its schools. The scheduled schools in the FTY and FPFTY are expected to result in 35 graduates (i.e., FTEs) hired into the Company's Field Ops by the end of the FPFTY.

Each school and its hiring goals are planned based upon current vacancies and forecasted attrition to enable the Company to maintain its required workforce. The schedule and hiring goals of these schools are also planned to align with the Company's Field Ops hiring plan and Gas Operations work plan, which are fundamental to ensuring continued safe and reliable operations, and which also support the Company's Pennsylvania Public Utility Commission ("Commission")-approved long-term infrastructure improvement plan ("LTIIP"). The Company needs to plan years in advance to ensure that it has enough fully trained and experienced employees, some of whom require more than three years of training to implement the Company's work plan and maintain a safe working environment.

As I noted earlier, the Company had to cancel its planned Gas Mechanic School in 2020 due to the COVID-19 pandemic. The cancelling of this school, and the pandemic, continued to have impacts into 2021, 2022 and even 2023, which are reflected in higher-than-usual vacancy rates in those years.

A number of employees will also be hired in the FTY and FPFTY, outside of PECO's schools, to support the Company's customer operations and administrative departments. These employees are expected to primarily support the increases in the Company's work plan, which includes the Commission-approved LTIIP.

B. <u>Incentive Compensation</u>

6. Q. Why did Mr. Defever recommend disallowance of 50% of the Company's incentive compensation plan?

A. Mr. Defever stated that the Company's incentive compensation plan does not appear to provide sufficient motivation to employees and, therefore, does not benefit ratepayers. Mr. Defever also took issue with the fact that at PECO all eligible employees have received awards under the Company's incentive compensation plan. He asserted that incentive compensation should only be awarded to employees that show greater effort, and that employee motivation may be reduced if employees assume they will be awarded a bonus.

7. Q. Did Mr. Defever provide any support for his conclusion that the Company's incentive plan does not appear to provide sufficient motivation to employees?

A. No, and I believe his conclusion is directly contradicted by the Company's actual performance, which is detailed in the testimony of Company witness Amy Hamilton (PECO Statements No. 1 and 1-R).

8. Q: Please explain why recovery of the Company's incentive compensation plan is appropriate.

The Company's Annual Incentive Plan ("AIP") and long-term incentive program ("LTIP") (which includes stock-based and cash-based components) are important and valuable components of PECO's total compensation plan. These incentives are common in the utility industry and necessary to attract and retain quality employees needed to operate the Company.

PECO competes for employee talent against other utility companies in the industry and other companies within its service territory, and it is critical that the Company offer comparable and competitive compensation programs to attract and retain experienced and skilled employees. The Company periodically reviews its compensation programs against peer utility groups to ensure we are able to attract and retain experienced and skilled employees. The Company's compensation plans are comparable to those of its peers in the utility industry.

I have been advised by Counsel that similar incentive compensation tools have been expressly permitted by the Commission. *See*, *e.g.*, *Pa. P.U.C. v. Pennsylvania-American Water Company*, Docket No. R-2020-3019369, Opinion and Order (Feb. 25, 2021), p. 53; *Pa. P.U.C. v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, Opinion and Order (Dec. 5, 2012), p. 26. Additionally, the Commission's 2022 Management Audit of the Company examined PECO's executive compensation and found no issues.

If the Company was unable to offer incentive compensation, it would need to increase its fixed compensation to remain competitive, which could increase payroll expenses even more. The Company determines how its employees should be compensated at each level within the various job categories needed to operate

the Company, and employees' total compensation, inclusive of potential AIP and LTIP awards, is set at that amount. AIP and LTIP are not *in addition* to each employee's compensation amount; rather, they are a part of the total annual employee compensation amount. After determining the appropriate total annual amount that employees should be paid for their work, the Company has a choice – it can either (a) pay its employees a guaranteed annual total compensation amount, or (b) make a portion of that compensation dependent on the overall performance of its employees in key areas designed to benefit customers. Rather than increase base salaries across the board to guarantee a higher level of annual total compensation as set forth in option (a) above, Company leadership has decided that to achieve the best results for customers and the best performance from its employees, a portion of employee salaries should be placed "at-risk," i.e., option (b) above. That "at-risk" portion of annual compensation is the portion represented by AIP and LTIP.

In order to be paid their full potential annual compensation (i.e., to receive the AIP portion, and where applicable, the LTIP portion of their compensation), employees must achieve specific goals that benefit customers through performance. By linking each employee's compensation to the Company's incentive plans, each employee is incentivized to ensure that the Company achieves the highest levels of safety, reliability, and customer service possible. AIP payouts are based on how well the employee, PECO, and Exelon as a whole perform against goals set for the year, which are measured by key performance indicators ("KPIs").

The Company made a deliberate decision to ensure that the incentive plans of all employees have safety, customer satisfaction, reliability, and total operations and maintenance expense levels as key requirements to achieve maximum available compensation, so that all employees are focused on maximizing Company performance in serving customers and minimizing costs. In order to receive total compensation, performance expectations must be met in these critical customer-focused performance categories.

Mr. Defever also appears to not understand, at a basic level, how the Company's incentive compensation plan works. Mr. Defever asserts that every eligible employee always receives an award and that, therefore, the Company's incentive plan does not properly motivate employees. *See* OCA Statement No. 1, p. 10. That is not the case. Individual performance is assessed annually and factored into awards given under the Company's incentive compensation plan through an individual performance multiplier ("IPM"). The IPM can reduce an individual's incentive payout by 50% if they are a limited performer, or even lower for those on performance improvement plans or those who had a "limited impact." Conversely, application of the IPM can reward employees with a payout of up to 120% of their targeted incentive for extraordinary performance. Underperforming employees regularly do not receive their targeted potential incentive, and exceptional employees can receive greater than the target. This component of the Company's incentive plan is specifically designed to differentiate between high performers and lesser performers, to motivate and reward high performance, and is exactly the type of individualized incentive that Mr. Defever stated the

Company's incentive plan lacks. Company witness Hamilton provides evidence of the motivating impact of our incentive programs, documented through continued high performance. *See* PECO Statement No. 1 and 1-R.

9. Q: You noted that the Company's AIP and LTIP are factored into an employee's total compensation. Has Mr. Defever challenged the amount that any employees are paid?

A. No. Moreover, it is worth noting that Company leadership goes to great efforts to make sure its employees are compensated appropriately at market rates. If PECO is denied recovery for portions of its employee costs, then PECO will be denied recovery for compensation costs that no party has even alleged to be unreasonable.

10. Q: Please describe and respond to Mr. Keller's proposed adjustments to the Company's incentive compensation claim.

A. The Company's claim was calculated utilizing the Company's projected 2025 capitalization percentage. Mr. Keller reduced the Company's claim by applying instead a three-year average of the Company's 2021, 2022, and 2023 capitalization percentages.

The capitalization percentages are driven by the work performed in any given year. Therefore, Mr. Keller's adjustment is not aligned with the actual work that the Company is expecting to complete in the FPFTY. And even if such an adjustment were to be made, a subsequent adjustment would also need to be made to increase the Company's rate base relative to the increased capitalization percentage Mr. Keller proposes.

C. **Supplemental Executive Retirement Plan**

11. Q. Did Mr. Defever oppose any other aspects of the Company's compensation?

A. Yes. Mr. Defever proposes disallowing the entirety of the Company's Supplemental Executive Retirement Plan ("SERP"), arguing that the Company has not demonstrated that the SERP has any connection to metrics regarding the provision of utility service and that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

12. Q: Does the Company agree with Mr. Defever's proposed disallowance of SERP expense?

A. No. The SERP is similar to the Company's other post-employment benefit expenses – the main difference being that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Mr. Defever is wrong in concluding that the SERP does not benefit PECO's customers. There are currently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The SERP is a part of these employees' overall compensation and is important to retaining them in a competitive market,

ensuring smooth and safe operations. A study performed by Willis Towers Watson in 2023 revealed that of the 27 utilities surveyed, all of them provide non-qualified benefits to address benefits limited by the IRC. It is important to PECO, and a benefit to customers, that these key employees remain employed at PECO. The SERP, therefore, benefits PECO's customers.

D. Severance

13. Q: Please describe Mr. Defever's and Mr. Keller's reasons for disallowing the Company's severance expense.

A. Mr. Defever asserts that the Company's severance expense should be borne by shareholders since ratepayers should not be responsible for the costs of employees no longer providing utility service. Mr. Defever also noted that the Company does not plan to terminate employees in the FPFTY. However, termination decisions are typically made within a short window based upon performance and, therefore, it would be highly unusual for a company to have long-term plans to terminate specific employees. Mr. Keller noted that Exelon Business Service Company ("EBSC") costs are either billed direct costs or allocated to the Company based on ratios such as a revenue-related ratio, expenditure-related ratio, labor/payroll-related ratio, units-related ratio, asset-related ratio, or a composite ratio. Similar to Mr. Defever, Mr. Keller claims that since severance expense would not be a direct cost to the provision of safe and reliable service, it is inappropriate for PECO to claim an allocated portion of EBSC employees' severance expense for ratemaking. Mr. Keller also notes that no employee time

or services are provided for the payment of severance expense and that there is no actuarial study available for the basis of the Company's FPFTY claim.

14. Q: How do you respond?

A. EBSC employee cost is allocated to PECO based on, among other things, (i) the time employees spend assisting PECO and (ii) the Modified Massachusetts formula. Neither Mr. Keller nor Mr. Defever disputes how these costs are allocated. PECO's utilization of EBSC employees provides significant savings to the Company in business areas including information technology, supply, commercial operations, finance, human resources, government, external affairs, public policy, legal, corporate governance, strategy, and communications. PECO obtains the services of these employees, per its Service Level Agreement with EBSC, at competitive rates that have generated significant savings to customers. As noted earlier in my testimony, PECO operates in a competitive environment to recruit and attract talented individuals to join its team. The same is true for EBSC, which, in turn, offers the services of its employees to PECO and its affiliated regulated utilities. PECO shares in the compensation of these EBSC employees and part of the overall compensation plan provided to certain EBSC employees (to be competitive in the market) is a severance program for certain involuntary separations, allowing the Company to efficiently terminate low performers and upgrade talent when necessary, which helps improve overall Company performance, benefitting customers. PECO has the benefit of the services provided by such EBSC employees at cost, and PECO should also share in such employees' "total compensation plan," which may include severance.

Such severance expenses are directly related to the provision of utility service since they enable EBSC to competitively hire and retain individuals who provide service to PECO. "Total compensation" is regularly reviewed to ensure that employees receive competitive salaries, but not more than the market dictates. Moreover, the Commission recently reviewed the Company's compensation and allocation of EBSC costs to PECO in the Company's 2022 Management Audit, finding no issues with such compensation.

The Company's FPFTY proposed severance expense is reasonable and based on historical expense and estimates. Between 2018 and 2023, the Company averaged about $253,000 in actual severance expense annually and has incurred no less than $184,000 of severance expense in any recent year. In contrast, the Company has only budgeted approximately $92,000 and $95,000 in the FTY and FPFTY, respectively, and believes this is a reasonable estimate since it is significantly less than that experienced in any year in recent history and recognizes that severance expense will be incurred in any given year.

E. <u>Board of Directors and Directors and Officers Liability Insurance</u>

15. Q: Why did Mr. Defever propose a 75/25 sharing of the Company's Board of Directors expense and Directors and Officers ("D&O") Liability Insurance between shareholders and ratepayers?

A. Mr. Defever asserts that the Board of Directors serve the interest of shareholders and, therefore, shareholders are the primary beneficiaries of these costs. Mr. Defever similarly claims that shareholders are the primary beneficiaries of the Company's D&O Liability Insurance since D&O insurance protects PECO and its

officers from lawsuits that arise as a result of their decisions and actions, and such lawsuits are often brought by the Company's shareholders.

16. Q: Do you agree with Mr. Defever's characterization of the Board of Directors, or that shareholders are the primary beneficiaries of the Company's D&O Liability Insurance?

A. No. The Board plays a critical role in supporting the Company and its customers. The Board's responsibilities and its role are set forth in its Corporate Governance Principles, which state:

> The Board is primarily responsible for overseeing the Company for the long-term benefit of the Company's shareholders and the employees, customers and communities served by the Company and its subsidiaries. The Board's responsibilities include, but are not limited to, oversight of the Company's development and execution of strategy and long-range business plan; business operations and performance, including safety and reliability; capital structure and capital allocation, including financing and investments; enterprise risks, including commodity markets, market design, enterprise security (physical and cyber), operating risks, and financial performance; executive compensation; customer experience; corporate citizenship, including sustainability and environmental stewardship, reputation, social responsibility, and ethical business practices; the lobbying, political contributions, and political activities of Exelon and its subsidiaries; and governance practices. The Board and its committees (each, a "Committee") select and oversee senior management, which is responsible for managing the business of the Company under the direction of the Board. In fulfilling its responsibilities, members of the Board provide sound stewardship through informed business judgment and exercising fiduciary duties of good faith loyalty and care. In so doing, directors may rely upon the recommendations of Committees, subsidiary boards of directors, management, outside advisors, and independent auditors.[1]

[1] Exelon Corporate Governance Principles (Approved April 30, 2024), https://www.exeloncorp.com/content/dam/exelon/company/Documents/EXC_CorporateGovernancePrinciples.pdf.

In other words, the Board effectively oversees and advises the Company on all areas of performance, and it is essential to PECO's customers that the Company performs well – especially in areas such as the execution of the Company's long-range business plan and safety and reliability. In addition, strong corporate governance is critical to effectively managing the Company for the benefit of all stakeholders, not just shareholders. Mr. Defever's proposed 75/25 cost sharing ignores the importance of the Board in protecting customer interests.

Furthermore, D&O liability insurance is a necessary and unavoidable expense. The purpose of D&O insurance is twofold. First, it enables the Company to attract and retain talented, competent directors and officers to oversee the conduct of the business and effectively carry out their responsibilities for the benefit of customers with the protections afforded by the insurance program. Second, D&O insurance provides a significant source of balance sheet protection, thereby safeguarding the Company from financial distress and preserving capital for uses that ensure the safe and reliable delivery of service to customers. Therefore, it is a necessary and prudent cost of providing service to customers and, as such, should be fully recoverable by the Company.

Mr. Defever also cites no support for his allegation that shareholders often sue the Company and its officers.

F. <u>Corporate Aircraft</u>

17. Q: Mr. Defever proposed disallowing the entirety of the Company's corporate aircraft expense. How does the Company respond?

A. Corporate aircraft are utilized on occasion by the Company's senior executives and Board of Directors. On certain occasions, other senior employees may also travel on corporate aircraft with senior executives and Board members to reduce expenses and ensure the aircraft are utilized to the maximum extent possible. Given the volume and frequency of travel that we expect of our executives, this use of corporate aircraft is considered both a time efficiency and a security benefit.

Corporate aircraft provide these executives and Board members flexible travel times and allow them to maximize efficiencies and the time they are able to devote to the Company. It is also often difficult for Company senior leaders and Board members to work and collaborate together on commercial flights because of sensitive-information restrictions under various governmental regulatory regimes (e.g., NERC, CIP, NRC, FERC). They have no restrictions on corporate aircraft on meeting, planning, and working with each other. Thus, productivity en route is greatly enhanced since employees can discuss proprietary information aboard corporate aircraft in a secure environment. Corporate aircraft also provide these executives and Board members with needed flexibility to maximize efficiency and the time they are able to devote to the Company. This flexibility also allows them to quickly change travel plans when needed to respond to emergent issues, to avoid potential delays or other incidents that could affect attendance at critical events, and to travel to several locations on a single trip.

III. CONCLUSION

18. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Marissa Humphrey, hereby state that I am the 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 statements and exhibits listed below 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.

- PECO Statement No. 2
- PECO Exhibit MH-1

- PECO Statement No. 2-R (Public and Confidential Versions)

Dated: August 5, 2024

Marissa Humphrey

PECO Statement No. 3:

Direct Testimony of
Michael J. Trzaska

PECO ENERGY COMPANY
STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO'S OVERALL REVENUE REQUIREMENT; CERTAIN RATEMAKING ADJUSTMENTS; AND PECO'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT RIDER

DATED: MARCH 28, 2024

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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, and 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 earned 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 natural gas 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, 2025 ("FPFTY"), a future test year ending December 31, 2024 ("FTY") and a historic test year ended December 31, 2023 ("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 proposed weather normalization adjustment ("WNA") mechanism.

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, and MJT-3.

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 twelve months

[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."

ending December 31, 2025, while the corresponding data for the FTY used to develop PECO Exhibit MJT-2 were derived from PECO's capital and operating budgets for the twelve months ending December 31, 2024. 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 twelve months ended December 31, 2023.

In addition to sponsoring the exhibits described above, I am responsible for responses to certain Pennsylvania Public Utility Commission ("Commission") standard data filing requirements.

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 twelve months ending December 31, 2024 and historic actual data for the twelve months ended December 31, 2023, 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, 2025, 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, 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, 2024. 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, 2023. 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 WNA mechanism.

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) cash working capital; (3) ADIT; (4) customer deposits; (5) customer advances for construction; (6) materials and supplies; (7) the regulatory liability for excess ADIT; and (8) gas storage inventory. 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, 2023, 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, 2024, 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, 2023 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, 2024. Accumulated depreciation on December 31, 2025 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 $3.8 billion.

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.

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, Gas Storage Inventory and Material and Supplies. The claimed levels of customer deposits

and customer advances for construction are deducted in determining the measures of value. The claimed levels of gas storage inventory and material and supplies are added in determining the measures of value. All the claimed levels are based on thirteen-month historic averages for the period ended December 31, 2023, 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 9-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. The sum of the Company's ADIT account and its regulatory liability for excess ADIT on December 31, 2025 is deducted from the Company's measures of value.

The components of the measures of value described above are shown in PECO Exhibit MJT-1 on Schedule A-1 at lines 1 to 13 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 based on the budgeted revenues for PECO's gas operations for the FPFTY. Adjustments were made to: (1) annualize revenues related to changes in the number of customers, including customers on PECO's Customer Assistance Plan ("CAP"), to reflect levels at the end of the FPFTY; and (2) normalize revenues to reflect 365.25 days. These adjustments are summarized on Schedule D-5 of PECO Exhibit MJT-1 and are discussed in more detail later in my testimony.

[2] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2022-3031113 (Order entered October 27, 2022).

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 twelve-month period ending December 31, 2025 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, 2023. 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 FPFTY salaries and wages ("S&W") adjustments, 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 gas and common plant is set forth on Schedule D-17 of PECO Exhibit MJT-1. Each of pages 72 through 74 have columns numbered 1 through 5. Each of pages 75 through 77 have columns

numbered 6 through 11. Each of pages 78 through 80 have columns numbered 12 through 17. Columns 1 through 5 show the annual depreciation for gas distribution and common plant. Column 6 shows the allocation factors used to allocate annual depreciation to the Gas Division. The allocation factor is 100% for gas distribution plant. For common plant, the allocation factor is 23.07%, which is the portion of common plant allocated to the Gas Division. Columns 7 through 11 show the annual depreciation allocated to the Gas Division. These figures are the same as those in columns 1 through 6 for gas distribution plant because it is allocated entirely to the Gas 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 23.07%. Column 12 is designed to allocate utility costs between Commission jurisdictional service and non-Commission jurisdictional service. However, because PECO's Gas Division furnishes only Commission-jurisdictional service, the Functional Allocation Factor shown in column 12 is 100%. Accordingly, the amounts shown in columns 13 through 17 represent the amounts properly allocated in their entirety to Commission-jurisdictional service for the Gas Division. For all of the columns, the total for FERC Account 403 Depreciation Expense is shown on line 65 and the total for FERC Account 404 Amortization of Limited-Term Plant is shown on line 96.

The annual depreciation expense budgeted by the Company for gas distribution plant and total-Company common plant is $172.0 million, which is the sum of the amounts shown in column 1, lines 65 and 96. This amount is the annual depreciation developed by Company witness Caroline Fulginiti (PECO Statement

No. 4) based on utility plant that will be in service on December 31, 2024 (as shown in Schedule D-17, column 3) and utility plant additions that will be in service on December 31, 2025 (as shown in Schedule D-17, column 2). As Ms. Fulginiti explains, the budgeted annual depreciation amounts for both plant-in-service on December 31, 2024 and for additions during the twelve months ending December 31, 2025 were calculated using depreciation rates that reflect the service life parameters developed in the Company's 2018 service life study. The annual depreciation for plant additions made during the twelve-month period ending December 31, 2025 is based on their expected actual in-service dates and, therefore, reflects less than twelve 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 twelve-month period ending December 31, 2025. Depreciation expense does not include Asset Retirement Obligations.

The resulting pro forma FPFTY depreciation expense of $182.7 million related to gas distribution plant and common plant is shown in column 5, line 98. The resulting pro forma FPFTY depreciation expense for gas distribution and common plant allocable to the Gas Division's Commission-jurisdictional service is $117.0 million, as shown in column 17, line 98. That amount is the sum of $101.1 million shown on line 65 and $15.9 million shown on line 96.

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. 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 15, summarize the pro forma measures of value.

Column 2, line 18, shows the Company's gas distribution base rate revenue at present rates. Column 3, line 18, shows the increase over revenues at present

rates needed to recover the Company's FPFTY revenue requirement, which is $111.2 million.

Lines 23 to 45 of column 2 set forth the calculation of the increase above present rate revenue required to provide the Company the opportunity to earn the overall rate of return of 8.08% calculated on Schedule B-7 and supported by Company witness Paul R. Moul (PECO Statement No. 5). The resulting required increase in net operating income on line 41 was increased by the Gross Revenue Conversion Factor ("GRCF"), shown on line 43, to provide for revenue from forfeited discounts, uncollectible accounts expenses, regulatory fees and income taxes on the increased revenues requested. The revenue increase shown on line 45 of column 2 is the difference between present rate revenue and revenues at proposed rates. The increase in unadjusted present rate revenue of $111.2 million is shown on line 45 of column 2 and line 18 of column 3. Column 3, lines 18 through 30, also contain 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 32 of column 4.

17. Q. What is the overall required increase in annual revenues for the Company's gas distribution operations for the FPFTY?

A. As shown on line 45 of PECO Exhibit MJT-1, Schedule A-1, the proposed increase in annual operating revenues is approximately $111.2 million.

18. Q. What is contained in Schedule B?

A. Schedule B consists of a balance sheet for the total Company on December 31, 2025 reflecting the Company's budget for the twelve months ending December 31, 2025 (Schedule B-1); a statement of Pennsylvania jurisdictional net operating income for the twelve months ending December 31, 2025 (Schedule B-2); a statement of Pennsylvania jurisdictional operating revenue for the twelve months ending December 31, 2025 (Schedule B-3); a statement of Pennsylvania jurisdictional operating and maintenance expense for the twelve months ending December 31, 2025 (Schedule B-4); a detailed breakdown of Pennsylvania jurisdictional taxes other than income for the twelve months ending December 31, 2025 (Schedule B-5); PECO's projected composite cost of long-term debt on December 31, 2025 (Schedule B-6); and the calculation of PECO's claimed overall rate of return for the FPFTY (Schedule B-7). Schedules B-6 and B-7 reflect information derived from the exhibits sponsored by Mr. Moul.

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 summarizes the measures of value for the FPFTY for the Company's total Gas Division. 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 Gas Division amounts. The Company's claimed measures of value for the FPFTY, as shown in column 4, on line 13, is approximately $3.5 billion.

B. Plant-In-Service

20. Q. Please describe Schedule C-2 of PECO Exhibit MJT-1.

A. Schedule C-2 contains 5 pages and presents the Company's claimed FPFTY utility plant-in-service.

21. Q. What is shown on Schedule C-2, page 15?

A. Schedule C-2, page 15, is a summary of estimated year-end plant-in-service balances for the FPFTY by functional plant category. Column 4 reflects the Company's estimated gas distribution plant-in-service at the end of the FPFTY of $4.6 billion (line 36), which is shown on PECO Exhibit MJT-1, Schedule A-1, at column 2, line 2.

22. Q. How was total utility plant-in-service for the Gas Division of $4.6 billion, shown on Schedule C-2, page 15, column 4, line 36, determined?

A. The amount of $4.6 billion represents the estimated plant-in-service balance on December 31, 2025 for the Gas Division, exclusive of allocated common plant, and is based on utility plant-in-service on December 31, 2023, plus budgeted capital expenditures estimated to be closed to plant-in-service in the FTY and FPFTY, less the estimated retirements in the FTY and FPFTY.

23. Q. What is shown on Schedule C-2, page 16?

A. Page 16 sets forth the Company's estimated additions to be closed to plant-in-service during the FPFTY. These data were developed based on the FPFTY capital budget. The total-Company additions of $429.2 million are shown on line 33, column 1.

24. Q. What is shown on Schedule C-2, page 17?

A. Page 17 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, 2021 through December 31, 2023.

C. Accumulated Depreciation

25. Q. What is the purpose of Schedule C-3 of PECO Exhibit MJT-1?

A. This schedule, consisting of 3 pages, presents the provision for accumulated depreciation on December 31, 2025 by FERC account, as developed by Ms. Fulginiti, and cost of removal net of salvage, as explained more fully below. PECO's accumulated depreciation of approximately $1.0 billion is summarized on Schedule C-3, page 20, and carried forward to Schedule A-1, line 3.

26. Q. Please describe Schedule C-3, page 20.

A. This page shows the accumulated depreciation balance for the FPFTY by account category.

27. Q. What is shown on Schedule C-3, page 21?

A. Page 21 shows the accumulated depreciation balance by FERC account at the end of the FPFTY. To determine the accumulated depreciation balance at the end of FPFTY, the Company started with the accumulated depreciation balance on December 31, 2023 and added depreciation expense, less retirements and cost of removal net of salvage, for the FTY and FPFTY. Schedule C-3 page 22 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, 2021 through December 31, 2023.

D. Cash Working Capital

28. Q. What is set forth on Schedule C-4, page 23 of PECO Exhibit MJT-1?

A. This is a summary of the Cash Working Capital ("CWC") calculations, which are detailed on pages 24 to 31. The total of $13.7 million shown on line 27 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. Page 23 summarizes the derivation of PECO's revenue collection lag and overall operating expense payment lag. The revenue lag of 48.86 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 10. Line 9 shows the lag associated with the purchase of accounts receivable from natural gas suppliers ("NGS") pursuant to PECO's Commission-approved purchase of receivables ("POR") program. The composite operating and maintenance expense and POR payment lag of 36.04 days is shown on line 13. The net lag of 12.80 days (48.86 – 36.05) shown on line 15 is multiplied by the average daily operating expense balance on line 19 to arrive at the base CWC amount of $17.8 million for operating expenses shown on line 21. The average daily operating expense balance of $1.4 million on line 19 was determined by dividing the total pro forma annual operating expenses, excluding uncollectible accounts expense, of $508.7 million on line 11, column 2, by the number of days in a year, 365. The other components of CWC are shown on lines 23 to 25 and

will be described in connection with my discussion of related supporting schedules.

29. Q. Please describe the revenue lag calculation shown on Schedule C-4, page 24.

A. The total revenue lag days shown on line 29 of 48.86 days consist of three parts. First, the total of the month-end accounts receivable balances for the thirteen months ended December 31, 2023 (shown in column 2 on line 17) was divided by thirteen to calculate an average accounts receivable factor. Annual revenue billed during the twelve months ended December 31, 2023 was then divided by the average accounts receivable balance to calculate an accounts receivable turnover rate of 11.18 (column 4, line 21). A turnover rate of 11.18 is equivalent to 32.65 revenue lag days (365 days divided by 11.18 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 1-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 48.86 days, as shown on line 29.

30. 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 2, or 15.21 days.

31. Q. Please describe Schedule C-4, page 25.

A. Schedule C-4, page 25, 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 2024 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, line 13 and shown on Schedule C-4, page 23, line 7.

32. Q. How did you develop the lag days associated with the purchased gas costs shown on line 8 of Schedule C-4, page 23?

A. The lag in payment of purchased gas costs is based on an analysis of gas payments during the HTY. The total dollar amount of payments during that period was $184.2 million and the average payment lag equaled 33.24 days. The latter figure was calculated using the mid-point of the service period for each of the payments and the payment date for each, averaged for the entire year's worth of data.

33. Q. How was the expense lag of 56.21 days for POR payments determined?

A. PECO pays NGSs 40 days after bill-ready data are provided by the NGSs to the Company for both residential and commercial and industrial accounts. The weighted average payment lag for all accounts is 40 days as shown on page 31, line 3. The NGSs provide bill-ready data (page 31, line 5) to PECO one day after the meter reading date, and there is an average of 15.21 days from the mid-point of a service period to the meter reading date (page 31, line 6). The total payment lag, therefore, is 56.21 days (page 31, line 7).

34. 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 19 to 24 of Schedule C-4, page 25, was derived from data for the four months shown in detail on Schedule C-4, page 26. 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.

35. 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.

36. Q. What disbursements did you eliminate from the balances used on Schedule C-4, page 26?

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 26, lines 1 to 11. The total cash disbursements for all four months of $91.7 million, as shown in column 2, on line 14, of page 26 of Schedule C-4, and the related dollar-days of $3.7 billion, shown in column 3, were used to calculate the payment lag for general expenses of 40.07 days shown in column 4. The 40.07 lag days for Other Disbursements were then brought forward to page 23 of Schedule C-4, line 10.

37. Q. Describe what is shown on Schedule C-4, page 27.

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 $27.4 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 28, column 4. The net payment lag shown on page 28, column 5, is used to calculate the average daily amount for working capital shown on page 28, column 7. The net total of the amounts in column 7 are shown on Schedule C-4, page 23, column 2, line 24.

38. Q. Please describe the calculation of the interest expense lag shown on page 29 and included on Schedule C-4, page 23.

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 42.39 days for a reduction to the working capital allowance of $8.7 million, as shown on page 29 at line 10 and on page 23 at line 25.

39. Q. Please explain how the average prepayments of $2.7 million shown on Schedule C-4, page 30, line 25, were determined.

A. That amount is calculated on Schedule C-4, page 30, and represents the thirteen-month average of actual amounts at the end of each month from December 2022 to December 2023. The Company reviewed its prepaid accounts and selected only those prepaid expenses that were related, in whole or in part, to its gas delivery operations. The resulting prepaid accounts are shown in columns 2 to 14 of page 30. Where the account related to both gas and electric operations, the total and average were distributed using an appropriate allocation factor that eliminates non-gas related expenses, as shown on line 17 in columns 8 to 14. The thirteen-month average for prepaid expenses for the gas distribution operations is $2.7 million as shown on line 25 of Schedule C-4, page 30 and on Schedule C-4, page 23, line 23.

40. Q. What is the total amount of CWC included in the claimed measures of value?

A. That amount is the $13.7 million shown on Schedule C-4, page 23, line 27 and on Schedule A-1, page 1, line 7.

E. ADIT

41. Q. What is the purpose of Schedule C-6?

A. Schedule C-6 shows the December 31, 2025 balance of ADIT that is deducted in determining the measures of value. The ADIT shown on line 19 of $220.3 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. 2), the ADIT includes the deferred tax asset associated with the new corporate alternative minimum tax ("CAMT") implemented by the IRA beginning in 2023.

42. 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.

43. Q. What is the amount of ADIT used in the measures of value?

A. The amount for gas distribution operations is $220.3 million, as shown on line 19 of Schedule C-6 and on line 8 of Schedule A-1, in columns 2 and 4.

F. Customer Deposits

44. 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 in column 4 (lines 1-13) reflect the month-end balances for the thirteen months ended December 31, 2023. 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 gas distribution operations.

45. Q. Where are these amounts of customer deposits and interest shown?

A. The total of customer deposits for all classes of gas distribution customers is a deduction to measures of value of $13.4 million, as shown on Schedule C-7, line 25 and on Schedule A-1, line 9, columns 2 and 4. The calculated interest expense related to these customer deposits of $809,000, 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 45, column 13, line 79.

G. Common Plant

46. 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

47. Q. What is contained on Schedule C-9?

A. This schedule shows the average monthly balance of customer advances for construction of $1.3 million on line 19, which is deducted in calculating the measures of value on Schedule A-1, line 10, columns 2 and 4.

48. Q. How were the monthly balances determined?

A. The Company was able to identify the specific amounts attributable to its gas distribution operations based on a review of its accounting records.

I. Materials and Supplies

49. 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 gas distribution-related amounts and, therefore, 100% of those amounts is shown on line 20 in column 2. The undistributed stores expense shown in column 3 reflects amounts attributable to PECO's total utility operations and, therefore, the gas distribution allocation factor of 23.07% was applied to determine the thirteen-month average of monthly balances, as shown on line 22, in column 3. The claimed amount of $2.1 million reflected in column 4 is based on the thirteen-month average for the period ended December 31, 2023 and is shown on line 11, columns 2 and 4, of the measures of value on Schedule A-1.

J. ADIT – Regulatory Liability

50. 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.

K. Gas Storage Inventory

51. Q. What is shown on Schedule C-13?

A. This schedule shows the calculation of the gas storage inventory included in the measures of value on Schedule A-1. The Company is using the thirteen-month average balance for the period ended December 31, 2023 for each of the stored underground, liquified natural gas and propane components.

52. Q. What is the Company's claimed measures of value in this proceeding?

A. PECO's claimed measures of value, or rate base, equals $3.52 billion, as shown on Schedule A-1, line 15.

IV. REVENUES AND EXPENSES

53. 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 gas 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 $111.2 million in column 3, line 10.

54. Q. What is the indicated net operating income before interest and income taxes at proposed rates?

A. As shown on Schedule D-1, column 4, line 30 and also on Schedule A-1, column 4, line 25, that amount is $300.6 million.

55. 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 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.

56. 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 2 of Schedule D-1. The FPFTY budgeted amounts are shown in column 1 and the revenue adjustment totals are shown in columns 2 to 6. The various expense adjustments are reflected in columns 7 to 18. 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 20.

57. 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

58. 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-5E.

59. 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 retail customer classifications this calculation determines the test-year net distribution revenues at present rates for the FPFTY. The net distribution revenues on line 5 were divided by the average number of customers for the budget for the twelve months ending December 31, 2025 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). The products of those calculations yield additional revenue of approximately $1.7 million for the residential and commercial and industrial customer classes. This pro forma adjustment is then reflected on Schedule D-5, column 2, by customer classification.

60. 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, 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 an increase in the CAP discount of $189,000, which is offset by adjustments for uncollectible accounts factor of 5.5% and CWC factor of 5% as shown on line 15. These offset factors are discussed in more detail by Company witness Jacqueline F. Golden (PECO Statement No. 10). The net change of $169,000 is shown on line 17, which is brought forward to column 3 in Schedule D-5.

61. Q. Please describe the adjustment shown on Schedule D-5C.

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 2025. 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 each thousand cubic feet ("Mcf") of usage and, therefore, are sensitive to the number of days of usage in the test year. Line 1 of Schedule D-5C shows the non-customer and non-reconcilable surcharge distribution revenue by customer class for February 2025. Lines 2 and 4 show the number of days in February 2025 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.

62. Q. Please describe the adjustment calculated on Schedule D-5E.

A. This schedule reflects the elimination of asset optimization revenues representing the Company's net margin from off-system sales and capacity release credits. Customers receive their share of the net proceeds from these sales and capacity releases through the Purchased Gas Cost rate, and the Company retains its appropriate share of the margin, which is recorded below the line for ratemaking purposes.

B. Operating Expense Adjustments

63. 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, rent, etc.

64. 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. 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 and then distributed the FPFTY forecasted S&W to each FERC account 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.

65. 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. 6) in the cost-of-service study.

66. 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.

67. Q. Were each of the pro forma adjustments reflected on Schedule D-4 also assigned to the appropriate FERC accounts?

A. Yes, they were.

68. 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.

69. 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 57 and 58 show the calculation of the pro forma adjustments for overall S&W. Pages 59 and 60 contain the forecasted data for the FPFTY summarized by FERC account categories showing a total to be expensed of $50.8 million in column 1, line 73. Column 2 shows the annualization adjustment of $1.7 million distributed to the FERC expense

categories, while column 3 provides the pro forma amounts for S&W expense, which totals $52.5 million, as shown on line 73. The adjustment of $1.7 million is reflected on Schedule D-4, column 3.

70. Q. How was the annualization adjustment derived?

A. The calculation is shown on Schedule D-6, pages 57 and 58. 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 2.5% wage increase for union employees forecasted to be effective on January 1, 2025 (lines 7 to 9 in column 2); (2) the 3.0% wage increase for non-union employees forecasted to be effective on March 1, 2025 (lines 7 to 9 in column 3); (3) the projected 2.5% wage increase for union employees to be effective on January 1, 2026 (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, 2026 (lines 13 to 15 in column 3).

71. Q. Please explain the adjustment shown on Schedule D-6, page 58, lines 6 to 10.

A. This adjustment normalizes a cash payment to union employees made in connection with the ratification of current union contracts in March 2021. The portion of the payment that was expensed ($1.303 million) was split between electric distribution, electric transmission and gas operations, and the amount allocated to gas distribution operations $249,000 was divided by six to reflect the

six-year term of the contract. The resulting amount of $42,000 shown in column 2, line 10, was added to the pro forma adjustment for S&W.

72. Q. Please explain the calculations shown on Schedule D-6, page 58, columns 1 and 2, lines 15-19.

A. These calculations annualize an increase in the number of employees during the FPFTY. As shown in column 2, line 15, the projected number of Company employees at the end of the FPFTY is 705. The average number of employees during the FPFTY is projected to be 703, which is the figure that the Company used to develop the S&W in its budget which is shown on line 1. The detailed calculation of the average number of employees included in the budgeted expense level is shown on Schedule D-8, page 62, in lines 2 to 15. The increase in employees shown in Schedule D-6, page 58, line 17, was multiplied by the average annual S&W per employee shown on line 18, to determine the total annualization adjustment to S&W of $126,000 due to the increase in number of employees, as shown on Schedule D-6, page 58, line 19.

73. Q. What is the total pro forma adjustment for S&W expense for the FPFTY?

A. The total amount is $1.695 million, which is an increase of 3.34% from the Company's S&W budget for the FPFTY, as shown on Schedule D-6, page 58, lines 23 and 25.

74. 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 $15,000 on this filing during the twelve

months ended December 31, 2023 (line 4) and has budgeted an additional $2.129 million (line 9) during the twelve months ending December 31, 2024. This total, $2.144 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 $1.072 million, as shown on line 17, column 2.

75. 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 $18,000 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.

76. 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 twelve-month average of employees that is reflected in the Company's budget. I compared the twelve-month average to the number of employees reflected in the budget to be employed on December 31, 2025. 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.

77. 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 gas distribution operating expense in the FPFTY is $973,000, as shown on line 13, while PECO's FPFTY budgeted amount for pension expense is a credit of $17,000, as shown on line 14. Accordingly, an adjustment of $990,000 has been made to the Company's FPFTY budget amount to reach the claimed amount of $973,000, as shown on line 15, and the adjustment amount was brought forward to Schedule D-3, column 10, line 95.

78. 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, 2021 through December 31, 2023. 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 0.3692% shown on line 4, column 4, of Schedule D-10 is applied to the pro forma revenues at present rates for the FPFTY to calculate the general pro forma uncollectible accounts expense of $3.0 million shown in column 6 on line 14. A three-year average of PPA write-offs associated with the CAP program, which are not included in other accounts, was developed on lines 16 to 20 of Schedule D-10 and

added to the general uncollectible accounts expense. The PPA average is $0.5 million, as shown on line 20 in column 6. The total pro forma amount for uncollectible account expenses at present rates for the FPFTY is $3.6 million, which is a net increase of $899,000, as shown on line 26 and brought forward to Schedule D-3, (column 11, line 80). In addition, the 0.3692% 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.

79. Q. Please describe the pro forma adjustment on Schedule D-11.

A. Schedule D-11, page 65, column 2, line 3 reflects the incremental costs of $350,000 associated with PECO's proposed changes to its residential energy efficiency program as described by Company witness Masalta (PECO Statement No. 9). Schedule D-11 also includes an adjustment to reduce PECO's revenue requirement in this case by the amount of unspent funds collected in base rates for the Company's commercial energy efficiency programs during the period of January 1, 2022 through December 31, 2023. In total, these two adjustments increase PECO's revenue requirement by $321,000 as shown column 2, line 5 and brought forward to Schedule D-3, column 12, line 111.

80. 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 8.0% and a monthly rate of

0.667%. An annual rate of 5.1% (a monthly rate of 0.425%) was used for commercial and industrial customers. The total pro forma expense of $809,000 is shown on Schedule D-12, line 33 and brought forward to Schedule D-3, column 13, line 79.

81. Q. Please explain what is shown on Schedule D-13.

A. Schedule D-13 shows the adjustment needed for PECO to recover costs to remediate former manufactured gas plant ("MGP") sites consistent with standards established by the Pennsylvania Department of Environmental Protection ("PADEP"). Each year, PECO reviews and updates the activities and costs associated with MGP remediation based on a report from its site consultants.

In PECO's 2020 gas base rate case, the Commission directed the Company to recover the remaining remediation costs over a 14-year period.[3] The figure of $14.309 million on line 1 reflects the amount PECO will not have recovered for its MGP remediation liability in its current rates as of December 31, 2024. PECO is proposing to recover the regulatory asset for the remaining unrecovered MGP remediation liability over 10 years, as shown on line 2 of Schedule D-13 and, therefore, has reflected an annual amortization amount of $1.431 million ($14.309 million/10 years) in its operating expense claim in this case, as shown on line 4 of that schedule.

[3] *Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021), pp. 122-123 ("2020 Gas Rate Case Order").

82. Q. How does PECO propose to recover any future changes in its estimated unrecovered MGP remediation costs?

A. Consistent with the framework approved by the Commission in prior rate cases, PECO previously established a regulatory asset to track and record any differences (positive or negative) between the annual amount of MGP remediation costs collected from customers through base rates and its updated MGP remediation liability from its site consultants, net of insurance recoveries, experienced during the applicable year. PECO proposes to reset its MGP remediation expense allowance in its next rate case based on a normalized annual level of the net balance of the regulatory asset. PECO believes this ratemaking treatment permits the Company to recover its costs in a reasonable manner while protecting customers and PECO from funding requirements if there is an over-or under-recovery during the MGP remediation process.

83. Q. Please describe the adjustments for miscellaneous items shown on Schedule D-14.

A. First, as noted by the Commission in the 2020 Gas Rate Case Order (pp. 122-23), PECO agreed to pay interest on the monthly balance of MGP funds that are not yet spent on remediation activities at the residential mortgage lending rate specified by the Secretary of the Pennsylvania Department of Banking and Securities after July 1, 2021. Line 1 reflects the total accrued interest of $1.387 million as of December 31, 2023 that has been applied to reduce PECO's revenue requirement in this case. As part of this proceeding, PECO proposes to collect interest on the monthly balance of MGP funds that are not yet collected from

customers at the same interest rates the Company used to pay interest as described above. Second, Schedule D-14 includes an adjustment to recover a small under-collection balance $63,000 from customers associated with the final reconciliation of the Company's Federal Tax Adjustment Credit ("FTAC") described by Company witness Megan A. McDevitt (PECO Statement No. 8). In total, these two adjustments reduce PECO's revenue requirement by $1.3 million, which is normalized over two years to arrive at the annual adjustment amount of ($662,000) shown in column 2, line 5.

84. Q. Please describe the adjustments shown on Schedule D-15.

A. Schedule D-15, page 69, contains two adjustments to PECO's expenses related to its Gas Procurement Charge ("GPC") rate and Merchant Function Charge ("MFC") uncollectible write-off factors. First, PECO's expenses must be adjusted accordingly to reflect GPC-related reductions based on procurement-related costs. In 2013, PECO reached a settlement in Docket No. P-2012-2328614 to unbundle certain annual procurement costs from base rates and include those costs in its Price to Compare. In compliance with that settlement and the regulations set forth at 52 Pa. Code Sections 62.221-62.225, PECO unbundled certain procurement costs from its base rates for non-shopping participants in its Low Volume Transportation ("LVT") program, which consists primarily of residential and small business customers who are eligible for PECO's Supplier of Last Resort service. The GPC-related reduction is shown in column 2, line 7.

Schedule D-15 also includes an adjustment to PECO's distribution expenses related to its MFC charge. Consistent with the settlement of PECO's 2010 gas rate case, PECO was authorized in Docket No. P-2012-2328614 to implement a MFC to recover uncollectible accounts expenses related to gas supply.

PECO has applied the total cost reduction of $2.9 million to its total distribution expense for each impacted class as shown in Schedule D-15, column 2.

C. Taxes – Other Than Income Taxes

85. Q. Please describe Schedule D-16 of PECO Exhibit MJT-1.

A. Schedule D-16 contains two pages. Page 70 is a summary showing the budgeted amounts for the FPFTY (column 1) for the Company's Gas Division, the total pro forma adjustments (column 2), and the pro forma expenses claimed in this case (column 3). The calculations of payroll-related changes are made on Schedule D-16, page 71. The increase in payroll taxes, shown on page 71, 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 $144,000. This amount is then reflected on page 70 in column 2, line 6.

D. Depreciation Expense

86. Q. What is shown on PECO Exhibit MJT-1, Schedule D-17, pages 72 to 83.

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 gas distribution and common plant. Schedule D-17 starts with the annual depreciation for gas distribution and common plant developed by Ms.

Fulginiti and presented in PECO Exhibit CF-3. The adjustments set forth on Schedule D-17, in addition to allocating a portion of common plant to the Gas Division, annualize depreciation expense related FPFTY additions to reflect a full year's depreciation for that plant. PECO's total depreciation expense annualization adjustment for the Company's gas business is $6.9 million, which is the sum of the amounts shown on Schedule D-17, column 16, line 65 and 96.

E. Income Taxes

87. Q. Please describe the income tax calculation shown on PECO Exhibit MJT-1, Schedule D-18, pages 81 and 82.

A. This schedule calculates the pro forma income tax expense for the FPFTY at present and proposed rates, as set forth in columns 1 and 3, respectively. Line 1 shows the revenue at present rates, the revenue increase (with the related forfeited discounts increase), and revenue at proposed rates. Line 2 shows the total operating expenses at present rates, changes related to the revenue increase and at the proposed rates from Schedule D-1. Line 3 shows the operating income before interest expense and 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 recommended by Mr. Moul on line 6. 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 7.99% was used to determine the pro forma current state income tax (expense)/credit shown on line 26. Federal income tax is calculated on lines 28 to 41 with a Federal corporate income tax rate of 21%. Line 43 shows the total current state and Federal income tax (expense)/credit 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)/credit 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 the ITC for gas distribution plant, including the portion of common plant allocated to gas distribution, as shown on line 59.

88. 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, 2025 reduces income tax expense at both present and proposed rates, shown on Schedule D-18, page 82.

89. 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 82, 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 impact of the CNI reduction in 2023 was incorporated in the Company's 2022 base rate case

proceeding under Docket No. R-2022-3031113 with a 9-year amortization for the associated excess ADIT. Schedule D-18, page 82, line 50 reflects the annual amount of the regulatory liability to be flowed back to customers over a period of 9 years.

90. Q. Has PECO included a consolidated income tax adjustment ("CTA") in its calculation of Federal income tax expense?

A. No, it has not, because such an adjustment is no longer authorized under Section 1301.1(a), which was added to the Public Utility Code by Act 40 of 2016. Act 40 became law on June 12, 2016 and was effective sixty days later (August 11, 2016) to "all cases where the final order is entered after the effective date of [Section 1301.1]." Consequently, Section 1301.1 applies to this case. Section 1301.1(a) specifies how the Commission is to compute income tax expense for ratemaking purposes. Section 1301.1(b) states how any incremental internally-generated funds produced by the application of Section 1301.1(a) should be used by an affected utility pending the December 31, 2025 "sunset" of Section 1301.1(b).

91. Q. What does Section 1301.1 direct the Commission to do in calculating income tax expenses for ratemaking purposes?

A. In summary, Section 1301.1(a) provides that current and deferred income taxes of a Pennsylvania utility are to be calculated for ratemaking purposes based only on the income, deductions, and credits of the utility itself. Therefore, the Commission may not take into account income, deductions (including taxable losses), or credits of the utility's parent or affiliated companies with which it joins in filing a consolidated Federal income tax return. This is generally referred to as

a "stand-alone" computation of income tax expense because it reflects income tax expense of the utility standing alone and without regard to taxable income, deductions or credits of other companies in the same consolidated group.

92. Q. How does Section 1301.1(a) change prior Commission practice?

A. Section 1301.1(a) terminates the practice of making a CTA when calculating a utility's Federal income taxes for ratemaking purposes in Pennsylvania. As directed by prior decisions of Pennsylvania appellate courts, the Commission, until Act 40 became effective, was required to calculate CTAs employing the "Modified Effective Tax Rate Method." Under the Modified Effective Tax Rate Method, the consolidated tax savings generated by the non-regulated companies of a corporate group were allocated to the regulated and non-regulated members of the group having positive taxable incomes. CTAs, therefore, captured a portion of the tax benefits of deductions and losses of unregulated affiliates of public utilities and gave those benefits to the utilities' customers (as lower income tax expense than the utilities would have on a stand-alone basis) even though the utilities' customers did not pay the expenses that gave rise to those tax benefits. With the enactment of Act 40, Pennsylvania joins the majority of other jurisdictions, including the Federal Energy Regulatory Commission, that do not make CTAs for ratemaking purposes.

93. Q. What does Section 1301.1(b) provide?

A. Section 1301.1(b) states as follows:

> If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> (1) fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
>
> (2) fifty percent for general corporate purposes.

Section 1301.1(b) will no longer apply after December 31, 2025.

94. Q. Have you calculated the "differential" in income taxes referenced in Section 1301.1(b)?

A. Yes, Schedule D-18, page 83 sets forth the computation of a CTA using the Modified Effective Tax Rate Method and data for tax years 2018 through 2022, which are the most recent five years for which tax returns have been filed. Column 7, line 28 shows the "differential" corresponding to the CTA calculated in the manner I described above.

95. Q. Does PECO propose to invest 50% of the differential in rate base-eligible reliability projects or other infrastructure improvements?

A. Yes. PECO's capital budget calls for overall gas distribution plant additions of approximately $345 million during the twelve months ending December 31, 2024 and $429 million during the twelve months ending December 31, 2025. As stated in Ms. Hamilton's testimony, these investments will target reliability projects and

other infrastructure improvements. These infrastructure improvements will support PECO's compliance with Act 40.

96. Q. What is PECO's total income tax expense claim in this proceeding?

A. As shown on Schedule D-18, page 82, line 61, column 1, pro forma income tax benefit at present rates equals $14.4 million. The increment for income tax expense associated with the proposed revenue increase is shown in column 2, in the amount of $30.2 million, and the total pro forma income tax credit at proposed rates of $15.9 million is shown in column 3.

97. 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, 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

98. 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.

99. 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.

100. 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.

101. Q. What is contained on Schedules B-1 to B-5?

A. These schedules contain budgeted financial data for the FTY.

102. Q. Please describe Schedules B-6 and B-7.

A. These two schedules contain the FTY pro forma capital structure and rate of return developed by Mr. Moul. As shown on lines 1 to 3 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.

103. 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 $3.2 billion, as shown on column 4, line 13.

104. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of five pages and shows the utility plant-in-service balances on December 31, 2024 for the Company's gas operations, as well as the additions, retirements, and adjustments for the FTY. Pages 18 and 19 contain the summary of pro forma plant-in-service balances by plant grouping. Page 15 shows the plant-in-service by FERC account. Pages 16 and 17 show the additions to plant and retirements from plant during the FTY. Finally, adjustments to plant are reflected on pages 18 and 19. The total pro forma plant-in-service at the end of the FTY is $4.2 billion and is shown on Schedule C-2, page 15, column 4, line 36.

105. Q. Please describe Schedule C-3.

A. Schedule C-3 contains three pages and shows the accumulated depreciation on December 31, 2024. 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 $971.4 million, as shown on page 20, column 4, line 36.

106. 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 $13.3 million on page 23, line 27. The information for average prepayments on line 23 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the thirteen-month average for the period ended December 31, 2023. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, gas purchases and other disbursements utilized in PECO Exhibit MJT-1 were also used in the FTY calculation.

Page 23 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 thirteen-month average of month-end balances through December 31, 2023. The resulting $13.3 million of CWC shown on line 27 is brought forward to Schedule A-1 in the calculation of the measures of value.

107. Q. Please describe Schedule C-4, pages 24 to 31.

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.

108. 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, 2024 balances were used. The resulting ADIT of $222.8 million for the total of gas distribution utility plant and the gas distribution portion of the common plant for the FTY is shown on line 13. As shown on Schedule C-12, line 9, $113.2 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

109. Q. Please describe the data presented on Schedules C-7, C-9, C-11 and C-13.

A. The data on these four schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1, since the same thirteen-month period was used.

110. Q. What is 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.

111. 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.

112. 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.

113. Q. Please describe Schedule D-3.

A. Schedule D-3 contains six 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.

114. 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.

115. 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-5E. All of these adjustments were prepared using the same methodology as described in connection with PECO Exhibit MJT-1.

116. 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.

117. 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 PECO Exhibit MJT-1, Schedule D-5B.

118. Q. Please describe the adjustment shown on Schedule D-5C.

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.

119. Q. Please describe the adjustment shown on Schedule D-5E.

A. This adjustment eliminates revenues associated with asset optimization items.

120. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the FTY. Pages 57 and 58 show the calculation of the annualization adjustments of S&W and the normalization of the union contract ratification payment, which follow the same procedures described in connection with the FPFTY using the data from the FTY for the wage increases. Pages 59 and 60 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category.

121. 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.

122. 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.

123. Q. Please describe the adjustment shown on Schedule D-9.

A. This adjustment to pension expense follows the same procedures used for the FPFTY, which were described in connection with PECO Exhibit MJT-1, Schedule D-9.

124. Q. Are the adjustments shown on Schedules D-10 to D-15 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.

125. 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.

126. 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 set forth in PECO Exhibit MJT-1.

127. 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 84 and 85 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 58 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

128. 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 to 32, and the revenue increase required on lines 34 to 45.

129. Q. What is contained on Schedules B-1 to B-5?

A. These schedules contain recorded financial data for the HTY.

130. Q. Please describe Schedules B-6 and B-7.

A. These two schedules contain the HTY capital structure and rate of return developed by Mr. Moul. As shown on lines 1 to 3 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.

131. 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 $2.8 billion, as shown on column 4, line 13.

132. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of five pages and shows the utility plant-in-service balances on December 31, 2023 for the Company's distribution operations, as well as the adjustments for the HTY. Pages 18 and 19 contain the summary of plant-in-service balances by plant grouping. Page 15 shows the plant-in-service by FERC account. Pages 16 and 17 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 18 and 19. The total plant-in-service at the end of the HTY is $3.9 billion and is shown on Schedule C-2, page 15, column 4, line 36.

133. Q. Please describe Schedule C-3.

A. Schedule C-3 contains three pages and shows the accumulated depreciation on December 31, 2023. These pages reflect the balances by FERC account for the HTY. The accumulated depreciation at the end of the HTY is $930 million, as shown on page 20, column 4, line 36.

134. 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 $12.6 million on page 23, line 27. The information for average prepayments shown on line 23 is the same as that utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the thirteen-month average for the period ended December 31, 2023. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, gas purchases, and other disbursements utilized in PECO Exhibit MJT-1 were also used in the HTY calculation.

Page 23 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 adjusted pro forma amounts for the HTY, while the prepayment amount is

the thirteen-month average through December 31, 2023. The resulting $12.6 million of CWC shown on line 27 is brought forward to Schedule A-1 in the calculation of the measures of value.

135. Q. Please describe what is shown on Schedule C-4, pages 24 to 31.

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 PECO Exhibit MJT-1 schedules.

136. 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 twelve-month ended December 31, 2023 balances were used. The resulting ADIT of $232.6 million for the total of gas distribution utility plant and the gas distribution portion of common plant for the HTY is shown on line 5. As shown on Schedule C-12, line 3, $116.7 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

137. Q. Please describe the data presented on Schedules C-7, C-9, C-11 and C-13.

A. The data on these four schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1, because the same thirteen-month period was used.

138. Q. What is 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 HTY.

139. Q. 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.

140. Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenues 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.

141. Q. Please describe Schedule D-3.

A. Schedule D-3 contains six 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.

142. 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.

143. 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-5E. All of these adjustments were prepared using the same methodology described in connection with PECO Exhibit MJT-1, except Schedule D-5D, which is the weather normalization adjustment to distribution revenue recorded for the twelve months ended December 31, 2023.

144. 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 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.

145. 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.

146. Q. Please describe the adjustment on Schedule D-5C.

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.

147. Q. Please describe the adjustment shown on Schedule D-5D.

A. Schedule D-5D shows the adjustment to normalize HTY distribution revenue to reflect normal weather for weather sensitive load. 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.

148. Q. Please describe the adjustment shown on Schedule D-5E.

A. This adjustment eliminates revenues associated with the asset optimization items.

149. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the HTY. Pages 57 and 58 show the recorded amounts in column 1, and the pro forma adjustment in column 2 by FERC expense category. Pages 59 and 60 show the calculation of the annualization adjustments of S&W and the normalization of the union contract ratification payment, which follows the same procedures described in connection with the FPFTY using the data from the HTY to calculate the wage increases.

150. 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.

151. 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.

152. 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.

153. Q. Are the adjustments on Schedules D-10 to D-15 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.

154. 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 HTY.

155. 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 adjustment set forth in PECO Exhibits MJT-1 and MJT-2.

156. 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 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 84 and 85 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 58 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

VI. WEATHER NORMALIZATION ADJUSTMENT MECHANISM

157. Q. Is the Company proposing a weather normalization adjustment mechanism in this case?

A. Yes.

158. Q. Why is the Company proposing the WNA mechanism?

A. The Company is proposing the WNA mechanism for two primary reasons: (i) to provide customers with more predictability in billing, which will better enable customers to budget and pay their bills and mitigate the impact of higher bills during severely cold months; and (ii) to provide PECO with a greater certainty in its ability to earn the distribution revenues authorized by the Commission when setting rates.

The Company's total revenue requirement is composed of fixed costs and volumetric costs. Base rates are designed to recover both in order to provide the

Company the opportunity to fully recover its authorized revenue requirement. While the Company's cost structure is largely fixed and does not vary depending on customer usage of natural gas, fixed costs are primarily still recovered on a volumetric basis through rate design. Volumetric rates are designed to match customers' contributions to fixed costs through rate calculations that are based upon the Company's sales projections utilizing "weather normal" assumptions. The Company's development of its gas sales forecasts using weather normal assumptions is described in the direct testimony of Ms. Humphrey.

Because actual weather will always vary to some degree from the Company's weather normal assumptions, the actual amounts paid by customers to the Company through the volumetric component of rates will not match the authorized volumetric cost recovery. When actual temperatures are colder than normal, customers will pay more to the Company in revenues than authorized by the Commission, and when actual temperatures are warmer than normal, customers will pay less to the Company in revenues than authorized by the Commission.

The impact of this is twofold. Customers may end up paying for more or less than their share of fixed costs depending on the weather. If temperatures are colder than normal, customers will use more gas, pay a greater amount in volumetric charges, and potentially overpay their share of fixed costs. The inverse will be true if weather is warmer than normal, which would leave the Company in the position where it may not be able to recover its total fixed costs.

159. Q. Has the Commission approved comparable mechanisms for any other Pennsylvania natural gas utilities?

A. Yes. The Commission approved comparable weather normalization mechanisms for most major gas utilities in Pennsylvania, including: National Fuel Gas ("NFG")[4], Columbia Gas of Pennsylvania ("Columbia")[5], Philadelphia Gas Works ("PGW")[6], and UGI Utilities, Inc. – Gas Division ("UGI").[7]

160. Q. Has the Commission indicated its opinion as to the general utility of WNA mechanisms?

A. Yes. In the Commission's Order authorizing the continuation of Columbia's WNA mechanism that had earlier been implemented on a pilot basis, then-PUC Chairman Gladys Brown Dutrieuille, stated:

> I commend the parties for their commitment to this mechanism. …The Weather Normalization Adjustment works bi-directionally to insulate customers from high bills during the extremely cold months, while also limiting the decline in revenue for Columbia during unseasonably warm heating months. This…stabilizes Columbia's cash flow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs. Further, since this decoupling mechanism is only applied to the distribution component of the bill, and not the natural gas commodity charge, incentives for efficient consumption are maintained.[8]

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4 *See Penn. Pub. Util. Comm'n v. National Fuel Gas Distribution Corporation*, Order, Docket No. R-2022-3035730 (June 15, 2023).

5 *See Penn. Pub. Util. Comm'n v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2018-2647577 (December 6, 2018).

6 *See Penn. Pub. Util. Comm'n v. Phil. Gas Works*, Docket No. R-2022-3034229 (September 21, 2023).

7 *See Penn. Pub. Util. Comm'n v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2021-3030218 (September 16, 2022).

8 See *Penn. Pub. Util. Comm'n v. Columbia Gas of Pennsylvania, Inc.*, *Statement of Chairman Gladys M. Brown*, Docket No. R-2018-2647577 (December 6, 2018).

161. Q. Please describe the Company's proposed WNA.

A. The Company's proposed WNA mechanism will apply to PECO's Residential and Non-Residential customers receiving service under GR and GC Rate Schedules. The WNA mechanism will adjust billings on a current monthly basis and use adjustment factors representative of each customer's consumption characteristics. The WNA mechanism will be effective for the bills rendered in the months of October through May and will adjust the amount billed to each customer to offset the impact of actual heating degree day ("AHDD") variations from normal heating degree days ("NHDD"), adjusted for a 1% deadband as I discuss further below.

162. Q. Is PECO's proposed WNA similar to the other WNA mechanisms the Commission has approved?

A. Yes. PECO's proposed WNA mechanism shares similarities with the NFG WNA,[9] Columbia's WNA rider,[10] PGW's WNA clause,[11] and UGI – Gas Division's WNA.[12] Similar to the Company's proposal, the WNA mechanism of most of these utilities applies to residential heating customers, and to certain non-residential heating customers. The specific calculation of PECO's proposed

[9] National Fuel Gas Distribution Corporation, "Rider C, Weather Normalization Adjustment", Rates, Rules and Regulations Governing the furnishing of Natural Gas Service in Territory Described Herein, available at https://www.nationalfuel.com/wp-content/uploads/documents/PATariff20240201.pdf.

[10] Columbia Gas of Pennsylvania, Inc., "Rider WNA – Weather Normalization Adjustment," Rates and Rules for Furnishing Gas Service, available at https://www.columbiagaspa.com/docs/librariesprovider14/rates-and-tariffs/pennsylvania- tariff.pdf.

[11] Philadelphia Gas Works, "Weather Normalization Adjustment Clause," Gas Service Tariff, available at https://www.pgworks.com/uploads/pdfs/PGW_Gas_Service_Tariff_Through_Supplement_145.pdf

[12] UGI Utilities, Inc. – Gas Division, "Rider C, Weather Normalization Adjustment," Gas Tariff Including the Gas Service Including the Gas Service Tariff No.7 and The Choice Supplier Tariff No. 7S, available at file:///C:/Users/mp076533/Downloads/UGI%20Gas%20Division_%20%20Service%20Tariff%20No.%207%20&%20Choice%20Supplier%20Tariff%20No.%207S_12_18_2023.pdf.

WNA is most similar to the calculations utilized in the WNA mechanisms of National Fuel and UGI.

163. Q. Would the adjustment to customers' bills be calculated on a calendar month or on a billing cycle month basis?

A. The adjustments on customer bills would be made on a billing cycle basis. This approach allows the adjustments to be calculated at the end of each customer's meter reading billing cycle and incorporated into the original bill rendered to each customer. It also gives a more accurate and timely adjustment for the customer because there is no additional time lag between when the customer experiences the bill variability and when the weather normalizing adjustment is made.

164. Q. Is PECO proposing a "deadband" in its WNA mechanism?

A. Yes. Deadbands can be used in the context of WNA mechanisms so that an adjustment will not be triggered if AHDDs are within a certain threshold of NHDDs. In other words, no adjustment will apply to customer bills if weather falls within that threshold, or deadband. When actual weather falls beyond the deadband, the WNA mechanism will be triggered, and it will only count for the variation of actual weather from normal weather outside of the deadband. PECO is proposing a 1% deadband since the intent of the WNA mechanism is to adjust for differences measured against normal weather. A higher deadband would undercut the intent of the WNA mechanism by limiting its application during instances when actual weather does vary from normal weather.

165. Q. Please provide a formulaic representation of the WNA mechanism that you just described.

A. The Company's proposed WNA formula is shown below:

$$\text{WNBC} = \text{BLMC} + [\frac{\text{NHDD} +/-(NHDD * 1\%)}{\text{AHDD}} \text{x } (\text{AMC } - \text{BLMC})]$$

$$\text{WNAC} = \text{WNBC } - \text{AMC}$$

$$\text{WNA} = \text{WNAC x Distribution Charge}$$

- WNA = Weather Normalization Adjustment will be applied to bills rendered for Residential and Non-Residential customers under GR and GC rate Schedules during the heating season of October through May.

- WNBC = Weather Normalized Billing Ccfs ("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of (1) the Normal Heating Degree Days ("NHDD") adjusted for a 1% deadband, divided by the Actual Heating Degree Days ("AHDD") and (2) the Actual Monthly Ccfs ("AMC") less the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.

- If AHDD is unavailable for any day(s) during the bill cycle, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any day(s) missing AHDD from the WNBC calculation.

- BLMC shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills in prior summers for two billing cycles with the starting read dates of June 15th multiplied by the number of days in the billing period. If less than

two billing cycles of bill history from prior summer is available for the premise, an average base load for the related customer rate schedule will be applied.

- AMC shall be measured for each customer and billing cycle. AMC will be subtracted from the WNBC to compute the Weather Normalized Adjustment Ccfs ("WNAC").

- The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Residential GR and GC Rate Schedules.

- A deadband of 1% shall apply. The WNA for a billing cycle will apply only if the AHDD for the billing cycle are lower than 99% or higher than 101% of the NHDD for the bill cycle.

- The WNA factor shall be calculated by first adjusting the NHDD for the billing cycle by the deadband percentage of 1%. The deadband percentage shall be multiplied by the NHDD and then added to the NHDD for the billing period when the weather is colder than normal (i.e., AHDD>NHDD) or subtracted from NHDD for the billing period when the weather is warmer than normal (i.e., AHDD<NHDD).

- In the event a customer's bill needs to be canceled and rebilled at any time, the WNA will be recalculated using the most recently available data for the

billing period. In some cases, updates in data used in the calculation, may result in a different WNA for the billing period. Bills requiring manual processing shall not have WNA applied.

166. Q. Please explain the process the Company will follow to calculate the WNA.

A. For each billing cycle, the Company will adjust the heat sensitive load to account for the ratio of normal weather to actual weather and then recalculate the customer's bill. The process will work as follows:

- For each billing cycle and each applicable customer, the Company will calculate the weather normalized billing Ccfs by multiplying the heat sensitive load (actual Ccfs less base load Ccfs) times the ratio of the adjusted normal HDDs with the 1% deadband for the billing cycle to the actual HDDs. This adjusted heat sensitive AHDD load will then be added to the base load Ccfs to calculate the Weather Normalized Billing Ccfs ("WNBC");

- The Company will then determine the Weather Normalized Adjustment Ccfs ("WNAC") of each applicable customer for each billing cycle by subtracting the actual monthly Ccfs from the Weather Normalized Billing Ccfs;

- This Weather Normalized Adjustment Ccfs will then be multiplied by the applicable rate class's volumetric distribution charge to develop the Weather Normalization Adjustment that will be applied on the customer's bill.

167. Q. Have tariff pages been developed that reflect the computational details and process of the proposed WNA mechanism?

A. Yes. The appropriate tariff pages to implement the proposed WNA mechanism are presented in PECO Exhibit JAB-2, the Company's proposed Gas Tariff No. 7 in blackline format.

168. Q. When does the Company propose to implement the WNA?

A. Although intended to apply for bills rendered during the months of October through May on a going forward basis, PECO is proposing the WNA mechanism initially be implemented as early as the first bill rendered in January 2025. The actual implementation date will depend on the PECO IT system readiness to implement the WNA mechanism, but no sooner than the first billing cycle of January 2025.

169. Q. How does the proposed WNA mechanism align with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883?

A. Each rate consideration identified in the Statement of Policy is listed below along with the relevant effect the proposed WNA mechanism has on each rate consideration:

1. Please explain how the WNA mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

PECO's proposed WNA mechanism is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding,

while mitigating the variance between actual and authorized distribution revenues due to weather. PECO recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance ("O&M") expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a Straight Fixed Variable ("SFV") rate design, where all fixed costs are recovered in a fixed monthly charge, the Company's WNA mechanism will better align distribution revenues with cost causation principles; appropriately accounting for customer variation in usage due to weather.

2. *Please explain how the WNA mechanism and rate design impact the fixed utility's capacity utilization.*

PECO's proposed WNA mechanism has no identifiable impact on capacity utilization.

3. *Please explain whether the WNA mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.*

Customer-specific usage factors corresponding to individual demand (the BLMC for each customer) are continually updated and reflect the level of demand associated with the customers' anticipated consumption levels.

4. *Please explain how the WNA mechanism and rate design limit or eliminate interclass and intraclass cost shifting.*

Since the proposed WNA mechanism is applying rates which are based upon the specific revenue allocation and rate design approved by the Commission, it will mitigate the potential for interclass or intraclass cost shifting related to weather driven usage variances from those weather assumptions used in establishing rates.

5. *Please explain how the WNA mechanism limits or eliminates disincentives for the promotion of efficiency programs.*

The WNA does not limit or eliminate disincentives for the promotion of energy efficiency programs as the WNA mechanism only addresses variations due to weather.

6. *Please explain how the WNA mechanism impacts customer incentives to employ efficiency measures and distributed energy resources.*

Customers will continue be incentivized to employ energy efficiency measures and distributed energy resources because the WNA mechanism will only be implemented in the event that actual weather varies from normal weather beyond the deadband. A reduction in a customer's usage resulting from any efficiency measures or distributed energy resources will still reduce the customer's overall bill, including the portion of their bill that is subject to the WNA mechanism.

7. *Please explain how the WNA mechanism impacts low-income customers and supports consumer assistance programs.*

Customers served under the Company's current CAP receive bill discounts determined by household size and income level. Under PECO's current percentage of income program, or PIPP, customers enrolled in CAP will receive the bill based on their affordability level and, therefore, will not be impacted by the proposed WNA mechanism.

8. Please explain how the WNA mechanism impacts customer rate stability principles.

The WNA mechanism will adjust applicable customers' bills due to variations from normal weather. The WNA mechanism will directly improve stability in customer billing and mitigate volatility in their monthly costs.

9. Please explain how weather impacts utility revenue under the WNA.

The proposed WNA mechanism will be employed for usage during the heating season months (October – May). The WNA mechanism will only apply to the Company's weather sensitive customer classes and its use does not ensure that the Company will recover 100% of its authorized distribution revenues. However, the WNA mechanism will reduce the amount of weather-related variation in both customer bills and PECO's associated distribution revenues.

10. Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.

The WNA is not anticipated to (nor is intended to) impact the frequency of rate cases or have an impact on regulatory lag.

11. Please explain if the WNA mechanism 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 WNA mechanism will apply to variable distribution service charges recovering the base distribution revenue requirement, the Consumer Education Charge, and the Universal Service Fund Charge from applicable WNA rate schedules for the heating season of October through May. The billing for the remainder of the Company's riders will continue to be based on actual monthly usage. The calculated WNA amounts shall be subject to the State Tax Adjustment Surcharge ("STAS") and Distribution System Improvement Charge ("DSIC").

12. Please explain whether the WNA mechanism includes appropriate consumer protections.

The WNA mechanism will assist in protecting consumers from higher bills during colder months. The WNA mechanism will result in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates in the base rate case proceeding. PECO will not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers. The WNA mechanism

insulates customers from high bills during colder than-normal months, as WNA bills will be otherwise lower than non-WNA bills during colder than normal periods.

13. Please explain whether the WNA mechanism is understandable to customers.

PECO's WNA mechanism is not a new concept to gas customers in Pennsylvania or the broader regulated utility industry. Similar mechanisms have been successfully implemented by other Pennsylvania natural gas distribution companies and by utilities in other jurisdictions across the country. PECO has proposed a WNA tariff that provides detailed information to customers of how the mechanism works based on successful working versions found in the tariffs of other Pennsylvania natural gas distribution companies that have implemented a WNA tariff. Educational materials and customer service training will be developed upon approval of the mechanism. PECO will also provide appropriate notice to customers related to the WNA being approved, pursuant to the Commission's alternative ratemaking notice requirements.

14. Please explain how the WNA will support improvements in the Company's reliability.

PECO's cost of service is inclusive of investments and costs to continue to enhance the safety and reliability of its system. The proposed WNA will help minimize the volatility of the recovery of these costs.

170. Q. What are the benefits of the WNA mechanism for the customer and the Company?

A. The WNA mechanism will benefit PECO and its customers in a number of ways. For customers, the WNA mechanism will reduce bill variability due to weather in the month when the variation occurs and provide bill relief in severely cold months, which will help customers in budgeting for and paying their bills. The WNA mechanism will also improve customer satisfaction by providing more stable annual bill amounts and mitigating volatility in monthly gas bills. Furthermore, the WNA mechanism will have no negative impacts on customers' energy conservation efforts.

PECO will benefit from the WNA mechanism since the WNA mechanism will minimize the volatility in financial results that can occur when actual weather varies significantly from normal weather, causing differences in actual and authorized recovery of the Company's annual distribution costs. This will have the added benefit of assisting the Company in attracting the capital necessary to fund its investments. The WNA mechanism will also improve PECO's ability to earn its approved level of distribution revenues that are set by the Commission to enable the Company to recover its authorized revenue requirement.

171. Q. Do any members of the peer group used to inform the recommended return on equity for PECO in this proceeding have similar mechanisms?

A. Yes, as indicated above, WNA mechanisms and decoupling mechanisms are common ratemaking mechanisms across the industry. As indicated in the

testimony of Mr. Moul, the utilities included in the Gas Group (the peer group) already have tariff mechanisms for stabilization of revenues due to variation in weather, either through WNA mechanisms similar to the mechanism proposed by PECO, or through full revenue decoupling mechanisms. The implementation of PECO's proposed WNA mechanism would place PECO on a more comparable footing to the benchmark proxy group that Mr. Moul uses in his direct testimony to establish the proposed return on equity.

172. Q. Do you believe PECO's proposed WNA mechanism is fair to both the Company and its customers?

A. Yes. The proposed WNA mechanism strikes an appropriate balance between the interests of the Company and its customers. Customers will be billed in a manner that reflects normal weather conditions (with the deadband) that underlie the Commission-authorized base rates on a monthly billing basis. The WNA mechanism will also reduce revenue variability, providing customers with predictability in billing and stabilization the Company's revenues.

VII. CONCLUSION

173. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit MJT-1:

Principal Accounting Exhibit - FPFTY ended December 31, 2025

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY 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	$4,630,050		$4,630,050
3	Accumulated Depreciation	C-3	1,022,690		1,022,690
4	Common Plant - Net of Accum Depr	C-8	190,266		190,266
5	Net Plant in service	L2 - L3 + L4	$3,797,627		$3,797,627
6					
7	Working Capital	C-1	$13,737		$13,737
8	Accum Deferred Income Taxes	C-1	(220,306)		(220,306)
9	Customer Deposits	C-1	(13,354)		(13,354)
10	Customer Advances for Construction	C-1	(1,323)		(1,323)
11	Materials and Supplies	C-1	2,123		2,123
12	Accum Deferred Income Taxes - Reg Liability	C-1	(111,469)		(111,469)
13	Gas Storage	C-1	56,972		56,972
14					
15	TOTAL RATE BASE	SUM L5 to L13	$3,524,007		$3,524,007
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$481,982	$111,168	$593,150
19	Supply Cost Revenue	D-5	260,915		260,915
20	Other Operating Revenues	D-5	3,549	179	3,728
21	Total Revenues	SUM L18 to L20	$746,445	$111,348	$857,793
22					
23	Operating Expenses	D-1	$556,448	$754	$557,202
24					
25	OIBIT	L21 - L23	$189,997	$110,594	$300,591
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	$14,354		$14,354
28	Income Taxes @ Statutory Rates	D-18		(30,206)	(30,206)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$204,351	$80,389	$284,740
31					
32	RATE OF RETURN	L30 / L15	5.80%		8.08%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	5.80%		
36					
37	Rate of Return Required	B-7	8.08%		
38					
39	Change in ROR	L37 - L35	2.28%		
40					
41	Change in Operating Income	L15 * L39	$80,389		
42					
43	Gross Revenue Conversion Factor	D-19	1.383		
44					
45	Change in Revenues	L41 * L43	$111,168		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	53.40%		
49	Common Equity Rate Base	L15 * L48	$1,881,820		
50	NET OPERATING INCOME	L30	$204,351		
51	Synchronized Interest Expense	D-18	$75,061		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$129,290		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	6.87%		

Line No.	Description	(1) Reference	(2) Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$20,046,501
3	Construction Work In Progress (107)		675,361
4	Total Utility Plant	SUM L2 to L3	$20,721,862
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,007,444
6	Net Utility Plant	L4 - L5	$15,714,417
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,448
11	Invest in Assoc Company (123)		7,725
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$45,204
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$25,000
17	Customer Accounts Receivable (142)		442,289
18	Other Accounts Receivable (143)		35,649
19	Accum. Prov. for Uncollectible (144)		(83,303)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		38,067
22	Plant Materials & Supplies (154)		69,125
23	Prepayments (165)		20,632
24	Accrued Utility Revenues (173)		215,498
25	Miscellaneous Current & Accrued Assets (174)		87,744
26	Total Current and Accrued Assets	SUM L16 to L25	$850,700
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$54,014
30	Other Regualtory Assets (182.3)		1,123,689
31	Miscellaneous Deferred Debits (186)		744,592
32	Unamortized Loss on Reacquired Debt (189)		636
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,922,930
35			
36	**Total Assets**	L6 + L13 + L26 + L34	$18,533,252

Line No.	Description	(1) Reference	(2) Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,703,533
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,418,361
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$7,544,811
46			
47	**Long Term Debt**		
48	Bonds (221)		$6,400,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(21,980)
53	Total Long-Term Debt	SUM L48 to L52	$6,562,439
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,528
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,430
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$153,029
65	Accounts Payable (232)		648,728
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(926)
70	Interest Accrued (237)		73,493
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		183,156
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,172,554
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		282,725
80	Deferred Investment Tax Credit (255)		286
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,577,039
83	Total Other Deferred Credits	SUM L77 to L82	$2,870,018
84			
85	**Total Liabilities and Other Credits**	L45 + L53 + L61 + L74 + L83	$18,533,252

Line No.	Category	Description	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$479,981		$479,981
2		Gas Cost Revenue	260,915		260,915
3		Other Operating Revenues	18,549		18,549
4		Total Operating Revenues	$759,445		$759,445
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$437,992		$437,992
7		Depreciation & Amortization Expense	110,058		110,058
8		Amortization of Regulatory Expense	649		649
9		Taxes Other Than Income Taxes - Other	8,923		8,923
10		Total Operating Expenses	$557,622		$557,622
11					
12	**Net Utility Operating Income Before Income Tax**		$201,823		$201,823

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$326,750		$326,750
2			C & I	481.0	123,263		123,263
3			Transportation of Gas of Others	489.3	29,969		29,969
4				Subtotal	$479,981		$479,981
5							
6		Gas Cost Revenue	Residential	480.0	$193,890		$193,890
7			C & I	481.0	67,025		67,025
8			Interdepartmental	484.0			
9				Subtotal	$260,915		$260,915
10							
11		Other Operating Revenues	Sales For Resale	483.0	$15,000		$15,000
12			Forfeited Discounts	487.0	1,329		1,329
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	1,703		1,703
15			Interdepartmental Rents	494.0			
16			Other Gas Revenues	495.0	517		517
17				Subtotal	$18,549		$18,549
18							
19				**Total Operating Revenues**	$759,445		$759,445
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0	$7		$7
22			Liquefied Petroleum Gas Expenses	717.0	127		127
23			Liquefied Petroleum Gas Expenses	728.0	0		0
24			Maintenance of Structures and Improvements	741.0	85		85
25			Maintenance of Production Equipment	742.0	211		211
26			Natural Gas City Gate Purchases	804.0	272,165		272,165
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1			
29			Purchased Gas Expenses	807.0	17		17
30			Gas Withdrawn from Storage-Debit	808.1			
31			Gas Delivered to Storage-Credit	808.2			
32			Other Gas Supply Purchases	813.0			
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	357		357
35			Operation Labor and Expenses	841.0	914		914

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	1,026		1,026
37			Maintenance of Structures and Improvements	843.2	3,950		3,950
38			Operation Supervision and Engineering	870.0	538		538
39			Mains and Services Expenses	874.0	18,799		18,799
40			Measuring and Regulating Station Expenses-General	875.0	1,862		1,862
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	7,562		7,562
43			Customer Installations Expenses	879.0	7,959		7,959
44			Other Expenses	880.0	19,796		19,796
45			Rents	881.0	21		21
46			Maintenance of Mains	887.0	26,329		26,329
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,512		1,512
48			Maintenance of Services	892.0	2,821		2,821
49			Maintenance of Meters & House Regulators	893.0	238		238
50			Maintenance of Other Equipment	894.0	676		676
51			Meter Reading	902.0	163		163
52			Customer Records and Collection	903.0	20,395		20,395
53			Uncollectible Accounts	904.0	2,679		2,679
54			Miscellaneous Customer Accounts	905.0	846		846
55			Customer Assistance	908.0	7,171		7,171
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	53		53
58			Demonstrating & Selling	912.0	764		764
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	6,973		6,973
61			Office Supplies and Expenses	921.0	1,197		1,197
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	17,810		17,810
64			Property Insurance	924.0	148		148
65			Franchise Requirements	925.0	405		405
66			Employee Pensions and Benefits	926.0	7,676		7,676
67			Regulatory Commission Expenses	928.0	2,566		2,566
68			Duplicate Charges-Credit	929.0	(7)		(7)
69			Miscellaneous General Expenses	930.2	828		828
70			Maintenance of General Plant	932.0	1,008		1,008

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
71				Subtotal	$437,992		$437,992
72							
73			Depreciation & Amortization Expense	403.0	$94,862		$94,862
74				403.1			
75				404.0	15,195		15,195
76				Subtotal	$110,058		$110,058
77							
78			Amortization of Regulatory Expense	407.3	$649		$649
79				Subtotal	$649		$649
80							
81			Taxes Other Than Income Taxes - Other	408.1	$8,923		$8,923
82				Subtotal	$8,923		$8,923
83							
84			**Total Operating Expenses**		$557,622		$557,622
85							
86			**Net Utility Operating Income Before Income Tax**		$201,823		201,823

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$326,750		$326,750
2			C & I	481.0	123,263		123,263
3			Transportation of Gas of Others	489.3	29,969		29,969
4				Subtotal	$479,981		$479,981
5							
6		**Gas Cost Revenue**	Residential	480.0	$193,890		$193,890
7			C & I	481.0	67,025		67,025
8			Interdepartmental	484.0			
9				Subtotal	$260,915		$260,915
10							
11				OPERATING REVENUE	$740,896		$740,896
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$15,000		$15,000
14			Forfeited Discounts	487.0	$1,329		1,329
15			Miscellaneous Service Revenues	488.0			
16				Subtotal	$16,329		$16,329
17							
18		**Other Gas Revenue**	Rent for Gas Property	493.0	$1,703		1,703
19			Interdepartmental Rents	494.0			
20			Other Gas Revenues	495.0	517		517
21				Subtotal	$2,220		$2,220
22							
23				OTHER REVENUE	$18,549		$18,549
24							
25				OTHER OPERATING REVENUES			
26							
27				**TOTAL**	**$759,445**		**$759,445**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	Budget FPFTY	Non-Jurisdictional	Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0	$7		$7
2			Liquefied Petroleum Gas Expenses	717.0	127		$127
3			Maintenance of Structures and Improvements	741.0	85		85
4			Maintenance of Production Equipment	742.0	211		211
5				SUM L1 to L4	$430		$430
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	0		0
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$272,165		$272,165
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1			
12			Purchased Gas Expenses	807.0	17		17
13			Gas Withdrawn from Storage-Debit	808.1			
14			Gas Delivered to Storage-Credit	808.2			
15			Other Gas Supply Purchases	813.0			
16				SUM L9 to L15	$272,182		$272,182
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$357		$357
21			Operation Labor and Expenses	841.0	914		914
22				SUM L20 to L21	$1,270		$1,270
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$1,026		$1,026
25			Maintenance of Structures and Improvements	843.2	3,950		3,950
26				SUM L24 to L25	$4,975		$4,975
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$6,246		$6,246
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$538		$538
31			Mains and Services Expenses	874.0	18,799		18,799
32			Measuring and Regulating Station Expenses-General	875.0	1,862		1,862
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	7,562		7,562
35			Customer Installations Expenses	879.0	7,959		7,959
36			Other Expenses	880.0	19,796		19,796
37			Rents	881.0	21		21
38				SUM L30 to L37	$56,537		$56,537
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$26,329		$26,329
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,512		1,512
42			Maintenance of Services	892.0	2,821		2,821
43			Maintenance of Meters & House Regulators	893.0	238		238
44			Maintenance of Other Equipment	894.0	676		676
45				SUM L40 to L44	$31,577		$31,577

Line No.	Category	Description	Description	Account	(1) Budget FPFTY	(2) Non-Jurisdictional	(3) Jurisdictional
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$88,114		$88,114
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$163		$163
50			Customer Records and Collection	903.0	20,395		20,395
51			Uncollectible Accounts	904.0	2,679		2,679
52			Miscellaneous Customer Accounts	905.0	846		846
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$24,083		$24,083
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$7,171		$7,171
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	53		53
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$7,569		$7,569
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$764		$764
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$764		$764
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$6,973		$6,973
65			Office Supplies and Expenses	921.0	1,197		1,197
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	17,810		17,810
68			Property Insurance	924.0	148		148
69			Injuries & Damages	925.0	405		405
70			Employee Pensions and Benefits	926.0	7,676		7,676
71			Regulatory Commission Expenses	928.0	2,566		2,566
72			Duplicate Charges-Credit	929.0	(7)		(7)
73			Miscellaneous General Expenses	930.2	828		828
74				SUM L64 to L73	$37,596		$37,596
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$1,008		$1,008
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$38,604		$38,604
79							
80			**Total**	Lines 5+10+16+28+48+54+59+63+79	$437,992		$437,992
81							
82			Total Operations Expense		$400,432		$400,432
83			Total Maintenance Expense		37,560		37,560
84			**Total O&M Expense**	L82 + L83	$437,992		$437,992

Line No.	Description	(1) Total	(2) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076	$2,076
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	732	732
4	Real Estate Tax Accrual	1,796	1,796
5	Miscellaneous TOTI		
6	Payroll Tax Accrued	4,319	4,463
7	**Total**	$8,923	$9,067

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2025
($ in Thousands)
B-6 Cost of Long Term Debt

Line No.	Type of Bond Issue	Bond Issue	Reference	(1) Amount Outstanding	(2) Percent to Total	(3) Effective Interest Rate	(4) Average Weighted Cost Rate	(5) Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025						
2								
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		$75,000		6.00%		
4					1.14%		0.07%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					4.56%		0.28%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.66%		0.15%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					3.80%		0.19%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					4.56%		0.19%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					4.94%		0.19%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					9.87%		0.40%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					4.94%		0.15%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.32%		0.15%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					5.70%		0.18%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					5.70%		0.17%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.32%		0.25%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					6.45%		0.29%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					8.73%		0.44%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					8.73%		0.48%	
33		PECO - FMB - $975 - 5.46% - Due 9-1-55		975,000		5.53%		
34					14.81%		0.82%	
35								
36		Sub-Total Mortgage Bonds	SUM L1 to L35	$6,400,000	97.20%		4.40%	
37								
38	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
39					1.22%		0.09%	
40		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
41					0.01%			
42		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
43					1.57%		0.09%	
44								
45		Sub-Total Capital Securities	SUM L38 to L43	$184,419	2.80%		0.18%	
46								
47		Total Long-Term Debt	L36 + L45	$6,584,419	100.00%		4.58%	
48								
49		Adjustments for Tenders & Calls		(521)				
50								
51		Net Long-Term Debt	L47 + L49	$6,583,898				
52								
53		Annualized Cost		301,566				
54								
55		Adjustment for Tenders & Calls Reacquired		68				
56								
57		**Total**	L53 + L55	$301,634				4.58%

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$6,583,898	46.60%	4.58%	2.13%
3					
4	Common Equity	7,544,811	53.40%	11.15%	5.95%
5					
6	Total	$14,128,708	100.00%		8.08%

Line No.	Description	(1) Reference	(2) FPFTY Amount	(3) Non-Jurisdictional	(4) Jurisdictional
1	Utility Plant	C-2	$4,630,050		$4,630,050
2	Accumulated Depreciation	C-3	1,022,690		1,022,690
3	Common Plant	C-8	190,266		190,266
4	**Net Plant in Service**	L1 - L2 + L3	$3,797,627		$3,797,627
5					
6	Working Capital	C-4	$13,737		$13,737
7	Accumulated Deferred Income Taxes	C-6	(220,306)		(220,306)
8	Customer Deposits	C-7	(13,354)		(13,354)
9	Customer Advances for Construction	C-9	(1,323)		(1,323)
10	Material & Supplies	C-11	2,123		2,123
11	ADIT - Reg Liability	C-12	(111,469)		(111,469)
12	Gas Storage	C-13	56,972		56,972
13	**Total Measures of Value**	SUM L4 to L12	$3,524,007		$3,524,007

				(1)	(2)	(3)	(4)
Line No.	Category	Account		Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents			$50		$50
2		G303 - Intangible Property			16,356		16,356
3			Subtotal	SUM L1 to L2	$16,406		$16,406
4							
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements			$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.			14,334		14,334
7			Subtotal	SUM L5 to L6	$15,559		$15,559
8							
9	**Other Storage Plant**	G360 - Land and Land Rights			$16		$16
10		G361 - Structures & Improvements			14,932		14,932
11		G362 - Gas Holders			7,084		7,084
12		G363 - Gas Storage Equipment			171,597		171,597
13			Subtotal	SUM L9 to L12	$193,629		$193,629
14							
15	**Distribution Plant**	G374 - Land and Land Rights			$3,915		$3,915
16		G375 - Structures and Improvements			16,785		16,785
17		G376 - Gas Mains			2,369,836		2,369,836
18		G378 - Measure & Regulate Sta Equip			26,029		26,029
19		G379 - City Gate Station			61,468		61,468
20		G380 - Services			1,417,248		1,417,248
21		G381 - Meters			179,005		179,005
22		G382 - Meter Installations			291,268		291,268
23		G387 - Other Equipment			2,084		2,084
24		G388 - ARO Costs Distribution Plt			884		884
25			Subtotal	SUM L15 to L24	$4,368,523		$4,368,523
26							
27	**General Plant**	G390 - Structures & Improvements			$11,508		$11,508
28		G391 - Office Furniture & Equipment			1,783		1,783
29		G394 - Tools, Shop & Garage Equip			16,536		16,536
30		G395 - Laboratory Equipment			69		69
31		G397 - Communication Equipment			5,786		5,786
32		G398 - Miscellaneous Equipment			127		127
33		G399.1 - ARO Costs General Plt			125		125
34			Subtotal	SUM L27 to L33	$35,933		$35,933
35							
36		**Total**		Lines 3+7+13+25+34	$4,630,050		$4,630,050

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	$4,799
2		Subtotal Intangible Plant	$4,799
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	31,641
12		Subtotal Other Storage Plant	$31,641
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	$496
16		G376 - Gas Mains	254,277
17		G378 - Measure & Regulate Station Equipment	843
18		G379 - City Gate Station	7
19		G380 - Services	108,581
20		G381 - Meters	5,601
21		G382 - Meter Installations	20,657
22		G387 - Other Equipment	
23		Subtotal Distribution Plant	$390,462
24			
25	**General Plant**	G390 - Structures & Improvements	$521
26		G391 - Office Furniture & Equipment	329
27		G394 - Tools, Shop & Garage Equipment	930
28		G395 - Laboratory Equipment	16
29		G397 - Communication Equipment	489
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	$2,285
32			
33		Total	$429,186

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	($5,597)
2		Subtotal Intangible Plant	($5,597)
3			
4	**Manufactured Gas Proc**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	($57)
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	(1,443)
12		Subtotal Other Storage Plant	($1,500)
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	($36)
16		G376 - Gas Mains	(8,737)
17		G378 - Measure & Regulate Station Equipment	(110)
18		G379 - City Gate Station	(41)
19		G380 - Services	(6,171)
20		G381 - Meters	(458)
21		G382 - Meter Installations	(841)
22		G387 - Other Equipment	(7)
23		G388 - ARO Costs Distribution Plant	(0)
24		Subtotal Distribution Plant	($16,402)
25			
26	**General Plant**	G390 - Structures & Improvements	($3)
27		G391 - Office Furniture & Equipment	(1,050)
28		G394 - Tools, Shop & Garage Equipment	(278)
29		G397 - Communication Equipment	(301)
30		G398 - Miscellaneous Equipment	
31		G399.1 - ARO Costs General Plant	(3)
32		Subtotal General Plant	($1,635)
33			
34		Total	($25,134)

Line No.	Description	Account	(1) FPFTY 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**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	16,356	100.00%	16,356	100.00%	16,356	
5			$16,356		$16,356		$16,356	
6								
7		Subtotal	**$16,406**		**$16,406**		**$16,406**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,334	100.00%	$14,334	100.00%	$14,334	
13			$14,334		$14,334		$14,334	
14								
15		Subtotal	**$15,559**		**$15,559**		**$15,559**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$14,932	100.00%	$14,932	100.00%	$14,932	
21			$14,932		$14,932		$14,932	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$171,597	100.00%	$171,597	100.00%	$171,597	
27			$171,597		$171,597		$171,597	
28								
29		Subtotal	**$193,629**		**$193,629**		**$193,629**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$3,915	100.00%	$3,915	100.00%	$3,915	
32			$3,915		$3,915		$3,915	
33								
34		G375 - Structures and Improvements	$16,785	100.00%	$16,785	100.00%	$16,785	
35			$16,785		$16,785		$16,785	
36								
37		G376 - Gas Mains	$2,369,836	100.00%	$2,369,836	100.00%	$2,369,836	
38			$2,369,836		$2,369,836		$2,369,836	
39								
40		G378 - Measure & Regulate Sta Equip	$26,029	100.00%	$26,029	100.00%	$26,029	
41			$26,029		$26,029		$26,029	
42								
43		G379 - City Gate Station	$61,468	100.00%	$61,468	100.00%	$61,468	
44			$61,468		$61,468		$61,468	
45								
46		G380 - Services	$1,417,248	100.00%	$1,417,248	100.00%	$1,417,248	
47			$1,417,248		$1,417,248		$1,417,248	
48								
49		G381 - Meters	$179,005	100.00%	$179,005	100.00%	$179,005	
50			$179,005		$179,005		$179,005	
51								
52		G382 - Meter Installations	$291,268	100.00%	$291,268	100.00%	$291,268	
53			$291,268		$291,268		$291,268	
54								
55		G387 - Other Equipment	$2,084	100.00%	$2,084	100.00%	$2,084	
56			$2,084		$2,084		$2,084	
57								
58		G388 - ARO Costs Distribution Plant	$884	100.00%	$884	100.00%	$884	

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2025
($ in Thousands)
C-2 Plant Pro Forma Adjustments

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
59			$884		$884		$884	
60								
61		Subtotal	**$4,368,523**		**$4,368,523**		**$4,368,523**	
62								
63	**General Plant**	G390 - Structures & Improvements	$11,508	100.00%	$11,508	100.00%	$11,508	
64			$11,508		$11,508		$11,508	
65								
66		G391 - Office Furniture & Equipment	$1,783	100.00%	$1,783	100.00%	$1,783	
67			$1,783		$1,783		$1,783	
68								
69		G394 - Tools, Shop & Garage Equip	$16,536	100.00%	$16,536	100.00%	$16,536	
70			$16,536		$16,536		$16,536	
71								
72		G395 - Laboratory Equipment	$69	100.00%	69	100.00%	69	
73			69		69		69	
74								
75		G397 - Communication Equipment	$5,786	100.00%	$5,786	100.00%	$5,786	
76			$5,786		$5,786		$5,786	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$125	100.00%	$125	100.00%	$125	
82			$125		$125		$125	
83								
84		Subtotal	**$35,933**		**$35,933**		**$35,933**	
85								
86								
87		**Total**	**$4,630,050**		**$4,630,050**		**$4,630,050**	

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$8,018		$8,018
3		Subtotal Intangible Plant	SUM L1 to L2	$8,018		$8,018
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$935		$935
6		G311 - Liquefied Petroleum Gas Equipment		13,004		13,004
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$13,939		$13,939
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$8,270		$8,270
11		G362 - Gas Holders		6,918		6,918
12		G363 - Gas Storage Equipment		20,898		20,898
13		Subtotal Other Storage Plant	SUM L9 to L12	$36,086		$36,086
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$6,841		6,841
17		G376 - Gas Mains		424,502		424,502
18		G378 - Measure & Regulate Station Equipment		5,942		5,942
19		G379 - City Gate Station		27,748		27,748
20		G380 - Services		312,616		312,616
21		G381 - Meters		88,274		88,274
22		G382 - Meter Installations		80,458		80,458
23		G387 - Other Equipment		1,716		1,716
24		G388 - ARO Costs Distribution Plant		608		608
25		Subtotal Distribution Plant	SUM L15 to L24	$948,707		$948,707
26						
27	**General Plant**	G390 - Structures & Improvements		$3,757		$3,757
28		G391 - Office Furniture & Equipment		561		561
29		G394 - Tools, Shop & Garage Equipment		7,010		7,010
30		G395 - Laboratory Equipment		19		19
31		G397 - Communication Equipment		4,458		4,458
32		G398 - Miscellaneous Equipment		76		76
33		G399.1 - ARO Costs General Plant		57		57
34		Subtotal General Plant	SUM L27 to L33	$15,939		$15,939
35						
36		**Total**	Lines 3+7+13+25+34	$1,022,690		$1,022,690

Line No.	Category	Account	(1) FPFTY 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**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$8,018	100.00%	$8,018	100.00%	$8,018	
4								
5		Subtotal	**$8,018**		**$8,018**		**$8,018**	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	6,841	100.00%	6,841	100.00%	6,841	
10								
11		G376 - Gas Mains	424,502	100.00%	424,502	100.00%	424,502	
12								
13		G378 - Measure & Regulate Sta Equip	5,942	100.00%	5,942	100.00%	5,942	
14								
15		G379 - City Gate Station	27,748	100.00%	27,748	100.00%	27,748	
16								
17		G380 - Services	312,616	100.00%	312,616	100.00%	312,616	
18								
19		G381 - Meters	88,274	100.00%	88,274	100.00%	88,274	
20								
21		G382 - Meter Installations	80,458	100.00%	80,458	100.00%	80,458	
22								
23		G387 - Other Equipment	1,716	100.00%	1,716	100.00%	1,716	
24								
25		G388 - ARO Costs Distribution Plant	608	100.00%	608	100.00%	608	
26								
27		Subtotal	**$948,707**		**$948,707**		**$948,707**	
28								
29	**General Plant**	G390 - Structures & Improvements	$3,757	100.00%	$3,757	100.00%	$3,757	
30								
31		G391 - Office Furniture & Equipment	561	100.00%	561	100.00%	561	
32								
33		G394 - Tools, Shop & Garage Equip	7,010	100.00%	7,010	100.00%	7,010	
34								
35		G395 - Laboratory Equipment	19	100.00%	19	100.00%	19	
36								
37		G397 - Communication Equipment	4,458	100.00%	4,458	100.00%	4,458	
38								
39		G398 - Miscellaneous Equipment	76	100.00%	76	100.00%	76	
40								
41		G399.1 - ARO Costs General Plant	57	100.00%	57	100.00%	57	
42								
43		Subtotal	**$15,939**		**$15,939**		**$15,939**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$935	100.00%	$935	100.00%	$935	
46								
47		G311 - Liquefied Petroleum Gas Eqp	13,004	100.00%	13,004	100.00%	13,004	
48								
49		Subtotal	**$13,939**		**$13,939**		**$13,939**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$8,270	100.00%	$8,270	100.00%	$8,270	
54								
55		G362 - Gas Holders	6,918	100.00%	6,918	100.00%	6,918	
56								
57		G363 - Gas Storage Equipment	20,898	100.00%	20,898	100.00%	20,898	
58								
59		Subtotal	**$36,086**		**$36,086**		**$36,086**	
60								
61		**Total**	**$1,022,690**		**$1,022,690**		**$1,022,690**	

Line No.	Category	Account		(1) Reference	(2) FPFTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements			
2		G311 - Liquefied Petroleum Gas Equipment			
3		Subtotal Gas - Production Plant		SUM L1 to L2	
4					
5	**Gas - Storage**	G361 - Structures & Improvements			
6		G363 - Gas Storage Equipment			(1,270)
7		Subtotal Gas - Storage		SUM L5 to L6	($1,270)
8					
9	**Gas - Distribution**	G374 - Land and Land Rights			
10		G375 - Structures and Improvements			($43)
11		G376 - Gas Mains			(6,122)
12		G378 - Measure & Regulate Station Equipment			(750)
13		G379 - City Gate Station			
14		G380 - Services			(4,084)
15		G381 - Meters			(211)
16		G382 - Meter Installations			(2,088)
17		G387 - Other Equipment			
18		Subtotal Gas - Distribution		SUM L9 to L17	($13,298)
19					
20	**Gas - General Plant**	G390 - Structures & Improvements			($36)
21		G391 - Office Furniture & Equipment			(7)
22		G394 - Tools, Shop & Garage Equipment			
23		G397 - Communication Equipment			(70)
24		Subtotal Gas - General Plant		SUM L20 to L23	($113)
25					
26			**Total**	Lines 3+7+18+24	($14,681)

Line No.	Description	(1) Reference	(2) FPFTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			48.86	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$52,481	13.58	$712,861
7	Pension Expense		973	(167.00)	(162,441)
8	Commodity Purchased - Gas		260,915	33.24	8,671,521
9	Payment to Suppliers		82,479	56.21	4,636,002
10	Other Expenses		111,873	40.07	4,482,986
11	Total O&M and POR Payments	SUM L6 to L10	$508,720		$18,340,928
12					
13	O&M Expense / POR Payment Lag Days			36.05	
14					
15	Net (Lead)/Lag Days	L3 - L13		12.80	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,394		
20					
21	Working Capital for O&M Expense		$17,844		
22					
23	Average Prepayments		$2,733		
24	Accrued Taxes		1,896		
25	Interest Payments		(8,736)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$13,737		
28					
29	Pro Forma O&M Expense		$428,619		
30	Uncollectible Expense		2,378		
31	Pro Forma Cash O&M Expense	L29 - L30	$426,241		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag	(5)
1	Annual Number of Days						365
2							
3	December		$105,193				
4	January		130,817	$141,332			
5	February		139,310	138,106			
6	March		111,688	102,326			
7	April		85,927	73,849			
8	May		52,305	43,873			
9	June		36,760	30,348			
10	July		30,198	25,587			
11	August		25,742	23,623			
12	September		27,856	24,134			
13	October		31,455	29,584			
14	November		47,500	51,027			
15	December		80,753	94,945			
16							
17	Total	SUM L3 to L15	$905,503	$778,733			
18							
19	Average A/R Balance		13				
20							
21	Factor		$69,654	$778,733	11.18		32.65
22							
23	Collection Days Lag						32.65
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					**48.86**

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				$50,786		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$689,843
4								
5		Payroll Lag	SUM L1 to L3			50,786	13.58	$689,843
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$3,300	(167.00)	($551,100)
12								
13		Sub-Total	SUM L7 to L11			$3,300		($551,100)
14								
15		Lag Days for Pension Payment					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	January				$16,812		$651,478
20		April				26,471		1,077,737
21		July				25,711		1,175,140
22		October				22,699		769,982
23								
24		TOTAL	SUM L19 to L22			$91,693	40.07	$3,674,337

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674		
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356		
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,289	$91,693	$3,674,337	40.07

Line No.	Tax	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	4/15/2025	7/1/2025	77	$27,406	25.00%	$6,851	$527,562
2		Second Payment	6/16/2025	7/1/2025	15	27,406	25.00%	6,851	102,772
3		Third Payment	9/15/2025	7/1/2025	(76)	27,406	25.00%	6,851	(520,710)
4		Fourth Payment	12/15/2025	7/1/2025	(167)	27,406	25.00%	6,851	(1,144,193)
5		Subtotal FEDERAL INCOME TAX					100.00%	$27,406	($1,034,569)
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	$1,764	25.00%	$441	$46,736
8		Second Payment	6/16/2025	7/1/2025	15	1,764	25.00%	441	6,614
9		Third Payment	9/15/2025	7/1/2025	(76)	1,764	25.00%	441	(33,509)
10		Fourth Payment	12/15/2025	7/1/2025	(167)	1,764	25.00%	441	(73,631)
11		Subtotal STATE INCOME TAX					100.00%	$1,764	($53,790)
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$2,076	100.00%	$2,076	$126,654
14		Subtotal PURTA					100.00%	$2,076	$126,654
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2025	7/1/2025	22	$1,796	100.00%	1,796	39,503
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	1,796	39,503
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

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	$27,406	($1,034,569)	(37.75)	48.86	11.11	$304,366	$834
2	STATE INCOME TAX	$1,764	($53,790)	(30.50)	48.86	18.36	$32,373	$89
3	PURTA	$2,076	$126,654	61.00	48.86	109.86	$228,094	$625
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$1,796	$39,503	22.00	48.86	70.86	$127,229	$349
6	GROSS RECEIPTS TAX							

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of Test Year		$3,524,007
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.58%
4	Pro Forma Interest Expense	L1 * L2 * L3	$75,212
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$206
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		48.86
9	Interest Payment Lag Days	L8 - L7	(42.39)
10	Total Interest for Working Capital	L6 * L9	($8,736)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December					$99	$925	$75	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January		$353			238	983	57	2,394	(18)	88	465	51	285	816	
3	February		$300			271	786	74	2,394	(35)	80	420	170	372	701	
4	March		$289			(20)	590	50	3,157	157	88	420	254	305	662	
5	April		$257	$133	47	93	393	38	3,157	139	80	433	112	276	728	
6	May		$225	$133	38	76	197	20	3,157	122	72	428	159	243	731	
7	June		$192	$66	38	59	0	37	3,584	105	119	422	294	223	739	
8	July		$160	$55	38	42	1,671	22	3,584	87	111	441	562	277	760	
9	August		$128	$44	38	25	1,457	3	3,584	70	103	441	761	214	685	
10	September		$96	$33	38	51	1,873	76	3,775	52	136	399	623	146	664	
11	October		$64	$22	38	564	1,687	59	3,775	35	128	404	561	92	664	
12	November		$32	$11	38	424	1,501	40	3,775	17	120	438	500	59	712	
13	December		($0)	$0	38	331	1,315	58	4,879	0	153	451	248	573	777	
14																
15	Total	SUM L1 to L13	$2,096	$498	$351	$2,253	$13,377	$608	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.07%	23.07%	23.07%	23.07%	25.50%	25.50%	25.50%	
18																
19	Distribution Amount	L15 * L17	$2,096	$498	$351	$2,253	$13,377	$608	$10,061	$169	$317	$1,294	$1,114	$865	$2,521	
20																
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																
23	Monthly Average	L19 / L21	$161	$38	$27	$173	$1,029	$47	$774	$13	$24	$100	$86	$67	$194	
24																
25	**Rate Case Amount**															**$2,733**

Line No.	Description	(1) Shopping Percentage	(2) Weighted Lag Days	(3) Lag Days
1	Residential	58%		40.00
2	Nonresidential	42%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
			(1)	(2)	(3)	(4)	(5)	(6)
1	**HTY**	ADIT - CIAC		($7,888)	100.00%	($7,888)	100.00%	($7,888)
2		ADIT - Common Plant		15,921	100.00%	15,921	100.00%	15,921
3		ADIT - Gas Distribution		246,541	100.00%	246,541	100.00%	246,541
4		ADIT - Corporate Alternative Minimum Tax		(22,017)	100.00%	(22,017)	100.00%	(22,017)
5		Sub-Total	SUM L1 to L4	$232,557		$232,557		$232,557
6								
7	**FTY**	DIT - CIAC		($1,805)	100.00%	($1,805)	100.00%	($1,805)
8		DIT - Common Plant			100.00%		100.00%	
9		DIT - Gas Distribution		9,631	100.00%	9,631	100.00%	9,631
10		DIT - Corporate Alternative Minimum Tax		(17,594)	100.00%	(17,594)	100.00%	(17,594)
11		Sub-Total	SUM L7 to L10	($9,767)		($9,767)		($9,767)
12								
13	**FPFTY**	DIT - CIAC		($1,998)	100.00%	($1,998)	100.00%	($1,998)
14		DIT - Common Plant			100.00%		100.00%	
15		DIT - Gas Distribution		9,794	100.00%	9,794	100.00%	9,794
16		DIT - Corporate Alternative Minimum Tax		(10,280)	100.00%	(10,280)	100.00%	(10,280)
17		Sub-Total	SUM L13 to L16	($2,483)		($2,483)		($2,483)
18								
19		**Total**	L5 + L11 + L17	$220,306		$220,306		$220,306

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$3,615	$8,076	$11,691
2	January		3,654	8,284	11,938
3	February		3,686	8,444	12,130
4	March		3,760	8,594	12,354
5	April		3,872	8,742	12,614
6	May		4,038	8,997	13,035
7	June		4,165	9,113	13,278
8	July		4,275	9,518	13,793
9	August		4,395	9,856	14,252
10	September		4,436	9,987	14,423
11	October		4,504	10,099	14,602
12	November		4,557	10,182	14,739
13	December		4,530	10,218	14,747
14					
15	Total	SUM L1 to L13	$53,486	$120,110	$173,596
16					
17	Average Monthly Balance	L15 / 13	$4,114	$9,239	$13,354
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$4,114
21	Small C&I				8,891
22	Large C&I				348
23	Transportation				
24					
25	Total	SUM L20 to L23			$13,354

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	$521	$156
4						
5		E303 - Misc Intangible Plant		$337,580	$256,611	$80,969
6						
7		E389 - Land and Land Rights		$6,783	$5,218	$1,565
8						
9		E390 - Structures and Improvements		$432,164	$332,464	$99,700
10		E391 - Office Furniture, Equipment		82,575	63,525	19,050
11		E392 - Transportation Equipment		218,349	167,976	50,373
12		E393 - Stores Equipment		1,144	880	264
13		E394 - Tools, Shop, Garage Equipmnt		2,144	1,649	495
14		E396 - Power Operated Equipment		185	142	43
15		E397 - Communication Equipment		160,034	123,114	36,920
16		E398 - Miscellaneous Equipment		1,158	891	267
17		E399 - Other Tangible Property		(0)	(0)	
18		E399.1 - ARO Costs General Plant		803	618	185
19		Sub Total - General Plant	SUM L9 to L18	$898,556	$691,259	$207,297
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,243,596	$953,609	$289,987
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$156,223	$119,610	$36,613
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,406	$54,164	$16,243
31		E391 - Office Furniture, Equipment		35,258	27,124	8,134
32		E392 - Transportation Equipment		115,297	88,698	26,599
33		E393 - Stores Equipment		246	189	57
34		E394 - Tools, Shop, Garage Equipmnt		834	641	192
35		E396 - Power Operated Equipment		185	142	43
36		E397 - Communication Equipment		50,731	39,028	11,704
37		E398 - Miscellaneous Equipment		974	749	225
38		E399 - Other Tangible Property		(0)	(0)	
39		E399.1 - ARO Costs General Plant		(386)	(297)	(89)
40		Sub Total - General Plant	SUM L30 to L39	$273,546	$210,439	$63,107
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$429,769	$330,048	$99,720
42						
43		Net Common Plant	L20 - L41	$813,827	$623,560	$190,266
44						
45						
46		Common Plant in Service to Utility	L20	$1,243,596	$953,609	$289,987
47		Common Plant Accum Depreciation to Utility	L41	429,769	330,048	99,720
48		Net Common Plant to Utility	L46 - L47	$813,827	$623,560	$190,266

(1)

Line No.	Description	Total FPFTY Amount
1	HTY 13-Month Average	
2	December	$888
3	January	984
4	February	1,106
5	March	1,659
6	April	1,632
7	May	1,208
8	June	1,037
9	July	1,242
10	August	1,221
11	September	1,817
12	October	1,684
13	November	1,404
14	December	1,318
15		
16	13-Month Total	$17,199
17		
18		
19	Average Monthly Balance	$1,323

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$645	($0)	$645
3	January		672	(191)	481
4	February		710	(372)	338
5	March		2,830	(1,490)	1,340
6	April		2,851	(1,111)	1,740
7	May		2,776	(1,460)	1,316
8	June		2,737	(1,693)	1,044
9	July		2,751	(1,197)	1,554
10	August		2,882	(1,126)	1,756
11	September		2,916	(1,077)	1,839
12	October		2,836	(660)	2,176
13	November		2,815	(686)	2,129
14	December		2,736	0	2,736
15					
16	Total	SUM L2 to L14	$30,156	($11,061)	$19,095
17					
18	Distribution Expense Allocation Factor		100.00%	23.07%	
19					
20	Allocation to Distribution	L16 * L18	$30,156	($2,552)	
21					
22	Average Monthly Balance	L20 / 13	$2,320	($196)	$2,123

			(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		$116,677	100.00%	$116,677	100.00%	$116,677
2		ADIT - CIAC			100.00%		100.00%	
3		Subtotal HTY	L1 + L2	116,677		116,677		116,677
4								
5	**FTY**	DIT - Distribution		($3,459)	100.00%	($3,459)	100.00%	($3,459)
6		DIT - CIAC			100.00%		100.00%	
7		Subtotal FTY	L5 + L6	(3,459)		(3,459)		(3,459)
8								
9	**FPFTY**	DIT - Distribution		($1,748)	100.00%	($1,748)	100.00%	($1,748)
10		DIT - CIAC			100.00%		100.00%	
11		Subtotal FPFTY	L9 + L10	(1,748)		(1,748)		(1,748)
12								
13		**Total**	L3 + L7 + L11	$111,469		$111,469		$111,469

Line No.	Description	Reference	(1) Stored Underground	(2) LNG	(3) Propane Gas	(4) Total
1	December		$92,465	$5,154	$1,616	$99,235
2	January		71,565	5,096	1,616	78,277
3	February		53,766	4,918	1,546	60,229
4	March		35,170	4,860	1,546	41,575
5	April		34,920	4,792	1,546	41,257
6	May		38,419	4,742	1,546	44,707
7	June		41,212	4,679	1,546	47,437
8	July		44,474	4,615	1,546	50,635
9	August		47,298	4,560	1,546	53,404
10	September		49,911	4,768	1,546	56,225
11	October		52,807	4,720	1,546	59,073
12	November		52,124	4,339	1,527	57,990
13	December		44,844	4,217	1,527	50,589
14						
15	Total	SUM L1 to L13	$658,974	$61,461	$20,199	$740,634
16						
17	Average Monthly Balance	L15 / 13	$50,690	$4,728	$1,554	$56,972

Line No.	Category	Description	Reference	Pro Forma Adjusted at Present Rates	Proposed Rate Increase	Adjusted Amounts with Proposed Rate Increase
			(1)	(2)	(3)	(4)
1	**Operating Revenues**	Residential		$521,656		$521,656
2		C & I		191,272		191,272
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		1,329	179	1,508
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		1,703		1,703
8		Other Gas Revenues		517		517
9		Transportation of Gas of Others		29,969		29,969
10		Revenue Increase			111,168	111,168
11		Subtotal Operating Revenues	SUM L1 to L10	$746,445	$111,348	$857,793
12						
13	**Operating Expenses**	Manufactured Gas Production		$438		$438
14		Storage Operations Expense		1,292		1,292
15		Storage Maintenance Expense		5,043		5,043
16		Underground Storage Expenses				
17		Other Gas Supply		260,932		260,932
18		Distribution Expense		87,480		87,480
19		Total Customer Accounts		24,173	410	24,583
20		Total Customer Service & Information		7,583		7,583
21		Total Sales		774		774
22		Administrative & General		40,903	343	41,246
23		O&M Expense	SUM L13 to L22	$428,619	$754	$429,372
24						
25		Depreciation & Amortization Expense		$116,982		$116,982
26		Amortization of Regulatory Expense		1,780		1,780
27		Taxes Other Than Income Taxes - Other		9,067		9,067
28		Subtotal Operating Expenses	SUM L23 to L27	$556,448	$754	$557,202
29						
30	**Net Operating Income - BIT**		L11 - L28	$189,997	$110,594	$300,591

Line No.	Category	Description	(1) FPFTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$520,639	$1,017	$521,656
2		C & I	190,288	984	191,272
3		Interdepartmental			
4		Sales for Resale	15,000	(15,000)	
5		Forfeited Discounts	1,329		1,329
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	1,703		1,703
8		Other Gas Revenues	517		517
9		Transportation of Gas of Others	29,969		29,969
10		Revenue Increase			
11		Subtotal Operating Revenues	$759,445	($12,999)	$746,445
12					
13	**Operating Expenses**	Manufactured Gas Production	$430	$8	$438
14		Storage Operations Expense	1,270	22	1,292
15		Storage Maintenance Expense	4,975	68	5,043
16		Underground Storage Expenses			
17		Other Gas Supply	272,182	(11,250)	260,932
18		Distribution Expense	88,114	(634)	87,480
19		Total Customer Accounts	24,083	90	24,173
20		Total Customer Service & Information	7,569	14	7,583
21		Total Sales	764	10	774
22		Administrative & General	38,604	2,299	40,903
23		O&M Expense	$437,992	($9,373)	$428,619
24					
25		Depreciation & Amortization Expense	$110,058	$6,925	$116,982
26		Amortization of Regulatory Expense	649	1,131	1,780
27		Taxes Other Than Income Taxes - Other	8,923	144	9,067
28		Subtotal Operating Expenses	$557,622	($1,173)	$556,448
29					
30	**Net Operating Income - BIT**		$201,823	($11,826)	$189,997

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension
1	**Operating Revenues**	Residential	Gas Cost	$193,890									
2			Cust & Dist	326,750	827	(169)	358						
3			Subtotal Residential	$520,639	$827	($169)	$358						
4													
5		C & I	Gas Cost	$67,025									
6			Cust & Dist	123,263	847		137						
7			Subtotal C & I	$190,288	$847		$137						
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$15,000					($15,000)				
13			Subtotal Sales for Resale	$15,000					($15,000)				
14													
15		Forfeited Discounts	Forfeited Discounts	$1,329									
16			Subtotal Forfeited Discounts	$1,329									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$1,703									
22			Subtotal Rent For Gas Property	$1,703									
23													
24		Other Gas Revenues	Other Gas Revenues	$517									
25			Subtotal Other Gas Revenues	$517									
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$29,969									
28			Subtotal Transportation of Gas of Others	$29,969									
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$759,445**	**$1,674**	**($169)**	**$495**		**($15,000)**				
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production	$7									
36			Liquefied Petroleum Gas Expenses	127						2			
37			Liquefied Petroleum Gas Expenses	0						0			
38			Maintenance of Structures and Improvements	85						2			
39			Maintenance of Production Equipment	211						4			
40			Subtotal Manufactured Gas Production	$430						$8			
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$272,165					($11,250)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses	17						0			
46			Gas Withdrawn from Storage-Debit										

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply	$272,182					($11,250)	$0			
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$1,026						$16			
52			Maintenance of Structures and Improvements	3,950						52			
53			Subtotal Storage Maintenance Expense	$4,975						$68			
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$357						$6			
56			Operation Labor and Expenses	914						15			
57			Subtotal Storage Operations Expense	$1,270						$22			
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$538						$0			
63			Mains and Services Expenses	18,799						$202			
64			Measuring and Regulating Station Expenses-General	1,862						$40			
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	7,562						$65			
67			Customer Installations Expenses	7,959						$181			
68			Other Expenses	19,796						$139			
69			Rents	21									
70			Maintenance of Mains	26,329						$404			
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	1,512						$25			
72			Maintenance of Services	2,821						$43			
73			Maintenance of Meters & House Regulators	238						$5			
74			Maintenance of Other Equipment	676						$4			
75			Subtotal Distribution Expense	$88,114						$1,108			
76													
77		Total Customer Accounts	Customer Records and Collection	$20,395						$237			
78			Meter Reading	163									
79			Miscellaneous Customer Accounts	846						$8			
80			Uncollectible Accounts	2,679									
81			Subtotal Total Customer Accounts	$24,083						$245			
82													
83		Total Customer Service & Information	Customer Assistance	$7,171						$13			
84			Informational & Instructional	345									
85			Miscellaneous Customer & Informational	53						$1			
86			Subtotal Total Customer Service & Information	$7,569						$14			
87													
88		Total Sales	Demonstrating & Selling	$764						$10			
89			Miscellaneous Sales										
90			Subtotal Total Sales	$764						$10			
91													
92		Administrative & General	Administrative and General Salaries	$6,973						$207			

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(7)									
95			Employee Pensions and Benefits	7,676								18	990
96			Franchise Requirements	405									
97			Injuries and Damages							$5			
98			Maintenance of General Plant	1,008						$7			
99			Miscellaneous General Expenses	828						$0			
100			Office Supplies and Expenses	1,197									
101			Outside Service Employed	17,810									
102			Property Insurance	148									
103			Regulatory Commission Expenses	2,566							1,072		
104			Subtotal Administrative & General	$38,604						$219	$1,072	$18	$990
105													
106			**O&M Expense**	**$437,992**					**($11,250)**	**$1,694**	**$1,072**	**$18**	**$990**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$110,058									
109			Subtotal Depreciation & Amortization Expense	$110,058									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$649									
112			Subtotal Amortization of Regulatory Expense	$649									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$8,923									
115			Subtotal Taxes Other Than Income Taxes - Other	$8,923									
116													
117			**Total Operating Expenses**	**$557,622**					**($11,250)**	**$1,694**	**$1,072**	**$18**	**$990**
118													
119	**Net Operating Income Before Income Tax**			**$201,823**	**$1,674**	**($169)**	**$495**		**($3,750)**	**($1,694)**	**($1,072)**	**($18)**	**($990)**

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost										$193,890
2			Cust & Dist									1,017	327,766
3			Subtotal Residential									$1,017	$521,656
4													
5		C & I	Gas Cost										$67,025
6			Cust & Dist									984	124,247
7			Subtotal C & I									$984	$191,272
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale									($15,000)	
13			Subtotal Sales for Resale									($15,000)	
14													
15		Forfeited Discounts	Forfeited Discounts										$1,329
16			Subtotal Forfeited Discounts										$1,329
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property										1,703
22			Subtotal Rent For Gas Property										1,703
23													
24		Other Gas Revenues	Other Gas Revenues										$517
25			Subtotal Other Gas Revenues										$517
26													
27		Transportation of Gas of Others	Transportation of Gas of Others										$29,969
28			Subtotal Transportation of Gas of Others										$29,969
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**									**($12,999)**	**$746,445**
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										$7
36			Liquefied Petroleum Gas Expenses									$2	129
37			Liquefied Petroleum Gas Expenses									$0	0
38			Maintenance of Structures and Improvements									$2	86
39			Maintenance of Production Equipment									$4	215
40			Subtotal Manufactured Gas Production									$8	$438
41													
42		Other Gas Supply	Natural Gas City Gate Purchases									($11,250)	$260,915
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses									$0	17
46			Gas Withdrawn from Storage-Debit										

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply									($11,250)	$260,932
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering									$16	$1,042
52			Maintenance of Structures and Improvements									$52	4,001
53			Subtotal Storage Maintenance Expense									$68	$5,043
54													
55		Storage Operations Expense	Operating Supervision and Engineering									$6	$363
56			Operation Labor and Expenses									$15	929
57			Subtotal Storage Operations Expense									$22	$1,292
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering									$0	$538
63			Mains and Services Expenses									$202	19,001
64			Measuring and Regulating Station Expenses-General									$40	1,901
65			Measuring and Regulating Station Expenses-City Gate										0
66			Meter and House Regulator Expenses									$65	7,627
67			Customer Installations Expenses									$181	8,140
68			Other Expenses						(1,742)			($1,603)	18,192
69			Rents										21
70			Maintenance of Mains									$404	26,734
71			Maintenance of Measuring & Reg. Station Equip.-Genl.									$25	1,537
72			Maintenance of Services									$43	2,864
73			Maintenance of Meters & House Regulators									$5	243
74			Maintenance of Other Equipment									$4	680
75			Subtotal Distribution Expense						($1,742)			($634)	$87,480
76													
77		Total Customer Accounts	Customer Records and Collection									$237	$20,632
78			Meter Reading										163
79			Miscellaneous Customer Accounts			809		(662)				$154	1,001
80			Uncollectible Accounts	899					(1,200)			($301)	2,378
81			Subtotal Total Customer Accounts	$899		$809		($662)	($1,200)			$90	$24,173
82													
83		Total Customer Service & Information	Customer Assistance									$13	$7,183
84			Informational & Instructional										345
85			Miscellaneous Customer & Informational									$1	54
86			Subtotal Total Customer Service & Information									$14	$7,583
87													
88		Total Sales	Demonstrating & Selling									$10	$774
89			Miscellaneous Sales										
90			Subtotal Total Sales									$10	$774
91													
92		Administrative & General	Administrative and General Salaries									$207	$7,180

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit										(7)
95			Employee Pensions and Benefits									$1,008	8,683
96			Franchise Requirements										405
97			Injuries and Damages									$5	5
98			Maintenance of General Plant									$7	1,015
99			Miscellaneous General Expenses									$0	828
100			Office Supplies and Expenses										1,197
101			Outside Service Employed										17,810
102			Property Insurance										148
103			Regulatory Commission Expenses									$1,072	3,637
104			Subtotal Administrative & General									$2,299	$40,903
105													
106			**O&M Expense**	**$899**		**$809**		**($662)**	**($2,942)**			**($9,373)**	**$428,619**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense								$6,925	$6,925	$116,982
109			Subtotal Depreciation & Amortization Expense								$6,925	$6,925	$116,982
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
112			Subtotal Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other							$144		$144	$9,067
115			Subtotal Taxes Other Than Income Taxes - Other							$144		$144	$9,067
116													
117			**Total Operating Expenses**	**$899**	**$321**	**$809**	**$810**	**($662)**	**($2,942)**	**$144**	**$6,925**	**($1,173)**	**$556,448**
118													
119	**Net Operating Income Before Income Tax**			**($899)**	**($321)**	**($809)**	**($810)**	**$662**	**$2,942**	**($144)**	**($6,925)**	**($11,826)**	**$189,997**

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.	$7		$0					
2			717.0 Liquefied Petroleum Gas Expenses.	127		2					
3			741.0 Maintenance Of Structures And Improvements.	85		2					
4			742.0 Maintenance Of Production Equipment.	211		4					
5			Subtotal	$430		$8					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	0		0					
8			Subtotal	$0		$0					
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$272,165	($11,250)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.	17		0					
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal	$272,182	($11,250)	$0					
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$357		$6					
23			841.0 Operation Labor And Expenses.	914		15					
24			Subtotal	$1,270		$22					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$1,026		$16					
27			843.2 Maintenance Of Structures And Improvements.	3,950		52					
28			Subtotal	$4,975		$68					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$538		$0					
31			874.0 Mains And Services Expenses.	18,799		202					
32			875.0 Measuring And Regulating Station Expenses--General.	1,862		40					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	7,562		65					
35			879.0 Customer Installations Expenses.	7,959		181					
36			880.0 Other Expenses.	19,796		139					
37			881.0 Rents.	21							
38			Subtotal	$56,537		$627					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$26,329		$404					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	1,512		25					
42			892.0 Maintenance Of Services.	2,821		43					
43			893.0 Maintenance Of Meters And House Regulators.	238		5					
44			894.0 Maintenance Of Other Equipment.	676		4					
45			Subtotal	$31,577		$481					
46											
47			Distribution Expense Subtotal	$88,114		$1,108					
48											

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$163		$0					
50			903.0 Customer Records And Collection Expenses.	20,395		237					
51			904.0 Uncollectible Accounts.	2,679						899	
52			905.0 Miscellaneous Customer Accounts Expenses.	846		8					
53											
54			Subtotal	$24,083		$245				$899	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$7,171		$13					
57			909.0 Informational And Instructional Advertising Expenses.	345							
58			910.0 Miscellaneous Customer Service And Informational Expenses.	53		1					
59			Subtotal	$7,569		$14					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$764		$10					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$764		$10					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$6,973		$207					
66			921.0 Office Supplies And Expenses.	1,197							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	17,810							
69			924.0 Property Insurance.	148							
70			925.0 Injuries And Damages.	405		5					
71			926.0 Employee Pensions And Benefits.	7,676				18	990		
72			928.0 Regulatory Commission Expenses.	2,566			1,072				
73			929.0 Duplicate Charges--Credit.	(7)							
74			930.2 Miscellaneous General Expenses.	828		0					
75											
76			Subtotal	$37,596		$212	$1,072	$18	$990		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$1,008		$7					
79			Subtotal	$1,008		$7					
80											
81			A&G Expense Sub-total	$38,604		$219	$1,072	$18	$990		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$94,862							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	15,195							
86			Subtotal	$110,058							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$649							$321
89			Subtotal	$649							$321
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$8,923							
92			Subtotal	$8,923							
93											
94			**Total**	**$557,622**	**($11,250)**	**$1,695**	**$1,072**	**$18**	**$990**	**$899**	**$321**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.							$0	$7
2			717.0 Liquefied Petroleum Gas Expenses.							2	129
3			741.0 Maintenance Of Structures And Improvements.							2	86
4			742.0 Maintenance Of Production Equipment.							4	215
5			Subtotal							$8	$438
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.							0	0
8			Subtotal							$0	$0
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($11,250)	$260,915
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.							0	17
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal							($11,250)	$260,932
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$6	$363
23			841.0 Operation Labor And Expenses.							15	929
24			Subtotal							$22	$1,292
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$16	$1,042
27			843.2 Maintenance Of Structures And Improvements.							52	4,001
28			Subtotal							$68	$5,043
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$538
31			874.0 Mains And Services Expenses.							202	19,001
32			875.0 Measuring And Regulating Station Expenses--General.							40	1,901
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							65	7,627
35			879.0 Customer Installations Expenses.							181	8,140
36			880.0 Other Expenses.				(1,742)			(1,603)	18,192
37			881.0 Rents.								21
38			Subtotal				($1,742)			($1,115)	$55,422
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$404	$26,734
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							25	1,537
42			892.0 Maintenance Of Services.							43	2,864
43			893.0 Maintenance Of Meters And House Regulators.							5	243
44			894.0 Maintenance Of Other Equipment.							4	680
45			Subtotal							$481	$32,058
46											
47			Distribution Expense Subtotal				($1,742)			($634)	$87,480
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.							$0	$163
50			903.0 Customer Records And Collection Expenses.							237	20,632
51			904.0 Uncollectible Accounts.				(1,200)			(301)	2,378
52			905.0 Miscellaneous Customer Accounts Expenses.	809		(662)				154	1,001
53											
54			Subtotal	$809		($662)	($1,200)			$90	$24,173
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$13	$7,183
57			909.0 Informational And Instructional Advertising Expenses.								345
58			910.0 Miscellaneous Customer Service And Informational Expenses.							1	54
59			Subtotal							$14	$7,583
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$10	$774
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$10	$774
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$207	$7,180
66			921.0 Office Supplies And Expenses.								1,197
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								17,810
69			924.0 Property Insurance.								148
70			925.0 Injuries And Damages.							5	410
71			926.0 Employee Pensions And Benefits.							1,008	8,683
72			928.0 Regulatory Commission Expenses.							1,072	3,637
73			929.0 Duplicate Charges--Credit.								(7)
74			930.2 Miscellaneous General Expenses.							0	828
75											
76			Subtotal							$2,292	$39,887
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$7	$1,015
79			Subtotal							$7	$1,015
80											
81			A&G Expense Sub-total							$2,299	$40,903
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$6,263	$6,263	$101,125
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						662	662	15,857
86			Subtotal						$6,925	$6,925	$116,982
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$810					$1,131	$1,780
89			Subtotal		$810					$1,131	$1,780
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$144		$144	$9,067
92			Subtotal					$144		$144	$9,067
93											
94			**Total**	**$809**	**$810**	**($662)**	**($2,942)**	**$144**	**$6,925**	**($1,173)**	**$556,449**

Line No.	Category	Description	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) Adjustments Sub-total	(8) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$326,750	$827	($169)	$358			$1,017	$327,766
2			C & I	481.0	123,263	847		137			984	124,247
3			Transportation of Gas of Others	489.3	29,969							29,969
4				Subtotal	$479,981	$1,674	($169)	$495			$2,001	$481,982
5												
6		**Gas Cost Revenue**	Residential	480.0	$193,890							$193,890
7			C & I	481.0	67,025							67,025
8			Interdepartmental	484.0								
9				Subtotal	$260,915							$260,915
10												
11			**Subtotal OPERATING REVENUE**		$740,896	$1,674	($169)	$495			$2,001	$742,897
12												
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$1,703							$1,703
14			Interdepartmental Rents	494.0								
15			Other Gas Revenues	495.0	517							517
16				Subtotal	$2,220							$2,220
17												
18		**Other Operating Revenue**	Sales For Resale	483.0	$15,000					($15,000)	(15,000)	
19			Forfeited Discounts	487.0	1,329							1,329
20												
21			Miscellaneous Service Revenues	488.0								
22				Subtotal	$16,329					($15,000)	($15,000)	$1,329
23												
24			**Subtotal OTHER REVENUE**		$18,549					($15,000)	($15,000)	$3,549
25												
26			**Total**		**$759,445**	**$1,674**	**($169)**	**$495**		**($15,000)**	**($12,999)**	**$746,445**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total	(7)
1	Total FPFTY Revenues		$520,639	$1,380	$186,353	$291	$2,106	$190,130	
2	Commodity Billings in Revenues		(193,890)	(656)	(64,687)	(107)	(1,491)	(66,941)	
3	Weather Adjustment								
4	Total Reconcilable Surcharge in Revenues								
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$326,750	$724	$121,667	$184	$614	$123,188	
6									
7	Average Monthly Customers in FPFTY		512,659	20	45,589	8	16		
8									
9	Average Annual Margin Per Customer	L5 / L7	$0.637	$36.644	$2.669	$22.982	$38.385		
10									
11	Number of Customers of Current Month		513,957	19	45,917	8	16	45,960	
12									
13	Increase in Customers During FPFTY	L11 - L7	1,298	(1)	328			45,960	
14									
15	Annualization of Revenue	L9 * L13	$827	($27)	$875			$847	

D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	Reference	(1) Residential Sales
1	CAP Discount		($13,675)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		297,552
7	Average Monthly CAP Customers		24,796
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.551)
9			
10	CAP Customers at End of FPFTY		25,138
11	Decrease of CAP Customers	L10 - L7	342
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($189)
14	Write-Offs & Working Capital Factor		10.5%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$20
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($169)**

(2)

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total
1	Revenue in February of FPFTY		$40,136	$113	$15,139	$13	$45	$15,311
2	Days in February of FPFTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	1,433	4	541	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$358**	**$1**	**$135**	**$0**	**$0**	**$137**

Line No.	Description	(1) Total
1	Residential Sales	
2	TCS Sales	
3	GC Sales	
4	C & I Total	
5	Revenues - Gas Transportation	
6	**Total**	

(1)

Line No.	Description	Account	Total
1	Other Operating Revenue	483000: Sales for Resale - Gas	($15,000)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($11,250)

Line No.	Description	(1) Reference	(2) Union	(3) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		348	348
2	Number of Employees @ HTY - Total		696	696
3	Percentage of Employees @ HTY	L1 / L2	50.01%	49.99%
4	Distribution of Budget S&W Expense		$25,396	$25,390
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$127
10		L4 + L9	$25,396	$25,517
11				
12	**Annualize January 1 and March 1, 2026 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$635	$766
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$26,031**	**$26,282**

Line No.	Description	(1) Reference	(2) PECO - Gas
1	Distribution of S&W Expense		$50,786
2			
3	Annualized S&W Including Wage Increases		$52,313
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		19.15%
8	Union Contract Payment for Utility	L6 * L7	$249
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$42
11			
12	Annualized S&W for Employees in FPFTY	L3 + L10	$52,355
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		705
16	Average Number of Employees in FPFTY - Total		703
17	Annualization for Number of Employees	L15 - L16	2
18	Annual S&W per Employee	L12 / L16	$74.5
19	Annualization of S&W for New Employees	L17 * L18	$126
20			
21	Pro Forma FPFTY S&W	L12 + L19	$52,481
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$1,695**
24			
25	S&W Pro Forma Factor	L23 / L1	3.34%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.	$3	$0	3
2			717.0 Liquefied Petroleum Gas Expenses.	74	2	$77
3			728.0 Liquefied Petroleum Gas.	0	0	0
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.	8	0	8
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	192	6	198
12			841.0 Operation Labor And Expenses.	464	15	480
13			843.1 Maintenance Supervision And Engineering.	491	16	507
14			843.2 Maintenance Of Structures And Improvements.	1,550	52	1,601
15			**Subtotal Power Supply Expenses**	$2,781	$93	$2,874
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$1	$0	$1
18			874.0 Mains And Services Expenses.	6,060	202	6,262
19			875.0 Measuring And Regulating Station Expenses--General.	1,189	40	1,228
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	1,947	65	2,012
22			879.0 Customer Installations Expenses.	5,431	181	5,612
23			880.0 Other Expenses.	4,152	139	4,291
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.	0	0	1
26			887.0 Maintenance Of Mains.	12,121	404	12,525
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	745	25	770
28			892.0 Maintenance Of Services.	1,290	43	1,334
29			893.0 Maintenance Of Meters And House Regulators.	149	5	154
30			894.0 Maintenance Of Other Equipment.	120	4	124
31			**Subtotal Distribution Expense**	$33,206	$1,108	$34,314
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	$0	$0	$0
34			903.0 Customer Records And Collection Expenses.	7,101	237	7,338
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	237	8	245
37						
38			**Subtotal Customer Accounts**	$7,339	$245	$7,583
39						
40		Customer Service & Information	908.0 Customer Assistance Expenses	$384	$13	$397

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.	40	1	42
43			**Subtotal Customer Service & Information**	$424	$14	$439
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$289	$10	$298
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$289	$10	$298
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$6,190	$207	$6,396
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	155	5	160
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	9	0	9
59						
60			**Subtotal Administration & General - General**	$6,354	$212	$6,566
61						
62			**Subtotal Operations**	$50,392	$1,681	$52,074
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$221	$7	$228
65			**Subtotal Administration & General - General**	$221	$7	$228
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$49	$2	$51
68			742.0 Maintenance Of Production Equipment.	123	4	128
69			**Subtotal Gas Expense**	$173	$6	$179
70						
71			**Subtotal Maintenance**	$394	$13	$407
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$50,786	$1,695	$52,481
74						
75	**Percent Increase**		**Percent Increase**			3.34%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$8
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$15
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,701
8	Materials, IT Costs, Travel, Copies, etc.		428
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$2,129
10			
11	**Total Rate Case Expense**	L4 + L9	$2,144
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,072
15			
16	Annual Amortization Amount Included in Budget		
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	$1,072

Line No.	Description	(1) Reference	(2) Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		706
3	Employees at Ten Months Prior		705
4	Employees at Nine Months Prior		704
5	Employees at Eight Months Prior		703
6	Employees at Seven Months Prior		702
7	Employees at Six Months Prior		701
8	Employees at Five Months Prior		701
9	Employees at Four Months Prior		700
10	Employees at Three Months Prior		699
11	Employees at Two Months Prior		707
12	Employees at One Month Prior		707
13	Employees at End of FPFTY		705
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	703
16	Additional Employees in FPFTY		2
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$7,386
20	Number of Employees for Budget		703
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	2
23	Total Benefits Pro Forma Adjustment	L21 * L22	$18

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$17,267
2	Pension Contribution for Three Years Prior to FPFTY		15,222
3	Pension Contribution for Two Years Prior to FPFTY		1,408
4	Pension Contribution for One Year Prior to FPFTY		2,878
5	Pension Contribution for FPFTY		3,300
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$8,015
8			
9	Allocation Percent to Utility		19.15%
10	Total Amount to Utility	L7 * L9	$1,535
11	Allocation Percent to Capital		36.61%
12	Pension Contribution To Be Capitalized	L10 * L11	$562
13	Pension Contribution To Be Expensed	L10 - L12	$973
14	Budgeted Test Year Distribution Pension Expense		($17)
15	Additional Pension Expense	L13 - L14	$990

Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
			(1)	(2)	(3)	(4)	(5)	(6)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$2,036	$595,534	0.3419%		
2		One Year Prior to HTY		2,826	780,108	0.3623%		
3		HTY		3,091	778,733	0.3970%		
4		Three Year Average	SUM L1 to L3 / 3	$2,651	$718,125	0.3692%		
5								
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY			$742,897			
7								
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6		$742,897			
9								
10	Tariff Revenue - Shopping Revenue	FPFTY			$82,479			
11								
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10		$825,376			
13								
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12					$3,047
15								
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY					$367	
17		One Year Prior to HTY					532	
18		HTY					693	
19								
20	**Three Year Average PPA**		SUM L16 to L18 / 3					$530
21								
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20					$3,578
23								
24	Uncollectible Accounts (904)	FPFTY						$2,679
25								
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24					$899

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$3,078
2	Residential Gas Energy Efficiency Program Costs in FPFTY Budget		2,728
3	Sub-total Pro Forma Increase in Residential Gas Energy Efficiency Program Costs	L1 - L2	$350
4	Gas Commercial EE Program Refund - Rate GC		(29)
5	Total Pro Forma Adjustment Amount	L3 + L4	$321

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				3,654	24		
4	February				3,686	25		
5	March				3,760	25		
6	April				3,872	26		
7	May				4,038	27		
8	June				4,165	28		
9	July				4,275	28		
10	August				4,395	29		
11	September				4,436	30		
12	October				4,504	30		
13	November				4,557	30		
14	December				4,530	30		
15	**Total Residential**		SUM Col 4 L3 to L14				$332	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				8,284	35		
20	February				8,444	36		
21	March				8,594	37		
22	April				8,742	37		
23	May				8,997	38		
24	June				9,113	39		
25	July				9,518	40		
26	August				9,856	42		
27	September				9,987	42		
28	October				10,099	43		
29	November				10,182	43		
30	December				10,218	43		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$476	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$809

Line No.	Description	(1) Reference	(2) Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$14,309
2	Amortization Years		10
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,431
5			
6	**Amount Included in Budget**		$621
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	$810

Line No.	Description	(1) Reference	(2) Total
1	Customer Interest on Unspent MGP Collections		($1,387)
2	Gas FTAC Final Reconciliation Recovery from Customers		$63
3	Total	L1 + L2	($1,325)
4	Amortization Years		2
5	Pro Forma Adjustment Amount	L3 / L4	($662)

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,119)
3	Rate GC		($609)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($1,742)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,057)
11	Rate GC		($143)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,200)
16			
17	Total Gas Procurement and Merchant Function Charges	L7 + L15	($2,942)

Line No.	Description	(1) Total	(2) Pro Forma Adjustments	(3) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076		$2,076
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	732		732
4	Real Estate Tax Accrual	1,796		1,796
5	Miscellaneous TOTI			
6	Payroll Tax Accrued	4,319	$144	4,463
7	**Total**	$8,923	$144	$9,067

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$50,786
2	Payroll Tax Expense		$4,319
3	Payroll Tax Expense - Percent	L2 / L1	8.50%
4	Pro Forma Increase in S&W		$1,695
5	**Payroll Tax Pro Forma**	L3 * L4	**$144**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2025
($ in Thousands)
D-17 Depreciation Adjustment

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.	Common-General Plant	PECO Common 3901 PA	$4,228	$43	$4,185	$43	$4,272
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	4,714	352	4,361	352	5,066
4			PECO Common 3903 PA	116	10	106	10	125
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,326	28	2,299	28	2,354
7			PECO Common 3913 IL	1,480	197	1,283	197	1,677
8			PECO Common 3913 PA	12,199	1,831	10,368	1,831	14,031
9			PECO Common 3930 PA	99	1	99	1	100
10			PECO Common 3941 PA	0		0		0
11			PECO Common 3942 PA	66		66		66
12			PECO Common 3970 PA	7,006	169	6,837	169	7,175
13			PECO Common 3980 PA	84		84		84
14			Subtotal Common - General Plant	$32,348	$2,631	$29,717	$2,631	$34,980
15								
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA					
17			Subtotal					
18								
19		Gas - Distribution	PECO Gas 3751 PA	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	40	3	38	3	43
21			PECO Gas 3753 PA	174	1	173	1	175
22			PECO Gas 3761 PA	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1,178		1,178		1,178
24			PECO Gas 3763 PA	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	565	18	547	18	584
26			PECO Gas 3790 PA	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	93		93		93
33			Subtotal Gas - Distribution	$78,724	$5,251	$73,473	$5,251	$83,975
34								

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
35		Gas - General Plant	PECO Gas 3901 PA	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	56	0	56	0	56
37			PECO Gas 3903 PA	86	5	81	5	91
38			PECO Gas 3911 PA	0		0		0
39			PECO Gas 3912 PA	34		34		34
40			PECO Gas 3913 IL	0		0		0
41			PECO Gas 3913 PA	442	4	438	4	445
42			PECO Gas 3940 PA	774	11	763	11	784
43			PECO Gas 3950 PA	2	0	2	0	2
44			PECO Gas 3970 PA	397	6	390	6	403
45			PECO Gas 3980 PA	8		8		8
46			Subtotal Gas - General Plant	$1,900	$27	$1,872	$27	$1,927
47								
48		Gas - Production Plant	PECO Gas 3050 PA	$31		$31		$31
49			PECO Gas 3053 PA					
50			PECO Gas 3110 PA	140		140		140
51			Subtotal Gas - Production Plant	$170		$170		$170
52								
53		Gas - Storage	PECO Gas 3611 PA	$49		$49		$49
54			PECO Gas 3612 PA	329		329		329
55			PECO Gas 3613 PA	23		23		23
56			PECO Gas 3620 PA	10		10		10
57			PECO Gas 3630 PA	25		25		25
58			PECO Gas 3631 PA	156		156		156
59			PECO Gas 3632 PA	3,965	237	3,728	237	4,201
60			PECO Gas 3633 PA	1,054	62	992	62	1,116
61			PECO Gas 3634 PA	671	64	607	64	735
62			PECO Gas 3635 PA	324	15	309	15	338
63			Subtotal Gas - Storage	$6,605	$377	$6,228	$377	$6,983
64								
65			Subtotal 403.0 Depreciation Expense.	$119,748	$8,287	$111,461	$8,287	$128,035
66								

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
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$12,690	$36	$12,653	$36	$12,726
68			PECO Com 3030-Apollo SW	967		967		967
69			PECO Com 3030-BIDA Customer Project	130		130		130
70			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
71			PECO Com 3030-CIS Transformation SW	120		120		120
72			PECO Com 3030-Cloud Serv 3 yr	6,069	169	5,901	169	6,238
73			PECO Com 3030-Cloud Serv 5 yr	2,585		2,585		2,585
74			PECO Com 3030-Common MDM SW	228		228		228
75			PECO Com 3030-EU Digital Program We	1,987		1,987		1,987
76			PECO Com 3030-EU oneMDS SW	5,269		5,269		5,269
77			PECO Com 3030-IT Cust Mobile App SW	111		111		111
78			PECO Com 3030-IVR System PA	159		159		159
79			PECO Com 3030-Misc 5 yr FR PA	9,884	2,098	7,787	2,098	11,982
80			PECO Com 3030-Misc 5 yr PA	60		60		60
81			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
82			PECO Com 3030-OBIEE Migration SW	275		275		275
83			PECO Com 3030-PECO RNI Upgrade SW	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant	$48,515	$2,303	$46,213	$2,303	$50,818
85								
86		Gas - General Plant	PECO Gas 3913 PA					
87			Subtotal					
88								
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	177		177		177
91			PECO Gas 303-SES IV G SW	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	51		51		51
94			Subtotal Gas - Intangible Plant	$3,695	$130	$3,565	$130	$3,824
95								
96			Subtotal 404.0 Amort. Of Limited-Term Plant	$52,210	$2,432	$49,778	$2,432	$54,642
97								
98			Grand Total	$171,958	$10,720	$161,238	$10,720	$182,678

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.	Common-General Plant	PECO Common 3901 PA	0.2307	$975	$10	$965	$10	$985
2			PECO Common 3902 IL	0.2307	4		4		4
3			PECO Common 3902 PA	0.2307	1,087	81	1,006	81	1,169
4			PECO Common 3903 PA	0.2307	27	2	24	2	29
5			PECO Common 3911 PA	0.2307	3		3		3
6			PECO Common 3912 PA	0.2307	537	6	530	6	543
7			PECO Common 3913 IL	0.2307	341	46	296	46	387
8			PECO Common 3913 PA	0.2307	2,814	422	2,392	422	3,237
9			PECO Common 3930 PA	0.2307	23	0	23	0	23
10			PECO Common 3941 PA	0.2307	0		0		0
11			PECO Common 3942 PA	0.2307	15		15		15
12			PECO Common 3970 PA	0.2307	1,616	39	1,577	39	1,655
13			PECO Common 3980 PA	0.2307	19		19		19
14			Subtotal Common - General Plant		$7,463	$607	$6,856	$607	$8,070
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	0.2307					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	1.0000	40	3	38	3	43
21			PECO Gas 3753 PA	1.0000	174	1	173	1	175
22			PECO Gas 3761 PA	1.0000	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	1.0000	565	18	547	18	584
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	1.0000	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	1.0000	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	1.0000	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	1.0000	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$78,724	$5,251	$73,473	$5,251	$83,975
34									

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)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	1.0000	56	0	56	0	56
37			PECO Gas 3903 PA	1.0000	86	5	81	5	91
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	442	4	438	4	445
42			PECO Gas 3940 PA	1.0000	774	11	763	11	784
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	397	6	390	6	403
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,900	$27	$1,872	$27	$1,927
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	3,965	237	3,728	237	4,201
60			PECO Gas 3633 PA	1.0000	1,054	62	992	62	1,116
61			PECO Gas 3634 PA	1.0000	671	64	607	64	735
62			PECO Gas 3635 PA	1.0000	324	15	309	15	338
63			Subtotal Gas - Storage		$6,605	$377	$6,228	$377	$6,983
64									
65			Subtotal 403.0 Depreciation Expense.		$94,862	$6,263	$88,600	$6,263	$101,125
66									

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)
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.2550	$3,236	$9	$3,226	$9	$3,245
68			PECO Com 3030-Apollo SW	0.2307	223		223		223
69			PECO Com 3030-BIDA Customer Project	0.2307	30		30		30
70			PECO Com 3030-BIDA-AMI Ph2 SW	0.2307	493		493		493
71			PECO Com 3030-CIS Transformation SW	0.2307	28		28		28
72			PECO Com 3030-Cloud Serv 3 yr	0.2307	1,400	39	1,361	39	1,439
73			PECO Com 3030-Cloud Serv 5 yr	0.2307	596		596		596
74			PECO Com 3030-Common MDM SW	0.2307	53		53		53
75			PECO Com 3030-EU Digital Program We	0.2307	458		458		458
76			PECO Com 3030-EU oneMDS SW	0.2307	1,216		1,216		1,216
77			PECO Com 3030-IT Cust Mobile App SW	0.2307	26		26		26
78			PECO Com 3030-IVR System PA	0.2307	37		37		37
79			PECO Com 3030-Misc 5 yr FR PA	0.2307	2,280	484	1,796	484	2,764
80			PECO Com 3030-Misc 5 yr PA	0.2307	14		14		14
81			PECO Com 3030-Mobile Dispatch Mappi	0.2307	1,348		1,348		1,348
82			PECO Com 3030-OBIEE Migration SW	0.2307	63		63		63
83			PECO Com 3030-PECO RNI Upgrade SW	0.2307	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant		$11,500	$532	$10,968	$532	$12,033
85									
86		Gas - General Plant	PECO Gas 3913 PA	1.0000					
87			Subtotal						
88									
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
91			PECO Gas 303-SES IV G SW	1.0000	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
94			Subtotal Gas - Intangible Plant		$3,695	$130	$3,565	$130	$3,824
95									
96			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,195	$662	$14,533	$662	$15,857
97									
98			Grand Total		$110,058	$6,925	$103,133	$6,925	$116,982

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 FPFTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$975	$10	$965	$10	$985
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	1,087	81	1,006	81	1,169
4			PECO Common 3903 PA	1.0000	27	2	24	2	29
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	537	6	530	6	543
7			PECO Common 3913 IL	1.0000	341	46	296	46	387
8			PECO Common 3913 PA	1.0000	2,814	422	2,392	422	3,237
9			PECO Common 3930 PA	1.0000	23	0	23	0	23
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	15		15		15
12			PECO Common 3970 PA	1.0000	1,616	39	1,577	39	1,655
13			PECO Common 3980 PA	1.0000	19		19		19
14			Subtotal Common - General Plant		$7,463	$607	$6,856	$607	$8,070
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	1.0000					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	1.0000	40	3	38	3	43
21			PECO Gas 3753 PA	1.0000	174	1	173	1	175
22			PECO Gas 3761 PA	1.0000	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	1.0000	565	18	547	18	584
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	1.0000	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	1.0000	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	1.0000	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	1.0000	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$78,724	$5,251	$73,473	$5,251	$83,975
34									

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 FPFTY Depr (Function)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	1.0000	56	0	56	0	56
37			PECO Gas 3903 PA	1.0000	86	5	81	5	91
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	442	4	438	4	445
42			PECO Gas 3940 PA	1.0000	774	11	763	11	784
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	397	6	390	6	403
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,900	$27	$1,872	$27	$1,927
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	3,965	237	3,728	237	4,201
60			PECO Gas 3633 PA	1.0000	1,054	62	992	62	1,116
61			PECO Gas 3634 PA	1.0000	671	64	607	64	735
62			PECO Gas 3635 PA	1.0000	324	15	309	15	338
63			Subtotal Gas - Storage		$6,605	$377	$6,228	$377	$6,983
64									
65			Subtotal 403.0 Depreciation Expense.		$94,862	$6,263	$88,600	$6,263	$101,125
66									

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 FPFTY Depr (Function)
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	1.0000	$3,236	$9	$3,226	$9	$3,245
68			PECO Com 3030-Apollo SW	1.0000	223		223		223
69			PECO Com 3030-BIDA Customer Project	1.0000	30		30		30
70			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	493		493		493
71			PECO Com 3030-CIS Transformation SW	1.0000	28		28		28
72			PECO Com 3030-Cloud Serv 3 yr	1.0000	1,400	39	1,361	39	1,439
73			PECO Com 3030-Cloud Serv 5 yr	1.0000	596		596		596
74			PECO Com 3030-Common MDM SW	1.0000	53		53		53
75			PECO Com 3030-EU Digital Program We	1.0000	458		458		458
76			PECO Com 3030-EU oneMDS SW	1.0000	1,216		1,216		1,216
77			PECO Com 3030-IT Cust Mobile App SW	1.0000	26		26		26
78			PECO Com 3030-IVR System PA	1.0000	37		37		37
79			PECO Com 3030-Misc 5 yr FR PA	1.0000	2,280	484	1,796	484	2,764
80			PECO Com 3030-Misc 5 yr PA	1.0000	14		14		14
81			PECO Com 3030-Mobile Dispatch Mappi	1.0000	1,348		1,348		1,348
82			PECO Com 3030-OBIEE Migration SW	1.0000	63		63		63
83			PECO Com 3030-PECO RNI Upgrade SW	1.0000	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant		$11,500	$532	$10,968	$532	$12,033
85									
86		Gas - General Plant	PECO Gas 3913 PA	1.0000					
87			Subtotal						
88									
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
91			PECO Gas 303-SES IV G SW	1.0000	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
94			Subtotal Gas - Intangible Plant		$3,695	$130	$3,565	$130	$3,824
95									
96			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,195	$662	$14,533	$662	$15,857
97									
98			Grand Total		$110,058	$6,925	$103,133	$6,925	$116,982

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$746,445	$111,348	$857,793
2	Operating Expenses		556,448	754	557,202
3	OIBIT	L1 - L2	$189,997	$110,594	$300,591
4					
5	Rate Base		$3,524,007		$3,524,007
6	Weighted Cost of Debt		2.130%		2.130%
7	Synchronized Interest Expense	L5 * L6	$75,061		$75,061
8	Base Taxable Income	L3 - L7	$114,936	$110,594	$225,530
9					
10	State Accelerated Tax Depreciation		$120,107		$120,107
11	Pro Forma Book Depreciation		116,982		116,982
12	State Tax Depreciation (Over) Under Book	L11 - L10	($3,125)		($3,125)
13	Regulatory Asset Programs M-1, Pension & Post-Retirement & Other		(3,619)		(3,619)
14	Other Property Basis Adjustments (CIAC/ICM)		(21,960)		(21,960)
15	Removal Costs/Software		(2,426)		(2,426)
16	AFUDC Equity		(7,418)		(7,418)
17	Permanent Adjustments		805		805
18	Repair Deduction		(151,000)		(151,000)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($73,806)	$110,594	$36,788
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$5,897	($8,836)	($2,939)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(2,359)	3,535	1,176
26	State Income Tax Benefit / (Expense)	L23 + L25	3,538	($5,302)	($1,764)
27					
28	Federal Accelerated Tax Depreciation		$112,651		$112,651
29	Pro Forma Book Depreciation		116,982		116,982
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$4,332		$4,332
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		(3,619)		(3,619)
32	Other Property Basis Adjustments (CIAC/ICM)		(21,960)		(21,960)
33	Removal Costs/Software		(2,426)		(2,426)
34	AFUDC Equity		(7,418)		(7,418)
35	Permanent Adjustments		805		805
36	Repair Deduction		(151,000)		(151,000)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($62,811)	$105,292	$42,481
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$13,190	($22,111)	($8,921)
42	Corporate Alternative Minimum Tax		($16,721)		($16,721)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$7	($27,413)	($27,406)
44					

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($5,037)	$742	($4,295)
47	Deferred Taxes on Timing Differences- State		(2,044)		(2,044)
48	Deferred Taxes on State NOL		2,359	(3,535)	(1,176)
49	Excess Deferred Amortization		3,023		3,023
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(951)		(951)
53	Corporate Alternative Minimum Tax		16,721		16,721
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$14,342	($2,792)	$11,550
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$14,350	($30,206)	($15,856)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$5		$5
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$14,354	($30,206)	($15,851)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$10,230	($21,369)	($11,139)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	4,125	(8,836)	(4,712)
65	Total Income Tax Benefit / (Expense)	L63 + L64	$14,354	($30,206)	($15,851)

Line No.	Description	(1) Reference	(2) 2018	(3) 2019	(4) 2020	(5) 2021	(6) 2022	(7) Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		($85,736)	($162,524)	($249,053)	($575,746)	($108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	($12,750)	($33,376)		($11,242)	($18,122)	
14								
15								
16	Gas Percentage		-1.20%	-21.27%	163.65%	-259.39%	-38.60%	
17								
18								
19	Loss Allocable to Gas	L13 * L16	$153	$7,100		$29,160	$6,994	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						8,681
24								
25								
26	Tax Rate							21.00%
27								
28	Section 1301.1(b) Differential	L23 * L26						$1,823

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2025
($ in Thousands)
D-19 Conversion Factor

Line No.	Description	(1) Reference	(2) Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		1,329
4	Total Customer Revenue		740,896
5	Shopping Revenue		82,479
6	LPC REVENUE	L3 / (L4 + L5)	0.001614
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.003692)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003087)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.994834
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.079487)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.915347
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.192223)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.723124
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.382888
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	27.171%
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-2:

Principal Accounting Exhibit - FTY ended December 31, 2024

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ 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	$4,225,998		$4,225,998
3	Accumulated Depreciation	C-3	971,399		971,399
4	Common Plant - Net of Accum Depr	C-8	189,797		189,797
5	Net Plant in service	L2 - L3 + L4	$3,444,396		$3,444,396
6					
7	Working Capital	C-1	$13,306		$13,306
8	Accum Deferred Income Taxes	C-1	(222,789)		(222,789)
9	Customer Deposits	C-1	(13,354)		(13,354)
10	Customer Advances for Construction	C-1	(1,323)		(1,323)
11	Materials and Supplies	C-1	2,123		2,123
12	Accum Deferred Income Taxes - Reg Liability	C-1	(113,217)		(113,217)
13	Gas Storage	C-1	56,972		56,972
14					
15	TOTAL RATE BASE	SUM L5 to L13	$3,166,113		$3,166,113
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$463,707	$78,475	$542,182
19	Supply Cost Revenue	D-5	222,867		222,867
20	Other Operating Revenues	D-5	3,468	133	3,602
21	Total Revenues	SUM L18 to L20	$690,043	$78,608	$768,651
22					
23	Operating Expenses	D-1	$502,676	$532	$503,208
24					
25	OIBIT	L21 - L23	$187,367	$78,076	$265,443
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	$8,845		$8,845
28	Income Taxes @ Statutory Rates	D-18		(21,633)	(21,633)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$196,212	$56,444	$252,656
31					
32	RATE OF RETURN	L30 / L15	6.20%		7.98%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	6.20%		
36					
37	Rate of Return Required	B-7	7.98%		
38					
39	Change in ROR	L37 - L35	1.78%		
40					
41	Change in Operating Income	L15 * L39	$56,444		
42					
43	Gross Revenue Conversion Factor	D-19	1.390		
44					
45	Change in Revenues	L41 * L43	$78,475		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	53.40%		
49	Common Equity Rate Base	L15 * L48	$1,690,705		
50	NET OPERATING INCOME	L30	$196,212		
51	Synchronized Interest Expense	D-18	$64,272		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$131,940		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	7.80%		

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$18,227,340
3	Construction Work In Progress (107)		672,351
4	Total Utility Plant	SUM L2 to L3	$18,899,691
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,525,376
6	Net Utility Plant	L4 - L5	$14,374,315
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,385
11	Invest in Assoc Company (123)		7,447
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$44,990
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$25,000
17	Customer Accounts Receivable (142)		453,358
18	Other Accounts Receivable (143)		35,952
19	Accum. Prov. for Uncollectible (144)		(93,617)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		36,209
22	Plant Materials & Supplies (154)		67,547
23	Prepayments (165)		20,246
24	Accrued Utility Revenues (173)		196,892
25	Miscellaneous Current & Accrued Assets (174)		90,803
26	Total Current and Accrued Assets	SUM L16 to L25	$832,391
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$46,779
30	Other Regualtory Assets (182.3)		957,139
31	Miscellaneous Deferred Debits (186)		741,145
32	Unamortized Loss on Reacquired Debt (189)		710
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,745,773
35			
36	**Total Assets**	L6 + L13 + L26 + L34	$16,997,468

Line No.	Description	(1) Reference	(2) Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,215,779
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,189,548
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$6,828,244
46			
47	**Long Term Debt**		
48	Bonds (221)		$5,775,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(23,151)
53	Total Long-Term Debt	SUM L48 to L52	$5,936,267
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,517
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,419
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$120,179
65	Accounts Payable (232)		615,561
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(3,750)
70	Interest Accrued (237)		59,215
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		181,503
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,087,780
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		318,330
80	Deferred Investment Tax Credit (255)		308
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,433,151
83	Total Other Deferred Credits	SUM L77 to L82	$2,761,758
84			
85	**Total Liabilities and Other Credits**	L45 + L53 + L61 + L74 + L83	$16,997,468

			(1)	(2)	(3)
Line No.	Category	Description	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$463,617		$463,617
2		Gas Cost Revenue	222,867		222,867
3		Other Operating Revenues	18,468		18,468
4		Total Operating Revenues	$704,952		$704,952
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$394,977		$394,977
7		Depreciation & Amortization Expense	97,547		97,547
8		Amortization of Regulatory Expense	649		649
9		Taxes Other Than Income Taxes - Other	8,737		8,737
10		Total Operating Expenses	$501,911		$501,911
11					
12	**Net Utility Operating Income Before Income Tax**		$203,041		$203,041

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$318,035		$318,035
2			C & I	481.0	117,869		117,869
3			Transportation of Gas of Others	489.3	27,712		27,712
4				Subtotal	$463,617		$463,617
5							
6		Gas Cost Revenue	Residential	480.0	$165,260		$165,260
7			C & I	481.0	57,607		57,607
8			Interdepartmental	484.0			
9				Subtotal	$222,867		$222,867
10							
11		Other Operating Revenues	Sales For Resale	483.0	$15,000		$15,000
12			Forfeited Discounts	487.0	1,292		1,292
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	1,670		1,670
15			Interdepartmental Rents	494.0			
16			Other Gas Revenues	495.0	507		507
17				Subtotal	$18,468		$18,468
18							
19				**Total Operating Revenues**	$704,952		$704,952
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0	$7		$7
22			Liquefied Petroleum Gas Expenses	717.0	123		123
23			Liquefied Petroleum Gas Expenses	728.0	0		0
24			Maintenance of Structures and Improvements	741.0	82		82
25			Maintenance of Production Equipment	742.0	205		205
26			Natural Gas City Gate Purchases	804.0	234,065		234,065
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1			
29			Purchased Gas Expenses	807.0	16		16
30			Gas Withdrawn from Storage-Debit	808.1			
31			Gas Delivered to Storage-Credit	808.2			
32			Other Gas Supply Purchases	813.0			
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	347		347
35			Operation Labor and Expenses	841.0	883		883

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	986		986
37			Maintenance of Structures and Improvements	843.2	3,857		3,857
38			Operation Supervision and Engineering	870.0	529		529
39			Mains and Services Expenses	874.0	18,370		18,370
40			Measuring and Regulating Station Expenses-General	875.0	1,788		1,788
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	7,454		7,454
43			Customer Installations Expenses	879.0	7,555		7,555
44			Other Expenses	880.0	19,247		19,247
45			Rents	881.0	7		7
46			Maintenance of Mains	887.0	25,311		25,311
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,457		1,457
48			Maintenance of Services	892.0	2,697		2,697
49			Maintenance of Meters & House Regulators	893.0	225		225
50			Maintenance of Other Equipment	894.0	733		733
51			Meter Reading	902.0	162		162
52			Customer Records and Collection	903.0	20,043		20,043
53			Uncollectible Accounts	904.0	2,611		2,611
54			Miscellaneous Customer Accounts	905.0	945		945
55			Customer Assistance	908.0	7,090		7,090
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	51		51
58			Demonstrating & Selling	912.0	751		751
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	6,763		6,763
61			Office Supplies and Expenses	921.0	1,579		1,579
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	17,217		17,217
64			Property Insurance	924.0	143		143
65			Franchise Requirements	925.0	395		395
66			Employee Pensions and Benefits	926.0	6,573		6,573
67			Regulatory Commission Expenses	928.0	2,566		2,566
68			Duplicate Charges-Credit	929.0	(2)		(2)
69			Miscellaneous General Expenses	930.2	816		816
70			Maintenance of General Plant	932.0	985		985

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
71				Subtotal	$394,977		$394,977
72							
73			Depreciation & Amortization Expense	403.0	$82,880		$82,880
74				403.1			
75				404.0	14,667		14,667
76				Subtotal	$97,547		$97,547
77							
78			Amortization of Regulatory Expense	407.3	$649		$649
79				Subtotal	$649		$649
80							
81			Taxes Other Than Income Taxes - Other	408.1	$8,737		$8,737
82				Subtotal	$8,737		$8,737
83							
84			**Total Operating Expenses**		$501,911		$501,911
85							
86			**Net Utility Operating Income Before Income Tax**		$203,042		203,042

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$318,035		$318,035
2			C & I	481.0	117,869		117,869
3			Transportation of Gas of Others	489.3	27,712		27,712
4				Subtotal	$463,617		$463,617
5							
6		**Gas Cost Revenue**	Residential	480.0	$165,260		$165,260
7			C & I	481.0	57,607		57,607
8			Interdepartmental	484.0			
9				Subtotal	$222,867		$222,867
10							
11				OPERATING REVENUE	$686,484		$686,484
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$15,000		$15,000
14			Forfeited Discounts	487.0	$1,292		1,292
15			Miscellaneous Service Revenues	488.0			
16				Subtotal	$16,292		$16,292
17							
18		**Other Gas Revenue**	Rent for Gas Property	493.0	$1,670		1,670
19			Interdepartmental Rents	494.0			
20			Other Gas Revenues	495.0	507		507
21				Subtotal	$2,177		$2,177
22							
23				OTHER REVENUE	$18,468		$18,468
24							
25				OTHER OPERATING REVENUES			
26							
27				**TOTAL**	**$704,952**		**$704,952**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	Budget FTY	Non-Jurisdictional	Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0	$7		$7
2			Liquefied Petroleum Gas Expenses	717.0	123		$123
3			Maintenance of Structures and Improvements	741.0	82		82
4			Maintenance of Production Equipment	742.0	205		205
5				SUM L1 to L4	$418		$418
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	0		0
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$234,065		$234,065
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1			
12			Purchased Gas Expenses	807.0	16		16
13			Gas Withdrawn from Storage-Debit	808.1			
14			Gas Delivered to Storage-Credit	808.2			
15			Other Gas Supply Purchases	813.0			
16				SUM L9 to L15	$234,081		$234,081
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$347		$347
21			Operation Labor and Expenses	841.0	883		883
22				SUM L20 to L21	$1,229		$1,229
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$986		$986
25			Maintenance of Structures and Improvements	843.2	3,857		3,857
26				SUM L24 to L25	$4,843		$4,843
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$6,072		$6,072
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$529		$529
31			Mains and Services Expenses	874.0	18,370		18,370
32			Measuring and Regulating Station Expenses-General	875.0	1,788		1,788
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	7,454		7,454
35			Customer Installations Expenses	879.0	7,555		7,555
36			Other Expenses	880.0	19,247		19,247
37			Rents	881.0	7		7
38				SUM L30 to L37	$54,951		$54,951
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$25,311		$25,311
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,457		1,457
42			Maintenance of Services	892.0	2,697		2,697
43			Maintenance of Meters & House Regulators	893.0	225		225
44			Maintenance of Other Equipment	894.0	733		733
45				SUM L40 to L44	$30,423		$30,423

Line No.	Category	Description	Description	Account	Budget FTY (1)	Non-Jurisdictional (2)	Jurisdictional (3)
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$85,374		$85,374
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$162		$162
50			Customer Records and Collection	903.0	20,043		20,043
51			Uncollectible Accounts	904.0	2,611		2,611
52			Miscellaneous Customer Accounts	905.0	945		945
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$23,761		$23,761
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$7,090		$7,090
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	51		51
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$7,486		$7,486
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$751		$751
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$751		$751
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$6,763		$6,763
65			Office Supplies and Expenses	921.0	1,579		1,579
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	17,217		17,217
68			Property Insurance	924.0	143		143
69			Injuries & Damages	925.0	395		395
70			Employee Pensions and Benefits	926.0	6,573		6,573
71			Regulatory Commission Expenses	928.0	2,566		2,566
72			Duplicate Charges-Credit	929.0	(2)		(2)
73			Miscellaneous General Expenses	930.2	816		816
74				SUM L64 to L73	$36,050		$36,050
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$985		$985
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$37,034		$37,034
79							
80			**Total**	Lines 5+10+16+28+48+54+59+63+79	$394,977		$394,977
81							
82			Total Operations Expense		$358,727		$358,727
83			Total Maintenance Expense		36,251		36,251
84			**Total O&M Expense**	L82 + L83	$394,977		$394,977

Line No.	Description	(1) Total	(2) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076	$2,076
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	732	732
4	Real Estate Tax Accrual	1,752	1,752
5	Miscellaneous TOTI		
6	Payroll Tax Accrued	4,177	4,333
7	**Total**	$8,737	$8,894

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ in Thousands)
B-6 Cost of Long Term Debt

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
		(1)		(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025		$350,000		3.29%		
2					5.87%		0.19%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.26%		0.08%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					5.03%		0.30%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.94%		0.17%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					4.20%		0.21%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					5.03%		0.21%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					5.45%		0.21%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					10.91%		0.45%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					5.45%		0.17%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.87%		0.17%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					6.29%		0.20%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					6.29%		0.18%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.87%		0.28%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					7.13%		0.32%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					9.65%		0.49%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					9.65%		0.53%	
33								
34		Sub-Total Mortgage Bonds	SUM L1 to L33	$5,775,000	96.91%		4.16%	
35								
36	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
37					1.35%		0.10%	
38		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
39					0.01%			
40		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
41					1.73%		0.10%	
42								
43		Sub-Total Capital Securities	SUM L36 to L41	$184,419	3.09%		0.20%	
44								
45		Total Long-Term Debt	L34 + L43	$5,959,419	100.00%		4.36%	
46								
47		Adjustments for Tenders & Calls		(589)				
48								
49		Net Long-Term Debt	L45 + L47	$5,958,830				
50								
51		Annualized Cost		259,831				
52								
53		Adjustment for Tenders & Calls Reacquired		68				
54								
55		**Total**	L51 + L53	$259,899				4.36%

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$5,958,830	46.60%	4.36%	2.03%
3					
4	Common Equity	6,828,244	53.40%	11.15%	5.95%
5					
6	Total	$12,787,074	100.00%		7.98%

Line No.	Description	(1) Reference	(2) FTY Amount	(3) Non-Jurisdictional	(4) Jurisdictional
1	Utility Plant	C-2	$4,225,998		$4,225,998
2	Accumulated Depreciation	C-3	971,399		971,399
3	Common Plant	C-8	189,797		189,797
4	**Net Plant in Service**	L1 - L2 + L3	$3,444,396		$3,444,396
5					
6	Working Capital	C-4	$13,306		$13,306
7	Accumulated Deferred Income Taxes	C-6	(222,789)		(222,789)
8	Customer Deposits	C-7	(13,354)		(13,354)
9	Customer Advances for Construction	C-9	(1,323)		(1,323)
10	Material & Supplies	C-11	2,123		2,123
11	ADIT - Reg Liability	C-12	(113,217)		(113,217)
12	Gas Storage	C-13	56,972		56,972
13	**Total Measures of Value**	SUM L4 to L12	$3,166,113		$3,166,113

				(1)	(2)	(3)	(4)
Line No.	Category	Account		Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents			$50		$50
2		G303 - Intangible Property			17,154		17,154
3			Subtotal	SUM L1 to L2	$17,204		$17,204
4							
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements			$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.			14,334		14,334
7			Subtotal	SUM L5 to L6	$15,559		$15,559
8							
9	**Other Storage Plant**	G360 - Land and Land Rights			$16		$16
10		G361 - Structures & Improvements			14,989		14,989
11		G362 - Gas Holders			7,084		7,084
12		G363 - Gas Storage Equipment			141,399		141,399
13			Subtotal	SUM L9 to L12	$163,488		$163,488
14							
15	**Distribution Plant**	G374 - Land and Land Rights			$3,915		$3,915
16		G375 - Structures and Improvements			16,325		16,325
17		G376 - Gas Mains			2,124,296		2,124,296
18		G378 - Measure & Regulate Sta Equip			25,296		25,296
19		G379 - City Gate Station			61,502		61,502
20		G380 - Services			1,314,839		1,314,839
21		G381 - Meters			173,862		173,862
22		G382 - Meter Installations			271,453		271,453
23		G387 - Other Equipment			2,091		2,091
24		G388 - ARO Costs Distribution Plt			884		884
25			Subtotal	SUM L15 to L24	$3,994,463		$3,994,463
26							
27	**General Plant**	G390 - Structures & Improvements			$10,989		$10,989
28		G391 - Office Furniture & Equipment			2,504		2,504
29		G394 - Tools, Shop & Garage Equip			15,884		15,884
30		G395 - Laboratory Equipment			53		53
31		G397 - Communication Equipment			5,598		5,598
32		G398 - Miscellaneous Equipment			127		127
33		G399.1 - ARO Costs General Plt			127		127
34			Subtotal	SUM L27 to L33	$35,283		$35,283
35							
36	**Total**			Lines 3+7+13+25+34	$4,225,998		$4,225,998

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	$2,022
2		Subtotal Intangible Plant	$2,022
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	32,620
12		Subtotal Other Storage Plant	$32,620
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	$496
16		G376 - Gas Mains	172,041
17		G378 - Measure & Regulate Station Equipment	842
18		G379 - City Gate Station	7
19		G380 - Services	108,461
20		G381 - Meters	5,595
21		G382 - Meter Installations	20,633
22		G387 - Other Equipment	
23		Subtotal Distribution Plant	$308,073
24			
25	**General Plant**	G390 - Structures & Improvements	$521
26		G391 - Office Furniture & Equipment	329
27		G394 - Tools, Shop & Garage Equipment	929
28		G395 - Laboratory Equipment	16
29		G397 - Communication Equipment	488
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	$2,282
32			
33		Total	$344,997

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	($4,793)
2		Subtotal Intangible Plant	($4,793)
3			
4	**Manufactured Gas Proc**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	($57)
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	(1,443)
12		Subtotal Other Storage Plant	($1,500)
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	($36)
16		G376 - Gas Mains	(8,737)
17		G378 - Measure & Regulate Station Equipment	(110)
18		G379 - City Gate Station	(41)
19		G380 - Services	(6,171)
20		G381 - Meters	(458)
21		G382 - Meter Installations	(841)
22		G387 - Other Equipment	(7)
23		G388 - ARO Costs Distribution Plant	(0)
24		Subtotal Distribution Plant	($16,402)
25			
26	**General Plant**	G390 - Structures & Improvements	($3)
27		G391 - Office Furniture & Equipment	(1,050)
28		G394 - Tools, Shop & Garage Equipment	(278)
29		G397 - Communication Equipment	(301)
30		G398 - Miscellaneous Equipment	
31		G399.1 - ARO Costs General Plant	(3)
32		Subtotal General Plant	($1,635)
33			
34		Total	($24,330)

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**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	17,154	100.00%	17,154	100.00%	17,154	
5			$17,154		$17,154		$17,154	
6								
7		Subtotal	**$17,204**		**$17,204**		**$17,204**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,334	100.00%	$14,334	100.00%	$14,334	
13			$14,334		$14,334		$14,334	
14								
15		Subtotal	**$15,559**		**$15,559**		**$15,559**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$14,989	100.00%	$14,989	100.00%	$14,989	
21			$14,989		$14,989		$14,989	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$141,399	100.00%	$141,399	100.00%	$141,399	
27			$141,399		$141,399		$141,399	
28								
29		Subtotal	**$163,488**		**$163,488**		**$163,488**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$3,915	100.00%	$3,915	100.00%	$3,915	
32			$3,915		$3,915		$3,915	
33								
34		G375 - Structures and Improvements	$16,325	100.00%	$16,325	100.00%	$16,325	
35			$16,325		$16,325		$16,325	
36								
37		G376 - Gas Mains	$2,124,296	100.00%	$2,124,296	100.00%	$2,124,296	
38			$2,124,296		$2,124,296		$2,124,296	
39								
40		G378 - Measure & Regulate Sta Equip	$25,296	100.00%	$25,296	100.00%	$25,296	
41			$25,296		$25,296		$25,296	
42								
43		G379 - City Gate Station	$61,502	100.00%	$61,502	100.00%	$61,502	
44			$61,502		$61,502		$61,502	
45								
46		G380 - Services	$1,314,839	100.00%	$1,314,839	100.00%	$1,314,839	
47			$1,314,839		$1,314,839		$1,314,839	
48								
49		G381 - Meters	$173,862	100.00%	$173,862	100.00%	$173,862	
50			$173,862		$173,862		$173,862	
51								
52		G382 - Meter Installations	$271,453	100.00%	$271,453	100.00%	$271,453	
53			$271,453		$271,453		$271,453	
54								
55		G387 - Other Equipment	$2,091	100.00%	$2,091	100.00%	$2,091	
56			$2,091		$2,091		$2,091	
57								
58		G388 - ARO Costs Distribution Plant	$884	100.00%	$884	100.00%	$884	

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
59			$884		$884		$884	
60								
61		Subtotal	**$3,994,463**		**$3,994,463**		**$3,994,463**	
62								
63	**General Plant**	G390 - Structures & Improvements	$10,989	100.00%	$10,989	100.00%	$10,989	
64			$10,989		$10,989		$10,989	
65								
66		G391 - Office Furniture & Equipment	$2,504	100.00%	$2,504	100.00%	$2,504	
67			$2,504		$2,504		$2,504	
68								
69		G394 - Tools, Shop & Garage Equip	$15,884	100.00%	$15,884	100.00%	$15,884	
70			$15,884		$15,884		$15,884	
71								
72		G395 - Laboratory Equipment	$53	100.00%	53	100.00%	53	
73			53		53		53	
74								
75		G397 - Communication Equipment	$5,598	100.00%	$5,598	100.00%	$5,598	
76			$5,598		$5,598		$5,598	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$127	100.00%	$127	100.00%	$127	
82			$127		$127		$127	
83								
84		Subtotal	**$35,283**		**$35,283**		**$35,283**	
85								
86								
87		**Total**	**$4,225,998**		**$4,225,998**		**$4,225,998**	

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$9,921		$9,921
3		Subtotal Intangible Plant	SUM L1 to L2	$9,921		$9,921
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$904		$904
6		G311 - Liquefied Petroleum Gas Equipment		12,864		12,864
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$13,769		$13,769
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$7,926		$7,926
11		G362 - Gas Holders		6,908		6,908
12		G363 - Gas Storage Equipment		17,418		17,418
13		Subtotal Other Storage Plant	SUM L9 to L12	$32,251		$32,251
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$6,566		6,566
17		G376 - Gas Mains		401,160		401,160
18		G378 - Measure & Regulate Station Equipment		6,238		6,238
19		G379 - City Gate Station		26,740		26,740
20		G380 - Services		295,838		295,838
21		G381 - Meters		83,247		83,247
22		G382 - Meter Installations		77,656		77,656
23		G387 - Other Equipment		1,630		1,630
24		G388 - ARO Costs Distribution Plant		607		607
25		Subtotal Distribution Plant	SUM L15 to L24	$899,681		$899,681
26						
27	**General Plant**	G390 - Structures & Improvements		$3,552		$3,552
28		G391 - Office Furniture & Equipment		1,143		1,143
29		G394 - Tools, Shop & Garage Equipment		6,514		6,514
30		G395 - Laboratory Equipment		17		17
31		G397 - Communication Equipment		4,432		4,432
32		G398 - Miscellaneous Equipment		69		69
33		G399.1 - ARO Costs General Plant		50		50
34		Subtotal General Plant	SUM L27 to L33	$15,777		$15,777
35						
36		**Total**	Lines 3+7+13+25+34	$971,399		$971,399

Line No.	Category	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**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$9,921	100.00%	$9,921	100.00%	$9,921	
4								
5		Subtotal	**$9,921**		**$9,921**		**$9,921**	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	6,566	100.00%	6,566	100.00%	6,566	
10								
11		G376 - Gas Mains	401,160	100.00%	401,160	100.00%	401,160	
12								
13		G378 - Measure & Regulate Sta Equip	6,238	100.00%	6,238	100.00%	6,238	
14								
15		G379 - City Gate Station	26,740	100.00%	26,740	100.00%	26,740	
16								
17		G380 - Services	295,838	100.00%	295,838	100.00%	295,838	
18								
19		G381 - Meters	83,247	100.00%	83,247	100.00%	83,247	
20								
21		G382 - Meter Installations	77,656	100.00%	77,656	100.00%	77,656	
22								
23		G387 - Other Equipment	1,630	100.00%	1,630	100.00%	1,630	
24								
25		G388 - ARO Costs Distribution Plant	607	100.00%	607	100.00%	607	
26								
27		Subtotal	**$899,681**		**$899,681**		**$899,681**	
28								
29	**General Plant**	G390 - Structures & Improvements	$3,552	100.00%	$3,552	100.00%	$3,552	
30								
31		G391 - Office Furniture & Equipment	1,143	100.00%	1,143	100.00%	1,143	
32								
33		G394 - Tools, Shop & Garage Equip	6,514	100.00%	6,514	100.00%	6,514	
34								
35		G395 - Laboratory Equipment	17	100.00%	17	100.00%	17	
36								
37		G397 - Communication Equipment	4,432	100.00%	4,432	100.00%	4,432	
38								
39		G398 - Miscellaneous Equipment	69	100.00%	69	100.00%	69	
40								
41		G399.1 - ARO Costs General Plant	50	100.00%	50	100.00%	50	
42								
43		Subtotal	**$15,777**		**$15,777**		**$15,777**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$904	100.00%	$904	100.00%	$904	
46								
47		G311 - Liquefied Petroleum Gas Eqp	12,864	100.00%	12,864	100.00%	12,864	
48								
49		Subtotal	**$13,769**		**$13,769**		**$13,769**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$7,926	100.00%	$7,926	100.00%	$7,926	
54								
55		G362 - Gas Holders	6,908	100.00%	6,908	100.00%	6,908	
56								
57		G363 - Gas Storage Equipment	17,418	100.00%	17,418	100.00%	17,418	
58								
59		Subtotal	**$32,251**		**$32,251**		**$32,251**	
60								
61		**Total**	**$971,399**		**$971,399**		**$971,399**	

Line No.	Category	Account		(1) Reference	(2) FTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements			
2		G311 - Liquefied Petroleum Gas Equipment			
3		Subtotal Gas - Production Plant		SUM L1 to L2	
4					
5	**Gas - Storage**	G361 - Structures & Improvements			
6		G363 - Gas Storage Equipment			(1,270)
7		Subtotal Gas - Storage		SUM L5 to L6	($1,270)
8					
9	**Gas - Distribution**	G374 - Land and Land Rights			
10		G375 - Structures and Improvements			($43)
11		G376 - Gas Mains			(6,122)
12		G378 - Measure & Regulate Station Equipment			(750)
13		G379 - City Gate Station			
14		G380 - Services			(4,084)
15		G381 - Meters			(211)
16		G382 - Meter Installations			(2,088)
17		G387 - Other Equipment			
18		Subtotal Gas - Distribution		SUM L9 to L17	($13,298)
19					
20	**Gas - General Plant**	G390 - Structures & Improvements			($36)
21		G391 - Office Furniture & Equipment			(7)
22		G394 - Tools, Shop & Garage Equipment			
23		G397 - Communication Equipment			(70)
24		Subtotal Gas - General Plant		SUM L20 to L23	($113)
25					
26			**Total**	Lines 3+7+18+24	($14,681)

Line No.	Description	(1) Reference	(2) FTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			48.86	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$50,635	13.58	$687,789
7	Pension Expense		1,330	(168.00)	(223,382)
8	Commodity Purchased - Gas		222,815	33.24	7,405,272
9	Payment to Suppliers		75,555	56.21	4,246,815
10	Other Expenses		109,569	40.07	4,390,636
11	Total O&M and POR Payments	SUM L6 to L10	$459,903		$16,507,130
12					
13	O&M Expense / POR Payment Lag Days			35.89	
14					
15	Net (Lead)/Lag Days	L3 - L13		12.96	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,260		
20					
21	Working Capital for O&M Expense		$16,334		
22					
23	Average Prepayments		$2,733		
24	Accrued Taxes		1,711		
25	Interest Payments		(7,472)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$13,306		
28					
29	Pro Forma O&M Expense		$386,492		
30	Uncollectible Expense		2,144		
31	Pro Forma Cash O&M Expense	L29 - L30	$384,348		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag	(5)
1	Annual Number of Days						365
2							
3	December		$105,193				
4	January		130,817	$141,332			
5	February		139,310	138,106			
6	March		111,688	102,326			
7	April		85,927	73,849			
8	May		52,305	43,873			
9	June		36,760	30,348			
10	July		30,198	25,587			
11	August		25,742	23,623			
12	September		27,856	24,134			
13	October		31,455	29,584			
14	November		47,500	51,027			
15	December		80,753	94,945			
16							
17	Total	SUM L3 to L15	$905,503	$778,733			
18							
19	Average A/R Balance		13				
20							
21	Factor		$69,654	$778,733	11.18		32.65
22							
23	Collection Days Lag						32.65
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					**48.86**

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				$48,801		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$662,884
4								
5		Payroll Lag	SUM L1 to L3			48,801	13.58	$662,884
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2024	7/1/2024	$2,878	(168.00)	($483,504)
12								
13		Sub-Total	SUM L7 to L11			$2,878		($483,504)
14								
15		Lag Days for Pension Payment					(168.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	January				$16,812		$651,478
20		April				26,471		1,077,737
21		July				25,711		1,175,140
22		October				22,699		769,982
23								
24		TOTAL	SUM L19 to L22			$91,693	40.07	$3,674,337

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674		
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356		
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,289	$91,693	$3,674,337	40.07

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Tax	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	4/15/2024	7/1/2024	77	$25,147	25.00%	$6,287	$484,071
2		Second Payment	6/17/2024	7/1/2024	14	25,147	25.00%	6,287	88,013
3		Third Payment	9/16/2024	7/1/2024	(77)	25,147	25.00%	6,287	(484,071)
4		Fourth Payment	12/16/2024	7/1/2024	(168)	25,147	25.00%	6,287	(1,056,155)
5		Subtotal FEDERAL INCOME TAX					100.00%	$25,147	($968,142)
6									
7	**STATE INCOME TAX**	First Payment	3/15/2024	7/1/2024	108	$666	25.00%	$166	$17,978
8		Second Payment	6/17/2024	7/1/2024	14	666	25.00%	166	2,331
9		Third Payment	9/16/2024	7/1/2024	(77)	666	25.00%	166	(12,818)
10		Fourth Payment	12/16/2024	7/1/2024	(168)	666	25.00%	166	(27,966)
11		Subtotal STATE INCOME TAX					100.00%	$666	($20,475)
12									
13	**PURTA**	First Payment	5/1/2024	7/1/2024	61	$2,076	100.00%	$2,076	$126,654
14		Subtotal PURTA					100.00%	$2,076	$126,654
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2024	7/1/2024	22	$1,752	100.00%	1,752	38,540
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	1,752	38,540
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

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	$25,147	($968,142)	(38.50)	48.86	10.36	$260,415	$713
2	STATE INCOME TAX	$666	($20,475)	(30.75)	48.86	18.11	$12,056	$33
3	PURTA	$2,076	$126,654	61.00	48.86	109.86	$228,094	$625
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$1,752	$38,540	22.00	48.86	70.86	$124,126	$340
6	GROSS RECEIPTS TAX							

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of Test Year		$3,166,113
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.36%
4	Pro Forma Interest Expense	L1 * L2 * L3	$64,328
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$176
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		48.86
9	Interest Payment Lag Days	L8 - L7	(42.39)
10	Total Interest for Working Capital	L6 * L9	($7,472)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December					$99	$925	$75	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January		$353			238	983	57	2,394	(18)	88	465	51	285	816	
3	February		$300			271	786	74	2,394	(35)	80	420	170	372	701	
4	March		$289			(20)	590	50	3,157	157	88	420	254	305	662	
5	April		$257	$133	47	93	393	38	3,157	139	80	433	112	276	728	
6	May		$225	$133	38	76	197	20	3,157	122	72	428	159	243	731	
7	June		$192	$66	38	59	0	37	3,584	105	119	422	294	223	739	
8	July		$160	$55	38	42	1,671	22	3,584	87	111	441	562	277	760	
9	August		$128	$44	38	25	1,457	3	3,584	70	103	441	761	214	685	
10	September		$96	$33	38	51	1,873	76	3,775	52	136	399	623	146	664	
11	October		$64	$22	38	564	1,687	59	3,775	35	128	404	561	92	664	
12	November		$32	$11	38	424	1,501	40	3,775	17	120	438	500	59	712	
13	December		($0)	$0	38	331	1,315	58	4,879	0	153	451	248	573	777	
14																
15	Total	SUM L1 to L13	$2,096	$498	$351	$2,253	$13,377	$608	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.07%	23.07%	23.07%	23.07%	25.50%	25.50%	25.50%	
18																
19	Distribution Amount	L15 * L17	$2,096	$498	$351	$2,253	$13,377	$608	$10,061	$169	$317	$1,294	$1,114	$865	$2,521	
20																
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																
23	Monthly Average	L19 / L21	$161	$38	$27	$173	$1,029	$47	$774	$13	$24	$100	$86	$67	$194	
24																
25	**Rate Case Amount**															**$2,733**

Line No.	Description	(1) Shopping Percentage	(2) Weighted Lag Days	(3) Lag Days
1	Residential	59%		40.00
2	Nonresidential	41%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

Line No.	Test Year	Description	(1) Reference	(2) Total Amount	(3) Percent to Utility	(4) Utility Amount	(5) Percent to Distribution	(6) Distribution Amount
1	**HTY**	ADIT - CIAC		($7,888)	100.00%	($7,888)	100.00%	($7,888)
2		ADIT - Common Plant		15,921	100.00%	15,921	100.00%	15,921
3		ADIT - Gas Distribution		246,541	100.00%	246,541	100.00%	246,541
4		ADIT - Corporate Alternative Minimum Tax		(22,017)	100.00%	(22,017)	100.00%	(22,017)
5		Sub-Total	SUM L1 to L3	$232,557		$232,557		$232,557
6								
7	**FTY**	DIT - CIAC		($1,805)	100.00%	($1,805)	100.00%	($1,805)
8		DIT - Common Plant			100.00%		100.00%	
9		DIT - Gas Distribution		9,631	100.00%	$9,631	100.00%	$9,631
10		DIT - Corporate Alternative Minimum Tax		(17,594)	100.00%	($17,594)	100.00%	($17,594)
11		Sub-Total	SUM L6 to L8	($9,767)		($9,767)		($9,767)
12								
13		**Total**	L4 + L9	$222,789		$222,789		$222,789

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$3,615	$8,076	$11,691
2	January		3,654	8,284	11,938
3	February		3,686	8,444	12,130
4	March		3,760	8,594	12,354
5	April		3,872	8,742	12,614
6	May		4,038	8,997	13,035
7	June		4,165	9,113	13,278
8	July		4,275	9,518	13,793
9	August		4,395	9,856	14,252
10	September		4,436	9,987	14,423
11	October		4,504	10,099	14,602
12	November		4,557	10,182	14,739
13	December		4,530	10,218	14,747
14					
15	Total	SUM L1 to L13	$53,486	$120,110	$173,596
16					
17	Average Monthly Balance	L15 / 13	$4,114	$9,239	$13,354
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$4,114
21	Small C&I				8,891
22	Large C&I				348
23	Transportation				
24					
25	Total	SUM L20 to L23			$13,354

Line No.	Category	Account	Reference	(1) FTY Amount	(2) Allocated to Non Jurisdiction	(3) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$318,316	$241,810	$76,506
6						
7		E389 - Land and Land Rights		$6,783	$5,218	$1,565
8						
9		E390 - Structures and Improvements		$409,398	$314,950	$94,448
10		E391 - Office Furniture, Equipment		76,600	58,928	17,672
11		E392 - Transportation Equipment		213,002	163,863	49,140
12		E393 - Stores Equipment		1,255	965	289
13		E394 - Tools, Shop, Garage Equipmnt		2,348	1,806	542
14		E396 - Power Operated Equipment		185	142	43
15		E397 - Communication Equipment		147,623	113,566	34,057
16		E398 - Miscellaneous Equipment		1,175	904	271
17		E399 - Other Tangible Property		(0)	(0)	
18		E399.1 - ARO Costs General Plant		916	705	211
19		Sub Total - General Plant	SUM L9 to L18	$852,502	$655,830	$196,672
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,178,278	$903,378	$274,900
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$120,838	$92,696	$28,142
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,146	$53,963	$16,183
31		E391 - Office Furniture, Equipment		28,248	21,731	6,517
32		E392 - Transportation Equipment		102,106	78,550	23,556
33		E393 - Stores Equipment		309	238	71
34		E394 - Tools, Shop, Garage Equipmnt		898	690	207
35		E396 - Power Operated Equipment		185	142	43
36		E397 - Communication Equipment		44,465	34,207	10,258
37		E398 - Miscellaneous Equipment		907	697	209
38		E399 - Other Tangible Property		(0)	(0)	
39		E399.1 - ARO Costs General Plant		(358)	(276)	(83)
40		Sub Total - General Plant	SUM L30 to L39	$246,904	$189,944	$56,961
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$367,743	$282,640	$85,103
42						
43		Net Common Plant	L20 - L41	$810,535	$620,738	$189,797
44						
45						
46		Common Plant in Service to Utility	L20	$1,178,278	$903,378	$274,900
47		Common Plant Accum Depreciation to Utility	L41	367,743	282,640	85,103
48		Net Common Plant to Utility	L46 - L47	$810,535	$620,738	$189,797

(1)

Line No.	Description	Total FTY Amount
1	HTY 13-Month Average	
2	December	$888
3	January	984
4	February	1,106
5	March	1,659
6	April	1,632
7	May	1,208
8	June	1,037
9	July	1,242
10	August	1,221
11	September	1,817
12	October	1,684
13	November	1,404
14	December	1,318
15		
16	13-Month Total	$17,199
17		
18		
19	Average Monthly Balance	$1,323

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$645	($0)	$645
3	January		672	(191)	481
4	February		710	(372)	338
5	March		2,830	(1,490)	1,340
6	April		2,851	(1,111)	1,740
7	May		2,776	(1,460)	1,316
8	June		2,737	(1,693)	1,044
9	July		2,751	(1,197)	1,554
10	August		2,882	(1,126)	1,756
11	September		2,916	(1,077)	1,839
12	October		2,836	(660)	2,176
13	November		2,815	(686)	2,129
14	December		2,736	0	2,736
15					
16	Total	SUM L2 to L14	$30,156	($11,061)	$19,095
17					
18	Distribution Expense Allocation Factor		100.00%	23.07%	
19					
20	Allocation to Distribution	L16 * L18	$30,156	($2,552)	
21					
22	Average Monthly Balance	L20 / 13	$2,320	($196)	$2,123

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		$116,677	100.00%	$116,677	100.00%	$116,677
2		ADIT - CIAC			100.00%		100.00%	
3		Subtotal HTY	L1 + L2	116,677		116,677		116,677
4								
5	**FTY**	DIT - Distribution		($3,459)	100.00%	($3,459)	100.00%	($3,459)
6		DIT - CIAC			100.00%		100.00%	
7		Subtotal FTY	L5 + L6	(3,459)		(3,459)		(3,459)
8								
9		**Total**	L3 + L7	$113,217		$113,217		$113,217

Line No.	Description	Reference	(1) Stored Underground	(2) LNG	(3) Propane Gas	(4) Total
1	December		$92,465	$5,154	$1,616	$99,235
2	January		71,565	5,096	1,616	78,277
3	February		53,766	4,918	1,546	60,229
4	March		35,170	4,860	1,546	41,575
5	April		34,920	4,792	1,546	41,257
6	May		38,419	4,742	1,546	44,707
7	June		41,212	4,679	1,546	47,437
8	July		44,474	4,615	1,546	50,635
9	August		47,298	4,560	1,546	53,404
10	September		49,911	4,768	1,546	56,225
11	October		52,807	4,720	1,546	59,073
12	November		52,124	4,339	1,527	57,990
13	December		44,844	4,217	1,527	50,589
14						
15	Total	SUM L1 to L13	$658,974	$61,461	$20,199	$740,634
16						
17	Average Monthly Balance	L15 / 13	$50,690	$4,728	$1,554	$56,972

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		$482,959		$482,959
2		C & I		175,903		175,903
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		1,292	133	1,425
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		1,670		1,670
8		Other Gas Revenues		507		507
9		Transportation of Gas of Others		27,712		27,712
10		Revenue Increase			78,475	78,475
11		Subtotal Operating Revenues	SUM L1 to L10	$690,043	$78,608	$768,651
12						
13	**Operating Expenses**	Manufactured Gas Production		$427		$427
14		Storage Operations Expense		1,253		1,253
15		Storage Maintenance Expense		4,917		4,917
16		Underground Storage Expenses				
17		Other Gas Supply		221,089		221,089
18		Distribution Expense		86,570		86,570
19		Total Customer Accounts		23,707	290	23,997
20		Total Customer Service & Information		7,501		7,501
21		Total Sales		761		761
22		Administrative & General		40,267	242	40,510
23		O&M Expense	SUM L13 to L22	$386,492	$532	$387,024
24						
25		Depreciation & Amortization Expense		$105,510		$105,510
26		Amortization of Regulatory Expense		1,780		1,780
27		Taxes Other Than Income Taxes - Other		8,894		8,894
28		Subtotal Operating Expenses	SUM L23 to L27	$502,676	$532	$503,208
29						
30	**Net Operating Income - BIT**		L11 - L28	$187,367	$78,076	$265,443

Line No.	Category	Description	(1) FTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$483,295	($337)	$482,959
2		C & I	175,476	427	175,903
3		Interdepartmental			
4		Sales for Resale	15,000	(15,000)	
5		Forfeited Discounts	1,292		1,292
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	1,670		1,670
8		Other Gas Revenues	507		507
9		Transportation of Gas of Others	27,712		27,712
10		Revenue Increase			
11		Subtotal Operating Revenues	$704,952	($14,910)	$690,043
12					
13	**Operating Expenses**	Manufactured Gas Production	$418	$9	$427
14		Storage Operations Expense	1,229	24	1,253
15		Storage Maintenance Expense	4,843	74	4,917
16		Underground Storage Expenses			
17		Other Gas Supply	234,081	(12,992)	221,089
18		Distribution Expense	85,374	1,196	86,570
19		Total Customer Accounts	23,761	(54)	23,707
20		Total Customer Service & Information	7,486	15	7,501
21		Total Sales	751	11	761
22		Administrative & General	37,034	3,233	40,267
23		O&M Expense	$394,977	($8,485)	$386,492
24					
25		Depreciation & Amortization Expense	$97,547	$7,962	$105,510
26		Amortization of Regulatory Expense	649	1,131	1,780
27		Taxes Other Than Income Taxes - Other	8,737	157	8,894
28		Subtotal Operating Expenses	$501,911	$765	$502,676
29					
30	**Net Operating Income - BIT**		$203,042	($15,675)	$187,367

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension
1	**Operating Revenues**	Residential	Gas Cost	$165,260									
2			Cust & Dist	318,035	847	(136)	(1,048)						
3			Subtotal Residential	$483,295	$847	($136)	($1,048)						
4													
5		C & I	Gas Cost	$57,607									
6			Cust & Dist	117,869	826		(399)						
7			Subtotal C & I	$175,476	$826		($399)						
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$15,000					($15,000)				
13			Subtotal Sales for Resale	$15,000					($15,000)				
14													
15		Forfeited Discounts	Forfeited Discounts	$1,292									
16			Subtotal Forfeited Discounts	$1,292									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$1,670									
22			Subtotal Rent For Gas Property	$1,670									
23													
24		Other Gas Revenues	Other Gas Revenues	$507									
25			Subtotal Other Gas Revenues	$507									
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$27,712									
28			Subtotal Transportation of Gas of Others	$27,712									
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$704,952**	**$1,673**	**($136)**	**($1,447)**		**($15,000)**				
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production	$7									
36			Liquefied Petroleum Gas Expenses	123						3			
37			Liquefied Petroleum Gas Expenses	0						0			
38			Maintenance of Structures and Improvements	82						2			
39			Maintenance of Production Equipment	205						4			
40			Subtotal Manufactured Gas Production	$418						$9			
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$234,065					($11,250)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses	16						0			
46			Gas Withdrawn from Storage-Debit										

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply	$234,081					($11,250)	$0			
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$986						$18			
52			Maintenance of Structures and Improvements	3,857						56			
53			Subtotal Storage Maintenance Expense	$4,843						$74			
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$347						$7			
56			Operation Labor and Expenses	883						17			
57			Subtotal Storage Operations Expense	$1,229						$24			
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$529						$0			
63			Mains and Services Expenses	18,370						$218			
64			Measuring and Regulating Station Expenses-General	1,788						$43			
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	7,454						$71			
67			Customer Installations Expenses	7,555						$194			
68			Other Expenses	19,247						$151			
69			Rents	7									
70			Maintenance of Mains	25,311						$436			
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	1,457						$27			
72			Maintenance of Services	2,697						$46			
73			Maintenance of Meters & House Regulators	225						$5			
74			Maintenance of Other Equipment	733						$4			
75			Subtotal Distribution Expense	$85,374						$1,196			
76													
77		Total Customer Accounts	Customer Records and Collection	$20,043						$258			
78			Meter Reading	162									
79			Miscellaneous Customer Accounts	945						$9			
80			Uncollectible Accounts	2,611									
81			Subtotal Total Customer Accounts	$23,761						$267			
82													
83		Total Customer Service & Information	Customer Assistance	$7,090						$14			
84			Informational & Instructional	345									
85			Miscellaneous Customer & Informational	51						$1			
86			Subtotal Total Customer Service & Information	$7,486						$15			
87													
88		Total Sales	Demonstrating & Selling	$751						$11			
89			Miscellaneous Sales										
90			Subtotal Total Sales	$751						$11			
91													
92		Administrative & General	Administrative and General Salaries	$6,763						$225			

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(2)									
95			Employee Pensions and Benefits	6,573								45	1,877
96			Franchise Requirements	395									
97			Injuries and Damages							$6			
98			Maintenance of General Plant	985						$8			
99			Miscellaneous General Expenses	816						$0			
100			Office Supplies and Expenses	1,579									
101			Outside Service Employed	17,217									
102			Property Insurance	143									
103			Regulatory Commission Expenses	2,566							1,072		
104			Subtotal Administrative & General	$37,034						$239	$1,072	$45	$1,877
105													
106			**O&M Expense**	**$394,977**					**($11,250)**	**$1,834**	**$1,072**	**$45**	**$1,877**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$97,547									
109			Subtotal Depreciation & Amortization Expense	$97,547									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$649									
112			Subtotal Amortization of Regulatory Expense	$649									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$8,737									
115			Subtotal Taxes Other Than Income Taxes - Other	$8,737									
116													
117			**Total Operating Expenses**	**$501,911**					**($11,250)**	**$1,834**	**$1,072**	**$45**	**$1,877**
118													
119	**Net Operating Income Before Income Tax**			**$203,042**	**$1,673**	**($136)**	**($1,447)**		**($3,750)**	**($1,834)**	**($1,072)**	**($45)**	**($1,877)**

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost										$165,260
2			Cust & Dist									(337)	317,699
3			Subtotal Residential									($337)	$482,959
4													
5		C & I	Gas Cost										$57,607
6			Cust & Dist									427	118,296
7			Subtotal C & I									$427	$175,903
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale									($15,000)	
13			Subtotal Sales for Resale									($15,000)	
14													
15		Forfeited Discounts	Forfeited Discounts										$1,292
16			Subtotal Forfeited Discounts										$1,292
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property										1,670
22			Subtotal Rent For Gas Property										1,670
23													
24		Other Gas Revenues	Other Gas Revenues										$507
25			Subtotal Other Gas Revenues										$507
26													
27		Transportation of Gas of Others	Transportation of Gas of Others										$27,712
28			Subtotal Transportation of Gas of Others										$27,712
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**									**($14,910)**	**$690,043**
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										$7
36			Liquefied Petroleum Gas Expenses									$3	126
37			Liquefied Petroleum Gas Expenses									$0	0
38			Maintenance of Structures and Improvements									$2	84
39			Maintenance of Production Equipment									$4	210
40			Subtotal Manufactured Gas Production									$9	$427
41													
42		Other Gas Supply	Natural Gas City Gate Purchases									($11,250)	$222,815
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses					(1,742)				($1,742)	(1,726)
46			Gas Withdrawn from Storage-Debit										

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply						($1,742)			($12,992)	$221,089
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering									$18	$1,004
52			Maintenance of Structures and Improvements									$56	3,913
53			Subtotal Storage Maintenance Expense									$74	$4,917
54													
55		Storage Operations Expense	Operating Supervision and Engineering									$7	$354
56			Operation Labor and Expenses									$17	899
57			Subtotal Storage Operations Expense									$24	$1,253
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering									$0	$529
63			Mains and Services Expenses									$218	18,588
64			Measuring and Regulating Station Expenses-General									$43	1,831
65			Measuring and Regulating Station Expenses-City Gate										0
66			Meter and House Regulator Expenses									$71	7,525
67			Customer Installations Expenses									$194	7,749
68			Other Expenses									$151	19,398
69			Rents										7
70			Maintenance of Mains									$436	25,747
71			Maintenance of Measuring & Reg. Station Equip.-Genl.									$27	1,484
72			Maintenance of Services									$46	2,743
73			Maintenance of Meters & House Regulators									$5	231
74			Maintenance of Other Equipment									$4	737
75			Subtotal Distribution Expense									$1,196	$86,570
76													
77		Total Customer Accounts	Customer Records and Collection									$258	$20,301
78			Meter Reading										162
79			Miscellaneous Customer Accounts			809		(662)				$155	1,100
80			Uncollectible Accounts	733					(1,200)			($467)	2,144
81			Subtotal Total Customer Accounts	$733		$809		($662)	($1,200)			($54)	$23,707
82													
83		Total Customer Service & Information	Customer Assistance									$14	$7,103
84			Informational & Instructional										345
85			Miscellaneous Customer & Informational									$1	53
86			Subtotal Total Customer Service & Information									$15	$7,501
87													
88		Total Sales	Demonstrating & Selling									$11	$761
89			Miscellaneous Sales										
90			Subtotal Total Sales									$11	$761
91													
92		Administrative & General	Administrative and General Salaries									$225	$6,988

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit										(2)
95			Employee Pensions and Benefits									$1,922	8,496
96			Franchise Requirements										395
97			Injuries and Damages									$6	6
98			Maintenance of General Plant									$8	993
99			Miscellaneous General Expenses									$0	816
100			Office Supplies and Expenses										1,579
101			Outside Service Employed										17,217
102			Property Insurance										143
103			Regulatory Commission Expenses									$1,072	3,638
104			Subtotal Administrative & General									$3,233	$40,267
105													
106			**O&M Expense**	**$733**		**$809**		**($662)**	**($2,942)**			**($8,485)**	**$386,492**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense								$7,962	$7,962	$105,510
109			Subtotal Depreciation & Amortization Expense								$7,962	$7,962	$105,510
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
112			Subtotal Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other							$157		$157	$8,894
115			Subtotal Taxes Other Than Income Taxes - Other							$157		$157	$8,894
116													
117			**Total Operating Expenses**	**$733**	**$321**	**$809**	**$810**	**($662)**	**($2,942)**	**$157**	**$7,962**	**$765**	**$502,676**
118													
119	**Net Operating Income Before Income Tax**			**($733)**	**($321)**	**($809)**	**($810)**	**$662**	**$2,942**	**($157)**	**($7,962)**	**($15,675)**	**$187,367**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.	$7							
2			717.0 Liquefied Petroleum Gas Expenses.	123		3					
3			741.0 Maintenance Of Structures And Improvements.	82		2					
4			742.0 Maintenance Of Production Equipment.	205		4					
5			Subtotal	$418		$9					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	0		0					
8			Subtotal	$0		$0					
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$234,065	($11,250)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.	16		0					
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal	$234,081	($11,250)	$0					
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$347	$7						
23			841.0 Operation Labor And Expenses.	883	17						
24			Subtotal	$1,229	$24						
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$986	$18						
27			843.2 Maintenance Of Structures And Improvements.	3,857	56						
28			Subtotal	$4,843	$74						
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$529	$0						
31			874.0 Mains And Services Expenses.	18,370	218						
32			875.0 Measuring And Regulating Station Expenses--General.	1,788	43						
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	7,454	71						
35			879.0 Customer Installations Expenses.	7,555	194						
36			880.0 Other Expenses.	19,247	151						
37			881.0 Rents.	7							
38			Subtotal	$54,951	$677						
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$25,311	$436						
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	1,457	27						
42			892.0 Maintenance Of Services.	2,697	46						
43			893.0 Maintenance Of Meters And House Regulators.	225	5						
44			894.0 Maintenance Of Other Equipment.	733	4						
45			Subtotal	$30,423	$519						
46											
47			Distribution Expense Subtotal	$85,374	$1,196						
48											

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$162							
50			903.0 Customer Records And Collection Expenses.	20,043		258					
51			904.0 Uncollectible Accounts.	2,611						733	
52			905.0 Miscellaneous Customer Accounts Expenses.	945		9					
53											
54			Subtotal	$23,761		$267				$733	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$7,090		$14					
57			909.0 Informational And Instructional Advertising Expenses.	345							
58			910.0 Miscellaneous Customer Service And Informational Expenses.	51		1					
59			Subtotal	$7,486		$15					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$751		$11					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$751		$11					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$6,763		$225					
66			921.0 Office Supplies And Expenses.	1,579							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	17,217							
69			924.0 Property Insurance.	143							
70			925.0 Injuries And Damages.	395		6					
71			926.0 Employee Pensions And Benefits.	6,573				45	1,877		
72			928.0 Regulatory Commission Expenses.	2,566			1,072				
73			929.0 Duplicate Charges--Credit.	(2)							
74			930.2 Miscellaneous General Expenses.	816		0					
75											
76			Subtotal	$36,050		$231	$1,072	$45	$1,877		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$985		$8					
79			Subtotal	$985		$8					
80											
81			A&G Expense Sub-total	$37,034		$239	$1,072	$45	$1,877		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$82,880							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	14,667							
86			Subtotal	$97,547							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$649							$321
89			Subtotal	$649							$321
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$8,737							
92			Subtotal	$8,737							
93											
94			**Total**	**$501,911**	**($11,250)**	**$1,834**	**$1,072**	**$45**	**$1,877**	**$733**	**$321**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								$7
2			717.0 Liquefied Petroleum Gas Expenses.							3	126
3			741.0 Maintenance Of Structures And Improvements.							2	84
4			742.0 Maintenance Of Production Equipment.							4	210
5			Subtotal							$9	$427
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.							0	0
8			Subtotal							$0	$0
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($11,250)	$222,815
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.				(1,742)			(1,742)	(1,726)
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal				($1,742)			($12,992)	$221,089
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$7	$354
23			841.0 Operation Labor And Expenses.							17	899
24			Subtotal							$24	$1,253
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$18	$1,004
27			843.2 Maintenance Of Structures And Improvements.							56	3,913
28			Subtotal							$74	$4,917
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$529
31			874.0 Mains And Services Expenses.							218	18,588
32			875.0 Measuring And Regulating Station Expenses--General.							43	1,831
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							71	7,525
35			879.0 Customer Installations Expenses.							194	7,749
36			880.0 Other Expenses.							151	19,398
37			881.0 Rents.								7
38			Subtotal							$677	$55,628
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$436	$25,747
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							27	1,484
42			892.0 Maintenance Of Services.							46	2,743
43			893.0 Maintenance Of Meters And House Regulators.							5	231
44			894.0 Maintenance Of Other Equipment.							4	737
45			Subtotal							$519	$30,942
46											
47			Distribution Expense Subtotal							$1,196	$86,570
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.								$162
50			903.0 Customer Records And Collection Expenses.							258	20,301
51			904.0 Uncollectible Accounts.				(1,200)			(467)	2,144
52			905.0 Miscellaneous Customer Accounts Expenses.	809		(662)				155	1,100
53											
54			Subtotal	$809		($662)	($1,200)			($54)	$23,707
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$14	$7,103
57			909.0 Informational And Instructional Advertising Expenses.								345
58			910.0 Miscellaneous Customer Service And Informational Expenses.							1	53
59			Subtotal							$15	$7,501
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$11	$761
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$11	$761
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$225	$6,988
66			921.0 Office Supplies And Expenses.								1,579
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								17,217
69			924.0 Property Insurance.								143
70			925.0 Injuries And Damages.							6	400
71			926.0 Employee Pensions And Benefits.							1,922	8,496
72			928.0 Regulatory Commission Expenses.							1,072	3,638
73			929.0 Duplicate Charges--Credit.								(2)
74			930.2 Miscellaneous General Expenses.							0	816
75											
76			Subtotal							$3,225	$39,275
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$8	$993
79			Subtotal							$8	$993
80											
81			A&G Expense Sub-total							$3,233	$40,267
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$4,384	$4,384	$87,264
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						3,579	3,579	18,246
86			Subtotal						$7,962	$7,962	$105,510
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$810					$1,131	$1,780
89			Subtotal		$810					$1,131	$1,780
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$157		$157	$8,894
92			Subtotal					$157		$157	$8,894
93											
94			**Total**	**$809**	**$810**	**($662)**	**($2,942)**	**$157**	**$7,962**	**$765**	**$502,676**

Line No.	Category	Description	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) Adjustments Sub-total	(8) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$318,035	$847	($136)	($1,048)			($337)	$317,699
2			C & I	481.0	117,869	826		(399)			427	118,296
3			Transportation of Gas of Others	489.3	27,712							27,712
4				Subtotal	$463,617	$1,673	($136)	($1,447)			$90	$463,707
5												
6		**Gas Cost Revenue**	Residential	480.0	$165,260							$165,260
7			C & I	481.0	57,607							57,607
8			Interdepartmental	484.0								
9				Subtotal	$222,867							$222,867
10												
11			**Subtotal OPERATING REVENUE**		$686,484	$1,673	($136)	($1,447)			$90	$686,574
12												
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$1,670							$1,670
14			Interdepartmental Rents	494.0								
15			Other Gas Revenues	495.0	507							507
16				Subtotal	$2,177							$2,177
17												
18		**Other Operating Revenue**	Sales For Resale	483.0	$15,000					($15,000)	(15,000)	
19			Forfeited Discounts	487.0	1,292							1,292
20												
21			Miscellaneous Service Revenues	488.0								
22				Subtotal	$16,292					($15,000)	($15,000)	$1,292
23												
24			**Subtotal OTHER REVENUE**		$18,468					($15,000)	($15,000)	$3,468
25												
26			**Total**		**$704,952**	**$1,673**	**($136)**	**($1,447)**		**($15,000)**	**($14,910)**	**$690,043**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total
1	Total FPFTY Revenues		$483,295	$1,265	$171,911	$268	$1,848	$175,291
2	Commodity Billings in Revenues		(165,260)	(621)	(55,542)	(90)	(1,283)	(57,536)
3	Weather Adjustment							
4	Total Reconcilable Surcharge in Revenues							
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$318,035	$644	$116,369	$177	$566	$117,755
6								
7	Average Monthly Customers in FTY		509,018	22	45,257	8	16	
8								
9	Average Annual Margin Per Customer	L5 / L7	$0.625	$29.939	$2.571	$22.181	$35.349	
10								
11	Number of Customers of Current Month		510,374	21	45,584	8	16	45,629
12								
13	Increase in Customers During FTY	L11 - L7	1,356	(1)	327			45,629
14								
15	Annualization of Revenue	L9 * L13	$847	($15)	$841			$826

D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	Reference	(1) Residential Sales
1	CAP Discount		($11,003)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		288,769
7	Average Monthly CAP Customers		24,064
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.457)
9			
10	CAP Customers at End of FTY		24,396
11	Decrease of CAP Customers	L10 - L7	332
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($152)
14	Write-Offs & Working Capital Factor		10.5%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$16
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($136)**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total
1	Revenue in February of FTY		$40,514	$115	$15,254	$12	$44	$15,426
2	Days in February of FTY		29	29	29	29	29	
3	Average Daily Revenue in February	L1 / L2	1,397	4	526	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	(0.75)	(0.75)	(0.75)	(0.75)	(0.75)	
6								
7	**Leap Year Adjustment**	L3 * L5	**($1,048)**	**($3)**	**($395)**	**($0)**	**($1)**	**($399)**

Line No.	Description	(1) Total
1	Residential Sales	
2	TCS Sales	
3	GC Sales	
4	C & I Total	
5	Revenues - Gas Transportation	
6	**Total**	

(1)

Line No.	Description	Account	Total
1	Other Operating Revenue	483000: Sales for Resale - Gas	($15,000)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($11,250)

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		348	348
2	Number of Employees @ HTY - Total		696	696
3	Percentage of Employees @ HTY	L1 / L2	50.01%	49.99%
4	Distribution of Budget S&W Expense		$24,404	$24,398
5				
6	**Annualize March 1 Wage Increase for FTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$122
10		L4 + L9	$24,404	$24,520
11				
12	**Annualize January 1 and March 1, 2025 Wage Increase**			
13	Number of Months TY		12	12
14	Rate for Increase TY		2.50%	3.00%
15	Total Wage Increase TY	(L10 * L13 * L14) / 12	$610	$736
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$25,014**	**$25,255**

Line No.	Description	(1) Reference	(2) PECO - Gas
1	Distribution of S&W Expense		$48,801
2			
3	Annualized S&W Including Wage Increases		$50,269
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		19.15%
8	Union Contract Payment for Utility	L6 * L7	$249
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$42
11			
12	Annualized S&W for Employees in FTY	L3 + L10	$50,311
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FTY		701
16	Average Number of Employees in FTY - Total		697
17	Annualization for Number of Employees	L15 - L16	4
18	Annual S&W per Employee	L12 / L16	$72.2
19	Annualization of S&W for New Employees	L17 * L18	$324
20			
21	Pro Forma FTY S&W	L12 + L19	$50,635
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$1,834**
24			
25	S&W Pro Forma Factor	L23 / L1	3.76%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.	$3		3
2			717.0 Liquefied Petroleum Gas Expenses.	71	$3	$74
3			728.0 Liquefied Petroleum Gas.	0	0	0
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.	7	0	7
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	184	7	191
12			841.0 Operation Labor And Expenses.	446	17	462
13			843.1 Maintenance Supervision And Engineering.	471	18	489
14			843.2 Maintenance Of Structures And Improvements.	1,489	56	1,545
15			**Subtotal Power Supply Expenses**	$2,671	$100	$2,771
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$1	$0	$1
18			874.0 Mains And Services Expenses.	5,802	218	6,020
19			875.0 Measuring And Regulating Station Expenses--General.	1,142	43	1,185
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	1,884	71	1,954
22			879.0 Customer Installations Expenses.	5,171	194	5,365
23			880.0 Other Expenses.	4,007	151	4,158
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.	0		0
26			887.0 Maintenance Of Mains.	11,612	436	12,048
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	716	27	743
28			892.0 Maintenance Of Services.	1,226	46	1,272
29			893.0 Maintenance Of Meters And House Regulators.	142	5	147
30			894.0 Maintenance Of Other Equipment.	116	4	120
31			**Subtotal Distribution Expense**	$31,818	$1,196	$33,013
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	0		0
34			903.0 Customer Records And Collection Expenses.	$6,863	$258	$7,121
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	230	9	239
37						
38			**Subtotal Customer Accounts**	$7,093	$267	$7,359
39						
40		Customer Service & Information	908.0 Customer Assistance Expenses	$372	$14	$386

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.	39	1	41
43			**Subtotal Customer Service & Information**	$411	$15	$427
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$280	$11	$290
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$280	$11	$290
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$5,993	$225	$6,218
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	150	6	156
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	8	0	9
59						
60			**Subtotal Administration & General - General**	$6,151	$231	$6,382
61						
62			**Subtotal Operations**	$48,423	$1,819	$50,243
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$212	$8	$220
65			**Subtotal Administration & General - General**	$212	$8	$220
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$47	$2	$49
68			742.0 Maintenance Of Production Equipment.	118	4	123
69			**Subtotal Gas Expense**	$165	$6	$172
70						
71			**Subtotal Maintenance**	$378	$14	$392
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$48,801	$1,834	$50,635
74						
75	**Percent Increase**		**Percent Increase**			3.76%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$8
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$15
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,701
8	Materials, IT Costs, Travel, Copies, etc.		428
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$2,129
10			
11	**Total Rate Case Expense**	L4 + L9	$2,144
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,072
15			
16	Annual Amortization Amount Included in Budget		
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	$1,072

Line No.	Description	(1) Reference	(2) Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		699
3	Employees at Ten Months Prior		698
4	Employees at Nine Months Prior		695
5	Employees at Eight Months Prior		693
6	Employees at Seven Months Prior		693
7	Employees at Six Months Prior		691
8	Employees at Five Months Prior		690
9	Employees at Four Months Prior		691
10	Employees at Three Months Prior		704
11	Employees at Two Months Prior		703
12	Employees at One Month Prior		703
13	Employees at End of FTY		701
14			
15	Average Monthly Employees in FTY	AVERAGE L2 to L13	697
16	Additional Employees in FTY		4
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$7,026
20	Number of Employees for Budget		697
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	4
23	Total Benefits Pro Forma Adjustment	L21 * L22	$45

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to FTY		$18,006
2	Pension Contribution for Three Years Prior to FTY		17,267
3	Pension Contribution for Two Years Prior to FTY		15,222
4	Pension Contribution for One Year Prior to FTY		1,408
5	Pension Contribution for FTY		2,878
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$10,956
8			
9	Allocation Percent to Utility		19.15%
10	Total Amount to Utility	L7 * L9	$2,098
11	Allocation Percent to Capital		36.61%
12	Pension Contribution To Be Capitalized	L10 * L11	$768
13	Pension Contribution To Be Expensed	L10 - L12	$1,330
14	Budgeted Test Year Distribution Pension Expense		($547)
15	Additional Pension Expense	L13 - L14	$1,877

Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
			(1)	(2)	(3)	(4)	(5)	(6)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$2,036	$595,534	0.3419%		
2		One Year Prior to HTY		2,826	780,108	0.3623%		
3		HTY		3,091	778,733	0.3970%		
4		Three Year Average	SUM L1 to L3 / 3	$2,651	$718,125	0.3692%		
5								
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FTY			$686,574			
7								
8	Tariff Revenue - Non Shopping Revenue	FTY	L6		$686,574			
9								
10	Tariff Revenue - Shopping Revenue	FTY			$75,555			
11								
12	Tariff Revenue - Including Shopping Revenue	FTY	L8 + L10		$762,129			
13								
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12					$2,814
15								
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY				$367		
17		One Year Prior to HTY				532		
18		HTY				693		
19								
20	**Three Year Average PPA**		SUM L16 to L18 / 3					$530
21								
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20					$3,344
23								
24	Uncollectible Accounts (904)	FTY						$2,611
25								
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24					$733

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$3,078
2	Residential Gas Energy Efficiency Program Costs in FTY Budget		2,728
3	Sub-total Pro Forma Increase in Residential Gas Energy Efficiency Program Costs	L1 - L2	$350
4	Gas Commercial EE Program Refund - Rate GC		(29)
5	Total Pro Forma Adjustment Amount	L3 + L4	$321

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				3,654	24		
4	February				3,686	25		
5	March				3,760	25		
6	April				3,872	26		
7	May				4,038	27		
8	June				4,165	28		
9	July				4,275	28		
10	August				4,395	29		
11	September				4,436	30		
12	October				4,504	30		
13	November				4,557	30		
14	December				4,530	30		
15	**Total Residential**		SUM Col 4 L3 to L14				$332	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				8,284	35		
20	February				8,444	36		
21	March				8,594	37		
22	April				8,742	37		
23	May				8,997	38		
24	June				9,113	39		
25	July				9,518	40		
26	August				9,856	42		
27	September				9,987	42		
28	October				10,099	43		
29	November				10,182	43		
30	December				10,218	43		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$476	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$809

Line No.	Description	(1) Reference	(2) Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$14,309
2	Amortization Years		10
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,431
5			
6	**Amount Included in Budget**		$621
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	$810

Line No.	Description	(1) Reference	(2) Total
1	Customer Interest on Unspent MGP Collections		($1,387)
2	Gas FTAC Final Reconciliation Recovery from Customers		$63
3	Total	L1 + L2	($1,325)
4	Amortization Years		2
5	Pro Forma Adjustment Amount	L3 / L4	($662)

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,119)
3	Rate GC		($609)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($1,742)
8			
9	Merchant Function Charge / POR		($1,057)
10	Rate GR		($143)
11	Rate GC		
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,200)
16			
17	Total Gas Procurement and Merchant Function Charges	L7 + L15	($2,942)

Line No.	Description	(1) Total	(2) Pro Forma Adjustments	(3) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076		$2,076
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	732		732
4	Real Estate Tax Accrual	1,752		1,752
5	Miscellaneous TOTI			
6	Payroll Tax Accrued	4,177	$157	4,333
7	**Total**	$8,737	$157	$8,894

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$48,801
2	Payroll Tax Expense		$4,177
3	Payroll Tax Expense - Percent	L2 / L1	8.56%
4	Pro Forma Increase in S&W		$1,834
5	**Payroll Tax Pro Forma**	L3 * L4	**$157**

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.	Common-General Plant	PECO Common 3901 PA	$4,118	$127	$3,990	$127	$4,245
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	3,818	1,031	2,787	1,031	4,849
4			PECO Common 3903 PA	91	28	63	28	119
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,256	81	2,175	81	2,337
7			PECO Common 3913 IL	1,039	144	895	144	1,184
8			PECO Common 3913 PA	8,106	1,341	6,764	1,341	9,447
9			PECO Common 3930 PA	98	2	96	2	100
10			PECO Common 3941 PA	1		1		1
11			PECO Common 3942 PA	66		66		66
12			PECO Common 3970 PA	6,577	494	6,083	494	7,071
13			PECO Common 3980 PA	84		84		84
14			Subtotal Common - General Plant	$26,282	$3,250	$23,032	$3,250	$29,531
15								
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA					
17			Subtotal					
18								
19		Gas - Distribution	PECO Gas 3751 PA	$135	$2	$132	$2	$137
20			PECO Gas 3752 PA	34	3	32	3	37
21			PECO Gas 3753 PA	172	1	171	1	173
22			PECO Gas 3761 PA	10,661	484	10,177	484	11,145
23			PECO Gas 3762 PA	1,178		1,178		1,178
24			PECO Gas 3763 PA	20,296	1,322	18,974	1,322	21,618
25			PECO Gas 3780 PA	525	16	509	16	541
26			PECO Gas 3790 PA	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	3,595	8	3,586	8	3,603
28			PECO Gas 3802 PA	20,594	1,132	19,462	1,132	21,726
29			PECO Gas 3810 PA	2,065	43	2,022	43	2,108
30			PECO Gas 3811 PA	3,485	16	3,469	16	3,501
31			PECO Gas 3820 PA	5,157	230	4,926	230	5,387
32			PECO Gas 3870 PA	93		93		93
33			Subtotal Gas - Distribution	$69,038	$3,257	$65,781	$3,257	$72,296
34								

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
35		Gas - General Plant	PECO Gas 3901 PA	$100	$1	$99	$1	$101
36			PECO Gas 3902 PA	55	0	55	0	56
37			PECO Gas 3903 PA	75	5	70	5	79
38			PECO Gas 3911 PA	0		0		0
39			PECO Gas 3912 PA	34		34		34
40			PECO Gas 3913 IL	0		0		0
41			PECO Gas 3913 PA	433	3	430	3	437
42			PECO Gas 3940 PA	750	9	741	9	760
43			PECO Gas 3950 PA	2	0	2	0	2
44			PECO Gas 3970 PA	382	6	377	6	388
45			PECO Gas 3980 PA	8		8		8
46			Subtotal Gas - General Plant	$1,839	$24	$1,815	$24	$1,864
47								
48		Gas - Production Plant	PECO Gas 3050 PA	$31		$31		$31
49			PECO Gas 3053 PA					
50			PECO Gas 3110 PA	140		140		140
51			Subtotal Gas - Production Plant	$170		$170		$170
52								
53		Gas - Storage	PECO Gas 3611 PA	$49		$49		$49
54			PECO Gas 3612 PA	329		329		329
55			PECO Gas 3613 PA	23		23		23
56			PECO Gas 3620 PA	10		10		10
57			PECO Gas 3630 PA	25		25		25
58			PECO Gas 3631 PA	156		156		156
59			PECO Gas 3632 PA	3,438	228	3,210	228	3,666
60			PECO Gas 3633 PA	918	55	863	55	972
61			PECO Gas 3634 PA	530	56	474	56	587
62			PECO Gas 3635 PA	291	13	278	13	304
63			Subtotal Gas - Storage	$5,769	$352	$5,417	$352	$6,121
64								
65			Subtotal 403.0 Depreciation Expense.	$103,099	$6,883	$96,216	$6,883	$109,982
66								

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
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$10,909	$10,909		$10,909	$21,819
68			PECO Com 3030- North Star RE SW	391		$391		$391
69			PECO Com 3030-Apollo SW	967		$967		$967
70			PECO Com 3030-BIDA Customer Project	849		$849		$849
71			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		$2,139		$2,139
72			PECO Com 3030-CIS Transformation SW	204		$204		$204
73			PECO Com 3030-Cloud Serv 3 yr	4,143	2,109	$2,034	$2,109	$6,252
74			PECO Com 3030-Cloud Serv 5 yr	3,358		$3,358		$3,358
75			PECO Com 3030-Common MDM SW	2,040		$2,040		$2,040
76			PECO Com 3030-Cust Appt Sched SW	436		$436		$436
77			PECO Com 3030-EU Dig Strat EPay SW	164		$164		$164
78			PECO Com 3030-EU Digital Program We	2,002		$2,002		$2,002
79			PECO Com 3030-EU oneMDS SW	5,269		$5,269		$5,269
80			PECO Com 3030-Fusion Mig Non-MDM SW	33		$33		$33
81			PECO Com 3030-I Sign Up and Move	466		$466		$466
82			PECO Com 3030-IT Cust Mobile App SW	112		$112		$112
83			PECO Com 3030-IVR System PA	159		$159		$159
84			PECO Com 3030-Lease IT SW	14		$14		$14
85			PECO Com 3030-Misc 5 yr FR PA	6,164	652	$5,512	$652	$6,816
86			PECO Com 3030-Misc 5 yr PA	60		$60		$60
87			PECO Com 3030-Mobile Dispatch Mappi	5,842		$5,842		$5,842
88			PECO Com 3030-OBIEE Migration SW	801		$801		$801
89			PECO Com 3030-PECO RNI Upgrade SW	(0)		($0)		($0)
90			PECO Com 3030-Robotic Process Auto	63		$63		$63
91			Subtotal Common - Intangible Plant	$46,585	$13,670	$32,914	$13,670	$60,255
92								
93		Gas - General Plant	PECO Gas 3913 PA					
94			Subtotal					
95								
96		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$2,323	$160	$2,163	$160	$2,484
97			PECO Gas 303-PECO RNI Upgrade SW G	440		440		440
98			PECO Gas 303-SES IV G SW	759		759		759
99			PECO Gas 3030-Cloud Serv 3 yr	82		82		82
100			PECO Gas 3030-Cloud Serv 5 yr	51		51		51
101			Subtotal Gas - Intangible Plant	$3,655	$160	$3,495	$160	$3,816
102								
103			Subtotal 404.0 Amort. Of Limited-Term Plant	$50,240	$13,831	$36,409	$13,831	$64,071
104								
105			Grand Total	$153,339	$20,714	$132,625	$20,714	$174,053

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.	Common-General Plant	PECO Common 3901 PA	0.2307	$950	$29	$921	$29	$979
2			PECO Common 3902 IL	0.2307	4		4		4
3			PECO Common 3902 PA	0.2307	881	238	643	238	1,119
4			PECO Common 3903 PA	0.2307	21	7	14	7	28
5			PECO Common 3911 PA	0.2307	3		3		3
6			PECO Common 3912 PA	0.2307	520	19	502	19	539
7			PECO Common 3913 IL	0.2307	240	33	206	33	273
8			PECO Common 3913 PA	0.2307	1,870	309	1,560	309	2,179
9			PECO Common 3930 PA	0.2307	23	0	22	0	23
10			PECO Common 3941 PA	0.2307	0		0		0
11			PECO Common 3942 PA	0.2307	15		15		15
12			PECO Common 3970 PA	0.2307	1,517	114	1,403	114	1,631
13			PECO Common 3980 PA	0.2307	19		19		19
14			Subtotal Common - General Plant		$6,063	$750	$5,314	$750	$6,813
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	0.2307					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$135	$2	$132	$2	$137
20			PECO Gas 3752 PA	1.0000	34	3	32	3	37
21			PECO Gas 3753 PA	1.0000	172	1	171	1	173
22			PECO Gas 3761 PA	1.0000	10,661	484	10,177	484	11,145
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	20,296	1,322	18,974	1,322	21,618
25			PECO Gas 3780 PA	1.0000	525	16	509	16	541
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,595	8	3,586	8	3,603
28			PECO Gas 3802 PA	1.0000	20,594	1,132	19,462	1,132	21,726
29			PECO Gas 3810 PA	1.0000	2,065	43	2,022	43	2,108
30			PECO Gas 3811 PA	1.0000	3,485	16	3,469	16	3,501
31			PECO Gas 3820 PA	1.0000	5,157	230	4,926	230	5,387
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$69,038	$3,257	$65,781	$3,257	$72,296
34									

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)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$100	$1	$99	$1	$101
36			PECO Gas 3902 PA	1.0000	55	0	55	0	56
37			PECO Gas 3903 PA	1.0000	75	5	70	5	79
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	433	3	430	3	437
42			PECO Gas 3940 PA	1.0000	750	9	741	9	760
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	382	6	377	6	388
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,839	$24	$1,815	$24	$1,864
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	3,438	228	3,210	228	3,666
60			PECO Gas 3633 PA	1.0000	918	55	863	55	972
61			PECO Gas 3634 PA	1.0000	530	56	474	56	587
62			PECO Gas 3635 PA	1.0000	291	13	278	13	304
63			Subtotal Gas - Storage		$5,769	$352	$5,417	$352	$6,121
64									
65			Subtotal 403.0 Depreciation Expense.		$82,880	$4,384	$78,497	$4,384	$87,264
66									

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)
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.2550	$2,782	$2,782		$2,782	$5,563
68			PECO Com 3030- North Star RE SW	0.2307	$90		$90		$90
69			PECO Com 3030-Apollo SW	0.2307	$223		$223		$223
70			PECO Com 3030-BIDA Customer Project	0.2307	$196		$196		$196
71			PECO Com 3030-BIDA-AMI Ph2 SW	0.2307	$493		$493		$493
72			PECO Com 3030-CIS Transformation SW	0.2307	$47		$47		$47
73			PECO Com 3030-Cloud Serv 3 yr	0.2307	$956	$487	$469	$487	$1,442
74			PECO Com 3030-Cloud Serv 5 yr	0.2307	$775		$775		$775
75			PECO Com 3030-Common MDM SW	0.2307	$471		$471		$471
76			PECO Com 3030-Cust Appt Sched SW	0.2307	$101		$101		$101
77			PECO Com 3030-EU Dig Strat EPay SW	0.2307	$38		$38		$38
78			PECO Com 3030-EU Digital Program We	0.2307	$462		$462		$462
79			PECO Com 3030-EU oneMDS SW	0.2307	$1,216		$1,216		$1,216
80			PECO Com 3030-Fusion Mig Non-MDM SW	0.2307	$8		$8		$8
81			PECO Com 3030-I Sign Up and Move	0.2307	$108		$108		$108
82			PECO Com 3030-IT Cust Mobile App SW	0.2307	$26		$26		$26
83			PECO Com 3030-IVR System PA	0.2307	$37		$37		$37
84			PECO Com 3030-Lease IT SW	0.2307	$3		$3		$3
85			PECO Com 3030-Misc 5 yr FR PA	0.2307	$1,422	$150	$1,272	$150	$1,573
86			PECO Com 3030-Misc 5 yr PA	0.2307	$14		$14		$14
87			PECO Com 3030-Mobile Dispatch Mappi	0.2307	$1,348		$1,348		$1,348
88			PECO Com 3030-OBIEE Migration SW	0.2307	$185		$185		$185
89			PECO Com 3030-PECO RNI Upgrade SW	0.2307	($0)		($0)		($0)
90			PECO Com 3030-Robotic Process Auto	0.2307	$15		$15		$15
91			Subtotal Common - Intangible Plant		$11,012	$3,419	$7,593	$3,419	$14,430
92									
93		Gas - General Plant	PECO Gas 3913 PA	1.0000					
94			Subtotal						
95									
96		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,323	$160	$2,163	$160	$2,484
97			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	440		440		440
98			PECO Gas 303-SES IV G SW	1.0000	759		759		759
99			PECO Gas 3030-Cloud Serv 3 yr	1.0000	82		82		82
100			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
101			Subtotal Gas - Intangible Plant		$3,655	$160	$3,495	$160	$3,816
102									
103			Subtotal 404.0 Amort. Of Limited-Term Plant		$14,667	$3,579	$11,088	$3,579	$18,246
104									
105			Grand Total		$97,547	$7,962	$89,585	$7,962	$105,510

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 FTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$950	$29	$921	$29	$979
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	881	238	643	238	1,119
4			PECO Common 3903 PA	1.0000	21	7	14	7	28
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	520	19	502	19	539
7			PECO Common 3913 IL	1.0000	240	33	206	33	273
8			PECO Common 3913 PA	1.0000	1,870	309	1,560	309	2,179
9			PECO Common 3930 PA	1.0000	23	0	22	0	23
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	15		15		15
12			PECO Common 3970 PA	1.0000	1,517	114	1,403	114	1,631
13			PECO Common 3980 PA	1.0000	19		19		19
14			Subtotal Common - General Plant		$6,063	$750	$5,314	$750	$6,813
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	1.0000					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$135	$2	$132	$2	$137
20			PECO Gas 3752 PA	1.0000	34	3	32	3	37
21			PECO Gas 3753 PA	1.0000	172	1	171	1	173
22			PECO Gas 3761 PA	1.0000	10,661	484	10,177	484	11,145
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	20,296	1,322	18,974	1,322	21,618
25			PECO Gas 3780 PA	1.0000	525	16	509	16	541
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,595	8	3,586	8	3,603
28			PECO Gas 3802 PA	1.0000	20,594	1,132	19,462	1,132	21,726
29			PECO Gas 3810 PA	1.0000	2,065	43	2,022	43	2,108
30			PECO Gas 3811 PA	1.0000	3,485	16	3,469	16	3,501
31			PECO Gas 3820 PA	1.0000	5,157	230	4,926	230	5,387
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$69,038	$3,257	$65,781	$3,257	$72,296
34									

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 FTY Depr (Function)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$100	$1	$99	$1	$101
36			PECO Gas 3902 PA	1.0000	55	0	55	0	56
37			PECO Gas 3903 PA	1.0000	75	5	70	5	79
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	433	3	430	3	437
42			PECO Gas 3940 PA	1.0000	750	9	741	9	760
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	382	6	377	6	388
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,839	$24	$1,815	$24	$1,864
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	3,438	228	3,210	228	3,666
60			PECO Gas 3633 PA	1.0000	918	55	863	55	972
61			PECO Gas 3634 PA	1.0000	530	56	474	56	587
62			PECO Gas 3635 PA	1.0000	291	13	278	13	304
63			Subtotal Gas - Storage		$5,769	$352	$5,417	$352	$6,121
64									
65			Subtotal 403.0 Depreciation Expense.		$82,880	$4,384	$78,497	$4,384	$87,264
66									

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 FTY Depr (Function)
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	1.0000	$2,782	$2,782		$2,782	$5,563
68			PECO Com 3030- North Star RE SW	1.0000	$90		$90		$90
69			PECO Com 3030-Apollo SW	1.0000	$223		$223		$223
70			PECO Com 3030-BIDA Customer Project	1.0000	$196		$196		$196
71			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	$493		$493		$493
72			PECO Com 3030-CIS Transformation SW	1.0000	$47		$47		$47
73			PECO Com 3030-Cloud Serv 3 yr	1.0000	$956	$487	$469	$487	$1,442
74			PECO Com 3030-Cloud Serv 5 yr	1.0000	$775		$775		$775
75			PECO Com 3030-Common MDM SW	1.0000	$471		$471		$471
76			PECO Com 3030-Cust Appt Sched SW	1.0000	$101		$101		$101
77			PECO Com 3030-EU Dig Strat EPay SW	1.0000	$38		$38		$38
78			PECO Com 3030-EU Digital Program We	1.0000	$462		$462		$462
79			PECO Com 3030-EU oneMDS SW	1.0000	$1,216		$1,216		$1,216
80			PECO Com 3030-Fusion Mig Non-MDM SW	1.0000	$8		$8		$8
81			PECO Com 3030-I Sign Up and Move	1.0000	$108		$108		$108
82			PECO Com 3030-IT Cust Mobile App SW	1.0000	$26		$26		$26
83			PECO Com 3030-IVR System PA	1.0000	$37		$37		$37
84			PECO Com 3030-Lease IT SW	1.0000	$3		$3		$3
85			PECO Com 3030-Misc 5 yr FR PA	1.0000	$1,422	$150	$1,272	$150	$1,573
86			PECO Com 3030-Misc 5 yr PA	1.0000	$14		$14		$14
87			PECO Com 3030-Mobile Dispatch Mappi	1.0000	$1,348		$1,348		$1,348
88			PECO Com 3030-OBIEE Migration SW	1.0000	$185		$185		$185
89			PECO Com 3030-PECO RNI Upgrade SW	1.0000	($0)		($0)		($0)
90			PECO Com 3030-Robotic Process Auto	1.0000	$15		$15		$15
91			Subtotal Common - Intangible Plant		$11,012	$3,419	$7,593	$3,419	$14,430
92									
93		Gas - General Plant	PECO Gas 3913 PA	1.0000					
94			Subtotal						
95									
96		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,323	$160	$2,163	$160	$2,484
97			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	440		440		440
98			PECO Gas 303-SES IV G SW	1.0000	759		759		759
99			PECO Gas 3030-Cloud Serv 3 yr	1.0000	82		82		82
100			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
101			Subtotal Gas - Intangible Plant		$3,655	$160	$3,495	$160	$3,816
102									
103			Subtotal 404.0 Amort. Of Limited-Term Plant		$14,667	$3,579	$11,088	$3,579	$18,246
104									
105			Grand Total		$97,547	$7,962	$89,585	$7,962	$105,510

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$690,043	$78,608	$768,651
2	Operating Expenses		502,676	532	503,208
3	OIBIT	L1 - L2	$187,367	$78,076	$265,443
4					
5	Rate Base		$3,166,113		$3,166,113
6	Weighted Cost of Debt		2.030%		2.030%
7	Synchronized Interest Expense	L5 * L6	$64,272		$64,272
8	Base Taxable Income	L3 - L7	$123,095	$78,076	$201,171
9					
10	State Accelerated Tax Depreciation		$121,140		$121,140
11	Pro Forma Book Depreciation		105,510		105,510
12	State Tax Depreciation (Over) Under Book	L11 - L10	($15,630)		($15,630)
13	Regulatory Asset Programs M-1, Pension & Post-Retirement		(8,349)		(8,349)
14	Other Property Basis Adjustments (CIAC/ICM)		(20,352)		(20,352)
15	Removal Costs/Software		(2,132)		(2,132)
16	AFUDC Equity		(6,929)		(6,929)
17	Permanent Adjustments		792		792
18	Repair Deduction		(135,500)		(135,500)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($65,005)	$78,076	$13,072
21					
22	State Income Tax Rate		8.49%	8.49%	8.49%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$5,519	($6,629)	($1,110)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(2,208)	2,651	444
26	State Income Tax Benefit / (Expense)	L23 + L25	3,311	($3,977)	($666)
27					
28	Federal Accelerated Tax Depreciation		$100,751		$100,751
29	Pro Forma Book Depreciation		105,510		105,510
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$4,759		$4,759
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		(8,349)		(8,349)
32	Other Property Basis Adjustments (CIAC/ICM)		(20,352)		(20,352)
33	Removal Costs/Software		(2,132)		(2,132)
34	AFUDC Equity		(6,929)		(6,929)
35	Permanent Adjustments		792		792
36	Repair Deduction		(135,500)		(135,500)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($41,304)	$74,099	$32,795
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$8,674	($15,561)	($6,887)
42	Corporate Alternative Minimum Tax		($17,594)		($17,594)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($5,609)	($19,538)	($25,147)
44					

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($5,427)	$557	($4,871)
47	Deferred Taxes on Timing Differences- State		(2,437)		(2,437)
48	Deferred Taxes on State NOL		2,208	(2,651)	(444)
49	Excess Deferred Amortization		3,023		3,023
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(783)		(783)
53	Corporate Alternative Minimum Tax		17,594		17,594
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$14,448	($2,095)	$12,354
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$8,840	($21,633)	($12,793)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$5		$5
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$8,845	($21,633)	($12,787)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$5,492	($15,004)	($9,512)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	3,353	(6,629)	(3,275)
65	Total Income Tax Benefit / (Expense)	L63 + L64	$8,845	($21,633)	($12,787)

Line No.	Description	(1) Reference	(2) 2018	(3) 2019	(4) 2020	(5) 2021	(6) 2022	(7) Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		($85,736)	($162,524)	($249,053)	($575,746)	($108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	($12,750)	($33,376)		($11,242)	($18,122)	
14								
15								
16	Gas Percentage		-1.20%	-21.27%	163.65%	-259.39%	-38.60%	
17								
18								
19	Loss Allocable to Gas	L13 * L16	$153	$7,100		$29,160	$6,994	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						8,681
24								
25								
26	Tax Rate							21.00%
27								
28	Section 1301.1(b) Differential	L23 * L26						$1,823

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ in Thousands)
D-19 Conversion Factor

Line No.	Description	(1) Reference	(2) Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		1,292
4	Total Customer Revenue		686,484
5	Shopping Revenue		75,555
6	LPC REVENUE	L3 / (L4 + L5)	0.001695
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.003692)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003087)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.994916
13			
14	STATE INCOME TAX RATE		8.490%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.084468)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.910448
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.191194)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.719254
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.390330
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	27.566%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		8.490%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.084900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.915100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.192171)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.722929
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.383262
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.707%

PECO Exhibit MJT-3:

Principal Accounting Exhibit - HTY ended December 31, 2023

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2023
($ 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	$3,905,331		$3,905,331
3	Accumulated Depreciation	C-3	929,927		929,927
4	Common Plant - Net of Accum Depr	C-8	148,978		148,978
5	Net Plant in service	L2 - L3 + L4	$3,124,383		$3,124,383
6					
7	Working Capital	C-1	$12,564		$12,564
8	Accum Deferred Income Taxes	C-1	(232,557)		(232,557)
9	Customer Deposits	C-1	(13,354)		(13,354)
10	Customer Advances for Construction	C-1	(1,323)		(1,323)
11	Materials and Supplies	C-1	2,123		2,123
12	Accum Deferred Income Taxes - Reg Liability	C-1	(116,677)		(116,677)
13	Gas Storage	C-1	56,972		56,972
14					
15	TOTAL RATE BASE	SUM L5 to L13	$2,832,132		$2,832,132
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$455,015	$6,063	$461,077
19	Supply Cost Revenue	D-5	268,143		268,143
20	Other Operating Revenues	D-5	4,633	17	4,649
21	Total Revenues	SUM L18 to L20	$727,790	$6,080	$733,870
22					
23	Operating Expenses	D-1	$523,248	$41	$523,289
24					
25	OIBIT	L21 - L23	$204,542	$6,039	$210,580
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	$14,855		$14,855
28	Income Taxes @ Statutory Rates	D-18		(1,697)	(1,697)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$219,397	$4,342	$223,738
31					
32	RATE OF RETURN	L30 / L15	7.75%		7.90%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	7.75%		
36					
37	Rate of Return Required	B-7	7.90%		
38					
39	Change in ROR	L37 - L35	0.15%		
40					
41	Change in Operating Income	L15 * L39	$4,342		
42					
43	Gross Revenue Conversion Factor	D-19	1.396		
44					
45	Change in Revenues	L41 * L43	$6,063		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	52.99%		
49	Common Equity Rate Base	L15 * L48	$1,500,746		
50	NET OPERATING INCOME	L30	$219,397		
51	Synchronized Interest Expense	D-18	$56,359		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$163,037		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	10.86%		

Line No.	Description	(1) Reference	(2) Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$16,364,069
3	Construction Work In Progress (107)		884,592
4	Total Utility Plant	SUM L2 to L3	$17,248,662
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,108,917
6	Net Utility Plant	L4 - L5	$13,139,744
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$13,257
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,321
11	Invest in Assoc Company (123)		(20,325)
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$19,290
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$44,405
17	Customer Accounts Receivable (142)		342,083
18	Other Accounts Receivable (143)		116,656
19	Accum. Prov. for Uncollectible (144)		(102,633)
20	Receivables from Assoc. Comp. (146)		2,361
21	Fuel Stock (151)		50,589
22	Plant Materials & Supplies (154)		67,119
23	Prepayments (165)		19,523
24	Accrued Utility Revenues (173)		184,653
25	Miscellaneous Current & Accrued Assets (174)		38,560
26	Total Current and Accrued Assets	SUM L16 to L25	$763,315
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$43,162
30	Other Regualtory Assets (182.3)		919,812
31	Miscellaneous Deferred Debits (186)		717,805
32	Unamortized Loss on Reacquired Debt (189)		
33	Accumulated Deferred Income Taxes (190)		278,338
34	Total Deferred Debits	SUM L29 to L33	$1,959,118
35			
36	**Total Assets**	L6 + L13 + L26 + L34	$15,881,468

Line No.	Description	(1) Reference	(2) Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		2,627,435
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		5,436,968
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		(3,419,976)
44	Accum Other Comprehensive Income (219)		2,176
45	Total Propriety Capital & Margins	SUM L38 to L44	$6,069,521
46			
47	**Long Term Debt**		
48	Bonds (221)		$5,200,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(24,352)
53	Total Long-Term Debt	SUM L48 to L52	$5,360,066
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$36,915
58	Accum. Prov for Pensions & Benefits (228.3)		303,421
59	Accum. Miscellaneous Operating Prov (228.4)		16,430
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,115
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$164,783
65	Accounts Payable (232)		508,750
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		40,237
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		64,430
70	Interest Accrued (237)		49,878
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		38
73	Misc Current & Accrued Liabilities (242)		151,816
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,058,804
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		1,521
79	Other Regulatory Liabilities (254)		404,351
80	Deferred Investment Tax Credit (255)		332
81	Unamortized Gain on Reacquired Debt (257)		788
82	Accumulated Deferred Income Taxes (281-283)		2,598,799
83	Total Other Deferred Credits	SUM L77 to L82	$3,009,962
84			
85	**Total Liabilities and Other Credits**	L45 + L53 + L61 + L74 + L83	$15,881,468

Line No.	Category	Description	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$404,798		$404,798
2		Gas Cost Revenue	268,143		268,143
3		Other Operating Revenues	18,914		18,914
4		Total Operating Revenues	$691,855		$691,855
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$426,930		$426,930
7		Depreciation & Amortization Expense	87,057		87,057
8		Amortization of Regulatory Expense	649		649
9		Taxes Other Than Income Taxes - Other	7,951		7,951
10		Total Operating Expenses	$522,587		$522,587
11					
12	**Net Utility Operating Income Before Income Tax**		$169,268		$169,268

						(1)	(2)	(3)
Line No.	Category	Description	Description		Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential		480.0	$273,788		$273,788
2			C & I		481.0	103,618		103,618
3			Transportation of Gas of Others		489.3	27,392		27,392
4					Subtotal	$404,798		$404,798
5								
6		Gas Cost Revenue	Residential		480.0	$199,532		$199,532
7			C & I		481.0	68,611		68,611
8			Interdepartmental		484.0			
9					Subtotal	$268,143		$268,143
10								
11		Other Operating Revenues	Sales For Resale		483.0	$14,152		$14,152
12			Forfeited Discounts		487.0	2,108		2,108
13			Miscellaneous Service Revenues		488.0			
14			Rent for Gas Property		493.0	1,598		1,598
15			Interdepartmental Rents		494.0			
16			Other Gas Revenues		495.0	927		927
17					Subtotal	$18,785		$18,785
18								
19				**Total Operating Revenues**		$691,725		$691,725
20								
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production		710.0	$8		$8
22			Liquefied Petroleum Gas Expenses		717.0	111		111
23			Liquefied Petroleum Gas Expenses		728.0	89		89
24			Maintenance of Structures and Improvements		741.0	74		74
25			Maintenance of Production Equipment		742.0	185		185
26			Natural Gas City Gate Purchases		804.0	174,495		174,495
27			Other Gas Purchases		805.0			
28			Purchases Gas Cost Adjustments		805.1	51,136		51,136
29			Purchased Gas Expenses		807.0	18		18
30			Gas Withdrawn from Storage-Debit		808.1	71,573		71,573
31			Gas Delivered to Storage-Credit		808.2	(23,015)		(23,015)
32			Other Gas Supply Purchases		813.0	278		278
33			Other Expenses		824.0			
34			Operating Supervision and Engineering		840.0	319		319
35			Operation Labor and Expenses		841.0	820		820

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	929		929
37			Maintenance of Structures and Improvements	843.2	3,565		3,565
38			Operation Supervision and Engineering	870.0	697		697
39			Mains and Services Expenses	874.0	16,392		16,392
40			Measuring and Regulating Station Expenses-General	875.0	1,686		1,686
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	6,516		6,516
43			Customer Installations Expenses	879.0	7,303		7,303
44			Other Expenses	880.0	19,453		19,453
45			Rents	881.0	217		217
46			Maintenance of Mains	887.0	23,599		23,599
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,410		1,410
48			Maintenance of Services	892.0	2,579		2,579
49			Maintenance of Meters & House Regulators	893.0	222		222
50			Maintenance of Other Equipment	894.0	686		686
51			Meter Reading	902.0	134		134
52			Customer Records and Collection	903.0	18,990		18,990
53			Uncollectible Accounts	904.0	2,895		2,895
54			Miscellaneous Customer Accounts	905.0	931		931
55			Customer Assistance	908.0	7,341		7,341
56			Informational & Instructional	909.0	284		284
57			Miscellaneous Customer & Informational	910.0	45		45
58			Demonstrating & Selling	912.0	695		695
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	5,963		5,963
61			Office Supplies and Expenses	921.0	1,565		1,565
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	17,244		17,244
64			Property Insurance	924.0	145		145
65			Franchise Requirements	925.0	376		376
66			Employee Pensions and Benefits	926.0	4,630		4,630
67			Regulatory Commission Expenses	928.0	2,567		2,567
68			Duplicate Charges-Credit	929.0	(71)		(71)
69			Miscellaneous General Expenses	930.2	908		908
70			Maintenance of General Plant	932.0	946		946

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
71				Subtotal	$426,930		$426,930
72							
73			Depreciation & Amortization Expense	403.0	$74,876		$74,876
74				403.1			
75				404.0	12,181		12,181
76				Subtotal	$87,057		$87,057
77							
78			Amortization of Regulatory Expense	407.3	$649		$649
79				Subtotal	$649		$649
80							
81			Taxes Other Than Income Taxes - Other	408.1	$7,951		$7,951
82				Subtotal	$7,951		$7,951
83							
84			**Total Operating Expenses**		$522,587		$522,587
85							
86			**Net Utility Operating Income Before Income Tax**		$169,139		169,139
			PUC ck		$168,875		
			advertising		$355		
			PECO contributions, Lobbying, Fines		$30		
			BSC contributions, Lobbying, Memberships		$219		
			PECO below the line Memberships		$14		
					$619		

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$273,788		$273,788
2			C & I	481.0	103,618		103,618
3			Transportation of Gas of Others	489.3	27,392		27,392
4				Subtotal	$404,798		$404,798
5							
6		**Gas Cost Revenue**	Residential	480.0	$199,532		$199,532
7			C & I	481.0	68,611		68,611
8			Interdepartmental	484.0			
9				Subtotal	$268,143		$268,143
10							
11				OPERATING REVENUE	$672,941		$672,941
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$14,152		$14,152
14			Interdepartmental Sales	484.0	129		129
15			Forfeited Discounts	487.0	2,108		2,108
16			Miscellaneous Service Revenues	488.0			
17				Subtotal	$16,389		$16,389
18							
19		**Other Gas Revenue**	Rent for Gas Property	493.0	$1,598		1,598
20			Interdepartmental Rents	494.0			
21			Other Gas Revenues	495.0	927		927
22				Subtotal	$2,525		$2,525
23							
24				OTHER REVENUE	$18,914		$18,914
25							
26				OTHER OPERATING REVENUES			
27							
28				**TOTAL**	**$691,855**		**$691,855**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	Budget HTY	Non-Jurisdictional	Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0	$8		$8
2			Liquefied Petroleum Gas Expenses	717.0	111		$111
3			Maintenance of Structures and Improvements	741.0	74		74
4			Maintenance of Production Equipment	742.0	185		185
5				SUM L1 to L4	$378		$378
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	89		89
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$174,495		$174,495
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1	51,136		51,136
12			Purchased Gas Expenses	807.0	18		18
13			Gas Withdrawn from Storage-Debit	808.1	71,573		71,573
14			Gas Delivered to Storage-Credit	808.2	(23,015)		(23,015)
15			Other Gas Supply Purchases	813.0	278		278
16				SUM L9 to L15	$274,485		$274,485
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$319		$319
21			Operation Labor and Expenses	841.0	820		820
22				SUM L20 to L21	$1,139		$1,139
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$929		$929
25			Maintenance of Structures and Improvements	843.2	3,565		3,565
26				SUM L24 to L25	$4,493		$4,493
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$5,632		$5,632
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$697		$697
31			Mains and Services Expenses	874.0	16,392		16,392
32			Measuring and Regulating Station Expenses-General	875.0	1,686		1,686
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	6,516		6,516
35			Customer Installations Expenses	879.0	7,303		7,303
36			Other Expenses	880.0	19,453		19,453
37			Rents	881.0	217		217
38				SUM L30 to L37	$52,264		$52,264
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$23,599		$23,599
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,410		1,410
42			Maintenance of Services	892.0	2,579		2,579
43			Maintenance of Meters & House Regulators	893.0	222		222
44			Maintenance of Other Equipment	894.0	686		686
45				SUM L40 to L44	$28,496		$28,496

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	Budget HTY	Non-Jurisdictional	Jurisdictional
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$80,760		$80,760
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$134		$134
50			Customer Records and Collection	903.0	18,990		18,990
51			Uncollectible Accounts	904.0	2,895		2,895
52			Miscellaneous Customer Accounts	905.0	931		931
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$22,949		$22,949
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$7,341		$7,341
56			Informational & Instructional	909.0	284		284
57			Miscellaneous Customer & Informational	910.0	45		45
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$7,670		$7,670
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$695		$695
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$695		$695
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$5,963		$5,963
65			Office Supplies and Expenses	921.0	1,565		1,565
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	17,244		17,244
68			Property Insurance	924.0	145		145
69			Injuries & Damages	925.0	376		376
70			Employee Pensions and Benefits	926.0	4,630		4,630
71			Regulatory Commission Expenses	928.0	2,567		2,567
72			Duplicate Charges-Credit	929.0	(71)		(71)
73			Miscellaneous General Expenses	930.2	908		908
74				SUM L64 to L73	$33,327		$33,327
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$946		$946
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$34,273		$34,273
79							
80			**Total**	Lines 5+10+16+28+48+54+59+63+79	$426,930		$426,930
81							
82			Total Operations Expense		$392,995		$392,995
83			Total Maintenance Expense		33,935		33,935
84			**Total O&M Expense**	L82 + L83	$426,930		$426,930
					$426,930		
					$152,445		
					$355		

Line No.	Description	(1) Total	(2) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$1,995	$1,995
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	640	640
4	Real Estate Tax Accrual	1,659	1,659
5	Miscellaneous TOTI	13	13
6	Payroll Tax Accrued	3,645	3,833
7	**Total**	$7,951	$8,140

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2023
($ in Thousands)
B-6 Cost of Long Term Debt

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
		(1)		(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025		$350,000		3.29%		
2					6.50%		0.21%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.39%		0.08%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					5.57%		0.34%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					3.25%		0.19%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					4.64%		0.23%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					5.57%		0.23%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					6.04%		0.23%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					12.07%		0.49%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					6.04%		0.19%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					6.50%		0.19%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					6.96%		0.22%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					6.96%		0.20%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					6.50%		0.31%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					7.89%		0.35%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					10.68%		0.54%	
31								
32		Sub-Total Mortgage Bonds	SUM L1 to L31	$5,200,000	96.57%		4.00%	
33								
34	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
35					1.50%		0.11%	
36		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
37					0.01%			
38		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
39					1.91%		0.11%	
40								
41		Sub-Total Capital Securities	SUM L38 to L40	$184,419	3.43%		0.22%	
42								
43		Total Long-Term Debt	L32 + L41	$5,384,419	100.00%		4.22%	
44								
45		Adjustments for Tenders & Calls		(864)				
46								
47		Net Long-Term Debt	L43 + L45	$5,383,555				
48								
49		Annualized Cost		227,222				
50								
51		Adjustment for Tenders & Calls Reacquired		341				
52								
53		**Total**	L49 + L51	$227,563				4.23%

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$5,383,555	47.01%	4.23%	1.99%
3					
4	Common Equity	6,069,521	52.99%	11.15%	5.91%
5					
6	Total	$11,453,075	100.00%		7.90%

Line No.	Description	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
		(1)	(2)	(3)	(4)
1	Utility Plant	C-2	$3,905,331		$3,905,331
2	Accumulated Depreciation	C-3	929,927		929,927
3	Common Plant	C-8	148,978		148,978
4	**Net Plant in Service**	L1 - L2 + L3	$3,124,383		$3,124,383
5					
6	Working Capital	C-4	$12,564		$12,564
7	Accumulated Deferred Income Taxes	C-6	(232,557)		(232,557)
8	Customer Deposits	C-7	(13,354)		(13,354)
9	Customer Advances for Construction	C-9	(1,323)		(1,323)
10	Material & Supplies	C-11	2,123		2,123
11	ADIT - Reg Liability	C-12	(116,677)		(116,677)
12	Gas Storage	C-13	56,972		56,972
13	**Total Measures of Value**	SUM L4 to L12	$2,832,132		$2,832,132

				(1)	(2)	(3)	(4)
Line No.	Category	Account		Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents			$50		$50
2		G303 - Intangible Property			19,926		19,926
3			Subtotal	SUM L1 to L2	$19,976		$19,976
4							
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements			$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.			14,334		14,334
7			Subtotal	SUM L5 to L6	$15,559		$15,559
8							
9	**Other Storage Plant**	G360 - Land and Land Rights			$16		$16
10		G361 - Structures & Improvements			15,047		15,047
11		G362 - Gas Holders			7,084		7,084
12		G363 - Gas Storage Equipment			110,222		110,222
13			Subtotal	SUM L9 to L12	$132,368		$132,368
14							
15	**Distribution Plant**	G374 - Land and Land Rights			$3,915		$3,915
16		G375 - Structures and Improvements			15,865		15,865
17		G376 - Gas Mains			1,960,993		1,960,993
18		G378 - Measure & Regulate Sta Equip			24,565		24,565
19		G379 - City Gate Station			61,537		61,537
20		G380 - Services			1,212,549		1,212,549
21		G381 - Meters			168,726		168,726
22		G382 - Meter Installations			251,661		251,661
23		G387 - Other Equipment			2,098		2,098
24		G388 - ARO Costs Distribution Plt			884		884
25			Subtotal	SUM L15 to L24	$3,702,792		$3,702,792
26							
27	**General Plant**	G390 - Structures & Improvements			$10,471		$10,471
28		G391 - Office Furniture & Equipment			3,226		3,226
29		G394 - Tools, Shop & Garage Equip			15,233		15,233
30		G395 - Laboratory Equipment			38		38
31		G397 - Communication Equipment			5,411		5,411
32		G398 - Miscellaneous Equipment			127		127
33		G399.1 - ARO Costs General Plt			130		130
34			Subtotal	SUM L27 to L33	$34,636		$34,636
35							
36		**Total**		Lines 3+7+13+25+34	$3,905,331		$3,905,331

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	
2		Subtotal Intangible Plant	
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	
12		Subtotal Other Storage Plant	
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	
16		G376 - Gas Mains	
17		G378 - Measure & Regulate Station Equipment	
18		G379 - City Gate Station	
19		G380 - Services	
20		G381 - Meters	
21		G382 - Meter Installations	
22		G387 - Other Equipment	
23		Subtotal Distribution Plant	
24			
25	**General Plant**	G390 - Structures & Improvements	
26		G391 - Office Furniture & Equipment	
27		G394 - Tools, Shop & Garage Equipment	
28		G395 - Laboratory Equipment	
29		G397 - Communication Equipment	
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	
32			
33		Total	

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	
2		Subtotal Intangible Plant	
3			
4	**Manufactured Gas Proc**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	
12		Subtotal Other Storage Plant	
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	
16		G376 - Gas Mains	
17		G378 - Measure & Regulate Station Equipment	
18		G379 - City Gate Station	
19		G380 - Services	
20		G381 - Meters	
21		G382 - Meter Installations	
22		G387 - Other Equipment	
23		G388 - ARO Costs Distribution Plant	
24		Subtotal Distribution Plant	
25			
26	**General Plant**	G390 - Structures & Improvements	
27		G391 - Office Furniture & Equipment	
28		G394 - Tools, Shop & Garage Equipment	
29		G397 - Communication Equipment	
30		G398 - Miscellaneous Equipment	
31		G399.1 - ARO Costs General Plant	
32		Subtotal General Plant	
33			
34		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**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	19,926	100.00%	19,926	100.00%	19,926	
5			$19,926		$19,926		$19,926	
6								
7		Subtotal	**$19,976**		**$19,976**		**$19,976**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,334	100.00%	$14,334	100.00%	$14,334	
13			$14,334		$14,334		$14,334	
14								
15		Subtotal	**$15,559**		**$15,559**		**$15,559**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$15,047	100.00%	$15,047	100.00%	$15,047	
21			$15,047		$15,047		$15,047	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$110,222	100.00%	$110,222	100.00%	$110,222	
27			$110,222		$110,222		$110,222	
28								
29		Subtotal	**$132,368**		**$132,368**		**$132,368**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$3,915	100.00%	$3,915	100.00%	$3,915	
32			$3,915		$3,915		$3,915	
33								
34		G375 - Structures and Improvements	$15,865	100.00%	$15,865	100.00%	$15,865	
35			$15,865		$15,865		$15,865	
36								
37		G376 - Gas Mains	$1,960,993	100.00%	$1,960,993	100.00%	$1,960,993	
38			$1,960,993		$1,960,993		$1,960,993	
39								
40		G378 - Measure & Regulate Sta Equip	$24,565	100.00%	$24,565	100.00%	$24,565	
41			$24,565		$24,565		$24,565	
42								
43		G379 - City Gate Station	$61,537	100.00%	$61,537	100.00%	$61,537	
44			$61,537		$61,537		$61,537	
45								
46		G380 - Services	$1,212,549	100.00%	$1,212,549	100.00%	$1,212,549	
47			$1,212,549		$1,212,549		$1,212,549	
48								
49		G381 - Meters	$168,726	100.00%	$168,726	100.00%	$168,726	
50			$168,726		$168,726		$168,726	
51								
52		G382 - Meter Installations	$251,661	100.00%	$251,661	100.00%	$251,661	
53			$251,661		$251,661		$251,661	
54								
55		G387 - Other Equipment	$2,098	100.00%	$2,098	100.00%	$2,098	
56			$2,098		$2,098		$2,098	
57								
58		G388 - ARO Costs Distribution Plant	$884	100.00%	$884	100.00%	$884	

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
59			$884		$884		$884	
60								
61		Subtotal	**$3,702,792**		**$3,702,792**		**$3,702,792**	
62								
63	**General Plant**	G390 - Structures & Improvements	$10,471	100.00%	$10,471	100.00%	$10,471	
64			$10,471		$10,471		$10,471	
65								
66		G391 - Office Furniture & Equipment	$3,226	100.00%	$3,226	100.00%	$3,226	
67			$3,226		$3,226		$3,226	
68								
69		G394 - Tools, Shop & Garage Equip	$15,233	100.00%	$15,233	100.00%	$15,233	
70			$15,233		$15,233		$15,233	
71								
72		G395 - Laboratory Equipment	$38	100.00%	38	100.00%	38	
73			38		38		38	
74								
75		G397 - Communication Equipment	$5,411	100.00%	$5,411	100.00%	$5,411	
76			$5,411		$5,411		$5,411	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$130	100.00%	$130	100.00%	$130	
82			$130		$130		$130	
83								
84		Subtotal	**$34,636**		**$34,636**		**$34,636**	
85								
86								
87		**Total**	**$3,905,331**		**$3,905,331**		**$3,905,331**	

Line No.	Category	Account	(1) Reference	(2) HTY Amount	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$11,059		$11,059
3		Subtotal Intangible Plant	SUM L1 to L2	$11,059		$11,059
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$874		$874
6		G311 - Liquefied Petroleum Gas Equipment		12,725		12,725
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$13,598		$13,598
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$7,581		$7,581
11		G362 - Gas Holders		6,898		6,898
12		G363 - Gas Storage Equipment		14,773		14,773
13		Subtotal Other Storage Plant	SUM L9 to L12	$29,252		$29,252
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$6,305		6,305
17		G376 - Gas Mains		383,884		383,884
18		G378 - Measure & Regulate Station Equipment		6,573		6,573
19		G379 - City Gate Station		25,731		25,731
20		G380 - Services		281,904		281,904
21		G381 - Meters		78,366		78,366
22		G382 - Meter Installations		75,429		75,429
23		G387 - Other Equipment		1,544		1,544
24		G388 - ARO Costs Distribution Plant		606		606
25		Subtotal Distribution Plant	SUM L15 to L24	$860,341		$860,341
26						
27	**General Plant**	G390 - Structures & Improvements		$3,360		$3,360
28		G391 - Office Furniture & Equipment		1,734		1,734
29		G394 - Tools, Shop & Garage Equipment		6,042		6,042
30		G395 - Laboratory Equipment		15		15
31		G397 - Communication Equipment		4,421		4,421
32		G398 - Miscellaneous Equipment		61		61
33		G399.1 - ARO Costs General Plant		44		44
34		Subtotal General Plant	SUM L27 to L33	$15,677		$15,677
35						
36		**Total**	Lines 3+7+13+25+34	$929,927		$929,927

Line No.	Category	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**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$11,059	100.00%	$11,059	100.00%	$11,059	
4								
5		Subtotal	**$11,059**		**$11,059**		**$11,059**	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	6,305	100.00%	6,305	100.00%	6,305	
10								
11		G376 - Gas Mains	383,884	100.00%	383,884	100.00%	383,884	
12								
13		G378 - Measure & Regulate Sta Equip	6,573	100.00%	6,573	100.00%	6,573	
14								
15		G379 - City Gate Station	25,731	100.00%	25,731	100.00%	25,731	
16								
17		G380 - Services	281,904	100.00%	281,904	100.00%	281,904	
18								
19		G381 - Meters	78,366	100.00%	78,366	100.00%	78,366	
20								
21		G382 - Meter Installations	75,429	100.00%	75,429	100.00%	75,429	
22								
23		G387 - Other Equipment	1,544	100.00%	1,544	100.00%	1,544	
24								
25		G388 - ARO Costs Distribution Plant	606	100.00%	606	100.00%	606	
26								
27		Subtotal	**$860,341**		**$860,341**		**$860,341**	
28								
29	**General Plant**	G390 - Structures & Improvements	$3,360	100.00%	$3,360	100.00%	$3,360	
30								
31		G391 - Office Furniture & Equipment	1,734	100.00%	1,734	100.00%	1,734	
32								
33		G394 - Tools, Shop & Garage Equip	6,042	100.00%	6,042	100.00%	6,042	
34								
35		G395 - Laboratory Equipment	15	100.00%	15	100.00%	15	
36								
37		G397 - Communication Equipment	4,421	100.00%	4,421	100.00%	4,421	
38								
39		G398 - Miscellaneous Equipment	61	100.00%	61	100.00%	61	
40								
41		G399.1 - ARO Costs General Plant	44	100.00%	44	100.00%	44	
42								
43		Subtotal	**$15,677**		**$15,677**		**$15,677**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$874	100.00%	$874	100.00%	$874	
46								
47		G311 - Liquefied Petroleum Gas Eqp	12,725	100.00%	12,725	100.00%	12,725	
48								
49		Subtotal	**$13,598**		**$13,598**		**$13,598**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$7,581	100.00%	$7,581	100.00%	$7,581	
54								
55		G362 - Gas Holders	6,898	100.00%	6,898	100.00%	6,898	
56								
57		G363 - Gas Storage Equipment	14,773	100.00%	14,773	100.00%	14,773	
58								
59		Subtotal	**$29,252**		**$29,252**		**$29,252**	
60								
61		**Total**	**$929,927**		**$929,927**		**$929,927**	

Line No.	Category	Account		(1) Reference	(2) HTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements			
2		G311 - Liquefied Petroleum Gas Equipment			
3		Subtotal Gas - Production Plant		SUM L1 to L2	
4					
5	**Gas - Storage**	G361 - Structures & Improvements			
6		G363 - Gas Storage Equipment			
7		Subtotal Gas - Storage		SUM L5 to L6	
8					
9	**Gas - Distribution**	G374 - Land and Land Rights			
10		G375 - Structures and Improvements			
11		G376 - Gas Mains			
12		G378 - Measure & Regulate Station Equipment			
13		G379 - City Gate Station			
14		G380 - Services			
15		G381 - Meters			
16		G382 - Meter Installations			
17		G387 - Other Equipment			
18		Subtotal Gas - Distribution		SUM L9 to L17	
19					
20	**Gas - General Plant**	G390 - Structures & Improvements			
21		G391 - Office Furniture & Equipment			
22		G394 - Tools, Shop & Garage Equipment			
23		G397 - Communication Equipment			
24		Subtotal Gas - General Plant		SUM L20 to L23	
25					
26			**Total**	Lines 3+7+18+24	

Line No.	Description	(1) Reference	(2) HTY Expenses	(3) (Lead)/Lag Days	(4) Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			48.86	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$47,842	13.58	$649,852
7	Pension Expense		1,899	(167.00)	(317,152)
8	Commodity Purchased - Gas		163,876	33.24	5,446,419
9	Payment to Suppliers		82,841	56.21	4,656,354
10	Other Expenses		205,326	40.07	8,227,839
11	Total O&M and POR Payments	SUM L6 to L10	$501,784		$18,663,312
12					
13	O&M Expense / POR Payment Lag Days			37.19	
14					
15	Net (Lead)/Lag Days	L3 - L13		11.66	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,375		
20					
21	Working Capital for O&M Expense		$16,032		
22					
23	Average Prepayments		$2,733		
24	Accrued Taxes		341		
25	Interest Payments		(6,541)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$12,564		
28					
29	Pro Forma O&M Expense		$421,249		
30	Uncollectible Expense		2,306		
31	Pro Forma Cash O&M Expense	L29 - L30	$418,943		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag	(5)
1	Annual Number of Days						365
2							
3	December		$105,193				
4	January		130,817	$141,332			
5	February		139,310	138,106			
6	March		111,688	102,326			
7	April		85,927	73,849			
8	May		52,305	43,873			
9	June		36,760	30,348			
10	July		30,198	25,587			
11	August		25,742	23,623			
12	September		27,856	24,134			
13	October		31,455	29,584			
14	November		47,500	51,027			
15	December		80,753	94,945			
16							
17	Total	SUM L3 to L15	$905,503	$778,733			
18							
19	Average A/R Balance		13				
20							
21	Factor		$69,654	$778,733	11.18		32.65
22							
23	Collection Days Lag						32.65
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					**48.86**

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				$45,489		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$617,889
4								
5		Payroll Lag	SUM L1 to L3			45,489	13.58	$617,889
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2023	7/1/2023	$1,408	(167.00)	($235,076)
12								
13		Sub-Total	SUM L7 to L11			$1,408		($235,076)
14								
15		Lag Days for Pension Payment					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	January				$16,812		$651,478
20		April				26,471		1,077,737
21		July				25,711		1,175,140
22		October				22,699		769,982
23								
24		TOTAL	SUM L19 to L22			$91,693	40.07	$3,674,337

Line No.	Months	Description	(1) Number of CDs	(2) Cash Disbursements	(3) Dollar-Days	(4) Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674		
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356		
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,289	$91,693	$3,674,337	40.07

Line No.	Tax	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	4/17/2023	7/1/2023	75	($19,556)	25.00%	($4,889)	($366,670)
2		Second Payment	6/15/2023	7/1/2023	16	(19,556)	25.00%	(4,889)	(78,223)
3		Third Payment	9/15/2023	7/1/2023	(76)	(19,556)	25.00%	(4,889)	371,559
4		Fourth Payment	12/15/2023	7/1/2023	(167)	(19,556)	25.00%	(4,889)	816,451
5		Subtotal FEDERAL INCOME TAX					100.00%	($19,556)	$743,117
6									
7	**STATE INCOME TAX**	First Payment	3/15/2023	7/1/2023	108		25.00%		
8		Second Payment	6/15/2023	7/1/2023	16		25.00%		
9		Third Payment	9/15/2023	7/1/2023	(76)		25.00%		
10		Fourth Payment	12/15/2023	7/1/2023	(167)		25.00%		
11		Subtotal STATE INCOME TAX					100.00%		
12									
13	**PURTA**	First Payment	5/1/2023	7/1/2023	61	$1,995	100.00%	$1,995	$121,674
14		Subtotal PURTA					100.00%	$1,995	$121,674
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2023	7/1/2023	22	$1,659	100.00%	1,659	36,496
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	1,659	36,496
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

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	($19,556)	$743,117	(38.00)	48.86	10.86	($212,295)	($582)
2	STATE INCOME TAX				48.86	48.86		
3	PURTA	$1,995	$121,674	61.00	48.86	109.86	$219,124	$600
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$1,659	$36,496	22.00	48.86	70.86	$117,543	$322
6	GROSS RECEIPTS TAX							

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of Test Year		$2,832,132
2	Long-Term Debt Ratio		47.01%
3	Embedded Cost of Long-Term Debt		4.23%
4	Pro Forma Interest Expense	L1 * L2 * L3	$56,318
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$154
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		48.86
9	Interest Payment Lag Days	L8 - L7	(42.39)
10	Total Interest for Working Capital	L6 * L9	($6,541)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December					$99	$925	$75	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January		$353			238	983	57	2,394	(18)	88	465	51	285	816	
3	February		$300			271	786	74	2,394	(35)	80	420	170	372	701	
4	March		$289			(20)	590	50	3,157	157	88	420	254	305	662	
5	April		$257	$133	47	93	393	38	3,157	139	80	433	112	276	728	
6	May		$225	$133	38	76	197	20	3,157	122	72	428	159	243	731	
7	June		$192	$66	38	59	0	37	3,584	105	119	422	294	223	739	
8	July		$160	$55	38	42	1,671	22	3,584	87	111	441	562	277	760	
9	August		$128	$44	38	25	1,457	3	3,584	70	103	441	761	214	685	
10	September		$96	$33	38	51	1,873	76	3,775	52	136	399	623	146	664	
11	October		$64	$22	38	564	1,687	59	3,775	35	128	404	561	92	664	
12	November		$32	$11	38	424	1,501	40	3,775	17	120	438	500	59	712	
13	December		($0)	$0	38	331	1,315	58	4,879	0	153	451	248	573	777	
14																
15	Total	SUM L1 to L13	$2,096	$498	$351	$2,253	$13,377	$608	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.07%	23.07%	23.07%	23.07%	25.50%	25.50%	25.50%	
18																
19	Distribution Amount	L15 * L17	$2,096	$498	$351	$2,253	$13,377	$608	$10,061	$169	$317	$1,294	$1,114	$865	$2,521	
20																
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																
23	Monthly Average	L19 / L21	$161	$38	$27	$173	$1,029	$47	$774	$13	$24	$100	$86	$67	$194	
24																
25	**Rate Case Amount**															**$2,733**

Line No.	Description	(1) Shopping Percentage	(2) Weighted Lag Days	(3) Lag Days
1	Residential	60%		40.00
2	Nonresidential	40%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

			(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		($7,888)	100.00%	($7,888)	100.00%	($7,888)
2		ADIT - Common Plant		15,921	100.00%	15,921	100.00%	15,921
3		ADIT - Gas Distribution		246,541	100.00%	246,541	100.00%	246,541
4		ADIT - Corporate Alternative Minimum Tax		(22,017)	100.00%	(22,017)	100.00%	(22,017)
5		**Total**	SUM L1 to L3	$232,557		$232,557		$232,557

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	December		$3,615	$8,076	$11,691
2	January		3,654	8,284	11,938
3	February		3,686	8,444	12,130
4	March		3,760	8,594	12,354
5	April		3,872	8,742	12,614
6	May		4,038	8,997	13,035
7	June		4,165	9,113	13,278
8	July		4,275	9,518	13,793
9	August		4,395	9,856	14,252
10	September		4,436	9,987	14,423
11	October		4,504	10,099	14,602
12	November		4,557	10,182	14,739
13	December		4,530	10,218	14,747
14					
15	Total	SUM L1 to L13	$53,486	$120,110	$173,596
16					
17	Average Monthly Balance	L15 / 13	$4,114	$9,239	$13,354
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$4,114
21	Small C&I				8,891
22	Large C&I				348
23	Transportation				
24					
25	Total	SUM L20 to L23			$13,354

Line No.	Category	Account	Reference	(1) HTY Amount	(2) Allocated to Non Jurisdiction	(3) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$327,035	$251,588	$75,447
6						
7		E389 - Land and Land Rights		$6,783	$5,218	$1,565
8						
9		E390 - Structures and Improvements		$371,001	$285,411	$85,590
10		E391 - Office Furniture, Equipment		71,621	55,098	16,523
11		E392 - Transportation Equipment		196,641	151,276	45,365
12		E393 - Stores Equipment		1,340	1,031	309
13		E394 - Tools, Shop, Garage Equipmnt		2,552	1,963	589
14		E396 - Power Operated Equipment		185	142	43
15		E397 - Communication Equipment		128,703	99,011	29,692
16		E398 - Miscellaneous Equipment		1,191	917	275
17		E399 - Other Tangible Property		(0)	(0)	
18		E399.1 - ARO Costs General Plant		1,030	792	238
19		Sub Total - General Plant	SUM L9 to L18	$774,264	$595,641	$178,623
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,108,760	$852,969	$255,791
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$234,192	$180,164	$54,028
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,917	$54,556	$16,360
31		E391 - Office Furniture, Equipment		25,843	19,881	5,962
32		E392 - Transportation Equipment		91,386	70,303	21,083
33		E393 - Stores Equipment		375	288	86
34		E394 - Tools, Shop, Garage Equipmnt		961	739	222
35		E396 - Power Operated Equipment		185	142	43
36		E397 - Communication Equipment		38,627	29,716	8,911
37		E398 - Miscellaneous Equipment		839	645	194
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(331)	(254)	(76)
40		Sub Total - General Plant	SUM L30 to L39	$228,801	$176,017	$52,784
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$462,993	$356,181	$106,812
42						
43		Net Common Plant	L20 - L41	$645,767	$496,788	$148,978
44						
45						
46		Common Plant in Service to Utility	L20	$1,108,760	$852,969	$255,791
47		Common Plant Accum Depreciation to Utility	L41	462,993	356,181	106,812
48		Net Common Plant to Utility	L46 - L47	$645,767	$496,788	$148,978

(1)

Line No.	Description	Total HTY Amount
1	HTY 13-Month Average	
2	December	$888
3	January	984
4	February	1,106
5	March	1,659
6	April	1,632
7	May	1,208
8	June	1,037
9	July	1,242
10	August	1,221
11	September	1,817
12	October	1,684
13	November	1,404
14	December	1,318
15		
16	13-Month Total	$17,199
17		
18		
19	Average Monthly Balance	$1,323

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$645	($0)	$645
3	January		672	(191)	481
4	February		710	(372)	338
5	March		2,830	(1,490)	1,340
6	April		2,851	(1,111)	1,740
7	May		2,776	(1,460)	1,316
8	June		2,737	(1,693)	1,044
9	July		2,751	(1,197)	1,554
10	August		2,882	(1,126)	1,756
11	September		2,916	(1,077)	1,839
12	October		2,836	(660)	2,176
13	November		2,815	(686)	2,129
14	December		2,736	0	2,736
15					
16	Total	SUM L2 to L14	$30,156	($11,061)	$19,095
17					
18	Distribution Expense Allocation Factor		100.00%	23.07%	
19					
20	Allocation to Distribution	L16 * L18	$30,156	($2,552)	
21					
22	Average Monthly Balance	L20 / 13	$2,320	($196)	$2,123

			(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		$116,677	100.00%	$116,677	100.00%	$116,677
2		ADIT - CIAC			100.00%		100.00%	
3		**Total**	L1 + L2	$116,677		$116,677		$116,677

Line No.	Description	Reference	(1) Stored Underground	(2) LNG	(3) Propane Gas	(4) Total
1	December		$92,465	$5,154	$1,616	$99,235
2	January		71,565	5,096	1,616	78,277
3	February		53,766	4,918	1,546	60,229
4	March		35,170	4,860	1,546	41,575
5	April		34,920	4,792	1,546	41,257
6	May		38,419	4,742	1,546	44,707
7	June		41,212	4,679	1,546	47,437
8	July		44,474	4,615	1,546	50,635
9	August		47,298	4,560	1,546	53,404
10	September		49,911	4,768	1,546	56,225
11	October		52,807	4,720	1,546	59,073
12	November		52,124	4,339	1,527	57,990
13	December		44,844	4,217	1,527	50,589
14						
15	Total	SUM L1 to L13	$658,974	$61,461	$20,199	$740,634
16						
17	Average Monthly Balance	L15 / 13	$50,690	$4,728	$1,554	$56,972

Line No.	Category	Description	Reference	Pro Forma Adjusted at Present Rates	Proposed Rate Increase	Adjusted Amounts with Proposed Rate Increase
			(1)	(2)	(3)	(4)
1	**Operating Revenues**	Residential		$511,325		$511,325
2		C & I		183,751		183,751
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		2,108	17	2,124
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		1,598		1,598
8		Other Gas Revenues		927		927
9		Transportation of Gas of Others		28,081		28,081
10		Revenue Increase			6,063	6,063
11		Subtotal Operating Revenues	SUM L1 to L10	$727,790	$6,080	$733,870
12						
13	**Operating Expenses**	Manufactured Gas Production		$478		$478
14		Storage Operations Expense		1,168		1,168
15		Storage Maintenance Expense		4,583		4,583
16		Underground Storage Expenses				
17		Other Gas Supply		262,123		262,123
18		Distribution Expense		82,246		82,246
19		Total Customer Accounts		22,819	22	22,841
20		Total Customer Service & Information		7,687		7,687
21		Total Sales		707		707
22		Administrative & General		39,439	19	39,458
23		O&M Expense	SUM L13 to L22	$421,249	$41	$421,290
24						
25		Depreciation & Amortization Expense		$92,080		$92,080
26		Amortization of Regulatory Expense		1,780		1,780
27		Taxes Other Than Income Taxes - Other		8,140		8,140
28		Subtotal Operating Expenses	SUM L23 to L27	$523,248	$41	$523,289
29						
30	**Net Operating Income - BIT**		L11 - L28	$204,542	$6,039	$210,580

Line No.	Category	Description	(1) HTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$473,320	$38,005	$511,325
2		C & I	172,229	11,522	183,751
3		Interdepartmental			
4		Sales for Resale	14,152	(14,152)	
5		Forfeited Discounts	2,108		2,108
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	1,598		1,598
8		Other Gas Revenues	927		927
9		Transportation of Gas of Others	27,392	690	28,081
10		Revenue Increase			
11		Subtotal Operating Revenues	$691,725	$36,065	$727,790
12					
13	**Operating Expenses**	Manufactured Gas Production	$466	$11	$478
14		Storage Operations Expense	1,139	29	1,168
15		Storage Maintenance Expense	4,493	90	4,583
16		Underground Storage Expenses			
17		Other Gas Supply	274,485	(12,362)	262,123
18		Distribution Expense	80,760	1,485	82,246
19		Total Customer Accounts	22,949	(131)	22,819
20		Total Customer Service & Information	7,670	18	7,687
21		Total Sales	695	12	707
22		Administrative & General	34,273	5,166	39,439
23		O&M Expense	$426,930	($5,681)	$421,249
24					
25		Depreciation & Amortization Expense	$87,057	$5,023	$92,080
26		Amortization of Regulatory Expense	649	1,131	1,780
27		Taxes Other Than Income Taxes - Other	7,951	189	8,140
28		Subtotal Operating Expenses	$522,587	$661	$523,248
29					
30	**Net Operating Income - BIT**		$169,139	$35,403	$204,542

Line No.	Category	Description	Description	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
1	**Operating Revenues**	Residential	Gas Cost	$199,532									
2			Cust & Dist	273,788	1,328	76	235	36,365					
3			Subtotal Residential	$473,320	$1,328	$76	$235	$36,365					
4													
5		C & I	Gas Cost	$68,611									
6			Cust & Dist	103,618	287		113	11,122					
7			Subtotal C & I	$172,229	$287		$113	$11,122					
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$14,152					($14,152)				
13			Subtotal Sales for Resale	$14,152					($14,152)				
14													
15		Forfeited Discounts	Forfeited Discounts	$2,108									
16			Subtotal Forfeited Discounts	$2,108									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$1,598									
22			Subtotal Rent For Gas Property	$1,598									
23													
24		Other Gas Revenues	Other Gas Revenues	$927									
25			Subtotal Other Gas Revenues	$927									
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$27,392				$690					
28			Subtotal Transportation of Gas of Others	$27,392				$690					
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$691,725**	**$1,616**	**$76**	**$348**	**$48,177**	**($14,152)**				
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production	$8									
36			Liquefied Petroleum Gas Expenses	111						3			
37			Liquefied Petroleum Gas Expenses	89						0			
38			Maintenance of Structures and Improvements	74						2			
39			Maintenance of Production Equipment	185						6			
40			Subtotal Manufactured Gas Production	$466						$11			
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$174,495					($10,620)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments	51,136									
45			Purchased Gas Expenses	18									
46			Gas Withdrawn from Storage-Debit	71,573									

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension
47			Gas Delivered to Storage-Credit	(23,015)									
48			Other Gas Supply Purchases	278									
49			Subtotal Other Gas Supply	$274,485					($10,620)				
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$929						$22			
52			Maintenance of Structures and Improvements	3,565						68			
53			Subtotal Storage Maintenance Expense	$4,493						$90			
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$319						$8			
56			Operation Labor and Expenses	820						20			
57			Subtotal Storage Operations Expense	$1,139						$29			
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$697						$0			
63			Mains and Services Expenses	16,392						$272			
64			Measuring and Regulating Station Expenses-General	1,686						$52			
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	6,516						$83			
67			Customer Installations Expenses	7,303						$252			
68			Other Expenses	19,453						$178			
69			Rents	217									
70			Maintenance of Mains	23,599						$543			
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	1,410						$33			
72			Maintenance of Services	2,579						$61			
73			Maintenance of Meters & House Regulators	222						$7			
74			Maintenance of Other Equipment	686						$5			
75			Subtotal Distribution Expense	$80,760						$1,485			
76													
77		Total Customer Accounts	Customer Records and Collection	$18,990						$302			
78			Meter Reading	134									
79			Miscellaneous Customer Accounts	931						$10			
80			Uncollectible Accounts	2,895									
81			Subtotal Total Customer Accounts	$22,949						$312			
82													
83		Total Customer Service & Information	Customer Assistance	$7,341						$16			
84			Informational & Instructional	284									
85			Miscellaneous Customer & Informational	45						$2			
86			Subtotal Total Customer Service & Information	$7,670						$18			
87													
88		Total Sales	Demonstrating & Selling	$695						$12			
89			Miscellaneous Sales										
90			Subtotal Total Sales	$695						$12			
91													
92		Administrative & General	Administrative and General Salaries	$5,963						$379			

Line No.	Category	Description	Description	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(71)									
95			Employee Pensions and Benefits	4,630								127	3,572
96			Franchise Requirements	376									
97			Injuries and Damages							$7			
98			Maintenance of General Plant	946						$10			
99			Miscellaneous General Expenses	908						$0			
100			Office Supplies and Expenses	1,565									
101			Outside Service Employed	17,244									
102			Property Insurance	145									
103			Regulatory Commission Expenses	2,567							1,072		
104			Subtotal Administrative & General	$34,273						$396	$1,072	$127	$3,572
105													
106			**O&M Expense**	**$426,930**					**($10,620)**	**$2,353**	**$1,072**	**$127**	**$3,572**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$87,057									
109			Subtotal Depreciation & Amortization Expense	$87,057									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$649									
112			Subtotal Amortization of Regulatory Expense	$649									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$7,951									
115			Subtotal Taxes Other Than Income Taxes - Other	$7,951									
116													
117			**Total Operating Expenses**	**$522,587**					**($10,620)**	**$2,353**	**$1,072**	**$127**	**$3,572**
118													
119	**Net Operating Income Before Income Tax**			**$169,139**	**$1,616**	**$76**	**$348**	**$48,177**	**($3,532)**	**($2,353)**	**($1,072)**	**($127)**	**($3,572)**

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost										$199,532
2			Cust & Dist									38,005	311,793
3			Subtotal Residential									$38,005	$511,325
4													
5		C & I	Gas Cost										$68,611
6			Cust & Dist									11,522	115,141
7			Subtotal C & I									$11,522	$183,751
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale									($14,152)	
13			Subtotal Sales for Resale									($14,152)	
14													
15		Forfeited Discounts	Forfeited Discounts										$2,108
16			Subtotal Forfeited Discounts										$2,108
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property										1,598
22			Subtotal Rent For Gas Property										1,598
23													
24		Other Gas Revenues	Other Gas Revenues										$927
25			Subtotal Other Gas Revenues										$927
26													
27		Transportation of Gas of Others	Transportation of Gas of Others									$690	$28,081
28			Subtotal Transportation of Gas of Others									$690	$28,081
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**									**$36,065**	**$727,790**
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										$8
36			Liquefied Petroleum Gas Expenses									$3	114
37			Liquefied Petroleum Gas Expenses									$0	89
38			Maintenance of Structures and Improvements									$2	76
39			Maintenance of Production Equipment									$6	190
40			Subtotal Manufactured Gas Production									$11	$478
41													
42		Other Gas Supply	Natural Gas City Gate Purchases									($10,620)	$163,876
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										51,136
45			Purchased Gas Expenses					(1,742)				($1,742)	(1,724)
46			Gas Withdrawn from Storage-Debit										71,573

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
47			Gas Delivered to Storage-Credit										(23,015)
48			Other Gas Supply Purchases										278
49			Subtotal Other Gas Supply						($1,742)			($12,362)	$262,123
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering									$22	$950
52			Maintenance of Structures and Improvements									$68	3,633
53			Subtotal Storage Maintenance Expense									$90	$4,583
54													
55		Storage Operations Expense	Operating Supervision and Engineering									$8	$327
56			Operation Labor and Expenses									$20	840
57			Subtotal Storage Operations Expense									$29	$1,168
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering									$0	$697
63			Mains and Services Expenses									$272	16,665
64			Measuring and Regulating Station Expenses-General									$52	1,739
65			Measuring and Regulating Station Expenses-City Gate										0
66			Meter and House Regulator Expenses									$83	6,599
67			Customer Installations Expenses									$252	7,555
68			Other Expenses									$178	19,631
69			Rents										217
70			Maintenance of Mains									$543	24,143
71			Maintenance of Measuring & Reg. Station Equip.-Genl.									$33	1,443
72			Maintenance of Services									$61	2,639
73			Maintenance of Meters & House Regulators									$7	229
74			Maintenance of Other Equipment									$5	691
75			Subtotal Distribution Expense									$1,485	$82,246
76													
77		Total Customer Accounts	Customer Records and Collection									$302	$19,292
78			Meter Reading										134
79			Miscellaneous Customer Accounts			809		(662)				$156	1,087
80			Uncollectible Accounts	611					(1,200)			($589)	2,306
81			Subtotal Total Customer Accounts	$611		$809		($662)	($1,200)			($131)	$22,819
82													
83		Total Customer Service & Information	Customer Assistance									$16	$7,357
84			Informational & Instructional										284
85			Miscellaneous Customer & Informational									$2	47
86			Subtotal Total Customer Service & Information									$18	$7,687
87													
88		Total Sales	Demonstrating & Selling									$12	$707
89			Miscellaneous Sales										
90			Subtotal Total Sales									$12	$707
91													
92		Administrative & General	Administrative and General Salaries									$379	$6,342

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub total	(20) Pro Forma Adjusted at Present Rates
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit										(71)
95			Employee Pensions and Benefits									$3,699	8,328
96			Franchise Requirements										376
97			Injuries and Damages									$7	7
98			Maintenance of General Plant									$10	956
99			Miscellaneous General Expenses									$0	909
100			Office Supplies and Expenses										1,565
101			Outside Service Employed										17,244
102			Property Insurance										145
103			Regulatory Commission Expenses									$1,072	3,639
104			Subtotal Administrative & General									$5,166	$39,439
105													
106			**O&M Expense**	**$611**		**$809**		**($662)**	**($2,942)**			**($5,681)**	**$421,249**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense								$5,023	$5,023	$92,080
109			Subtotal Depreciation & Amortization Expense								$5,023	$5,023	$92,080
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
112			Subtotal Amortization of Regulatory Expense		$321		$810					$1,131	$1,780
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other							$189		$189	$8,140
115			Subtotal Taxes Other Than Income Taxes - Other							$189		$189	$8,140
116													
117			**Total Operating Expenses**	**$611**	**$321**	**$809**	**$810**	**($662)**	**($2,942)**	**$189**	**$5,023**	**$661**	**$523,248**
118													
119	**Net Operating Income Before Income Tax**			**($611)**	**($321)**	**($809)**	**($810)**	**$662**	**$2,942**	**($189)**	**($5,023)**	**$35,403**	**$204,542**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2023
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.	$8							
2			717.0 Liquefied Petroleum Gas Expenses.	111		3					
3			741.0 Maintenance Of Structures And Improvements.	74		2					
4			742.0 Maintenance Of Production Equipment.	185		6					
5			Subtotal	$378		$11					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	89		0					
8			Subtotal	$89		$0					
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$174,495	($10,620)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.	51,136							
13			807.0 Purchased Gas Expenses.	18							
14			808.1 Gas Withdrawn From Storage-Debit.	71,573							
15			808.2 Gas Delivered To Storage-Credit.	(23,015)							
16			813.0 Other Gas Supply Expenses.	278							
17			Subtotal	$274,485	($10,620)						
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$319		$8					
23			841.0 Operation Labor And Expenses.	820		20					
24			Subtotal	$1,139		$29					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$929		$22					
27			843.2 Maintenance Of Structures And Improvements.	3,565		68					
28			Subtotal	$4,493		$90					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$697		$0					
31			874.0 Mains And Services Expenses.	16,392		272					
32			875.0 Measuring And Regulating Station Expenses--General.	1,686		52					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	6,516		83					
35			879.0 Customer Installations Expenses.	7,303		252					
36			880.0 Other Expenses.	19,453		178					
37			881.0 Rents.	217							
38			Subtotal	$52,264		$837					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$23,599		$543					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	1,410		33					
42			892.0 Maintenance Of Services.	2,579		61					
43			893.0 Maintenance Of Meters And House Regulators.	222		7					
44			894.0 Maintenance Of Other Equipment.	686		5					
45			Subtotal	$28,496		$649					
46											
47			Distribution Expense Subtotal	$80,760		$1,485					
48											

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$134							
50			903.0 Customer Records And Collection Expenses.	18,990		302					
51			904.0 Uncollectible Accounts.	2,895						611	
52			905.0 Miscellaneous Customer Accounts Expenses.	931		10					
53											
54			Subtotal	$22,949		$312				$611	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$7,341		$16					
57			909.0 Informational And Instructional Advertising Expenses.	284							
58			910.0 Miscellaneous Customer Service And Informational Expenses.	45		2					
59			Subtotal	$7,670		$18					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$695		$12					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$695		$12					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$5,963		$379					
66			921.0 Office Supplies And Expenses.	1,565							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	17,244							
69			924.0 Property Insurance.	145							
70			925.0 Injuries And Damages.	376		7					
71			926.0 Employee Pensions And Benefits.	4,630				127	3,572		
72			928.0 Regulatory Commission Expenses.	2,567			1,072				
73			929.0 Duplicate Charges--Credit.	(71)							
74			930.2 Miscellaneous General Expenses.	908		0					
75											
76			Subtotal	$33,327		$386	$1,072	$127	$3,572		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$946		$10					
79			Subtotal	$946		$10					
80											
81			A&G Expense Sub-total	$34,273		$396	$1,072	$127	$3,572		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$74,876							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	12,181							
86			Subtotal	$87,057							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$649							$321
89			Subtotal	$649							$321
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$7,951							
92			Subtotal	$7,951							
93											
94			**Total**	**$522,587**	**($10,620)**	**$2,353**	**$1,072**	**$127**	**$3,572**	**$611**	**$321**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								$8
2			717.0 Liquefied Petroleum Gas Expenses.							3	114
3			741.0 Maintenance Of Structures And Improvements.							2	76
4			742.0 Maintenance Of Production Equipment.							6	190
5			Subtotal							$11	$389
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.							0	89
8			Subtotal							$0	$89
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($10,620)	$163,876
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								51,136
13			807.0 Purchased Gas Expenses.				(1,742)			(1,742)	(1,724)
14			808.1 Gas Withdrawn From Storage-Debit.								71,573
15			808.2 Gas Delivered To Storage-Credit.								(23,015)
16			813.0 Other Gas Supply Expenses.								278
17			Subtotal				($1,742)			($12,362)	$262,123
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$8	$327
23			841.0 Operation Labor And Expenses.							20	840
24			Subtotal							$29	$1,168
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$22	$950
27			843.2 Maintenance Of Structures And Improvements.							68	3,633
28			Subtotal							$90	$4,583
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$697
31			874.0 Mains And Services Expenses.							272	16,665
32			875.0 Measuring And Regulating Station Expenses--General.							52	1,739
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							83	6,599
35			879.0 Customer Installations Expenses.							252	7,555
36			880.0 Other Expenses.							178	19,631
37			881.0 Rents.								217
38			Subtotal							$837	$53,101
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$543	$24,143
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							33	1,443
42			892.0 Maintenance Of Services.							61	2,639
43			893.0 Maintenance Of Meters And House Regulators.							7	229
44			894.0 Maintenance Of Other Equipment.							5	691
45			Subtotal							$649	$29,144
46											
47			Distribution Expense Subtotal							$1,485	$82,246
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.								$134
50			903.0 Customer Records And Collection Expenses.							302	19,292
51			904.0 Uncollectible Accounts.				(1,200)			(589)	2,306
52			905.0 Miscellaneous Customer Accounts Expenses.	809		(662)				156	1,087
53											
54			Subtotal	$809		($662)	($1,200)			($131)	$22,819
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$16	$7,357
57			909.0 Informational And Instructional Advertising Expenses.								284
58			910.0 Miscellaneous Customer Service And Informational Expenses.							2	47
59			Subtotal							$18	$7,687
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$12	$707
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$12	$707
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$379	$6,342
66			921.0 Office Supplies And Expenses.								1,565
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								17,244
69			924.0 Property Insurance.								145
70			925.0 Injuries And Damages.							7	383
71			926.0 Employee Pensions And Benefits.							3,699	8,328
72			928.0 Regulatory Commission Expenses.							1,072	3,639
73			929.0 Duplicate Charges--Credit.								(71)
74			930.2 Miscellaneous General Expenses.							0	909
75											
76			Subtotal							$5,157	$38,484
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$10	$956
79			Subtotal							$10	$956
80											
81			A&G Expense Sub-total							$5,166	$39,439
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$3,915	$3,915	$78,791
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						1,108	1,108	13,288
86			Subtotal						$5,023	$5,023	$92,080
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$810					$1,131	$1,780
89			Subtotal		$810					$1,131	$1,780
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$189		$189	$8,140
92			Subtotal					$189		$189	$8,140
93											
94			**Total**	**$809**	**$810**	**($662)**	**($2,942)**	**$189**	**$5,023**	**$661**	**$523,248**

Line No.	Category	Description	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) Adjustments Sub-total	(8) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$273,788	$1,328	$76	$235	$36,365		$38,005	$311,793
2			C & I	481.0	103,618	287		113	11,122		11,522	115,141
3			Transportation of Gas of Others	489.3	27,392				690		690	28,081
4				Subtotal	$404,798	$1,616	$76	$348	$48,177		$50,217	$455,015
5												
6		**Gas Cost Revenue**	Residential	480.0	$199,532							$199,532
7			C & I	481.0	68,611							68,611
8			Interdepartmental	484.0								
9				Subtotal	$268,143							$268,143
10												
11			**Subtotal OPERATING REVENUE**		$672,941	$1,616	$76	$348	$48,177		$50,217	$723,158
12												
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$1,598							$1,598
14			Interdepartmental Rents	494.0								
15			Other Gas Revenues	495.0	927							927
16				Subtotal	$2,525							$2,525
17												
18		**Other Operating Revenue**	Sales For Resale	483.0	$14,152					($14,152)	(14,152)	
19			Forfeited Discounts	487.0	2,108							2,108
20												
21			Miscellaneous Service Revenues	488.0								
22				Subtotal	$16,260					($14,152)	($14,152)	$2,108
23												
24			**Subtotal OTHER REVENUE**		$18,785					($14,152)	($14,152)	$4,633
25												
26			**Total**		**$691,725**	**$1,616**	**$76**	**$348**	**$48,177**	**($14,152)**	**$36,065**	**$727,790**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total	(7)
1	Total FPFTY Revenues		$473,135	$897	$168,752	$99	$2,064	$171,812	
2	Commodity Billings in Revenues		(199,532)	(446)	(66,455)	(28)	(1,529)	(68,458)	
3	Weather Adjustment		36,365		11,122			11,122	
4	Total Reconcilable Surcharge in Revenues								
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$309,968	$451	$113,419	$71	$535	$114,476	
6									
7	Average Monthly Customers in HTY		505,033	23	44,842	8	16		
8									
9	Average Annual Margin Per Customer	L5 / L7	$0.614	$19.761	$2.529	$8.573	$33.454		
10									
11	Number of Customers of Current Month		507,197	22	44,963	8	16	45,009	
12									
13	Increase in Customers During HTY	L11 - L7	2,165	(1)	121	(0)		45,009	
14									
15	Annualization of Revenue	L9 * L13	$1,328	($16)	$306	($2)		$287	

D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	Reference	(1) Residential Sales
1	CAP Discount		($10,913)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		282,698
7	Average Monthly CAP Customers		23,558
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.463)
9			
10	CAP Customers at End of HTY		23,375
11	Decrease of CAP Customers	L10 - L7	(183)
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	$85
14	Write-Offs & Working Capital Factor		10.5%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	($9)
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**$76**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total
1	Revenue in February of HTY		$26,361	$73	$12,547	$3	$43	$12,666
2	Days in February of HTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	941	3	448	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$235**	**$1**	**$112**	**$0**	**$0**	**$113**

Line No.	Description	(1) Total
1	Residential Sales	$36,365
2	TCS Sales	
3	GC Sales	11,122
4	C & I Total	11,122
5	Revenues - Gas Transportation	690
6	**Total**	$48,177

(1)

Line No.	Description	Account	Total
1	Other Operating Revenue	483000: Sales for Resale - Gas	($14,152)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($10,620)

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		348	348
2	Number of Employees @ HTY - Total		696	696
3	Percentage of Employees @ HTY	L1 / L2	50.01%	49.99%
4	Distribution of Budget S&W Expense		$22,747	$22,742
5				
6	**Annualize March 1 Wage Increase for HTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$114
10		L4 + L9	$22,747	$22,855
11				
12	**Annualize January 1 and March 1, 2024 Wage Increase**			
13	Number of Months TY		12	12
14	Rate for Increase TY		2.50%	3.00%
15	Total Wage Increase TY	(L10 * L13 * L14) / 12	$569	$686
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$23,316**	**$23,541**

Line No.	Description	(1) Reference	(2) PECO - Gas
1	Distribution of S&W Expense		$45,489
2			
3	Annualized S&W Including Wage Increases		$46,857
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		19.15%
8	Union Contract Payment for Utility	L6 * L7	$249
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$42
11			
12	Annualized S&W for Employees in HTY	L3 + L10	$46,898
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ HTY		696
16	Average Number of Employees in HTY - Total		682
17	Annualization for Number of Employees	L15 - L16	14
18	Annual S&W per Employee	L12 / L16	$68.8
19	Annualization of S&W for New Employees	L17 * L18	$944
20			
21	Pro Forma HTY S&W	L12 + L19	$47,842
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$2,353**
24			
25	S&W Pro Forma Factor	L23 / L1	5.17%

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.	$4		4
2			717.0 Liquefied Petroleum Gas Expenses.	65	$3	$68
3			728.0 Liquefied Petroleum Gas.	0	0	0
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.			
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	164	8	172
12			841.0 Operation Labor And Expenses.	395	20	416
13			843.1 Maintenance Supervision And Engineering.	418	22	439
14			843.2 Maintenance Of Structures And Improvements.	1,313	68	1,381
15			**Subtotal Power Supply Expenses**	$2,358	$122	$2,480
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$1	$0	$1
18			874.0 Mains And Services Expenses.	5,266	272	5,539
19			875.0 Measuring And Regulating Station Expenses--General.	1,013	52	1,066
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	1,595	83	1,677
22			879.0 Customer Installations Expenses.	4,866	252	5,118
23			880.0 Other Expenses.	3,436	178	3,613
24			881.0 Rents.			
25			887.0 Maintenance Of Mains.	10,500	543	11,044
26			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	634	33	667
27			892.0 Maintenance Of Services.	1,170	61	1,231
28			893.0 Maintenance Of Meters And House Regulators.	135	7	142
29			894.0 Maintenance Of Other Equipment.	97	5	102
30			**Subtotal Distribution Expense**	$28,713	$1,485	$30,199
31						
32		Customer Accounts	902.0 Meter Reading Expenses.	0		0
33			903.0 Customer Records And Collection Expenses.	$5,839	$302	$6,141
34			904.0 Uncollectible Accounts.			
35			905.0 Miscellaneous Customer Accounts Expenses.	193	10	203
36						
37			**Subtotal Customer Accounts**	$6,031	$312	$6,343
38						
39		Customer Service & Information	908.0 Customer Assistance Expenses	$312	$16	$328
40			909.0 Informational And Instructional Advertising Expenses.			

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			910.0 Miscellaneous Customer Service And Informational Expenses.	33	2	35
42			**Subtotal Customer Service & Information**	$344	$18	$362
43						
44		Sales	912.0 Demonstrating And Selling Expenses.	$234	$12	$246
45			916.0 Miscellaneous Sales Expenses.			
46			**Subtotal Sales**	$234	$12	$246
47						
48		Administration & General - General	920.0 Administrative And General Salaries.	$7,334	$379	$7,714
49			921.0 Office Supplies And Expenses.			
50			922.0 Administrative Expenses Transferred--Credit.			
51			923.0 Outside Services Employed.			
52			924.0 Property Insurance.			
53			925.0 Injuries And Damages.	127	7	134
54			926.0 Employee Pensions And Benefits.			
55			928.0 Regulatory Commission Expenses.			
56			929.0 Duplicate Charges--Credit.			
57			930.2 Miscellaneous General Expenses.	8	0	9
58						
59			**Subtotal Administration & General - General**	$7,470	$386	$7,856
60						
61			**Subtotal Operations**	$45,151	$2,336	$47,487
62						
63	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$187	$10	$197
64			**Subtotal Administration & General - General**	$187	$10	$197
65						
66		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$43	$2	$45
67			742.0 Maintenance Of Production Equipment.	108	6	113
68			**Subtotal Gas Expense**	$151	$8	$158
69						
70			**Subtotal Maintenance**	$337	$17	$355
71						
72	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$45,489	$2,353	$47,842
73						
74	**Percent Increase**		**Percent Increase**			5.17%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$8
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$15
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,701
8	Materials, IT Costs, Travel, Copies, etc.		428
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$2,129
10			
11	**Total Rate Case Expense**	L4 + L9	$2,144
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,072
15			
16	Annual Amortization Amount Included in Budget		
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	$1,072

Line No.	Description	(1) Reference	(2) Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		655
3	Employees at Ten Months Prior		661
4	Employees at Nine Months Prior		665
5	Employees at Eight Months Prior		666
6	Employees at Seven Months Prior		689
7	Employees at Six Months Prior		683
8	Employees at Five Months Prior		681
9	Employees at Four Months Prior		690
10	Employees at Three Months Prior		700
11	Employees at Two Months Prior		700
12	Employees at One Month Prior		698
13	Employees at End of HTY		696
14			
15	Average Monthly Employees in HTY	AVERAGE L2 to L13	682
16	Additional Employees in HTY		14
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$6,302
20	Number of Employees for Budget		682
21	Budget Expense Per Employee	L19 / L20	$9
22	Additional Employees for Annualization	L16	14
23	Total Benefits Pro Forma Adjustment	L21 * L22	$127

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to HTY		$26,339
2	Pension Contribution for Three Years Prior to HTY		18,006
3	Pension Contribution for Two Years Prior to HTY		17,267
4	Pension Contribution for One Year Prior to HTY		15,222
5	Pension Contribution for HTY		1,408
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$15,648
8			
9	Allocation Percent to Utility		19.15%
10	Total Amount to Utility	L7 * L9	$2,996
11	Allocation Percent to Capital		36.61%
12	Pension Contribution To Be Capitalized	L10 * L11	$1,097
13	Pension Contribution To Be Expensed	L10 - L12	$1,899
14	Budgeted Test Year Distribution Pension Expense		($1,673)
15	Additional Pension Expense	L13 - L14	$3,572

Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
			(1)	(2)	(3)	(4)	(5)	(6)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$2,036	$595,534	0.3419%		
2		One Year Prior to HTY		2,826	780,108	0.3623%		
3		HTY		3,091	778,733	0.3970%		
4		Three Year Average	SUM L1 to L3 / 3	$2,651	$718,125	0.3692%		
5								
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	HTY			$723,158			
7								
8	Tariff Revenue - Non Shopping Revenue	HTY	L6		$723,158			
9								
10	Tariff Revenue - Shopping Revenue	HTY			$82,841			
11								
12	Tariff Revenue - Including Shopping Revenue	HTY	L8 + L10		$805,999			
13								
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12					$2,976
15								
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY					$367	
17		One Year Prior to HTY					532	
18		HTY					693	
19								
20	**Three Year Average PPA**		SUM L16 to L18 / 3					$530
21								
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20					$3,506
23								
24	Uncollectible Accounts (904)	HTY						$2,895
25								
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24					$611

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$3,078
2	Residential Gas Energy Efficiency Program Costs in HTY Budget		2,728
3	Sub-total Pro Forma Increase in Residential Gas Energy Efficiency Program Costs	L1 - L2	$350
4	Gas Commercial EE Program Refund - Rate GC		(29)
5	Total Pro Forma Adjustment Amount	L3 + L4	$321

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		0.667%				
2								
3	January				3,654	24		
4	February				3,686	25		
5	March				3,760	25		
6	April				3,872	26		
7	May				4,038	27		
8	June				4,165	28		
9	July				4,275	28		
10	August				4,395	29		
11	September				4,436	30		
12	October				4,504	30		
13	November				4,557	30		
14	December				4,530	30		
15	**Total Residential**		SUM Col 4 L3 to L14				$332	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				8,284	35		
20	February				8,444	36		
21	March				8,594	37		
22	April				8,742	37		
23	May				8,997	38		
24	June				9,113	39		
25	July				9,518	40		
26	August				9,856	42		
27	September				9,987	42		
28	October				10,099	43		
29	November				10,182	43		
30	December				10,218	43		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$476	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$809

Line No.	Description	(1) Reference	(2) Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$14,309
2	Amortization Years		10
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,431
5			
6	**Amount Included in Budget**		$621
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	$810

Line No.	Description	(1) Reference	(2) Total
1	Customer Interest on Unspent MGP Collections		($1,387)
2	Gas FTAC Final Reconciliation Recovery from Customers		$63
3	Total	L1 + L2	($1,325)
4	Amortization Years		2
5	Pro Forma Adjustment Amount	L3 / L4	($662)

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,119)
3	Rate GC		($609)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($1,742)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,057)
11	Rate GC		($143)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,200)
16			
17	Total Gas Procurement and Merchant Function Charges	L7 + L15	($2,942)

Line No.	Description	(1) Total	(2) Pro Forma Adjustments	(3) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$1,995		$1,995
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	640		640
4	Real Estate Tax Accrual	1,659		1,659
5	Miscellaneous TOTI	13		13
6	Payroll Tax Accrued	3,645	$189	3,833
7	**Total**	$7,951	$189	$8,140

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$45,489
2	Payroll Tax Expense		$3,645
3	Payroll Tax Expense - Percent	L2 / L1	8.01%
4	Pro Forma Increase in S&W		$2,353
5	**Payroll Tax Pro Forma**	L3 * L4	**$189**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2024
($ in Thousands)
D-17 Depreciation Adjustment

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.	Common-General Plant	PECO Common 3901 PA	$4,133	($16)	$4,149	($16)	$4,117
2			PECO Common 3902 IL	17		17		17
3			PECO Common 3902 PA	2,453	289	2,164	289	2,742
4			PECO Common 3903 PA	57	5	52	5	62
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,125	102	2,023	102	2,228
7			PECO Common 3913 IL	1,056	65	991	65	1,120
8			PECO Common 3913 PA	7,239	1,461	5,778	1,461	8,700
9			PECO Common 3930 PA	104	9	95	9	113
10			PECO Common 3941 PA	2		2		2
11			PECO Common 3942 PA	66		66		66
12			PECO Common 3970 PA	5,691	139	5,552	139	5,830
13			PECO Common 3980 PA	84		84		84
14			Subtotal Common - General Plant	$23,040	$2,055	$20,986	$2,055	$25,095
15								
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA					
17			Subtotal					
18								
19		Gas - Distribution	PECO Gas 3751 PA	$137	($0)	$137	($0)	$136
20			PECO Gas 3752 PA	31	2	30	2	33
21			PECO Gas 3753 PA	165	8	157	8	173
22			PECO Gas 3761 PA	10,075	243	9,832	243	10,319
23			PECO Gas 3762 PA	1,171	80	1,091	80	1,251
24			PECO Gas 3763 PA	18,158	1,059	17,099	1,059	19,216
25			PECO Gas 3780 PA	506	35	471	35	541
26			PECO Gas 3790 PA	1,053		1,053		1,053
27			PECO Gas 3801 PA	3,610	55	3,555	55	3,664
28			PECO Gas 3802 PA	19,026	946	18,080	946	19,973
29			PECO Gas 3810 PA	2,017	81	1,937	81	2,098
30			PECO Gas 3811 PA	3,496	58	3,438	58	3,554
31			PECO Gas 3820 PA	4,865	258	4,608	258	5,123
32			PECO Gas 3870 PA	103		103		103
33			Subtotal Gas - Distribution	$64,414	$2,824	$61,590	$2,824	$67,238
34								

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
35		Gas - General Plant	PECO Gas 3901 PA	$104	$0	$104	$0	$104
36			PECO Gas 3902 PA	58		58		58
37			PECO Gas 3903 PA	62	19	44	19	81
38			PECO Gas 3911 PA	0		0		0
39			PECO Gas 3912 PA	35	12	23	12	47
40			PECO Gas 3913 IL	0		0		0
41			PECO Gas 3913 PA	820	76	743	76	896
42			PECO Gas 3940 PA	743	42	701	42	786
43			PECO Gas 3950 PA	2	(0)	2	(0)	2
44			PECO Gas 3970 PA	511	63	448	63	574
45			PECO Gas 3980 PA	8		8		8
46			Subtotal Gas - General Plant	$2,343	$213	$2,130	$213	$2,555
47								
48		Gas - Production Plant	PECO Gas 3050 PA	$31		$31		$31
49			PECO Gas 3053 PA	(0)		(0)		(0)
50			PECO Gas 3110 PA	140		140		140
51			Subtotal Gas - Production Plant	$170		$170		$170
52								
53		Gas - Storage	PECO Gas 3611 PA	$59	($3)	$63	($3)	$56
54			PECO Gas 3612 PA	329		329		329
55			PECO Gas 3613 PA	22	1	21	1	22
56			PECO Gas 3620 PA	10		10		10
57			PECO Gas 3630 PA	25		25		25
58			PECO Gas 3631 PA	156		156		156
59			PECO Gas 3632 PA	849	337	513	337	1,186
60			PECO Gas 3633 PA	863	(1)	864	(1)	862
61			PECO Gas 3634 PA	198	39	159	39	238
62			PECO Gas 3635 PA	121	33	89	33	154
63			Subtotal Gas - Storage	$2,633	$405	$2,229	$405	$3,038
64								
65			Subtotal 403.0 Depreciation Expense.	$92,601	$5,496	$87,105	$5,496	$98,097
66								
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 3030- North Star RE SW	$447		$447		$447
68			PECO Com 3030-Apollo SW	685	685		$685	$1,369
69			PECO Com 3030-BIDA Customer Project	1,849		$1,849		$1,849
70			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		$2,139		$2,139
71			PECO Com 3030-CIS Transformation SW	204		$204		$204
72			PECO Com 3030-Cloud Serv 3 yr	1,962	1,073	$889	$1,073	$3,035
73			PECO Com 3030-Cloud Serv 5 yr	2,780	1,357	$1,423	$1,357	$4,138
74			PECO Com 3030-Common MDM SW	8,309	219	$8,090	$219	$8,528
75			PECO Com 3030-CTA PHI Consol SW	19		$19		$19

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
76			PECO Com 3030-Cust Appt Sched SW	615		$615		$615
77			PECO Com 3030-Digital Strat Platfor	123		$123		$123
78			PECO Com 3030-EU Dig Strat EPay SW	444		$444		$444
79			PECO Com 3030-EU Digital Program We	1,657	863	$793	$863	$2,520
80			PECO Com 3030-EU oneMDS SW	2,759	2,759		$2,759	$5,518
81			PECO Com 3030-Fusion Mig Non-MDM SW	791		$791		$791
82			PECO Com 3030-I Sign Up and Move	1,568		$1,568		$1,568
83			PECO Com 3030-IT Cust Mobile App SW	102	67	$35	$67	$169
84			PECO Com 3030-IVR System PA	127	98	$29	$98	$226
85			PECO Com 3030-Lease IT SW	112		$112		$112
86			PECO Com 3030-Misc 5 yr FR PA	6,784	(2,595)	$9,379	($2,595)	$4,189
87			PECO Com 3030-Misc 5 yr PA	12	12		$12	$25
88			PECO Com 3030-Mobile Dispatch Mappi	5,842		$5,842		$5,842
89			PECO Com 3030-OBIEE Migration SW	1,099		$1,099		$1,099
90			PECO Com 3030-Oracle MW Upgrade SW	261		$261		$261
91			PECO Com 3030-Rev Req Filing SW	390		$390		$390
92			PECO Com 3030-Robotic Process Auto	89		$89		$89
93			PECO Com 3030-SCP Splunk SW	2		$2		$2
94			Subtotal Common - Intangible Plant	$41,174	$4,538	$36,636	$4,538	$45,713
95								
96		Gas - General Plant	PECO Gas 3913 PA					
97			Subtotal					
98								
99		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$1,350	$61	$1,289	$61	$1,411
100			PECO Gas 303-PECO RNI Upgrade SW G	440		440		440
101			PECO Gas 303-SES IV G SW	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	82		82		82
103			PECO Gas 3030-Cloud Serv 5 yr	51		51		51
104			Subtotal Gas - Intangible Plant	$2,682	$61	$2,621	$61	$2,742
105								
106			Subtotal 404.0 Amort. Of Limited-Term Plant	$43,856	$4,599	$39,257	$4,599	$48,455
107								
108			Grand Total	$136,457	$10,095	$126,362	$10,095	$146,552

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.	Common-General Plant	PECO Common 3901 PA	0.2307	$953	($4)	$957	($4)	$950
2			PECO Common 3902 IL	0.2307	4		4		4
3			PECO Common 3902 PA	0.2307	566	67	499	67	633
4			PECO Common 3903 PA	0.2307	13	1	12	1	14
5			PECO Common 3911 PA	0.2307	3		3		3
6			PECO Common 3912 PA	0.2307	490	24	467	24	514
7			PECO Common 3913 IL	0.2307	244	15	229	15	258
8			PECO Common 3913 PA	0.2307	1,670	337	1,333	337	2,007
9			PECO Common 3930 PA	0.2307	24	2	22	2	26
10			PECO Common 3941 PA	0.2307	1		1		1
11			PECO Common 3942 PA	0.2307	15		15		15
12			PECO Common 3970 PA	0.2307	1,313	32	1,281	32	1,345
13			PECO Common 3980 PA	0.2307	19		19		19
14			Subtotal Common - General Plant		$5,315	$474	$4,841	$474	$5,789
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	0.2307					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$137	($0)	$137	($0)	$136
20			PECO Gas 3752 PA	1.0000	31	2	30	2	33
21			PECO Gas 3753 PA	1.0000	165	8	157	8	173
22			PECO Gas 3761 PA	1.0000	10,075	243	9,832	243	10,319
23			PECO Gas 3762 PA	1.0000	1,171	80	1,091	80	1,251
24			PECO Gas 3763 PA	1.0000	18,158	1,059	17,099	1,059	19,216
25			PECO Gas 3780 PA	1.0000	506	35	471	35	541
26			PECO Gas 3790 PA	1.0000	1,053		1,053		1,053
27			PECO Gas 3801 PA	1.0000	3,610	55	3,555	55	3,664
28			PECO Gas 3802 PA	1.0000	19,026	946	18,080	946	19,973
29			PECO Gas 3810 PA	1.0000	2,017	81	1,937	81	2,098
30			PECO Gas 3811 PA	1.0000	3,496	58	3,438	58	3,554
31			PECO Gas 3820 PA	1.0000	4,865	258	4,608	258	5,123
32			PECO Gas 3870 PA	1.0000	103		103		103
33			Subtotal Gas - Distribution		$64,414	$2,824	$61,590	$2,824	$67,238
34									

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)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$104	$0	$104	$0	$104
36			PECO Gas 3902 PA	1.0000	58		58		58
37			PECO Gas 3903 PA	1.0000	62	19	44	19	81
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	35	12	23	12	47
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	820	76	743	76	896
42			PECO Gas 3940 PA	1.0000	743	42	701	42	786
43			PECO Gas 3950 PA	1.0000	2	(0)	2	(0)	2
44			PECO Gas 3970 PA	1.0000	511	63	448	63	574
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$2,343	$213	$2,130	$213	$2,555
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000	(0)		(0)		(0)
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$59	($3)	$63	($3)	$56
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	22	1	21	1	22
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	849	337	513	337	1,186
60			PECO Gas 3633 PA	1.0000	863	(1)	864	(1)	862
61			PECO Gas 3634 PA	1.0000	198	39	159	39	238
62			PECO Gas 3635 PA	1.0000	121	33	89	33	154
63			Subtotal Gas - Storage		$2,633	$405	$2,229	$405	$3,038
64									
65			Subtotal 403.0 Depreciation Expense.		$74,876	$3,915	$70,961	$3,915	$78,791
66									
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 3030- North Star RE SW	0.2307	$103		$103		$103
68			PECO Com 3030-Apollo SW	0.2307	$158	$158		$158	$316
69			PECO Com 3030-BIDA Customer Project	0.2307	$427		$427		$427
70			PECO Com 3030-BIDA-AMI Ph2 SW	0.2307	$493		$493		$493
71			PECO Com 3030-CIS Transformation SW	0.2307	$47		$47		$47
72			PECO Com 3030-Cloud Serv 3 yr	0.2307	$453	$248	$205	$248	$700
73			PECO Com 3030-Cloud Serv 5 yr	0.2307	$641	$313	$328	$313	$955
74			PECO Com 3030-Common MDM SW	0.2307	$1,917	$50	$1,866	$50	$1,967
75			PECO Com 3030-CTA PHI Consol SW	0.2307	$4		$4		$4

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)
76			PECO Com 3030-Cust Appt Sched SW	0.2307	$142		$142		$142
77			PECO Com 3030-Digital Strat Platfor	0.2307	$28		$28		$28
78			PECO Com 3030-EU Dig Strat EPay SW	0.2307	$102		$102		$102
79			PECO Com 3030-EU Digital Program We	0.2307	$382	$199	$183	$199	$581
80			PECO Com 3030-EU oneMDS SW	0.2307	$636	$636		$636	$1,273
81			PECO Com 3030-Fusion Mig Non-MDM SW	0.2307	$183		$183		$183
82			PECO Com 3030-I Sign Up and Move	0.2307	$362		$362		$362
83			PECO Com 3030-IT Cust Mobile App SW	0.2307	$24	$15	$8	$15	$39
84			PECO Com 3030-IVR System PA	0.2307	$29	$23	$7	$23	$52
85			PECO Com 3030-Lease IT SW	0.2307	$26		$26		$26
86			PECO Com 3030-Misc 5 yr FR PA	0.2307	$1,565	($599)	$2,164	($599)	$967
87			PECO Com 3030-Misc 5 yr PA	0.2307	$3	$3		$3	$6
88			PECO Com 3030-Mobile Dispatch Mappi	0.2307	$1,348		$1,348		$1,348
89			PECO Com 3030-OBIEE Migration SW	0.2307	$254		$254		$254
90			PECO Com 3030-Oracle MW Upgrade SW	0.2307	$60		$60		$60
91			PECO Com 3030-Rev Req Filing SW	0.2307	$90		$90		$90
92			PECO Com 3030-Robotic Process Auto	0.2307	$21		$21		$21
93			PECO Com 3030-SCP Splunk SW	0.2307	$1		$1		$1
94			Subtotal Common - Intangible Plant		$9,499	$1,047	$8,452	$1,047	$10,546
95									
96		Gas - General Plant	PECO Gas 3913 PA	1.0000					
97			Subtotal						
98									
99		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,350	$61	$1,289	$61	$1,411
100			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	440		440		440
101			PECO Gas 303-SES IV G SW	1.0000	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	1.0000	82		82		82
103			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
104			Subtotal Gas - Intangible Plant		$2,682	$61	$2,621	$61	$2,742
105									
106			Subtotal 404.0 Amort. Of Limited-Term Plant		$12,181	$1,108	$11,073	$1,108	$13,288
107									
108			Grand Total		$87,057	$5,023	$82,034	$5,023	$92,080

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 HTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$953	($4)	$957	($4)	$950
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	566	67	499	67	633
4			PECO Common 3903 PA	1.0000	13	1	12	1	14
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	490	24	467	24	514
7			PECO Common 3913 IL	1.0000	244	15	229	15	258
8			PECO Common 3913 PA	1.0000	1,670	337	1,333	337	2,007
9			PECO Common 3930 PA	1.0000	24	2	22	2	26
10			PECO Common 3941 PA	1.0000	1		1		1
11			PECO Common 3942 PA	1.0000	15		15		15
12			PECO Common 3970 PA	1.0000	1,313	32	1,281	32	1,345
13			PECO Common 3980 PA	1.0000	19		19		19
14			Subtotal Common - General Plant		$5,315	$474	$4,841	$474	$5,789
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	1.0000					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$137	($0)	$137	($0)	$136
20			PECO Gas 3752 PA	1.0000	31	2	30	2	33
21			PECO Gas 3753 PA	1.0000	165	8	157	8	173
22			PECO Gas 3761 PA	1.0000	10,075	243	9,832	243	10,319
23			PECO Gas 3762 PA	1.0000	1,171	80	1,091	80	1,251
24			PECO Gas 3763 PA	1.0000	18,158	1,059	17,099	1,059	19,216
25			PECO Gas 3780 PA	1.0000	506	35	471	35	541
26			PECO Gas 3790 PA	1.0000	1,053		1,053		1,053
27			PECO Gas 3801 PA	1.0000	3,610	55	3,555	55	3,664
28			PECO Gas 3802 PA	1.0000	19,026	946	18,080	946	19,973
29			PECO Gas 3810 PA	1.0000	2,017	81	1,937	81	2,098
30			PECO Gas 3811 PA	1.0000	3,496	58	3,438	58	3,554
31			PECO Gas 3820 PA	1.0000	4,865	258	4,608	258	5,123
32			PECO Gas 3870 PA	1.0000	103		103		103
33			Subtotal Gas - Distribution		$64,414	$2,824	$61,590	$2,824	$67,238
34									

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 HTY Depr (Function)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$104	$0	$104	$0	$104
36			PECO Gas 3902 PA	1.0000	58		58		58
37			PECO Gas 3903 PA	1.0000	62	19	44	19	81
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	35	12	23	12	47
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	820	76	743	76	896
42			PECO Gas 3940 PA	1.0000	743	42	701	42	786
43			PECO Gas 3950 PA	1.0000	2	(0)	2	(0)	2
44			PECO Gas 3970 PA	1.0000	511	63	448	63	574
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$2,343	$213	$2,130	$213	$2,555
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000	(0)		(0)		(0)
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$59	($3)	$63	($3)	$56
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	22	1	21	1	22
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	849	337	513	337	1,186
60			PECO Gas 3633 PA	1.0000	863	(1)	864	(1)	862
61			PECO Gas 3634 PA	1.0000	198	39	159	39	238
62			PECO Gas 3635 PA	1.0000	121	33	89	33	154
63			Subtotal Gas - Storage		$2,633	$405	$2,229	$405	$3,038
64									
65			Subtotal 403.0 Depreciation Expense.		$74,876	$3,915	$70,961	$3,915	$78,791
66									
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 3030- North Star RE SW	1.0000	$103		$103		$103
68			PECO Com 3030-Apollo SW	1.0000	$158	$158		$158	$316
69			PECO Com 3030-BIDA Customer Project	1.0000	$427		$427		$427
70			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	$493		$493		$493
71			PECO Com 3030-CIS Transformation SW	1.0000	$47		$47		$47
72			PECO Com 3030-Cloud Serv 3 yr	1.0000	$453	$248	$205	$248	$700
73			PECO Com 3030-Cloud Serv 5 yr	1.0000	$641	$313	$328	$313	$955
74			PECO Com 3030-Common MDM SW	1.0000	$1,917	$50	$1,866	$50	$1,967
75			PECO Com 3030-CTA PHI Consol SW	1.0000	$4		$4		$4

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 HTY Depr (Function)
76			PECO Com 3030-Cust Appt Sched SW	1.0000	$142		$142		$142
77			PECO Com 3030-Digital Strat Platfor	1.0000	$28		$28		$28
78			PECO Com 3030-EU Dig Strat EPay SW	1.0000	$102		$102		$102
79			PECO Com 3030-EU Digital Program We	1.0000	$382	$199	$183	$199	$581
80			PECO Com 3030-EU oneMDS SW	1.0000	$636	$636		$636	$1,273
81			PECO Com 3030-Fusion Mig Non-MDM SW	1.0000	$183		$183		$183
82			PECO Com 3030-I Sign Up and Move	1.0000	$362		$362		$362
83			PECO Com 3030-IT Cust Mobile App SW	1.0000	$24	$15	$8	$15	$39
84			PECO Com 3030-IVR System PA	1.0000	$29	$23	$7	$23	$52
85			PECO Com 3030-Lease IT SW	1.0000	$26		$26		$26
86			PECO Com 3030-Misc 5 yr FR PA	1.0000	$1,565	($599)	$2,164	($599)	$967
87			PECO Com 3030-Misc 5 yr PA	1.0000	$3	$3		$3	$6
88			PECO Com 3030-Mobile Dispatch Mappi	1.0000	$1,348		$1,348		$1,348
89			PECO Com 3030-OBIEE Migration SW	1.0000	$254		$254		$254
90			PECO Com 3030-Oracle MW Upgrade SW	1.0000	$60		$60		$60
91			PECO Com 3030-Rev Req Filing SW	1.0000	$90		$90		$90
92			PECO Com 3030-Robotic Process Auto	1.0000	$21		$21		$21
93			PECO Com 3030-SCP Splunk SW	1.0000	$1		$1		$1
94			Subtotal Common - Intangible Plant		$9,499	$1,047	$8,452	$1,047	$10,546
95									
96		Gas - General Plant	PECO Gas 3913 PA	1.0000					
97			Subtotal						
98									
99		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,350	$61	$1,289	$61	$1,411
100			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	440		440		440
101			PECO Gas 303-SES IV G SW	1.0000	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	1.0000	82		82		82
103			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
104			Subtotal Gas - Intangible Plant		$2,682	$61	$2,621	$61	$2,742
105									
106			Subtotal 404.0 Amort. Of Limited-Term Plant		$12,181	$1,108	$11,073	$1,108	$13,288
107									
108			Grand Total		$87,057	$5,023	$82,034	$5,023	$92,080

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$727,790	$6,080	$733,870
2	Operating Expenses		523,248	41	523,289
3	OIBIT	L1 - L2	$204,542	$6,039	$210,580
4					
5	Rate Base		$2,832,132		$2,832,132
6	Weighted Cost of Debt		1.990%		1.990%
7	Synchronized Interest Expense	L5 * L6	$56,359		$56,359
8	Base Taxable Income	L3 - L7	$148,182	$6,039	$154,221
9					
10	State Accelerated Tax Depreciation		$123,939		$123,939
11	Pro Forma Book Depreciation		92,080		92,080
12	State Tax Depreciation (Over) Under Book	L11 - L10	($31,859)		($31,859)
13	Regulatory Asset Programs M-1, Pension & Post-Retirement		(31,976)		(31,976)
14	Other Property Basis Adjustments (CIAC/ICM)		(16,168)		(16,168)
15	Removal Costs/Software		(4,685)		(4,685)
16	AFUDC Equity		(3,001)		(3,001)
17	Permanent Adjustments		687		687
18	Repair Deduction		(177,122)		(177,122)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($115,940)	$6,039	($109,902)
21					
22	State Income Tax Rate		8.99%	8.99%	8.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$10,423	($543)	$9,880
24	Net Operating Loss Utilization %		100.00%	40.00%	100.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(10,423)	217	(9,880)
26	State Income Tax Benefit / (Expense)	L23 + L25	-	($326)	
27					
28	Federal Accelerated Tax Depreciation		$106,834		$106,834
29	Pro Forma Book Depreciation		92,080		92,080
30	Federal Tax Deducts (Over) Under Book	L29 - L28	($14,754)		($14,754)
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		(31,976)		(31,976)
32	Other Property Basis Adjustments (CIAC/ICM)		(16,168)		(16,168)
33	Removal Costs/Software		(4,685)		(4,685)
34	AFUDC Equity		(3,001)		(3,001)
35	Permanent Adjustments		687		687
36	Repair Deduction		(177,122)		(177,122)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($98,835)	$5,713	($92,797)
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$20,755	($1,200)	$19,556
42	Corporate Alternative Minimum Tax		($22,017)		($22,017)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($1,262)	($1,525)	($2,461)
44					

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($15,472)	$46	($15,427)
47	Deferred Taxes on Timing Differences- State		(4,328)		(4,328)
48	Deferred Taxes on State NOL		10,423	(217)	10,206
49	Excess Deferred Amortization		3,188		3,188
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		9		9
53	Corporate Alternative Minimum Tax		22,017		22,017
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$16,108	($172)	$15,937
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$14,847	($1,697)	$13,475
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$8		$8
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$14,855	($1,697)	$13,484
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$8,489	($1,154)	$7,335
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	6,366	(543)	6,149
65	Total Income Tax Benefit / (Expense)	L63 + L64	$14,855	($1,697)	$13,484

Line No.	Description	(1) Reference	(2) 2018	(3) 2019	(4) 2020	(5) 2021	(6) 2022	(7) Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		($85,736)	($162,524)	($249,053)	($575,746)	($108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	($12,750)	($33,376)		($11,242)	($18,122)	
14								
15								
16	Gas Percentage		-1.20%	-21.27%	163.65%	-259.39%	-38.60%	
17								
18								
19	Loss Allocable to Gas	L13 * L16	$153	$7,100		$29,160	$6,994	
20								
21								
22								
23	2Average for 20168 to 2020	Average L19						8,681
24								
25								
26	Tax Rate							21.00%
27								
28	Section 1301.1(b) Differential	L23 * L26						$1,823

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2023
($ in Thousands)
D-19 Conversion Factor

Line No.	Description	(1) Reference	(2) Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		2,108
4	Total Customer Revenue		672,941
5	Shopping Revenue		82,841
6	LPC REVENUE	L3 / (L4 + L5)	0.002789
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.003692)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003087)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.996009
13			
14	STATE INCOME TAX RATE		8.990%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.089541)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.906468
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.190358)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.716110
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.396434
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	27.990%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		8.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.089900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.910100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.191121)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.718979
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.390861
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	28.102%

PECO ENERGY COMPANY
STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO ENERGY COMPANY'S UPDATED OVERALL REVENUE REQUIREMENT; RESPONSE TO CERTAIN OPPOSING PARTY ADJUSTMENTS; WEATHER NORMALIZATION ADJUSTMENT RIDER

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
MICHAEL J. TRZASKA

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Michael J. Trzaska. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rate Specialist. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 3. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. First, I describe the changes PECO is making to the revenue requirement previously presented in PECO Exhibit MJT-1 in order to reflect (a) more recent data or the Company's revised position on certain issues, as previously set forth in interrogatory responses; (b) the Company's decision to adopt certain adjustments proposed by the active parties; and (c) corrections to the Company's initial filing. Second, I respond to various portions of the direct testimony regarding rate base, revenue, and expense claims presented by Bureau of Investigation and Enforcement ("I&E") witnesses Ethan Cline and Christopher Keller and Office of Consumer Advocate ("OCA") witness John Defever. Third, I address objections and other comments to PECO's proposed weather normalization adjustment ("WNA") mechanism raised by OCA witnesses Ron Nelson and Roger Colton,

I&E witness Cline, Office of Small Business Advocate ("OSBA") witness Mark Ewen, and Tenant Union Representative Network and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("TURN/CAUSE-PA") witness Elizabeth Marx. Finally, I respond to the direct testimony of OCA witness Colton regarding the offset factor applied to reconcilable Customer Assistance Program ("CAP") costs recovered through PECO's Universal Service Fund Charge ("USFC").

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes. I will describe those exhibits during the course of my update and response to the other parties.

II. UPDATE OF THE COMPANY'S REVENUE REQUIREMENT

5. Q. As developed in your testimony, what is PECO's updated Fully Projected Future Test Year ("FPFTY") revenue requirement?

A. PECO's updated FPFTY revenue requirement, as shown in PECO Exhibit MJT-1 Revised, Schedule A-1, is $110.0 million, which translates into updated pro forma present rate revenue of $482.0 million. This represents an approximate $1.1 million reduction to PECO's initial increase request of $111.2 million.

6. Q. Please describe PECO Exhibit MJT-1 Revised.

A. PECO Exhibit MJT-1 Revised is an update of PECO Exhibit MJT-1. The schedules that are included with PECO Exhibit MJT-1 Revised are updated versions of the original schedules included with PECO Exhibit MJT-1. Pages that have been updated from the original schedules are marked "UPDATE 07-16-2024." PECO Exhibit MJT-1 Revised reflects a few revisions that affect the

Company's revenue requirement claim as described later in my rebuttal testimony.

7. Q. Please summarize the revisions to the Company's revenue requirement claims reflected in PECO Exhibit MJT-1 Revised.

A. PECO Exhibit MJT-1 Revised reflects four revisions that affect the Company's revenue requirement claim. First, the Company has updated its claims for Materials and Supplies, Gas Storage, Customer Deposits, and Customer Advances for Construction to reflect the respective thirteen-month average balances as of March 2024, reducing the Company's revenue requirement by $1.1 million. Second, the Company included an unamortized balance of approximately $7,000 for the Tax Accounting Repair Credit ("TARC") reflecting the final year of amortization of the TARC. *See* PECO Exhibit MJT-1 Revised, Schedule D-14. Third, in response to concerns expressed by Mr. Colton in his direct testimony, PECO is updating its proposed change to the negotiated USFC formula offset percentages established in the settlement approved by the Pennsylvania Public Utility Commission ("Commission" or "PUC") of PECO's first default service proceeding at Docket No. P-2008-2062739 (the "DSP Settlement") for uncollectible expense (22%) and cash working capital ("CWC") (5%). As discussed later in my testimony, PECO proposes to maintain the 5% USFC offset factor for CWC using current data in the same methodology recommended by Mr. Colton in PECO's 2008 gas rate case (Docket R-2008-2028394), which was the basis for calculating the 5% working capital adjustment adopted in the DSP Settlement. In addition, as explained by Company witness Jacqueline F. Golden

in her rebuttal testimony (PECO Statement No. 10-R), PECO is revising its recommended USFC offset percentage for uncollectible expense from 5.5% to 7.1%. In total, PECO's updated proposal for the USFC offset factor is 12.1%, which represents a 1.6% increase from the Company's original proposal of 10.5%. The net impact of this change is a $3,000 reduction in PECO's revenue requirement. Lastly, the Company corrected the classification of its requested increase in residential Energy Efficiency & Conservation program costs of $350,000, which was inadvertently included in Federal Energy Regulatory Commission ("FERC") Account 407.3, to FERC Account 908. This reclassification has no impact to the Company's revenue requirement.

III. RESPONSE TO OPPOSING PARTY ADJUSTMENTS

A. Rate Base

8. Q. I&E witness Cline recommends adjustments to the Company's FPFTY claims for Materials and Supplies, Gas Storage, Customer Deposits, and Customer Advances for Construction. Does the Company agree with Mr. Cline's adjustments?

A. Yes. PECO's original claims for these four components of the Company's rate base were based on the respective thirteen-month average balance for each component as of December 31, 2023. Mr. Cline proposed adjustments to reflect the respective thirteen-month average balances as of March 2024. PECO's updated claim for Materials and Supplies is shown on Schedule C-11 of PECO Exhibit MJT-1 Revised. PECO's updated claim for Gas Storage is shown on Schedule C-13 of PECO Exhibit MJT-1 Revised. PECO's updated claim for

Customer Deposits is shown on Schedule C-7 of PECO Exhibit MJT-1 Revised. PECO's updated claim for Customer Advances for Construction is shown on Schedule C-9 of PECO Exhibit MJT-1 Revised. The net impact of these changes decreases the Company's rate base claim by approximately $11.3 million and its revenue requirement by $1.1 million.

I would also like to note that it does not appear that Mr. Keller reflected these changes in the summary of I&E's proposed adjustments that appears in his direct testimony.

B. <u>Cash Working Capital</u>

9. Q. Please describe the adjustments to PECO's CWC claim proposed by I&E and the OCA.

A. Mr. Keller and Mr. Defever propose concomitant adjustments to the Company's CWC based on proposed expense adjustments. The Company agrees that its CWC allowance should be revaluated if the Company is not awarded its full claim. The Company also adjusted its CWC claim to reflect the updated thirteen-month averages for Materials and Supplies, Gas Storage, Customer Deposits, Customer Advances for Construction, and prepaid expenses as discussed above. The Company's updated analysis is shown on Schedule C-4 of MJT-1 Revised.

C. <u>FPFTY Plant-In-Service Additions</u>

10. Q. I&E witness Cline recommends that the Company provide I&E and the OCA with updates on plant additions that PECO projects to be in service during the future test year ("FTY") and FPFTY no later than April 1, 2026, which should include actual plant additions, and retirements for the twelve

months ending December 31, 2024, and the twelve months ending December 31, 2025. Will the Company provide the requested information?

A. Yes. The Company agrees that this request is reasonable and will provide the requested information in a timely manner.

D. <u>Payroll Expense</u>

11. Q. Please respond to I&E witness Keller's and OCA witness Defever's removal of PECO's annualization adjustment for annual pay increases effective January 1, 2026 and March 1, 2026.

A. The Company's salary and wage ("S&W") increases in 2026 are known and measurable expenses that will be incurred shortly after the end of the FPFTY. In fact, PECO's current collective bargaining agreements provide for annual 2.5% wage increases through 2026. There is no reason to disallow these known and measurable costs, which PECO is contractually obligated to incur.

In addition, PECO's annualization adjustment using the non-union salary increase that will become effective March 1, 2026, includes expenses that PECO will incur for some of the period until its next gas base rate case planned to be filed in two to three years. The use of a FPFTY and annualization adjustments that reflect known and measurable S&W increases is a reasonable approach to provide PECO with a fair opportunity to earn the rate of return used to set the rates in this proceeding during the period those rates are in effect.

12. Q. Do you agree with Mr. Keller's and Mr. Defever's proposed adjustment that would eliminate recognition of the normalized cash payment to union

employees made in connection with the ratification of the Company's current collective bargaining agreements?

A. No. The Company has consistently paid a ratification bonus to union employees each time it negotiates new union contracts, which is necessary to retain PECO's talented labor pool and ensure that the Company has access to skilled union workers to meet customer and system needs. Most recently the Company paid the bonus in March 2021 upon ratification of PECO's current union contracts. Consistent with Commission practice,[1] PECO proposes to spread this expense over the length of the Company's collective bargaining agreements (i.e., six years). Thus, Mr. Keller's and Mr. Defever's proposal to disallow costs related to the union contract ratification bonus that PECO incurs on a recurring basis should be rejected.

13. Q. Did I&E and the OCA make any adjustments related to PECO's payroll tax expense?

A. Yes. Mr. Keller and Mr. Defever made concomitant adjustments to the Company's payroll tax expense based on their payroll expense recommendations. These should be rejected for the same reasons the adjustments related to the Company's payroll expenses should be rejected.

[1] *See* James H. Cawley and Norman J. Kennard, *A Guide to Utility Ratemaking* (2018) at 86 (quoting *Pa. P.U.C. v. York Water Co.*, 78 P.U.R. 3d 113, 132 (1968) ("Expenses that occur irregularly during an extended period of years, but are certain of eventual recurrence, are a legitimate charge to ratepayers. Therefore, spreading of this expense over years of recurrence is logical.")).

E. Pension and Employee Benefits Expense

14. Q. Please respond to the concomitant pension and employee benefits adjustments proposed by Mr. Defever related to his proposed vacancy adjustment.

A. The concomitant adjustments should be rejected for the reasons described in the rebuttal testimony of Company witness Marissa Humphrey in PECO Statement 2-R related to the Company's vacancy rate.

15. Q. Did Mr. Keller make any further adjustments related to pension expense?

A. Yes. Mr. Keller recommended a further reduction of approximately $572,000. The Company's FPFTY pension expense claim was based on a five-year average of contributions from 2021 through the FPFTY. Mr. Keller stated it was unreasonable to use the 2021-2025 five-year average since, in his opinion, the Company's pension contributions in 2021 and 2022 were unusually high outliers and pension contributions are declining. Instead, Mr. Keller proposed utilizing the Company's projected pension contribution for 2025.

16. Q. Why is it preferable to utilize a five-year average of the Company's pension contributions than simply relying upon the 2025 forecast?

A. The Company's pension contributions are subject to variability based on annual actuarial analyses prepared by Willis Towers Watson consistent with common practice and in accordance with ASC 715 Compensation – Retirement Benefits. Utilizing a five-year average is appropriate as the Company's actual contributions will be impacted by a number of factors, including macroeconomic factors that are beyond the Company's control.

17. Q. Please describe and respond to Mr. Keller's proposed adjustment to PECO's FPFTY budgeted amount of employee benefits expense (net of pension expense) recorded to FERC Account 926.

A. PECO's overall employee pension and benefits expense claim of $8,683,000 is shown on line 71 of Schedule D-4 of PECO Exhibit No. MJT-1 Revised. Mr. Keller's recommended allowance of $7,404,000 is based on his incorrect belief that the entirety of the Company's supported employee benefits claim net of pension expense is $7,404,000. Mr. Keller arrived at this amount by adding together the amounts on lines 19 and 23 of PECO Exhibit MJT-1, Schedule D-8, which annualizes non-pension employee benefits expense. However, Schedule D-8 only represents a subset of the employee benefits expense recorded to FERC Account 926. That schedule does not include $377,000 in other post-employment benefits ("OPEB") costs recorded in FERC Account 926 that are reflected in the Company's overall claim of $8,683,000 shown on MJT-1 Revised, Schedule D-4. The $377,000 in OPEB costs is based on studies performed by the Company's actuary, Willis Towers Watson, for the FPFTY. Mr. Keller does not provide any basis to disallow the actuarial determined amount of OPEB expense for the FPFTY. Thus, Mr. Keller improperly excluded $306,000 from the Company's FPFTY employee benefits claim.

F. <u>Rate Case Expense</u>

18. Q. Does the Company agree with I&E's or the OCA's proposed normalization periods?

A. No. PECO projects that it will need to file another rate case in two to three years, which formed the basis for the two-year normalization period the Company used in this case. Assuming a longer filing interval, as Mr. Keller and Mr. Defever do, is at odds with Company witness Marissa Humphrey's testimony (PECO Statement No. 2, p. 3) that PECO needs to invest approximately $786 million in additional gas distribution plant between January 1, 2024 and December 31, 2025. With that level of investment and even marginal year-over-year increases in operating and maintenance expenses, it is not reasonable to assume that PECO could delay a subsequent base rate filing for more than three years. Moreover, PECO's actual filing cadence since 2020 has been 24 months or shorter, filing for rate increases in September 2020, March 2022, and March 2024. Mr. Keller's inclusion of the Company's 2010 filing in calculating his proposed normalization period is unreasonable, as the Company has clearly moved to a much shorter filing cadence.

G. Unamortized Balance of the Unspent Manufactured Gas Plant ("MGP") and Federal Tax Adjustment Clause ("FTAC") Being Refunded to Customers

19. Q. What adjustment has Mr. Keller proposed to the Company's proposal to refund interest on unspent MGP funds and FTAC overcollection balances totaling $662,000 to customers over two years?

A. Mr. Keller does not disagree with the amount of interest on unspent MGP fund or FTAC overcollections that will be credited to customers. However, Mr. Keller proposes an adjustment to increase the period over which these overcollection balances are to be amortized for ratemaking purposes from two years, as the Company proposed, to 55 months. That change would reduce the annual

amortization amount refunded to customers in this case by $372,909. In support, Mr. Keller states that the 55-month period is supported by the Company's filing frequency.

20. Q. Please respond to Mr. Keller's proposed adjustment.

A. Mr. Keller's proposed 55-month amortization period should be rejected for the same reasons as I described above with respect to Mr. Keller's proposed adjustment to the Company's proposed normalization period for rate case expense.

IV. WEATHER NORMALIZATION ADJUSTMENT RIDER

21. Q. Did any parties submit testimony regarding PECO's request to establish a WNA mechanism?

A. Yes. OCA witnesses Nelson and Colton submitted testimony in opposition to the Company's proposed WNA mechanism, as did TURN/CAUSE-PA witness Marx. I&E witness Cline and OSBA witness Ewen did not oppose the WNA mechanism, but proposed certain recommendations if the WNA is approved.

22. Q. Mr. Nelson and Ms. Marx contend that the WNA unfairly shifts risk from shareholders to customers. How do you respond?

A. The WNA is a reciprocal mechanism under which customers may be entitled to a credit when actual weather is colder than normal or a surcharge when actual weather is warmer than normal. The purpose of the WNA mechanism is twofold: (i) to provide customers with more predictability in billing, which will better enable customers to budget for their bills and mitigate the impact of higher bills during severely cold months; and (ii) to stabilize PECO's revenues by providing

PECO with greater certainty to earn PUC-approved distribution revenues. This is expressly permitted by the Commission's alternative ratemaking policies and the Code.

I do not agree that the WNA unfairly shifts risk to customers since the WNA is designed to ensure that customers will only pay for, and the Company will only be able to collect, the level of revenue that is authorized by the Commission, as adjusted by the proposed deadband – no more and no less. While the Company will benefit from greater certainty in revenue when weather is warmer than normal, customers will be protected against high bills when weather is colder than normal. Thus, the WNA acts to reduce risks to both the Company and customers. The Commission has approved similar WNA mechanisms for other natural gas utilities recognizing that customers will benefit during colder than normal weather and utilities will benefit from stabilized cash flows.

23. Q. Mr. Nelson also states that the WNA impermissibly shifts climate change risk to customers. Do you believe that is true?

A. No. The WNA will address short-term variability from the Company's weather normal assumptions since actual weather will always vary to some degree from those assumptions. But as I explained above, this is not an unfair transfer of risk to customers since the Company and its customers will mutually benefit from the WNA.

In addition, as I explained in my direct testimony, the WNA is designed to allow the Company to recover the actual amount of revenues that its rates are designed to produce based upon the Company's sales projections. Those sales projections

are based on weather normals, which are developed utilizing 30-year averages updated on an annual basis. PECO's weather normals, by design, take into account the most recent climate data in forecasting sales and usage and anticipated heating degree days ("HDDs"). Thus, the WNA already takes into account evolving temperatures.

24. Q. Mr. Nelson also stated that applying the WNA to only PECO's gas operations shifts climate risk to PECO's electric customers. Do you agree?

A. No. As noted above, I do not believe the WNA shifts any risk to customers. In addition, Mr. Nelson's position that the Company should automatically also implement a WNA for its electric operations is unreasonable and unsupported. The Company did in fact consider proposing a comparable WNA for its electric operations but determined that such a mechanism is not feasible. Implementation of the WNA requires establishing a base load. PECO is able to do so for its gas customers by analyzing usage during summer months when HDDs are close to zero. However, the Company is not able to similarly isolate a base load for electric customers since customers' electric usage is impacted by both cooling degree days ("CDDs") and HDDs. There is no single month where both CDDs and HDDs are close to zero.

25. Q. Mr. Nelson contends that the WNA should be "complemented by robust regulatory changes." Please respond.

A. The Commission has already evaluated decoupling mechanisms in a broader regulatory context. The Commission conducted a robust regulatory proceeding to consider alternative ratemaking in general and decoupling in particular. *See*

Docket No. M-2015-2518883; 66 Pa. C.S. § 1330. The Commission ultimately established a framework through which utilities may seek alternative rate mechanisms, which the Company has complied with in this proceeding.

26. Q. Mr. Nelson critiques the Company's revenue analysis, stating that it was applied at the class level while the Company proposes to apply the WNA at the customer-level. How do you respond?

A. The Company believes that its revenue analysis is reasonable and consistent with the level of analysis provided by other utilities to the Commission prior to receiving PUC approval of comparable WNA mechanisms. Mr. Nelson criticizes the Company's revenue analysis for being conducted at the class level, but he provides no support that a customer-level analysis would provide more accurate data than the Company's class-level analysis.

27. Q. How do you respond to Mr. Nelson's assertion that the WNA will result in surcharges on residential customers, and that those surcharges are likely to be larger than WNA credits since extreme warm weather has been more common than extreme cold weather?

A. The data relied upon by Mr. Nelson shows that no two years' actual weather was the same. Furthermore, the Company's weather normals will be updated annually based on rolling 30-year historical averages. In addition, the Company's proposal is consistent with alternative ratemaking mechanisms that have been approved by the Commission and it is important to recognize that the purpose of the WNA mechanism is to ensure that customers will only pay for, and the Company will

only be able to collect, the level of revenue that is authorized by the Commission, as adjusted by the proposed deadband.

28. Q. Please address Mr. Nelson's comments regarding the Company's use of a 3-year average to define "normal" weather within the WNA.

A. There was a typographical error in the Company's initial filing. The reference to a "3-year average" in the Company's proposed WNA tariff provisions should have been to a "30-year average."

29. Q. Mr. Nelson asserts that the Company should be evaluating climate change's impact on its business and regulatory model, and that the Commission should require comprehensive action related to gas utility planning processes. Specifically to PECO, Mr. Nelson recommends that the Commission require the Company "to explicitly and transparently evaluate and incorporate climate change risk into the Company's load forecasting and planning processes." Do you believe that Mr. Nelson's recommendation is appropriate?

A. No. This is not the proper forum to address broader policy questions like climate change and the natural gas utility business model. If the Commission determines that these issues should be addressed, it should be in a generic proceeding involving all natural gas utilities in the Commonwealth, not just PECO. In addition, as noted above, the WNA relies upon the Company's weather normal assumptions, which are based on 30-year averages updated on an annual basis. Neither Mr. Nelson nor any other witness expressed any concern regarding the Company's use of 30-year weather normals or PECO's forecasting process.

30. Q. Mr. Nelson recommends that if the Commission approves the Company's WNA, the Commission require PECO to update its most recent long-term infrastructure improvement plan ("LTIIP"). Does the Company agree with these recommendations?

A. Absolutely not. Mr. Nelson's proposals are inconsistent with the purpose of the Company's LTIIP, which is to replace infrastructure on an accelerated basis to enhance safety and reliability – not to expand the Company's gas distribution system.

31. Q. Mr. Nelson concluded that the Commission's policy statement at Docket No. M-2015-2518883 weighs against the WNA. Do you agree?

A. No. I believe the analysis set forth in pages 74-79 of my direct testimony is correct and that consideration of the 14 factors described in the Commission's policy statement supports approval of the WNA. I address Mr. Nelson's comments, briefly, as follows:

(1) As described in my direct testimony, PECO does have certain costs that are fixed and others that are variable. I disagree with Mr. Nelson that fixed costs are "poorly defined" and that "all costs are variable in the longer." Nor is the WNA duplicative or unnecessary. The WNA is needed for the reasons I have already described and will not result in the collection of any revenues other than revenues already authorized by the Commission.

(2) The WNA will not impact capacity utilization, and Mr. Nelson did not dispute this statement.

(3) Customer consumption is taken into account when forecasting customer usage and will be continuously updated. I disagree with Mr. Nelson's conclusion that PECO did not adequately define or analyze customers' anticipated consumption levels. This is simply not true for the reasons set forth herein and in my direct testimony.

(4) Mr. Nelson has provided no evidence to contradict my conclusion that the WNA will mitigate the potential for interclass or intraclass cost shifting related to weather-driven usage variances from those weather assumptions used in establishing rates.

(5)-(6) The WNA does not disincentivize energy efficiency programs. Customers will still benefit from making efficiency investments. PECO also disagrees that the WNA will make bills and savings confusing.

(7) The WNA will not impact customers enrolled in PECO's customer assistance program. Mr. Nelson did not support his conclusory statements that the WNA will harm low-income customers.

(8) Mr. Nelson did not support his conclusory statements that the WNA could increase volatility and make budgeting more challenging, or that budget billing addresses volatility and stability better than the WNA. The Company disagrees with Mr. Nelson. Customers are provided with the least volatility and the most stability with a combination of the WNA and budget billing.

(9) The intent of the WNA is to reduce the impact of weather variability from the Company's projected weather normal assumptions, which are based on 30-year

historical averages. The Company considered utilizing 10- and 20-year weather normals as well. The Company does not believe 10 years provides a large enough data set, and there is little variation between utilizing 20 years of data versus 30 years. The Company believes that utilizing 30 years is appropriate.

(10) Mr. Nelson did not contradict the Company's conclusion that the WNA is not anticipated to impact the frequency of rate cases or impact regulatory lag.

(11) Mr. Nelson did not contradict the Company's conclusions regarding how the WNA will interact with other revenue sources.

(12) The Company described numerous consumer protections built into the design of the WNA, which Mr. Nelson ignores.

(13) Mr. Nelson did not support his conclusory statement that the WNA will be challenging for customers to understand. The Company believes the WNA is understandable for the reasons set forth in my direct testimony.

(14) The WNA is addressing short-term variability in weather, not climate change. The WNA will support improvements in reliability by ensuring that PECO is better able to recover its approved revenue requirement.

32. Q. Do you agree with Mr. Nelson's concern about the inclusion of shoulder months in the WNA mechanism and how weather unpredictability in those months might impact bill predictability and stability?

A. While Philadelphia Gas Works ("PGW") did experience a high WNA surcharge in May 2022, to PECO's knowledge, no other Pennsylvania utility with a WNA has experienced any issue associated with the inclusion of shoulder months in its

WNA design. Nevertheless, the Company is willing to explore modifying its proposed WNA mechanism to further enhance customer protections, such as including a cap on adjusting May bills under the WNA.

33. Q. Do you agree with Mr. Nelson's and Mr. Colton's conclusion that budget billing (as opposed to the WNA) would be more effective at allowing billing predictability and stability for customers and would smooth out large winter bills?

A. No. Mr. Nelson and Mr. Colton both analyze the WNA and budget billing as if PECO, the Commission, and customers need to pick one or the other. The Company disagrees that budget billing will be more effective than a WNA, but the best option for smoothing predictability would be a combination of the WNA and budget billing.

The amount a customer will owe under budget billing will be determined by 12 months of actual bills. That amount is updated on a quarterly basis, along with a "catch-up" reconciliation. Therefore, budget billing will be impacted by variations in weather, which will be reflected in the budget billing amount and catch-up amount. Application of the WNA, combined with budget billing, would reduce variability in customer bills due to weather and provide customers with even greater bill stability than budget billing alone.

34. Q. Please address Mr. Nelson's concern that the Company's proposed deadband is too small, and Mr. Cline's proposal to utilize a 3% deadband.

A. The deadband by nature is an arbitrary figure because the purpose of alternative rate recovery tools like the WNA is to allow the utility to recover an amount that

the Commission has approved. For this reason, it is appropriate for the Company to apply a 1% deadband for the WNA surcharge calculations.

35. Q. Please address Mr. Nelson's claim that the WNA will decrease affordability, and Ms. Marx's and Mr. Colton's claim that the WNA will disproportionately impact low-income customers and deprive low-income customers with the ability to decrease their bills by reducing usage.

A. The Company does not anticipate that the WNA will impact affordability or otherwise disproportionately impact low-income customers. Low-income customers not enrolled in the Company's CAP will not be treated differently than any other residential customer. All low-income customers will also benefit from greater billing predictability and, as noted above, the combination of the WNA and budget billing is expected to provide greater stability than either the WNA or budget billing on its own. Low-income customers enrolled in the Company's CAP will also continue to receive bill discounts based on affordability under PECO's percentage of income payment plan ("PIPP") and, therefore, will not be impact by the proposed WNA mechanism. In addition, customers will still be incentivized to, and can benefit from, reduced usage since reductions will reduce the customer's overall bill, including the portion that is subject to the WNA mechanism and the amount of WNA. Moreover, PECO will only be entitled to earn its Commission-approved revenue requirement, and the WNA will protect customers against larger bills in colder-than-normal months.

36. Q. How do you respond to Mr. Colton's statement that the exclusion of CAP customers from the customer classes to whom or to which the WNA would

apply would prevent double-recovery of WNA charges from non-CAP customers?

A. I disagree with Mr. Colton's contention that there would be any double recovery from non-CAP customers under the Company's current proposal. As noted in my prior response, PECO will only be entitled to earn its Commission-approved revenue requirement, and any CAP "shortfall" will continue to be recovered as approved by the Commission and as described in the direct testimony of Company witness Golden (PECO Statement No. 10). The Company will be entitled to recover its Commission-approved revenues if weather is warmer than normal and customers will be protected in the event that weather is colder than normal.

Under the Company's proposal, this remains true for the aggregate amount of revenues collected from non-CAP customers through billed amounts for CAP costs and USFC recovery. If weather is colder than normal, the WNA will be applied to CAP customer bills before CAP credits are applied, and to non-CAP customer bills. This will true-up the amount that non-CAP customers are responsible for under actual weather to the amount that non-CAP customers would have been responsible for under normal weather and Commission-approved rates.

Under the OCA's proposal, excluding CAP customers from application of the WNA will increase the amount of CAP credits necessary to keep CAP customer bills at the required affordable level, thereby increasing the aggregate amount that non-CAP customers will be responsible for. Thus, the OCA's proposal will

eliminate a portion of the WNA benefits provided to non-CAP customers when weather is colder than normal, and result in over-recovery by the Company. Conversely, when weather is warmer than normal, OCA's proposal will result in a greater USFC credit to non-CAP customers than under Commission-approved rates, resulting in under-recovery by the Company.

In either case, the OCA's proposal would undermine the goal of the WNA of aligning PECO's revenue recovery with Commission-approved revenues, and fully insulating both CAP and non-CAP customers from rate increases in the event of colder than normal weather.

37. Q. Do you agree with Mr. Colton that the WNA will likely increase customer bills and, therefore, the amount of customer arrears?

A. No. As stated earlier in my testimony, the WNA is a reciprocal mechanism. Customers will benefit from credits when the actual weather is colder than normal. Furthermore, the WNA is designed to ensure the Company collects the amount of revenues approved by the Commission – no more. Mr. Colton has not explained why arrears would increase, or demonstrated that they will increase, if the WNA is approved.

38. Q. Mr. Cline recommended that if the Commission approves the WNA, the Company provide annual reporting of its WNA results. Is the Company willing to provide the requested data?

A. The Company does not oppose this recommendation.

39. Q. Mr. Ewen recommended that the Company's WNA be modified such that the WNA not apply when actual HDDs for a billing period are below 100 HDDs.

He also recommended that the Company develop a process for monitoring customers' implied heating usage per degree day, to determine whether the Company's use of a residual approach for deriving the heat sensitive load is producing wide variations in assumed heat sensitive load per degree day. Does the Company agree with these recommendations?

A. No. Mr. Ewen has not provided any support for either of these recommendations. Mr. Ewen's proposed 100 HDD cutoff is arbitrary and is solely supported by Mr. Ewen's observations with respect to PGW and the Normal Weather Adjustment mechanism of Liberty Utilities in New Hampshire ("Liberty"). In response to a PECO discovery question asking the OSBA to support his 100 HDD proposal, Mr. Ewen noted that "OSBA is open to alternative limits to 100 if the Company can provide evidence that application of the WNA will not produce large multipliers and bills for ratepayers." Yet Mr. Ewen has not provided any evidence that the WNA will produce large multipliers and bills for PECO's customers. While PGW did experience issues in May 2022, no other Pennsylvania gas utility with an approved WNA has experienced a similar issue. Furthermore, Liberty's service territory is hundreds of miles north of PECO's gas service territory and OSBA has not provided any evidence as to why PECO's WNA should align with Liberty's Normal Weather Adjustment mechanism. While the Company is willing to explore modifying its proposed WNA mechanism to further enhance customer protections, such as including a cap on adjusting May bills under the WNA, the 100 HDD cap proposed by Mr. Ewen is not reasonable or supported. Similarly, Mr. Ewen has not provided any support

for his recommendation that PECO develop a process for monitoring customers' implied heating usage per degree day.

40. Q. Do you agree with Mr. Ewen's recommendation that the Commission consider the risk reduction benefits of any WNA it approves in evaluating the Company's cost of capital claim?

A. No. As addressed in the direct testimony of Company witness Paul Moul (PECO Statement No. 5), the other members of PECO's proxy group already have decoupling mechanisms resembling the WNA. If the WNA is approved, PECO's risk will become more consistent with others in its proxy group.

41. Q. Mr. Ewen encouraged the Company to adopt communication strategies to explain how the WNA works, its impact on ratepayers in unusually cold and unusually warm months, and on unusually cold years and unusually warm years. Does the Company agree with the OSBA's recommendations?

A. The Company agrees, and it intends to conduct communication and outreach efforts consistent with the programs implemented by other Pennsylvania utilities after approval of a WNA mechanism. The Company provided notice to customers of its proposed WNA as noted in the Section 53.52 Filing Requirements and customer bill insert advising customers of this rate case proceeding. Upon receipt of final approval of the WNA, the Company will finalize its customer communication and outreach strategies. This will include customer notification of Commission approval of the WNA. PECO will provide customers with a bill insert describing the implementation of the WNA and provide customers with instructions to access further information regarding the

WNA on the Company website. PECO's website will also include a description of the WNA and its implementation, as well as "frequently asked questions" to educate customers. In addition, customer electronic and printed bills will be updated to include a separate line item in the delivery charge section to list the WNA amount (which will appear as a credit or surcharge). Furthermore, PECO will implement additional WNA-specific training for call center representatives to ensure that they have the necessary tools available to walk a customer through how a WNA amount on a bill was calculated.

Finally, the Company will continue to monitor customer feedback following implementation of the WNA mechanism and its initial communication efforts and PECO will modify its communications and outreach materials, if necessary, to support customer understanding of the WNA mechanism.

V. OFFSET FACTORS IN THE UNIVERSAL SERVICE FUND CHARGE

42. Q. Have any parties opposed PECO's proposal to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%?

A. Yes. Mr. Colton claims that PECO did not justify leaving the working capital component of the USFC factor at 5% while updating the uncollectible expense component established in 2008 by the DSP Settlement. According to Mr. Colton, the increase in the level of arrears leading to bad debt write-offs since the DSP Settlement would support a working capital offset of 20%.

Mr. Colton also contends that PECO's proposal to lower the bad debt component of the USFC offset factor from 22% to 5.5% based on the difference between the

three-year average (2021-2023) uncollectible rate for CAP customers and all residential customers artificially reduces the offset factor because of the impact of the COVID-19 pandemic on collections in 2021. Ms. Golden addresses Mr. Colton's objections to PECO's proposed update to the bad debt offset percentage in PECO Statement No. 10-R.

43. Q. Do you agree with Mr. Colton that the working capital component of the USFC offset factor should be updated if the Commission approves PECO's proposed changes to the bad debt offset percentage?

A. In part. I agree that PECO should update both components of the USFC offset factor with current data. However, I disagree with Mr. Colton's assertion that the 5% should be increased by 400% to 20%. Mr. Colton's position is based on his allegation that the level of residential arrears has quadrupled since the DSP Settlement in 2008. While it is true that the dollar amount of PECO's residential arrears have increased by 49% since 2008, the level of those arrears is impacted by many variables in addition to participation in CAP, such as write-offs, revenues, the economy, weather, and demographics. Contrary to Mr. Colton's assertion, the calculations underlying the working capital adjustment in the DSP Settlement were not based on three-year average residential customer arrears. The basis for those calculations was the methodology recommended by the OCA in PECO's 2008 gas rate case using the age of residential arrears at charge-offs based on data at that time ("2008 OCA Methodology"). As shown on PECO Exhibit MJT-4, employing PECO's current data on incremental age of arrears at charge-off in the 2008 OCA methodology results in a CWC offset percentage of

5.0%. Accordingly, it is appropriate to maintain the current offset percentage for working capital as PECO initially proposed.

VI. CONCLUSION

44. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

UPDATE 07-16-24

PECO Gas Operations
Before The PAPUC
FPFTY Ending Dec.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	$4,630,050		$4,630,050
3	Accumulated Depreciation	C-3	1,022,690		1,022,690
4	Common Plant - Net of Accum Depr	C-8	190,266		190,266
5	Net Plant in service	L2 - L3 + L4	$3,797,627		$3,797,627
6					
7	Working Capital	C-1	$13,764		$13,764
8	Accum Deferred Income Taxes	C-1	(220,306)		(220,306)
9	Customer Deposits	C-1	(13,830)		(13,830)
10	Customer Advances for Construction	C-1	(1,352)		(1,352)
11	Materials and Supplies	C-1	2,572		2,572
12	Accum Deferred Income Taxes - Reg Liability	C-1	(111,469)		(111,469)
13	Gas Storage	C-1	45,697		45,697
14					
15	TOTAL RATE BASE	SUM L5 to L13	$3,512,702		$3,512,702
16					
17	**OPERATING REVENUES AND EXPENSES**				
18	Base Customer Charges	D-5	$481,985	$110,016	$592,001
19	Supply Cost Revenue	D-5	260,915		260,915
20	Other Operating Revenues	D-5	3,549	178	3,726
21	Total Revenues	SUM L18 to L20	$746,448	$110,194	$856,642
22					
23	Operating Expenses	D-1	$556,472	$746	$557,217
24					
25	OIBIT	L21 - L23	$189,977	$109,448	$299,425
26					
27	Income Taxes @ Eff Inc Tax Rate	D-18	$14,294		$14,294
28	Income Taxes @ Statutory Rates	D-18		(29,893)	(29,893)
29					
30	NET OPERATING INCOME	SUM L25 to L28	$204,271	$79,555	$283,826
31					
32	RATE OF RETURN	L30 / L15	5.82%		8.08%
33					
34	**REVENUE INCREASE REQUIRED**				
35	Rate of Return at Present Rates	L32	5.82%		
36					
37	Rate of Return Required	B-7	8.08%		
38					
39	Change in ROR	L37 - L35	2.26%		
40					
41	Change in Operating Income	L15 * L39	$79,555		
42					
43	Gross Revenue Conversion Factor	D-19	1.383		
44					
45	Change in Revenues	L41 * L43	$110,016		
46					
47	**RETURN ON COMMON EQUITY**				
48	Common Equity Ratio	B-7	53.40%		
49	Common Equity Rate Base	L15 * L48	$1,875,783		
50	NET OPERATING INCOME	L30	$204,271		
51	Synchronized Interest Expense	D-18	$74,821		
52	NET OPERATING INCOME - COMMON EQUITY	L50 - L51	$129,450		
53	RATE OF RETURN ON COMMON EQUITY	L52 / L49	6.90%		

Line No.	Description	(1) Reference	(2) Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$20,046,501
3	Construction Work In Progress (107)		675,361
4	Total Utility Plant	SUM L2 to L3	$20,721,862
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,007,444
6	Net Utility Plant	L4 - L5	$15,714,417
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,448
11	Invest in Assoc Company (123)		7,725
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$45,204
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$25,000
17	Customer Accounts Receivable (142)		442,289
18	Other Accounts Receivable (143)		35,649
19	Accum. Prov. for Uncollectible (144)		(83,303)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		38,067
22	Plant Materials & Supplies (154)		69,125
23	Prepayments (165)		20,632
24	Accrued Utility Revenues (173)		215,498
25	Miscellaneous Current & Accrued Assets (174)		87,744
26	Total Current and Accrued Assets	SUM L16 to L25	$850,700
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$54,014
30	Other Regualtory Assets (182.3)		1,123,689
31	Miscellaneous Deferred Debits (186)		744,592
32	Unamortized Loss on Reacquired Debt (189)		636
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,922,930
35			
36	**Total Assets**	L6 + L13 + L26 + L34	$18,533,252

Line No.	Description	(1) Reference	(2) Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,703,533
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,418,361
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$7,544,811
46			
47	**Long Term Debt**		
48	Bonds (221)		$6,400,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(21,980)
53	Total Long-Term Debt	SUM L48 to L52	$6,562,439
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,528
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,430
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$153,029
65	Accounts Payable (232)		648,728
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(926)
70	Interest Accrued (237)		73,493
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		183,156
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,172,554
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		282,725
80	Deferred Investment Tax Credit (255)		286
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,577,039
83	Total Other Deferred Credits	SUM L77 to L82	$2,870,018
84			
85	**Total Liabilities and Other Credits**	L45 + L53 + L61 + L74 + L83	$18,533,252

Line No.	Category	Description	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$479,981		$479,981
2		Gas Cost Revenue	260,915		260,915
3		Other Operating Revenues	18,549		18,549
4		Total Operating Revenues	$759,445		$759,445
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$437,992		$437,992
7		Depreciation & Amortization Expense	110,058		110,058
8		Amortization of Regulatory Expense	649		649
9		Taxes Other Than Income Taxes - Other	8,923		8,923
10		Total Operating Expenses	$557,622		$557,622
11					
12	**Net Utility Operating Income Before Income Tax**		$201,823		$201,823

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$326,750		$326,750
2			C & I	481.0	123,263		123,263
3			Transportation of Gas of Others	489.3	29,969		29,969
4				Subtotal	$479,981		$479,981
5							
6		Gas Cost Revenue	Residential	480.0	$193,890		$193,890
7			C & I	481.0	67,025		67,025
8			Interdepartmental	484.0			
9				Subtotal	$260,915		$260,915
10							
11		Other Operating Revenues	Sales For Resale	483.0	$15,000		$15,000
12			Forfeited Discounts	487.0	1,329		1,329
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	1,703		1,703
15			Interdepartmental Rents	494.0			
16			Other Gas Revenues	495.0	517		517
17				Subtotal	$18,549		$18,549
18							
19				**Total Operating Revenues**	$759,445		$759,445
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0	$7		$7
22			Liquefied Petroleum Gas Expenses	717.0	127		127
23			Liquefied Petroleum Gas Expenses	728.0	0		0
24			Maintenance of Structures and Improvements	741.0	85		85
25			Maintenance of Production Equipment	742.0	211		211
26			Natural Gas City Gate Purchases	804.0	272,165		272,165
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1			
29			Purchased Gas Expenses	807.0	17		17
30			Gas Withdrawn from Storage-Debit	808.1			
31			Gas Delivered to Storage-Credit	808.2			
32			Other Gas Supply Purchases	813.0			
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	357		357
35			Operation Labor and Expenses	841.0	914		914

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	1,026		1,026
37			Maintenance of Structures and Improvements	843.2	3,950		3,950
38			Operation Supervision and Engineering	870.0	538		538
39			Mains and Services Expenses	874.0	18,799		18,799
40			Measuring and Regulating Station Expenses-General	875.0	1,862		1,862
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	7,562		7,562
43			Customer Installations Expenses	879.0	7,959		7,959
44			Other Expenses	880.0	19,796		19,796
45			Rents	881.0	21		21
46			Maintenance of Mains	887.0	26,329		26,329
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,512		1,512
48			Maintenance of Services	892.0	2,821		2,821
49			Maintenance of Meters & House Regulators	893.0	238		238
50			Maintenance of Other Equipment	894.0	676		676
51			Meter Reading	902.0	163		163
52			Customer Records and Collection	903.0	20,395		20,395
53			Uncollectible Accounts	904.0	2,679		2,679
54			Miscellaneous Customer Accounts	905.0	846		846
55			Customer Assistance	908.0	7,171		7,171
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	53		53
58			Demonstrating & Selling	912.0	764		764
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	6,973		6,973
61			Office Supplies and Expenses	921.0	1,197		1,197
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	17,810		17,810
64			Property Insurance	924.0	148		148
65			Franchise Requirements	925.0	405		405
66			Employee Pensions and Benefits	926.0	7,676		7,676
67			Regulatory Commission Expenses	928.0	2,566		2,566
68			Duplicate Charges-Credit	929.0	(7)		(7)
69			Miscellaneous General Expenses	930.2	828		828
70			Maintenance of General Plant	932.0	1,008		1,008

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
71				Subtotal	$437,992		$437,992
72							
73			Depreciation & Amortization Expense	403.0	$94,862		$94,862
74				403.1			
75				404.0	15,195		15,195
76				Subtotal	$110,058		$110,058
77							
78			Amortization of Regulatory Expense	407.3	$649		$649
79				Subtotal	$649		$649
80							
81			Taxes Other Than Income Taxes - Other	408.1	$8,923		$8,923
82				Subtotal	$8,923		$8,923
83							
84			**Total Operating Expenses**		$557,622		$557,622
85							
86			**Net Utility Operating Income Before Income Tax**		$201,823		201,823

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$326,750		$326,750
2			C & I	481.0	123,263		123,263
3			Transportation of Gas of Others	489.3	29,969		29,969
4				Subtotal	$479,981		$479,981
5							
6		**Gas Cost Revenue**	Residential	480.0	$193,890		$193,890
7			C & I	481.0	67,025		67,025
8			Interdepartmental	484.0			
9				Subtotal	$260,915		$260,915
10							
11				OPERATING REVENUE	$740,896		$740,896
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$15,000		$15,000
14			Forfeited Discounts	487.0	$1,329		1,329
15			Miscellaneous Service Revenues	488.0			
16				Subtotal	$16,329		$16,329
17							
18		**Other Gas Revenue**	Rent for Gas Property	493.0	$1,703		1,703
19			Interdepartmental Rents	494.0			
20			Other Gas Revenues	495.0	517		517
21				Subtotal	$2,220		$2,220
22							
23				OTHER REVENUE	$18,549		$18,549
24							
25				OTHER OPERATING REVENUES			
26							
27				**TOTAL**	**$759,445**		**$759,445**

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	Budget FPFTY	Non-Jurisdictional	Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0	$7		$7
2			Liquefied Petroleum Gas Expenses	717.0	127		$127
3			Maintenance of Structures and Improvements	741.0	85		85
4			Maintenance of Production Equipment	742.0	211		211
5				SUM L1 to L4	$430		$430
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	0		0
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$272,165		$272,165
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1			
12			Purchased Gas Expenses	807.0	17		17
13			Gas Withdrawn from Storage-Debit	808.1			
14			Gas Delivered to Storage-Credit	808.2			
15			Other Gas Supply Purchases	813.0			
16				SUM L9 to L15	$272,182		$272,182
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$357		$357
21			Operation Labor and Expenses	841.0	914		914
22				SUM L20 to L21	$1,270		$1,270
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$1,026		$1,026
25			Maintenance of Structures and Improvements	843.2	3,950		3,950
26				SUM L24 to L25	$4,975		$4,975
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$6,246		$6,246
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$538		$538
31			Mains and Services Expenses	874.0	18,799		18,799
32			Measuring and Regulating Station Expenses-General	875.0	1,862		1,862
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	7,562		7,562
35			Customer Installations Expenses	879.0	7,959		7,959
36			Other Expenses	880.0	19,796		19,796
37			Rents	881.0	21		21
38				SUM L30 to L37	$56,537		$56,537
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$26,329		$26,329
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,512		1,512
42			Maintenance of Services	892.0	2,821		2,821
43			Maintenance of Meters & House Regulators	893.0	238		238
44			Maintenance of Other Equipment	894.0	676		676
45				SUM L40 to L44	$31,577		$31,577

Line No.	Category	Description	Description	Account	(1) Budget FPFTY	(2) Non-Jurisdictional	(3) Jurisdictional
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$88,114		$88,114
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$163		$163
50			Customer Records and Collection	903.0	20,395		20,395
51			Uncollectible Accounts	904.0	2,679		2,679
52			Miscellaneous Customer Accounts	905.0	846		846
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$24,083		$24,083
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$7,171		$7,171
56			Informational & Instructional	909.0	345		345
57			Miscellaneous Customer & Informational	910.0	53		53
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$7,569		$7,569
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$764		$764
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$764		$764
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$6,973		$6,973
65			Office Supplies and Expenses	921.0	1,197		1,197
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	17,810		17,810
68			Property Insurance	924.0	148		148
69			Injuries & Damages	925.0	405		405
70			Employee Pensions and Benefits	926.0	7,676		7,676
71			Regulatory Commission Expenses	928.0	2,566		2,566
72			Duplicate Charges-Credit	929.0	(7)		(7)
73			Miscellaneous General Expenses	930.2	828		828
74				SUM L64 to L73	$37,596		$37,596
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$1,008		$1,008
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$38,604		$38,604
79							
80			**Total**	Lines 5+10+16+28+48+54+59+63+79	$437,992		$437,992
81							
82			Total Operations Expense		$400,432		$400,432
83			Total Maintenance Expense		37,560		37,560
84			**Total O&M Expense**	L82 + L83	$437,992		$437,992

Line No.	Description	(1) Total	(2) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076	$2,076
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	732	732
4	Real Estate Tax Accrual	1,796	1,796
5	Miscellaneous TOTI		
6	Payroll Tax Accrued	4,319	4,463
7	**Total**	$8,923	$9,067

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
			(1)	(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025						
2								
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		$75,000		6.00%		
4					1.14%		0.07%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					4.56%		0.28%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.66%		0.15%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					3.80%		0.19%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					4.56%		0.19%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					4.94%		0.19%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					9.87%		0.40%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					4.94%		0.15%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.32%		0.15%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					5.70%		0.18%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					5.70%		0.17%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.32%		0.25%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					6.45%		0.29%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					8.73%		0.44%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					8.73%		0.48%	
33		PECO - FMB - $975 - 5.46% - Due 9-1-55		975,000		5.53%		
34					14.81%		0.82%	
35								
36		Sub-Total Mortgage Bonds	SUM L1 to L35	$6,400,000	97.20%		4.40%	
37								
38	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
39					1.22%		0.09%	
40		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
41					0.01%			
42		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
43					1.57%		0.09%	
44								
45		Sub-Total Capital Securities	SUM L38 to L43	$184,419	2.80%		0.18%	
46								
47		Total Long-Term Debt	L36 + L45	$6,584,419	100.00%		4.58%	
48								
49		Adjustments for Tenders & Calls		(521)				
50								
51		Net Long-Term Debt	L47 + L49	$6,583,898				
52								
53		Annualized Cost		301,566				
54								
55		Adjustment for Tenders & Calls Reacquired		68				
56								
57		**Total**	L53 + L55	$301,634				4.58%

Line No.	Description	(1) Capitalization	(2) Capitalization Ratio	(3) Embedded Cost	(4) Return %
1					
2	Long-Term Debt	$6,583,898	46.60%	4.58%	2.13%
3					
4	Common Equity	7,544,811	53.40%	11.15%	5.95%
5					
6	Total	$14,128,708	100.00%		8.08%

Line No.	Description	Reference	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	Utility Plant	C-2	$4,630,050		$4,630,050
2	Accumulated Depreciation	C-3	1,022,690		1,022,690
3	Common Plant	C-8	190,266		190,266
4	**Net Plant in Service**	L1 - L2 + L3	$3,797,627		$3,797,627
5					
6	Working Capital	C-4	$13,764		$13,764
7	Accumulated Deferred Income Taxes	C-6	(220,306)		(220,306)
8	Customer Deposits	C-7	(13,830)		(13,830)
9	Customer Advances for Construction	C-9	(1,352)		(1,352)
10	Material & Supplies	C-11	2,572		2,572
11	ADIT - Reg Liability	C-12	(111,469)		(111,469)
12	Gas Storage	C-13	45,697		45,697
13	**Total Measures of Value**	SUM L4 to L12	$3,512,702		$3,512,702

Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
			(1)	(2)	(3)	(4)
1	**Intangible Plant**	G302 - Franchises & Consents		$50		$50
2		G303 - Intangible Property		16,356		16,356
3		Subtotal	SUM L1 to L2	$16,406		$16,406
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.		14,334		14,334
7		Subtotal	SUM L5 to L6	$15,559		$15,559
8						
9	**Other Storage Plant**	G360 - Land and Land Rights		$16		$16
10		G361 - Structures & Improvements		14,932		14,932
11		G362 - Gas Holders		7,084		7,084
12		G363 - Gas Storage Equipment		171,597		171,597
13		Subtotal	SUM L9 to L12	$193,629		$193,629
14						
15	**Distribution Plant**	G374 - Land and Land Rights		$3,915		$3,915
16		G375 - Structures and Improvements		16,785		16,785
17		G376 - Gas Mains		2,369,836		2,369,836
18		G378 - Measure & Regulate Sta Equip		26,029		26,029
19		G379 - City Gate Station		61,468		61,468
20		G380 - Services		1,417,248		1,417,248
21		G381 - Meters		179,005		179,005
22		G382 - Meter Installations		291,268		291,268
23		G387 - Other Equipment		2,084		2,084
24		G388 - ARO Costs Distribution Plt		884		884
25		Subtotal	SUM L15 to L24	$4,368,523		$4,368,523
26						
27	**General Plant**	G390 - Structures & Improvements		$11,508		$11,508
28		G391 - Office Furniture & Equipment		1,783		1,783
29		G394 - Tools, Shop & Garage Equip		16,536		16,536
30		G395 - Laboratory Equipment		69		69
31		G397 - Communication Equipment		5,786		5,786
32		G398 - Miscellaneous Equipment		127		127
33		G399.1 - ARO Costs General Plt		125		125
34		Subtotal	SUM L27 to L33	$35,933		$35,933
35						
36		**Total**	Lines 3+7+13+25+34	$4,630,050		$4,630,050

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	$4,799
2		Subtotal Intangible Plant	$4,799
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	31,641
12		Subtotal Other Storage Plant	$31,641
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	$496
16		G376 - Gas Mains	254,277
17		G378 - Measure & Regulate Station Equipment	843
18		G379 - City Gate Station	7
19		G380 - Services	108,581
20		G381 - Meters	5,601
21		G382 - Meter Installations	20,657
22		G387 - Other Equipment	
23		Subtotal Distribution Plant	$390,462
24			
25	**General Plant**	G390 - Structures & Improvements	$521
26		G391 - Office Furniture & Equipment	329
27		G394 - Tools, Shop & Garage Equipment	930
28		G395 - Laboratory Equipment	16
29		G397 - Communication Equipment	489
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	$2,285
32			
33		Total	$429,186

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	($5,597)
2		Subtotal Intangible Plant	($5,597)
3			
4	**Manufactured Gas Proc**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	($57)
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	(1,443)
12		Subtotal Other Storage Plant	($1,500)
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	($36)
16		G376 - Gas Mains	(8,737)
17		G378 - Measure & Regulate Station Equipment	(110)
18		G379 - City Gate Station	(41)
19		G380 - Services	(6,171)
20		G381 - Meters	(458)
21		G382 - Meter Installations	(841)
22		G387 - Other Equipment	(7)
23		G388 - ARO Costs Distribution Plant	(0)
24		Subtotal Distribution Plant	($16,402)
25			
26	**General Plant**	G390 - Structures & Improvements	($3)
27		G391 - Office Furniture & Equipment	(1,050)
28		G394 - Tools, Shop & Garage Equipment	(278)
29		G397 - Communication Equipment	(301)
30		G398 - Miscellaneous Equipment	
31		G399.1 - ARO Costs General Plant	(3)
32		Subtotal General Plant	($1,635)
33			
34		Total	($25,134)

PECO Gas Operations
Before The PAPUC
FPFTY Ending December 2025
($ in Thousands)
C-2 Plant Pro Forma Adjustments

Line No.	Description	Account	(1) FPFTY 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**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	16,356	100.00%	16,356	100.00%	16,356	
5			$16,356		$16,356		$16,356	
6								
7		Subtotal	**$16,406**		**$16,406**		**$16,406**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,334	100.00%	$14,334	100.00%	$14,334	
13			$14,334		$14,334		$14,334	
14								
15		Subtotal	**$15,559**		**$15,559**		**$15,559**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$14,932	100.00%	$14,932	100.00%	$14,932	
21			$14,932		$14,932		$14,932	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$171,597	100.00%	$171,597	100.00%	$171,597	
27			$171,597		$171,597		$171,597	
28								
29		Subtotal	**$193,629**		**$193,629**		**$193,629**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$3,915	100.00%	$3,915	100.00%	$3,915	
32			$3,915		$3,915		$3,915	
33								
34		G375 - Structures and Improvements	$16,785	100.00%	$16,785	100.00%	$16,785	
35			$16,785		$16,785		$16,785	
36								
37		G376 - Gas Mains	$2,369,836	100.00%	$2,369,836	100.00%	$2,369,836	
38			$2,369,836		$2,369,836		$2,369,836	
39								
40		G378 - Measure & Regulate Sta Equip	$26,029	100.00%	$26,029	100.00%	$26,029	
41			$26,029		$26,029		$26,029	
42								
43		G379 - City Gate Station	$61,468	100.00%	$61,468	100.00%	$61,468	
44			$61,468		$61,468		$61,468	
45								
46		G380 - Services	$1,417,248	100.00%	$1,417,248	100.00%	$1,417,248	
47			$1,417,248		$1,417,248		$1,417,248	
48								
49		G381 - Meters	$179,005	100.00%	$179,005	100.00%	$179,005	
50			$179,005		$179,005		$179,005	
51								
52		G382 - Meter Installations	$291,268	100.00%	$291,268	100.00%	$291,268	
53			$291,268		$291,268		$291,268	
54								
55		G387 - Other Equipment	$2,084	100.00%	$2,084	100.00%	$2,084	
56			$2,084		$2,084		$2,084	
57								
58		G388 - ARO Costs Distribution Plant	$884	100.00%	$884	100.00%	$884	

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
59			$884		$884		$884	
60								
61		Subtotal	**$4,368,523**		**$4,368,523**		**$4,368,523**	
62								
63	**General Plant**	G390 - Structures & Improvements	$11,508	100.00%	$11,508	100.00%	$11,508	
64			$11,508		$11,508		$11,508	
65								
66		G391 - Office Furniture & Equipment	$1,783	100.00%	$1,783	100.00%	$1,783	
67			$1,783		$1,783		$1,783	
68								
69		G394 - Tools, Shop & Garage Equip	$16,536	100.00%	$16,536	100.00%	$16,536	
70			$16,536		$16,536		$16,536	
71								
72		G395 - Laboratory Equipment	$69	100.00%	69	100.00%	69	
73			69		69		69	
74								
75		G397 - Communication Equipment	$5,786	100.00%	$5,786	100.00%	$5,786	
76			$5,786		$5,786		$5,786	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$125	100.00%	$125	100.00%	$125	
82			$125		$125		$125	
83								
84		Subtotal	**$35,933**		**$35,933**		**$35,933**	
85								
86								
87		**Total**	**$4,630,050**		**$4,630,050**		**$4,630,050**	

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$8,018		$8,018
3		Subtotal Intangible Plant	SUM L1 to L2	$8,018		$8,018
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$935		$935
6		G311 - Liquefied Petroleum Gas Equipment		13,004		13,004
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$13,939		$13,939
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$8,270		$8,270
11		G362 - Gas Holders		6,918		6,918
12		G363 - Gas Storage Equipment		20,898		20,898
13		Subtotal Other Storage Plant	SUM L9 to L12	$36,086		$36,086
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$6,841		6,841
17		G376 - Gas Mains		424,502		424,502
18		G378 - Measure & Regulate Station Equipment		5,942		5,942
19		G379 - City Gate Station		27,748		27,748
20		G380 - Services		312,616		312,616
21		G381 - Meters		88,274		88,274
22		G382 - Meter Installations		80,458		80,458
23		G387 - Other Equipment		1,716		1,716
24		G388 - ARO Costs Distribution Plant		608		608
25		Subtotal Distribution Plant	SUM L15 to L24	$948,707		$948,707
26						
27	**General Plant**	G390 - Structures & Improvements		$3,757		$3,757
28		G391 - Office Furniture & Equipment		561		561
29		G394 - Tools, Shop & Garage Equipment		7,010		7,010
30		G395 - Laboratory Equipment		19		19
31		G397 - Communication Equipment		4,458		4,458
32		G398 - Miscellaneous Equipment		76		76
33		G399.1 - ARO Costs General Plant		57		57
34		Subtotal General Plant	SUM L27 to L33	$15,939		$15,939
35						
36		**Total**	Lines 3+7+13+25+34	$1,022,690		$1,022,690

Line No.	Category	Account	(1) FPFTY 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**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$8,018	100.00%	$8,018	100.00%	$8,018	
4								
5		Subtotal	**$8,018**		**$8,018**		**$8,018**	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	6,841	100.00%	6,841	100.00%	6,841	
10								
11		G376 - Gas Mains	424,502	100.00%	424,502	100.00%	424,502	
12								
13		G378 - Measure & Regulate Sta Equip	5,942	100.00%	5,942	100.00%	5,942	
14								
15		G379 - City Gate Station	27,748	100.00%	27,748	100.00%	27,748	
16								
17		G380 - Services	312,616	100.00%	312,616	100.00%	312,616	
18								
19		G381 - Meters	88,274	100.00%	88,274	100.00%	88,274	
20								
21		G382 - Meter Installations	80,458	100.00%	80,458	100.00%	80,458	
22								
23		G387 - Other Equipment	1,716	100.00%	1,716	100.00%	1,716	
24								
25		G388 - ARO Costs Distribution Plant	608	100.00%	608	100.00%	608	
26								
27		Subtotal	**$948,707**		**$948,707**		**$948,707**	
28								
29	**General Plant**	G390 - Structures & Improvements	$3,757	100.00%	$3,757	100.00%	$3,757	
30								
31		G391 - Office Furniture & Equipment	561	100.00%	561	100.00%	561	
32								
33		G394 - Tools, Shop & Garage Equip	7,010	100.00%	7,010	100.00%	7,010	
34								
35		G395 - Laboratory Equipment	19	100.00%	19	100.00%	19	
36								
37		G397 - Communication Equipment	4,458	100.00%	4,458	100.00%	4,458	
38								
39		G398 - Miscellaneous Equipment	76	100.00%	76	100.00%	76	
40								
41		G399.1 - ARO Costs General Plant	57	100.00%	57	100.00%	57	
42								
43		Subtotal	**$15,939**		**$15,939**		**$15,939**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$935	100.00%	$935	100.00%	$935	
46								
47		G311 - Liquefied Petroleum Gas Eqp	13,004	100.00%	13,004	100.00%	13,004	
48								
49		Subtotal	**$13,939**		**$13,939**		**$13,939**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$8,270	100.00%	$8,270	100.00%	$8,270	
54								
55		G362 - Gas Holders	6,918	100.00%	6,918	100.00%	6,918	
56								
57		G363 - Gas Storage Equipment	20,898	100.00%	20,898	100.00%	20,898	
58								
59		Subtotal	**$36,086**		**$36,086**		**$36,086**	
60								
61		**Total**	**$1,022,690**		**$1,022,690**		**$1,022,690**	

Line No.	Category	Account		(1) Reference	(2) FPFTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements			
2		G311 - Liquefied Petroleum Gas Equipment			
3		Subtotal Gas - Production Plant		SUM L1 to L2	
4					
5	**Gas - Storage**	G361 - Structures & Improvements			
6		G363 - Gas Storage Equipment			(1,270)
7		Subtotal Gas - Storage		SUM L5 to L6	($1,270)
8					
9	**Gas - Distribution**	G374 - Land and Land Rights			
10		G375 - Structures and Improvements			($43)
11		G376 - Gas Mains			(6,122)
12		G378 - Measure & Regulate Station Equipment			(750)
13		G379 - City Gate Station			
14		G380 - Services			(4,084)
15		G381 - Meters			(211)
16		G382 - Meter Installations			(2,088)
17		G387 - Other Equipment			
18		Subtotal Gas - Distribution		SUM L9 to L17	($13,298)
19					
20	**Gas - General Plant**	G390 - Structures & Improvements			($36)
21		G391 - Office Furniture & Equipment			(7)
22		G394 - Tools, Shop & Garage Equipment			
23		G397 - Communication Equipment			(70)
24		Subtotal Gas - General Plant		SUM L20 to L23	($113)
25					
26			**Total**	Lines 3+7+18+24	($14,681)

Line No.	Description	Reference	FPFTY Expenses	(Lead)/Lag Days	Dollar-Days
		(1)	(2)	(3)	(4)
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			48.86	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$52,481	13.58	$712,861
7	Pension Expense		973	(167.00)	(162,441)
8	Commodity Purchased - Gas		260,915	33.24	8,671,521
9	Payment to Suppliers		82,479	56.21	4,636,002
10	Other Expenses		112,217	40.07	4,496,783
11	Total O&M and POR Payments	SUM L6 to L10	$509,064		$18,354,725
12					
13	O&M Expense / POR Payment Lag Days			36.06	
14					
15	Net (Lead)/Lag Days	L3 - L13		12.80	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,395		
20					
21	Working Capital for O&M Expense		$17,852		
22					
23	Average Prepayments		$2,733		
24	Accrued Taxes		1,887		
25	Interest Payments		(8,708)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$13,764		
28					
29	Pro Forma O&M Expense		$428,963		
30	Uncollectible Expense		2,378		
31	Pro Forma Cash O&M Expense	L29 - L30	$426,585		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag	(5)
1	Annual Number of Days						365
2							
3	December		$105,193				
4	January		130,817	$141,332			
5	February		139,310	138,106			
6	March		111,688	102,326			
7	April		85,927	73,849			
8	May		52,305	43,873			
9	June		36,760	30,348			
10	July		30,198	25,587			
11	August		25,742	23,623			
12	September		27,856	24,134			
13	October		31,455	29,584			
14	November		47,500	51,027			
15	December		80,753	94,945			
16							
17	Total	SUM L3 to L15	$905,503	$778,733			
18							
19	Average A/R Balance		13				
20							
21	Factor		$69,654	$778,733	11.18		32.65
22							
23	Collection Days Lag						32.65
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					**48.86**

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				$50,786		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$689,843
4								
5		Payroll Lag	SUM L1 to L3			50,786	13.58	$689,843
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$3,300	(167.00)	($551,100)
12								
13		Sub-Total	SUM L7 to L11			$3,300		($551,100)
14								
15		Lag Days for Pension Payment					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	January				$16,812		$651,478
20		April				26,471		1,077,737
21		July				25,711		1,175,140
22		October				22,699		769,982
23								
24		TOTAL	SUM L19 to L22			$91,693	40.07	$3,674,337

Line No.	Months	Description	(1) Number of CDs	(2) Cash Disbursements	(3) Dollar-Days	(4) Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674		
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356		
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,289	$91,693	$3,674,337	40.07

Line No.	Tax	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	4/15/2025	7/1/2025	77	$27,176	25.00%	$6,794	$523,146
2		Second Payment	6/16/2025	7/1/2025	15	27,176	25.00%	6,794	101,912
3		Third Payment	9/15/2025	7/1/2025	(76)	27,176	25.00%	6,794	(516,352)
4		Fourth Payment	12/15/2025	7/1/2025	(167)	27,176	25.00%	6,794	(1,134,616)
5		Subtotal FEDERAL INCOME TAX					100.00%	$27,176	($1,025,910)
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	$1,719	25.00%	$430	$45,560
8		Second Payment	6/16/2025	7/1/2025	15	1,719	25.00%	430	6,447
9		Third Payment	9/15/2025	7/1/2025	(76)	1,719	25.00%	430	(32,666)
10		Fourth Payment	12/15/2025	7/1/2025	(167)	1,719	25.00%	430	(71,779)
11		Subtotal STATE INCOME TAX					100.00%	$1,719	($52,437)
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$2,076	100.00%	$2,076	$126,654
14		Subtotal PURTA					100.00%	$2,076	$126,654
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2025	7/1/2025	22	$1,796	100.00%	1,796	39,503
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	1,796	39,503
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

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	$27,176	($1,025,910)	(37.75)	48.86	11.11	$301,818	$827
2	STATE INCOME TAX	$1,719	($52,437)	(30.50)	48.86	18.36	$31,558	$86
3	PURTA	$2,076	$126,654	61.00	48.86	109.86	$228,094	$625
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$1,796	$39,503	22.00	48.86	70.86	$127,229	$349
6	GROSS RECEIPTS TAX							

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Measures of Value at End of Test Year		$3,512,702
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.58%
4	Pro Forma Interest Expense	L1 * L2 * L3	$74,971
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$205
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		48.86
9	Interest Payment Lag Days	L8 - L7	(42.39)
10	Total Interest for Working Capital	L6 * L9	($8,708)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December					$99	$925	$75	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January		$353			238	983	57	2,394	(18)	88	465	51	285	816	
3	February		$300			271	786	74	2,394	(35)	80	420	170	372	701	
4	March		$289			(20)	590	50	3,157	157	88	420	254	305	662	
5	April		$257	$133	47	93	393	38	3,157	139	80	433	112	276	728	
6	May		$225	$133	38	76	197	20	3,157	122	72	428	159	243	731	
7	June		$192	$66	38	59	0	37	3,584	105	119	422	294	223	739	
8	July		$160	$55	38	42	1,671	22	3,584	87	111	441	562	277	760	
9	August		$128	$44	38	25	1,457	3	3,584	70	103	441	761	214	685	
10	September		$96	$33	38	51	1,873	76	3,775	52	136	399	623	146	664	
11	October		$64	$22	38	564	1,687	59	3,775	35	128	404	561	92	664	
12	November		$32	$11	38	424	1,501	40	3,775	17	120	438	500	59	712	
13	December		($0)	$0	38	331	1,315	58	4,879	0	153	451	248	573	777	
14																
15	Total	SUM L1 to L13	$2,096	$498	$351	$2,253	$13,377	$608	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.07%	23.07%	23.07%	23.07%	25.50%	25.50%	25.50%	
18																
19	Distribution Amount	L15 * L17	$2,096	$498	$351	$2,253	$13,377	$608	$10,061	$169	$317	$1,294	$1,114	$865	$2,521	
20																
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																
23	Monthly Average	L19 / L21	$161	$38	$27	$173	$1,029	$47	$774	$13	$24	$100	$86	$67	$194	
24																
25	**Rate Case Amount**															**$2,733**

Line No.	Description	(1) Shopping Percentage	(2) Weighted Lag Days	(3) Lag Days
1	Residential	58%		40.00
2	Nonresidential	42%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

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		($7,888)	100.00%	($7,888)	100.00%	($7,888)
2		ADIT - Common Plant		15,921	100.00%	15,921	100.00%	15,921
3		ADIT - Gas Distribution		246,541	100.00%	246,541	100.00%	246,541
4		ADIT - Corporate Alternative Minimum Tax		(22,017)	100.00%	(22,017)	100.00%	(22,017)
5		Sub-Total	SUM L1 to L4	$232,557		$232,557		$232,557
6								
7	**FTY**	DIT - CIAC		($1,805)	100.00%	($1,805)	100.00%	($1,805)
8		DIT - Common Plant			100.00%		100.00%	
9		DIT - Gas Distribution		9,631	100.00%	9,631	100.00%	9,631
10		DIT - Corporate Alternative Minimum Tax		(17,594)	100.00%	(17,594)	100.00%	(17,594)
11		Sub-Total	SUM L7 to L10	($9,767)		($9,767)		($9,767)
12								
13	**FPFTY**	DIT - CIAC		($1,998)	100.00%	($1,998)	100.00%	($1,998)
14		DIT - Common Plant			100.00%		100.00%	
15		DIT - Gas Distribution		9,794	100.00%	9,794	100.00%	9,794
16		DIT - Corporate Alternative Minimum Tax		(10,280)	100.00%	(10,280)	100.00%	(10,280)
17		Sub-Total	SUM L13 to L16	($2,483)		($2,483)		($2,483)
18								
19		**Total**	L5 + L11 + L17	$220,306		$220,306		$220,306

Line No.	Description	Reference	(1) Residential	(2) Non-Residential	(3) Total
1	March 2023		$3,760	$8,594	$12,354
2	April		3,872	8,742	12,614
3	May		4,038	8,997	13,035
4	June		4,165	9,113	13,278
5	July		4,275	9,518	13,793
6	August		4,395	9,856	14,252
7	September		4,436	9,987	14,423
8	October		4,504	10,099	14,602
9	November		4,557	10,182	14,739
10	December		4,530	10,218	14,747
11	January 2024		4,178	9,927	14,104
12	February		4,082	9,907	13,989
13	March		4,142	9,717	13,859
14					
15	Total	SUM L1 to L13	$54,932	$124,857	$179,789
16					
17	Average Monthly Balance	L15 / 13	$4,226	$9,604	$13,830
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$4,226
21	Small C&I				9,210
22	Large C&I				394
23	Transportation				
24					
25	Total	SUM L20 to L23			$13,830

Line No.	Category	Account	Reference	FPFTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
			(1)	(2)	(3)	(4)
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$337,580	$256,611	$80,969
6						
7		E389 - Land and Land Rights		$6,783	$5,218	$1,565
8						
9		E390 - Structures and Improvements		$432,164	$332,464	$99,700
10		E391 - Office Furniture, Equipment		82,575	63,525	19,050
11		E392 - Transportation Equipment		218,349	167,976	50,373
12		E393 - Stores Equipment		1,144	880	264
13		E394 - Tools, Shop, Garage Equipmnt		2,144	1,649	495
14		E396 - Power Operated Equipment		185	142	43
15		E397 - Communication Equipment		160,034	123,114	36,920
16		E398 - Miscellaneous Equipment		1,158	891	267
17		E399 - Other Tangible Property		(0)	(0)	
18		E399.1 - ARO Costs General Plant		803	618	185
19		Sub Total - General Plant	SUM L9 to L18	$898,556	$691,259	$207,297
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,243,596	$953,609	$289,987
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$156,223	$119,610	$36,613
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,406	$54,164	$16,243
31		E391 - Office Furniture, Equipment		35,258	27,124	8,134
32		E392 - Transportation Equipment		115,297	88,698	26,599
33		E393 - Stores Equipment		246	189	57
34		E394 - Tools, Shop, Garage Equipmnt		834	641	192
35		E396 - Power Operated Equipment		185	142	43
36		E397 - Communication Equipment		50,731	39,028	11,704
37		E398 - Miscellaneous Equipment		974	749	225
38		E399 - Other Tangible Property		(0)	(0)	
39		E399.1 - ARO Costs General Plant		(386)	(297)	(89)
40		Sub Total - General Plant	SUM L30 to L39	$273,546	$210,439	$63,107
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$429,769	$330,048	$99,720
42						
43		Net Common Plant	L20 - L41	$813,827	$623,560	$190,266
44						
45						
46		Common Plant in Service to Utility	L20	$1,243,596	$953,609	$289,987
47		Common Plant Accum Depreciation to Utility	L41	429,769	330,048	99,720
48		Net Common Plant to Utility	L46 - L47	$813,827	$623,560	$190,266

(1)

Line No.	Description	Total FPFTY Amount
1	HTY 13-Month Average	
2	March 2023	$1,659
3	April	1,632
4	May	1,208
5	June	1,037
6	July	1,242
7	August	1,221
8	September	1,817
9	October	1,684
10	November	1,404
11	December	1,318
12	January 2024	761
13	February	1,499
14	March	1,100
15		
16	13-Month Total	$17,582
17		
18		
19	Average Monthly Balance	$1,352

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Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				(4)
2	March 2023		$2,830	($1,490)	$1,340
3	April		2,851	(1,111)	1,740
4	May		2,776	(1,460)	1,316
5	June		2,737	(1,693)	1,044
6	July		2,751	(1,197)	1,554
7	August		2,882	(1,126)	1,756
8	September		2,916	(1,077)	1,839
9	October		2,836	(660)	2,176
10	November		2,815	(686)	2,129
11	December		2,736	0	2,736
12	January 2024		2,729	(788)	1,941
13	February		2,731	(730)	2,001
14	March		2,672	(241)	2,431
15					
16	Total	SUM L2 to L14	$36,260	($12,257)	$24,003
17					
18	Distribution Expense Allocation Factor		100.00%	23.07%	
19					
20	Allocation to Distribution	L16 * L18	$36,260	($2,828)	
21					
22	Average Monthly Balance	L20 / 13	$2,789	($218)	$2,572

			(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		$116,677	100.00%	$116,677	100.00%	$116,677
2		ADIT - CIAC			100.00%		100.00%	
3		Subtotal HTY	L1 + L2	116,677		116,677		116,677
4								
5	**FTY**	DIT - Distribution		($3,459)	100.00%	($3,459)	100.00%	($3,459)
6		DIT - CIAC			100.00%		100.00%	
7		Subtotal FTY	L5 + L6	(3,459)		(3,459)		(3,459)
8								
9	**FPFTY**	DIT - Distribution		($1,748)	100.00%	($1,748)	100.00%	($1,748)
10		DIT - CIAC			100.00%		100.00%	
11		Subtotal FPFTY	L9 + L10	(1,748)		(1,748)		(1,748)
12								
13		**Total**	L3 + L7 + L11	$111,469		$111,469		$111,469

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Line No.	Description	Reference	(1) Stored Underground	(2) LNG	(3) Propane Gas	(4) Total
1	December		$35,170	$4,860	$1,546	$41,575
2	January		34,920	4,792	1,546	41,257
3	February		38,419	4,742	1,546	44,707
4	March		41,212	4,679	1,546	47,437
5	April		44,474	4,615	1,546	50,635
6	May		47,298	4,560	1,546	53,404
7	June		49,911	4,768	1,546	56,225
8	July		52,807	4,720	1,546	59,073
9	August		52,124	4,339	1,527	57,990
10	September		44,844	4,217	1,527	50,589
11	October		33,086	4,155	1,527	38,768
12	November		24,784	4,102	1,527	30,413
13	December		16,788	3,675	1,527	21,991
14						
15	Total	SUM L1 to L13	$515,838	$58,223	$20,003	$594,065
16						
17	Average Monthly Balance	L15 / 13	$39,680	$4,479	$1,539	$45,697

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		$521,659		$521,659
2		C & I		191,272		191,272
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		1,329	178	1,506
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		1,703		1,703
8		Other Gas Revenues		517		517
9		Transportation of Gas of Others		29,969		29,969
10		Revenue Increase			110,016	110,016
11		Subtotal Operating Revenues	SUM L1 to L10	$746,448	$110,194	$856,642
12						
13	**Operating Expenses**	Manufactured Gas Production		$438		$438
14		Storage Operations Expense		1,292		1,292
15		Storage Maintenance Expense		5,043		5,043
16		Underground Storage Expenses				
17		Other Gas Supply		260,932		260,932
18		Distribution Expense		87,480		87,480
19		Total Customer Accounts		24,196	406	24,602
20		Total Customer Service & Information		7,904		7,904
21		Total Sales		774		774
22		Administrative & General		40,903	340	41,242
23		O&M Expense	SUM L13 to L22	$428,963	$746	$429,709
24						
25		Depreciation & Amortization Expense		$116,982		$116,982
26		Amortization of Regulatory Expense		1,459		1,459
27		Taxes Other Than Income Taxes - Other		9,067		9,067
28		Subtotal Operating Expenses	SUM L23 to L27	$556,472	$746	$557,217
29						
30	**Net Operating Income - BIT**		L11 - L28	$189,977	$109,448	$299,425

Line No.	Category	Description	(1) FPFTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$520,639	$1,020	$521,659
2		C & I	190,288	984	191,272
3		Interdepartmental			
4		Sales for Resale	15,000	(15,000)	
5		Forfeited Discounts	1,329		1,329
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	1,703		1,703
8		Other Gas Revenues	517		517
9		Transportation of Gas of Others	29,969		29,969
10		Revenue Increase			
11		Subtotal Operating Revenues	$759,445	($12,996)	$746,448
12					
13	**Operating Expenses**	Manufactured Gas Production	$430	$8	$438
14		Storage Operations Expense	1,270	22	1,292
15		Storage Maintenance Expense	4,975	68	5,043
16		Underground Storage Expenses			
17		Other Gas Supply	272,182	(11,250)	260,932
18		Distribution Expense	88,114	(634)	87,480
19		Total Customer Accounts	24,083	113	24,196
20		Total Customer Service & Information	7,569	335	7,904
21		Total Sales	764	10	774
22		Administrative & General	38,604	2,299	40,903
23		O&M Expense	$437,992	($9,029)	$428,963
24					
25		Depreciation & Amortization Expense	$110,058	$6,925	$116,982
26		Amortization of Regulatory Expense	649	810	1,459
27		Taxes Other Than Income Taxes - Other	8,923	144	9,067
28		Subtotal Operating Expenses	$557,622	($1,150)	$556,472
29					
30	**Net Operating Income - BIT**		$201,823	($11,846)	$189,977

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
1	**Operating Revenues**	Residential	Gas Cost	$193,890									
2			Cust & Dist	326,750	827	(166)	358						
3			Subtotal Residential	$520,639	$827	($166)	$358						
4													
5		C & I	Gas Cost	$67,025									
6			Cust & Dist	123,263	847		137						
7			Subtotal C & I	$190,288	$847		$137						
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$15,000					($15,000)				
13			Subtotal Sales for Resale	$15,000					($15,000)				
14													
15		Forfeited Discounts	Forfeited Discounts	$1,329									
16			Subtotal Forfeited Discounts	$1,329									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$1,703									
22			Subtotal Rent For Gas Property	$1,703									
23													
24		Other Gas Revenues	Other Gas Revenues	$517									
25			Subtotal Other Gas Revenues	$517									
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$29,969									
28			Subtotal Transportation of Gas of Others	$29,969									
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$759,445**	**$1,674**	**($166)**	**$495**		**($15,000)**				
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production	$7									
36			Liquefied Petroleum Gas Expenses	127						2			
37			Liquefied Petroleum Gas Expenses	0						0			
38			Maintenance of Structures and Improvements	85						2			
39			Maintenance of Production Equipment	211						4			
40			Subtotal Manufactured Gas Production	$430						$8			
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$272,165					($11,250)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses	17						0			
46			Gas Withdrawn from Storage-Debit										

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply	$272,182					($11,250)	$0			
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$1,026						$16			
52			Maintenance of Structures and Improvements	3,950						52			
53			Subtotal Storage Maintenance Expense	$4,975						$68			
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$357						$6			
56			Operation Labor and Expenses	914						15			
57			Subtotal Storage Operations Expense	$1,270						$22			
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$538						$0			
63			Mains and Services Expenses	18,799						$202			
64			Measuring and Regulating Station Expenses-General	1,862						$40			
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	7,562						$65			
67			Customer Installations Expenses	7,959						$181			
68			Other Expenses	19,796						$139			
69			Rents	21									
70			Maintenance of Mains	26,329						$404			
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	1,512						$25			
72			Maintenance of Services	2,821						$43			
73			Maintenance of Meters & House Regulators	238						$5			
74			Maintenance of Other Equipment	676						$4			
75			Subtotal Distribution Expense	$88,114						$1,108			
76													
77		Total Customer Accounts	Customer Records and Collection	$20,395						$237			
78			Meter Reading	163									
79			Miscellaneous Customer Accounts	846						$8			
80			Uncollectible Accounts	2,679									
81			Subtotal Total Customer Accounts	$24,083						$245			
82													
83		Total Customer Service & Information	Customer Assistance	$7,171						$13			
84			Informational & Instructional	345									
85			Miscellaneous Customer & Informational	53						$1			
86			Subtotal Total Customer Service & Information	$7,569						$14			
87													
88		Total Sales	Demonstrating & Selling	$764						$10			
89			Miscellaneous Sales										
90			Subtotal Total Sales	$764						$10			
91													
92		Administrative & General	Administrative and General Salaries	$6,973						$207			

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 Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-6 Salary & Wages	(8) D-7 Rate Case Expense	(9) D-8 Adjustments for Employee Benefits	(10) D-9 Adjustments for Pension
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(7)									
95			Employee Pensions and Benefits	7,676								18	990
96			Franchise Requirements	405									
97			Injuries and Damages							$5			
98			Maintenance of General Plant	1,008						$7			
99			Miscellaneous General Expenses	828						$0			
100			Office Supplies and Expenses	1,197									
101			Outside Service Employed	17,810									
102			Property Insurance	148									
103			Regulatory Commission Expenses	2,566							1,072		
104			Subtotal Administrative & General	$38,604						$219	$1,072	$18	$990
105													
106			**O&M Expense**	**$437,992**					**($11,250)**	**$1,694**	**$1,072**	**$18**	**$990**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$110,058									
109			Subtotal Depreciation & Amortization Expense	$110,058									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$649									
112			Subtotal Amortization of Regulatory Expense	$649									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$8,923									
115			Subtotal Taxes Other Than Income Taxes - Other	$8,923									
116													
117			**Total Operating Expenses**	**$557,622**					**($11,250)**	**$1,694**	**$1,072**	**$18**	**$990**
118													
119	**Net Operating Income Before Income Tax**			**$201,823**	**$1,674**	**($166)**	**$495**		**($3,750)**	**($1,694)**	**($1,072)**	**($18)**	**($990)**

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost										$193,890
2			Cust & Dist									1,020	327,769
3			Subtotal Residential									$1,020	$521,659
4													
5		C & I	Gas Cost										$67,025
6			Cust & Dist									984	124,247
7			Subtotal C & I									$984	$191,272
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale									($15,000)	
13			Subtotal Sales for Resale									($15,000)	
14													
15		Forfeited Discounts	Forfeited Discounts										$1,329
16			Subtotal Forfeited Discounts										$1,329
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property										1,703
22			Subtotal Rent For Gas Property										1,703
23													
24		Other Gas Revenues	Other Gas Revenues										$517
25			Subtotal Other Gas Revenues										$517
26													
27		Transportation of Gas of Others	Transportation of Gas of Others										$29,969
28			Subtotal Transportation of Gas of Others										$29,969
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**									**($12,996)**	**$746,448**
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										$7
36			Liquefied Petroleum Gas Expenses									$2	129
37			Liquefied Petroleum Gas Expenses									$0	0
38			Maintenance of Structures and Improvements									$2	86
39			Maintenance of Production Equipment									$4	215
40			Subtotal Manufactured Gas Production									$8	$438
41													
42		Other Gas Supply	Natural Gas City Gate Purchases									($11,250)	$260,915
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses									$0	17
46			Gas Withdrawn from Storage-Debit										

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply									($11,250)	$260,932
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering									$16	$1,042
52			Maintenance of Structures and Improvements									$52	4,001
53			Subtotal Storage Maintenance Expense									$68	$5,043
54													
55		Storage Operations Expense	Operating Supervision and Engineering									$6	$363
56			Operation Labor and Expenses									$15	929
57			Subtotal Storage Operations Expense									$22	$1,292
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering									$0	$538
63			Mains and Services Expenses									$202	19,001
64			Measuring and Regulating Station Expenses-General									$40	1,901
65			Measuring and Regulating Station Expenses-City Gate										0
66			Meter and House Regulator Expenses									$65	7,627
67			Customer Installations Expenses									$181	8,140
68			Other Expenses						(1,742)			($1,603)	18,192
69			Rents										21
70			Maintenance of Mains									$404	26,734
71			Maintenance of Measuring & Reg. Station Equip.-Genl.									$25	1,537
72			Maintenance of Services									$43	2,864
73			Maintenance of Meters & House Regulators									$5	243
74			Maintenance of Other Equipment									$4	680
75			Subtotal Distribution Expense						($1,742)			($634)	$87,480
76													
77		Total Customer Accounts	Customer Records and Collection									$237	$20,632
78			Meter Reading										163
79			Miscellaneous Customer Accounts			835		(666)				$177	1,024
80			Uncollectible Accounts	899					(1,200)			($301)	2,378
81			Subtotal Total Customer Accounts	$899		$835		($666)	($1,200)			$113	$24,196
82													
83		Total Customer Service & Information	Customer Assistance		$321							$334	$7,505
84			Informational & Instructional										345
85			Miscellaneous Customer & Informational									$1	54
86			Subtotal Total Customer Service & Information		$321							$335	$7,904
87													
88		Total Sales	Demonstrating & Selling									$10	$774
89			Miscellaneous Sales										
90			Subtotal Total Sales									$10	$774
91													
92		Administrative & General	Administrative and General Salaries									$207	$7,180

Line No.	Category	Description	Description	(11) D-10 Uncollectible Accounts	(12) D-11 Energy Efficiency	(13) D-12 Customer Deposit Interest	(14) D-13 MGP Recovery	(15) D-14 MGP Interest and FTAC	(16) D-15 GPC / MFC	(17) D-16 Taxes Other Than Income	(18) D-17 Depreciation Annualization	(19) Adjustments Sub-total	(20) Pro Forma Adjusted at Present Rates
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit										(7)
95			Employee Pensions and Benefits									$1,008	8,683
96			Franchise Requirements										405
97			Injuries and Damages									$5	5
98			Maintenance of General Plant									$7	1,015
99			Miscellaneous General Expenses									$0	828
100			Office Supplies and Expenses										1,197
101			Outside Service Employed										17,810
102			Property Insurance										148
103			Regulatory Commission Expenses									$1,072	3,637
104			Subtotal Administrative & General									$2,299	$40,903
105													
106			**O&M Expense**	**$899**	**$321**	**$835**		**($666)**	**($2,942)**			**($9,029)**	**$428,963**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense								$6,925	$6,925	$116,982
109			Subtotal Depreciation & Amortization Expense								$6,925	$6,925	$116,982
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense				$810					$810	$1,459
112			Subtotal Amortization of Regulatory Expense				$810					$810	$1,459
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other							$144		$144	$9,067
115			Subtotal Taxes Other Than Income Taxes - Other							$144		$144	$9,067
116													
117			**Total Operating Expenses**	**$899**	**$321**	**$835**	**$810**	**($666)**	**($2,942)**	**$144**	**$6,925**	**($1,150)**	**$556,472**
118													
119	**Net Operating Income Before Income Tax**			**($899)**	**($321)**	**($835)**	**($810)**	**$666**	**$2,942**	**($144)**	**($6,925)**	**($11,846)**	**$189,977**

PECO Gas Operations
Before The PAPUC
FPFTY Ending Dec. 2025
($ in Thousands)
D-4 Expense Adjustment Summary

UPDATE 07-16-24

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.	$7		$0					
2			717.0 Liquefied Petroleum Gas Expenses.	127		2					
3			741.0 Maintenance Of Structures And Improvements.	85		2					
4			742.0 Maintenance Of Production Equipment.	211		4					
5			Subtotal	$430		$8					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	0		0					
8			Subtotal	$0		$0					
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$272,165	($11,250)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.	17		0					
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal	$272,182	($11,250)	$0					
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$357		$6					
23			841.0 Operation Labor And Expenses.	914		15					
24			Subtotal	$1,270		$22					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$1,026		$16					
27			843.2 Maintenance Of Structures And Improvements.	3,950		52					
28			Subtotal	$4,975		$68					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$538		$0					
31			874.0 Mains And Services Expenses.	18,799		202					
32			875.0 Measuring And Regulating Station Expenses--General.	1,862		40					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	7,562		65					
35			879.0 Customer Installations Expenses.	7,959		181					
36			880.0 Other Expenses.	19,796		139					
37			881.0 Rents.	21							
38			Subtotal	$56,537		$627					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$26,329		$404					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	1,512		25					
42			892.0 Maintenance Of Services.	2,821		43					
43			893.0 Maintenance Of Meters And House Regulators.	238		5					
44			894.0 Maintenance Of Other Equipment.	676		4					
45			Subtotal	$31,577		$481					
46											
47			Distribution Expense Subtotal	$88,114		$1,108					
48											

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(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 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$163		$0					
50			903.0 Customer Records And Collection Expenses.	20,395		237					
51			904.0 Uncollectible Accounts.	2,679						899	
52			905.0 Miscellaneous Customer Accounts Expenses.	846		8					
53											
54			Subtotal	$24,083		$245				$899	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$7,171		$13					$321
57			909.0 Informational And Instructional Advertising Expenses.	345							
58			910.0 Miscellaneous Customer Service And Informational Expenses.	53		1					
59			Subtotal	$7,569		$14					$321
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$764		$10					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$764		$10					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$6,973		$207					
66			921.0 Office Supplies And Expenses.	1,197							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	17,810							
69			924.0 Property Insurance.	148							
70			925.0 Injuries And Damages.	405		5					
71			926.0 Employee Pensions And Benefits.	7,676				18	990		
72			928.0 Regulatory Commission Expenses.	2,566			1,072				
73			929.0 Duplicate Charges--Credit.	(7)							
74			930.2 Miscellaneous General Expenses.	828		0					
75											
76			Subtotal	$37,596		$212	$1,072	$18	$990		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$1,008		$7					
79			Subtotal	$1,008		$7					
80											
81			A&G Expense Sub-total	$38,604		$219	$1,072	$18	$990		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$94,862							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	15,195							
86			Subtotal	$110,058							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$649							
89			Subtotal	$649							
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$8,923							
92			Subtotal	$8,923							
93											
94			**Total**	**$557,622**	**($11,250)**	**$1,695**	**$1,072**	**$18**	**$990**	**$899**	**$321**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.							$0	$7
2			717.0 Liquefied Petroleum Gas Expenses.							2	129
3			741.0 Maintenance Of Structures And Improvements.							2	86
4			742.0 Maintenance Of Production Equipment.							4	215
5			Subtotal							$8	$438
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.							0	0
8			Subtotal							$0	$0
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($11,250)	$260,915
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.							0	17
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal							($11,250)	$260,932
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$6	$363
23			841.0 Operation Labor And Expenses.							15	929
24			Subtotal							$22	$1,292
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$16	$1,042
27			843.2 Maintenance Of Structures And Improvements.							52	4,001
28			Subtotal							$68	$5,043
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$538
31			874.0 Mains And Services Expenses.							202	19,001
32			875.0 Measuring And Regulating Station Expenses--General.							40	1,901
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							65	7,627
35			879.0 Customer Installations Expenses.							181	8,140
36			880.0 Other Expenses.				(1,742)			(1,603)	18,192
37			881.0 Rents.								21
38			Subtotal				($1,742)			($1,115)	$55,422
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$404	$26,734
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							25	1,537
42			892.0 Maintenance Of Services.							43	2,864
43			893.0 Maintenance Of Meters And House Regulators.							5	243
44			894.0 Maintenance Of Other Equipment.							4	680
45			Subtotal							$481	$32,058
46											
47			Distribution Expense Subtotal				($1,742)			($634)	$87,480
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest and FTAC	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.							$0	$163
50			903.0 Customer Records And Collection Expenses.							237	20,632
51			904.0 Uncollectible Accounts.				(1,200)			(301)	2,378
52			905.0 Miscellaneous Customer Accounts Expenses.	835		(666)				177	1,024
53											
54			Subtotal	$835		($666)	($1,200)			$113	$24,196
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$334	$7,505
57			909.0 Informational And Instructional Advertising Expenses.								345
58			910.0 Miscellaneous Customer Service And Informational Expenses.							1	54
59			Subtotal							$335	$7,904
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$10	$774
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$10	$774
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$207	$7,180
66			921.0 Office Supplies And Expenses.								1,197
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								17,810
69			924.0 Property Insurance.								148
70			925.0 Injuries And Damages.							5	410
71			926.0 Employee Pensions And Benefits.							1,008	8,683
72			928.0 Regulatory Commission Expenses.							1,072	3,637
73			929.0 Duplicate Charges--Credit.								(7)
74			930.2 Miscellaneous General Expenses.							0	828
75											
76			Subtotal							$2,292	$39,887
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$7	$1,015
79			Subtotal							$7	$1,015
80											
81			A&G Expense Sub-total							$2,299	$40,903
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$6,263	$6,263	$101,125
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						662	662	15,857
86			Subtotal						$6,925	$6,925	$116,982
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$810					$810	$1,459
89			Subtotal		$810					$810	$1,459
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$144		$144	$9,067
92			Subtotal					$144		$144	$9,067
93											
94			**Total**	**$835**	**$810**	**($666)**	**($2,942)**	**$144**	**$6,925**	**($1,150)**	**$556,472**

PECO Gas Operations
Before The PAPUC
FPFTY Ending December 2025
($ in Thousands)
D-5 Revenue Adjustment Summary

Line No.	Category	Description	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) Adjustments Sub-total	(8) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$326,750	$827	($166)	$358			$1,020	$327,769
2			C & I	481.0	123,263	847		137			984	124,247
3			Transportation of Gas of Others	489.3	29,969							29,969
4				Subtotal	$479,981	$1,674	($166)	$495			$2,004	$481,985
5												
6		**Gas Cost Revenue**	Residential	480.0	$193,890							$193,890
7			C & I	481.0	67,025							67,025
8			Interdepartmental	484.0								
9				Subtotal	$260,915							$260,915
10												
11			**Subtotal OPERATING REVENUE**		$740,896	$1,674	($166)	$495			$2,004	$742,900
12												
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$1,703							$1,703
14			Interdepartmental Rents	494.0								
15			Other Gas Revenues	495.0	517							517
16				Subtotal	$2,220							$2,220
17												
18		**Other Operating Revenue**	Sales For Resale	483.0	$15,000					($15,000)	(15,000)	
19			Forfeited Discounts	487.0	1,329							1,329
20												
21			Miscellaneous Service Revenues	488.0								
22				Subtotal	$16,329					($15,000)	($15,000)	$1,329
23												
24			**Subtotal OTHER REVENUE**		$18,549					($15,000)	($15,000)	$3,549
25												
26			**Total**		**$759,445**	**$1,674**	**($166)**	**$495**		**($15,000)**	**($12,996)**	**$746,448**

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total	(7)
1	Total FPFTY Revenues		$520,639	$1,380	$186,353	$291	$2,106	$190,130	
2	Commodity Billings in Revenues		(193,890)	(656)	(64,687)	(107)	(1,491)	(66,941)	
3	Weather Adjustment								
4	Total Reconcilable Surcharge in Revenues								
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$326,750	$724	$121,667	$184	$614	$123,188	
6									
7	Average Monthly Customers in FPFTY		512,659	20	45,589	8	16		
8									
9	Average Annual Margin Per Customer	L5 / L7	$0.637	$36.644	$2.669	$22.982	$38.385		
10									
11	Number of Customers of Current Month		513,957	19	45,917	8	16	45,960	
12									
13	Increase in Customers During FPFTY	L11 - L7	1,298	(1)	328			45,960	
14									
15	Annualization of Revenue	L9 * L13	$827	($27)	$875			$847	

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D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	Reference	(1) Residential Sales
1	CAP Discount		($13,675)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		297,552
7	Average Monthly CAP Customers		24,796
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.551)
9			
10	CAP Customers at End of FPFTY		25,138
11	Decrease of CAP Customers	L10 - L7	342
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($189)
14	Write-Offs & Working Capital Factor		12.1%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$23
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($166)**

(2)

Line No.	Description	Reference	(1) 480000: Residential Sales	(2) 481001: TCS Sales	(3) 481002: GC Sales	(4) 481003: L Sales	(5) 481005: Other Sales	(6) C & I Total
1	Revenue in February of FPFTY		$40,136	$113	$15,139	$13	$45	$15,311
2	Days in February of FPFTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	1,433	4	541	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$358**	**$1**	**$135**	**$0**	**$0**	**$137**

Line No.	Description	(1) Total
1	Residential Sales	
2	TCS Sales	
3	GC Sales	
4	C & I Total	
5	Revenues - Gas Transportation	
6	**Total**	

(1)

Line No.	Description	Account	Total
1	Other Operating Revenue	483000: Sales for Resale - Gas	($15,000)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($11,250)

Line No.	Description	(1) Reference	(2) Union	(3) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		348	348
2	Number of Employees @ HTY - Total		696	696
3	Percentage of Employees @ HTY	L1 / L2	50.01%	49.99%
4	Distribution of Budget S&W Expense		$25,396	$25,390
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$127
10		L4 + L9	$25,396	$25,517
11				
12	**Annualize January 1 and March 1, 2026 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$635	$766
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$26,031**	**$26,282**

Line No.	Description	(1) Reference	(2) PECO - Gas
1	Distribution of S&W Expense		$50,786
2			
3	Annualized S&W Including Wage Increases		$52,313
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		19.15%
8	Union Contract Payment for Utility	L6 * L7	$249
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$42
11			
12	Annualized S&W for Employees in FPFTY	L3 + L10	$52,355
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		705
16	Average Number of Employees in FPFTY - Total		703
17	Annualization for Number of Employees	L15 - L16	2
18	Annual S&W per Employee	L12 / L16	$74.5
19	Annualization of S&W for New Employees	L17 * L18	$126
20			
21	Pro Forma FPFTY S&W	L12 + L19	$52,481
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$1,695**
24			
25	S&W Pro Forma Factor	L23 / L1	3.34%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.	$3	$0	3
2			717.0 Liquefied Petroleum Gas Expenses.	74	2	$77
3			728.0 Liquefied Petroleum Gas.	0	0	0
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.	8	0	8
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	192	6	198
12			841.0 Operation Labor And Expenses.	464	15	480
13			843.1 Maintenance Supervision And Engineering.	491	16	507
14			843.2 Maintenance Of Structures And Improvements.	1,550	52	1,601
15			**Subtotal Power Supply Expenses**	$2,781	$93	$2,874
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$1	$0	$1
18			874.0 Mains And Services Expenses.	6,060	202	6,262
19			875.0 Measuring And Regulating Station Expenses--General.	1,189	40	1,228
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	1,947	65	2,012
22			879.0 Customer Installations Expenses.	5,431	181	5,612
23			880.0 Other Expenses.	4,152	139	4,291
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.	0	0	1
26			887.0 Maintenance Of Mains.	12,121	404	12,525
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	745	25	770
28			892.0 Maintenance Of Services.	1,290	43	1,334
29			893.0 Maintenance Of Meters And House Regulators.	149	5	154
30			894.0 Maintenance Of Other Equipment.	120	4	124
31			**Subtotal Distribution Expense**	$33,206	$1,108	$34,314
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	$0	$0	$0
34			903.0 Customer Records And Collection Expenses.	7,101	237	7,338
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	237	8	245
37						
38			**Subtotal Customer Accounts**	$7,339	$245	$7,583
39						
40		Customer Service & Information	908.0 Customer Assistance Expenses	$384	$13	$397

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.	40	1	42
43			**Subtotal Customer Service & Information**	$424	$14	$439
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$289	$10	$298
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$289	$10	$298
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$6,190	$207	$6,396
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	155	5	160
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	9	0	9
59						
60			**Subtotal Administration & General - General**	$6,354	$212	$6,566
61						
62			**Subtotal Operations**	$50,392	$1,681	$52,074
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$221	$7	$228
65			**Subtotal Administration & General - General**	$221	$7	$228
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$49	$2	$51
68			742.0 Maintenance Of Production Equipment.	123	4	128
69			**Subtotal Gas Expense**	$173	$6	$179
70						
71			**Subtotal Maintenance**	$394	$13	$407
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$50,786	$1,695	$52,481
74						
75	**Percent Increase**		**Percent Increase**			3.34%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$8
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$15
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,701
8	Materials, IT Costs, Travel, Copies, etc.		428
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$2,129
10			
11	**Total Rate Case Expense**	L4 + L9	$2,144
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,072
15			
16	Annual Amortization Amount Included in Budget		
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	$1,072

Line No.	Description	(1) Reference	(2) Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		706
3	Employees at Ten Months Prior		705
4	Employees at Nine Months Prior		704
5	Employees at Eight Months Prior		703
6	Employees at Seven Months Prior		702
7	Employees at Six Months Prior		701
8	Employees at Five Months Prior		701
9	Employees at Four Months Prior		700
10	Employees at Three Months Prior		699
11	Employees at Two Months Prior		707
12	Employees at One Month Prior		707
13	Employees at End of FPFTY		705
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	703
16	Additional Employees in FPFTY		2
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$7,386
20	Number of Employees for Budget		703
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	2
23	Total Benefits Pro Forma Adjustment	L21 * L22	$18

Line No.	Description	(1) Reference	(2) Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$17,267
2	Pension Contribution for Three Years Prior to FPFTY		15,222
3	Pension Contribution for Two Years Prior to FPFTY		1,408
4	Pension Contribution for One Year Prior to FPFTY		2,878
5	Pension Contribution for FPFTY		3,300
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$8,015
8			
9	Allocation Percent to Utility		19.15%
10	Total Amount to Utility	L7 * L9	$1,535
11	Allocation Percent to Capital		36.61%
12	Pension Contribution To Be Capitalized	L10 * L11	$562
13	Pension Contribution To Be Expensed	L10 - L12	$973
14	Budgeted Test Year Distribution Pension Expense		($17)
15	Additional Pension Expense	L13 - L14	$990

Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
			(1)	(2)	(3)	(4)	(5)	(6)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$2,036	$595,534	0.3419%		
2		One Year Prior to HTY		2,826	780,108	0.3623%		
3		HTY		3,091	778,733	0.3970%		
4		Three Year Average	SUM L1 to L3 / 3	$2,651	$718,125	0.3692%		
5								
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY			$742,900			
7								
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6		$742,900			
9								
10	Tariff Revenue - Shopping Revenue	FPFTY			$82,479			
11								
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10		$825,379			
13								
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12					$3,047
15								
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY				$367		
17		One Year Prior to HTY				532		
18		HTY				693		
19								
20	**Three Year Average PPA**		SUM L16 to L18 / 3					$530
21								
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20					$3,578
23								
24	Uncollectible Accounts (904)	FPFTY						$2,679
25								
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24					$899

Line No.	Description	Reference	(1) Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$3,078
2	Residential Gas Energy Efficiency Program Costs in FPFTY Budget		2,728
3	Sub-total Pro Forma Increase in Residential Gas Energy Efficiency Program Costs	L1 - L2	$350
4	Gas Commercial EE Program Refund - Rate GC		(29)
5	Total Pro Forma Adjustment Amount	L3 + L4	$321

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		0.667%				
2								
3	January				3,872	26		
4	February				4,038	27		
5	March				4,165	28		
6	April				4,275	28		
7	May				4,395	29		
8	June				4,436	30		
9	July				4,504	30		
10	August				4,557	30		
11	September				4,530	30		
12	October				4,178	28		
13	November				4,082	27		
14	December				4,142	28		
15	**Total Residential**		SUM Col 4 L3 to L14				$341	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				8,742	37		
20	February				8,997	38		
21	March				9,113	39		
22	April				9,518	40		
23	May				9,856	42		
24	June				9,987	42		
25	July				10,099	43		
26	August				10,182	43		
27	September				10,218	43		
28	October				9,927	42		
29	November				9,907	42		
30	December				9,717	41		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$494	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$835

Line No.	Description	(1) Reference	(2) Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$14,309
2	Amortization Years		10
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,431
5			
6	**Amount Included in Budget**		$621
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	$810

PECO Gas Operations
Before The PAPUC
FPFTY Ending Dec. 2025
($ in Thousands)
D-14 Adjustments for MGP Interest, FTAC and TARC Reconciliation

UPDATE 07-16-24

Line No.	Description	(1) Reference	(2) Total
1	Customer Interest on Unspent MGP Collections		($1,387)
2	Gas FTAC Final Reconciliation Recovery from Customers		$63
3	Gas TARC Final Reconciliation Refund to Customers		
4	Rate GC Refund		($6)
5	Rate TS-I Refund		($1)
6	Rate TS-F Refund		($1)
7	Other Rates Refund		($0)
8	Sub-total Gas TARC Final Reconciliation Refund to Customers		($7)
9	Total	L1 + L2	($1,332)
10	Amortization Years		2
11	Pro Forma Adjustment Amount	L3 / L4	($666)

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,119)
3	Rate GC		($609)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($1,742)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,057)
11	Rate GC		($143)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,200)
16			
17	Total Gas Procurement and Merchant Function Charges	L7 + L15	($2,942)

Line No.	Description	(1) Total	(2) Pro Forma Adjustments	(3) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,076		$2,076
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	732		732
4	Real Estate Tax Accrual	1,796		1,796
5	Miscellaneous TOTI			
6	Payroll Tax Accrued	4,319	$144	4,463
7	**Total**	$8,923	$144	$9,067

Line No.	Description	Reference	(1) Jurisdictional
1	Total Payroll Charged to Expense		$50,786
2	Payroll Tax Expense		$4,319
3	Payroll Tax Expense - Percent	L2 / L1	8.50%
4	Pro Forma Increase in S&W		$1,695
5	**Payroll Tax Pro Forma**	L3 * L4	**$144**

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.	Common-General Plant	PECO Common 3901 PA	$4,228	$43	$4,185	$43	$4,272
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	4,714	352	4,361	352	5,066
4			PECO Common 3903 PA	116	10	106	10	125
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,326	28	2,299	28	2,354
7			PECO Common 3913 IL	1,480	197	1,283	197	1,677
8			PECO Common 3913 PA	12,199	1,831	10,368	1,831	14,031
9			PECO Common 3930 PA	99	1	99	1	100
10			PECO Common 3941 PA	0		0		0
11			PECO Common 3942 PA	66		66		66
12			PECO Common 3970 PA	7,006	169	6,837	169	7,175
13			PECO Common 3980 PA	84		84		84
14			Subtotal Common - General Plant	$32,348	$2,631	$29,717	$2,631	$34,980
15								
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA					
17			Subtotal					
18								
19		Gas - Distribution	PECO Gas 3751 PA	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	40	3	38	3	43
21			PECO Gas 3753 PA	174	1	173	1	175
22			PECO Gas 3761 PA	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1,178		1,178		1,178
24			PECO Gas 3763 PA	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	565	18	547	18	584
26			PECO Gas 3790 PA	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	93		93		93
33			Subtotal Gas - Distribution	$78,724	$5,251	$73,473	$5,251	$83,975
34								

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
35		Gas - General Plant	PECO Gas 3901 PA	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	56	0	56	0	56
37			PECO Gas 3903 PA	86	5	81	5	91
38			PECO Gas 3911 PA	0		0		0
39			PECO Gas 3912 PA	34		34		34
40			PECO Gas 3913 IL	0		0		0
41			PECO Gas 3913 PA	442	4	438	4	445
42			PECO Gas 3940 PA	774	11	763	11	784
43			PECO Gas 3950 PA	2	0	2	0	2
44			PECO Gas 3970 PA	397	6	390	6	403
45			PECO Gas 3980 PA	8		8		8
46			Subtotal Gas - General Plant	$1,900	$27	$1,872	$27	$1,927
47								
48		Gas - Production Plant	PECO Gas 3050 PA	$31		$31		$31
49			PECO Gas 3053 PA					
50			PECO Gas 3110 PA	140		140		140
51			Subtotal Gas - Production Plant	$170		$170		$170
52								
53		Gas - Storage	PECO Gas 3611 PA	$49		$49		$49
54			PECO Gas 3612 PA	329		329		329
55			PECO Gas 3613 PA	23		23		23
56			PECO Gas 3620 PA	10		10		10
57			PECO Gas 3630 PA	25		25		25
58			PECO Gas 3631 PA	156		156		156
59			PECO Gas 3632 PA	3,965	237	3,728	237	4,201
60			PECO Gas 3633 PA	1,054	62	992	62	1,116
61			PECO Gas 3634 PA	671	64	607	64	735
62			PECO Gas 3635 PA	324	15	309	15	338
63			Subtotal Gas - Storage	$6,605	$377	$6,228	$377	$6,983
64								
65			Subtotal 403.0 Depreciation Expense.	$119,748	$8,287	$111,461	$8,287	$128,035
66								

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
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$12,690	$36	$12,653	$36	$12,726
68			PECO Com 3030-Apollo SW	967		967		967
69			PECO Com 3030-BIDA Customer Project	130		130		130
70			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
71			PECO Com 3030-CIS Transformation SW	120		120		120
72			PECO Com 3030-Cloud Serv 3 yr	6,069	169	5,901	169	6,238
73			PECO Com 3030-Cloud Serv 5 yr	2,585		2,585		2,585
74			PECO Com 3030-Common MDM SW	228		228		228
75			PECO Com 3030-EU Digital Program We	1,987		1,987		1,987
76			PECO Com 3030-EU oneMDS SW	5,269		5,269		5,269
77			PECO Com 3030-IT Cust Mobile App SW	111		111		111
78			PECO Com 3030-IVR System PA	159		159		159
79			PECO Com 3030-Misc 5 yr FR PA	9,884	2,098	7,787	2,098	11,982
80			PECO Com 3030-Misc 5 yr PA	60		60		60
81			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
82			PECO Com 3030-OBIEE Migration SW	275		275		275
83			PECO Com 3030-PECO RNI Upgrade SW	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant	$48,515	$2,303	$46,213	$2,303	$50,818
85								
86		Gas - General Plant	PECO Gas 3913 PA					
87			Subtotal					
88								
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	177		177		177
91			PECO Gas 303-SES IV G SW	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	51		51		51
94			Subtotal Gas - Intangible Plant	$3,695	$130	$3,565	$130	$3,824
95								
96			Subtotal 404.0 Amort. Of Limited-Term Plant	$52,210	$2,432	$49,778	$2,432	$54,642
97								
98			Grand Total	$171,958	$10,720	$161,238	$10,720	$182,678

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.	Common-General Plant	PECO Common 3901 PA	0.2307	$975	$10	$965	$10	$985
2			PECO Common 3902 IL	0.2307	4		4		4
3			PECO Common 3902 PA	0.2307	1,087	81	1,006	81	1,169
4			PECO Common 3903 PA	0.2307	27	2	24	2	29
5			PECO Common 3911 PA	0.2307	3		3		3
6			PECO Common 3912 PA	0.2307	537	6	530	6	543
7			PECO Common 3913 IL	0.2307	341	46	296	46	387
8			PECO Common 3913 PA	0.2307	2,814	422	2,392	422	3,237
9			PECO Common 3930 PA	0.2307	23	0	23	0	23
10			PECO Common 3941 PA	0.2307	0		0		0
11			PECO Common 3942 PA	0.2307	15		15		15
12			PECO Common 3970 PA	0.2307	1,616	39	1,577	39	1,655
13			PECO Common 3980 PA	0.2307	19		19		19
14			Subtotal Common - General Plant		$7,463	$607	$6,856	$607	$8,070
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	0.2307					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	1.0000	40	3	38	3	43
21			PECO Gas 3753 PA	1.0000	174	1	173	1	175
22			PECO Gas 3761 PA	1.0000	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	1.0000	565	18	547	18	584
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	1.0000	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	1.0000	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	1.0000	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	1.0000	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$78,724	$5,251	$73,473	$5,251	$83,975
34									

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)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	1.0000	56	0	56	0	56
37			PECO Gas 3903 PA	1.0000	86	5	81	5	91
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	442	4	438	4	445
42			PECO Gas 3940 PA	1.0000	774	11	763	11	784
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	397	6	390	6	403
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,900	$27	$1,872	$27	$1,927
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
58			PECO Gas 3631 PA	1.0000	156		156		156
59			PECO Gas 3632 PA	1.0000	3,965	237	3,728	237	4,201
60			PECO Gas 3633 PA	1.0000	1,054	62	992	62	1,116
61			PECO Gas 3634 PA	1.0000	671	64	607	64	735
62			PECO Gas 3635 PA	1.0000	324	15	309	15	338
63			Subtotal Gas - Storage		$6,605	$377	$6,228	$377	$6,983
64									
65			Subtotal 403.0 Depreciation Expense.		$94,862	$6,263	$88,600	$6,263	$101,125
66									

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)
67	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.2550	$3,236	$9	$3,226	$9	$3,245
68			PECO Com 3030-Apollo SW	0.2307	223		223		223
69			PECO Com 3030-BIDA Customer Project	0.2307	30		30		30
70			PECO Com 3030-BIDA-AMI Ph2 SW	0.2307	493		493		493
71			PECO Com 3030-CIS Transformation SW	0.2307	28		28		28
72			PECO Com 3030-Cloud Serv 3 yr	0.2307	1,400	39	1,361	39	1,439
73			PECO Com 3030-Cloud Serv 5 yr	0.2307	596		596		596
74			PECO Com 3030-Common MDM SW	0.2307	53		53		53
75			PECO Com 3030-EU Digital Program We	0.2307	458		458		458
76			PECO Com 3030-EU oneMDS SW	0.2307	1,216		1,216		1,216
77			PECO Com 3030-IT Cust Mobile App SW	0.2307	26		26		26
78			PECO Com 3030-IVR System PA	0.2307	37		37		37
79			PECO Com 3030-Misc 5 yr FR PA	0.2307	2,280	484	1,796	484	2,764
80			PECO Com 3030-Misc 5 yr PA	0.2307	14		14		14
81			PECO Com 3030-Mobile Dispatch Mappi	0.2307	1,348		1,348		1,348
82			PECO Com 3030-OBIEE Migration SW	0.2307	63		63		63
83			PECO Com 3030-PECO RNI Upgrade SW	0.2307	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant		$11,500	$532	$10,968	$532	$12,033
85									
86		Gas - General Plant	PECO Gas 3913 PA	1.0000					
87			Subtotal						
88									
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
91			PECO Gas 303-SES IV G SW	1.0000	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
94			Subtotal Gas - Intangible Plant		$3,695	$130	$3,565	$130	$3,824
95									
96			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,195	$662	$14,533	$662	$15,857
97									
98			Grand Total		$110,058	$6,925	$103,133	$6,925	$116,982

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 FPFTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$975	$10	$965	$10	$985
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	1,087	81	1,006	81	1,169
4			PECO Common 3903 PA	1.0000	27	2	24	2	29
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	537	6	530	6	543
7			PECO Common 3913 IL	1.0000	341	46	296	46	387
8			PECO Common 3913 PA	1.0000	2,814	422	2,392	422	3,237
9			PECO Common 3930 PA	1.0000	23	0	23	0	23
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	15		15		15
12			PECO Common 3970 PA	1.0000	1,616	39	1,577	39	1,655
13			PECO Common 3980 PA	1.0000	19		19		19
14			Subtotal Common - General Plant		$7,463	$607	$6,856	$607	$8,070
15									
16		Intangible Plant	PECO Com 3030-Misc 5 yr FR PA	1.0000					
17			Subtotal						
18									
19		Gas - Distribution	PECO Gas 3751 PA	1.0000	$140	$2	$138	$2	$143
20			PECO Gas 3752 PA	1.0000	40	3	38	3	43
21			PECO Gas 3753 PA	1.0000	174	1	173	1	175
22			PECO Gas 3761 PA	1.0000	13,431	2,111	11,320	2,111	15,542
23			PECO Gas 3762 PA	1.0000	1,178		1,178		1,178
24			PECO Gas 3763 PA	1.0000	23,592	1,497	22,095	1,497	25,088
25			PECO Gas 3780 PA	1.0000	565	18	547	18	584
26			PECO Gas 3790 PA	1.0000	1,050	0	1,050	0	1,050
27			PECO Gas 3801 PA	1.0000	3,616	10	3,606	10	3,625
28			PECO Gas 3802 PA	1.0000	23,417	1,282	22,135	1,282	24,699
29			PECO Gas 3810 PA	1.0000	2,172	49	2,124	49	2,221
30			PECO Gas 3811 PA	1.0000	3,524	18	3,507	18	3,542
31			PECO Gas 3820 PA	1.0000	5,731	261	5,470	261	5,992
32			PECO Gas 3870 PA	1.0000	93		93		93
33			Subtotal Gas - Distribution		$78,724	$5,251	$73,473	$5,251	$83,975
34									

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 FPFTY Depr (Function)
35		Gas - General Plant	PECO Gas 3901 PA	1.0000	$102	$1	$101	$1	$103
36			PECO Gas 3902 PA	1.0000	56	0	56	0	56
37			PECO Gas 3903 PA	1.0000	86	5	81	5	91
38			PECO Gas 3911 PA	1.0000	0		0		0
39			PECO Gas 3912 PA	1.0000	34		34		34
40			PECO Gas 3913 IL	1.0000	0		0		0
41			PECO Gas 3913 PA	1.0000	442	4	438	4	445
42			PECO Gas 3940 PA	1.0000	774	11	763	11	784
43			PECO Gas 3950 PA	1.0000	2	0	2	0	2
44			PECO Gas 3970 PA	1.0000	397	6	390	6	403
45			PECO Gas 3980 PA	1.0000	8		8		8
46			Subtotal Gas - General Plant		$1,900	$27	$1,872	$27	$1,927
47									
48		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$31		$31		$31
49			PECO Gas 3053 PA	1.0000					
50			PECO Gas 3110 PA	1.0000	140		140		140
51			Subtotal Gas - Production Plant		$170		$170		$170
52									
53		Gas - Storage	PECO Gas 3611 PA	1.0000	$49		$49		$49
54			PECO Gas 3612 PA	1.0000	329		329		329
55			PECO Gas 3613 PA	1.0000	23		23		23
56			PECO Gas 3620 PA	1.0000	10		10		10
57			PECO Gas 3630 PA	1.0000	25		25		25
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61			PECO Gas 3634 PA	1.0000	671	64	607	64	735
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64									
65			Subtotal 403.0 Depreciation Expense.		$94,862	$6,263	$88,600	$6,263	$101,125
66									

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69			PECO Com 3030-BIDA Customer Project	1.0000	30		30		30
70			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	493		493		493
71			PECO Com 3030-CIS Transformation SW	1.0000	28		28		28
72			PECO Com 3030-Cloud Serv 3 yr	1.0000	1,400	39	1,361	39	1,439
73			PECO Com 3030-Cloud Serv 5 yr	1.0000	596		596		596
74			PECO Com 3030-Common MDM SW	1.0000	53		53		53
75			PECO Com 3030-EU Digital Program We	1.0000	458		458		458
76			PECO Com 3030-EU oneMDS SW	1.0000	1,216		1,216		1,216
77			PECO Com 3030-IT Cust Mobile App SW	1.0000	26		26		26
78			PECO Com 3030-IVR System PA	1.0000	37		37		37
79			PECO Com 3030-Misc 5 yr FR PA	1.0000	2,280	484	1,796	484	2,764
80			PECO Com 3030-Misc 5 yr PA	1.0000	14		14		14
81			PECO Com 3030-Mobile Dispatch Mappi	1.0000	1,348		1,348		1,348
82			PECO Com 3030-OBIEE Migration SW	1.0000	63		63		63
83			PECO Com 3030-PECO RNI Upgrade SW	1.0000	(0)		(0)		(0)
84			Subtotal Common - Intangible Plant		$11,500	$532	$10,968	$532	$12,033
85									
86		Gas - General Plant	PECO Gas 3913 PA	1.0000					
87			Subtotal						
88									
89		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,697	$130	$2,568	$130	$2,827
90			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
91			PECO Gas 303-SES IV G SW	1.0000	759		759		759
92			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
93			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
94			Subtotal Gas - Intangible Plant		$3,695	$130	$3,565	$130	$3,824
95									
96			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,195	$662	$14,533	$662	$15,857
97									
98			Grand Total		$110,058	$6,925	$103,133	$6,925	$116,982

UPDATE 07-16-24

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$746,448	$110,194	$856,642
2	Operating Expenses		556,472	746	557,217
3	OIBIT	L1 - L2	$189,977	$109,448	$299,425
4					
5	Rate Base		$3,512,702		$3,512,702
6	Weighted Cost of Debt		2.130%		2.130%
7	Synchronized Interest Expense	L5 * L6	$74,821		$74,821
8	Base Taxable Income	L3 - L7	$115,156	$109,448	$224,604
9					
10	State Accelerated Tax Depreciation		$120,107		$120,107
11	Pro Forma Book Depreciation		116,982		116,982
12	State Tax Depreciation (Over) Under Book	L11 - L10	($3,125)		($3,125)
13	Regulatory Asset Programs M-1, Pension & Post-Retirement & Other		(3,619)		(3,619)
14	Other Property Basis Adjustments (CIAC/ICM)		(21,960)		(21,960)
15	Removal Costs/Software		(2,426)		(2,426)
16	AFUDC Equity		(7,418)		(7,418)
17	Permanent Adjustments		805		805
18	Repair Deduction		(151,000)		(151,000)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($73,585)	$109,448	$35,863
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$5,879	($8,745)	($2,865)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(2,352)	3,498	1,146
26	State Income Tax Benefit / (Expense)	L23 + L25	3,528	($5,247)	($1,719)
27					
28	Federal Accelerated Tax Depreciation		$112,651		$112,651
29	Pro Forma Book Depreciation		116,982		116,982
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$4,332		$4,332
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		(3,619)		(3,619)
32	Other Property Basis Adjustments (CIAC/ICM)		(21,960)		(21,960)
33	Removal Costs/Software		(2,426)		(2,426)
34	AFUDC Equity		(7,418)		(7,418)
35	Permanent Adjustments		805		805
36	Repair Deduction		(151,000)		(151,000)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($62,601)	$104,201	$41,600
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$13,146	($21,882)	($8,736)
42	Corporate Alternative Minimum Tax		($16,721)		($16,721)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($47)	($27,129)	($27,176)
44					

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($5,036)	$735	($4,301)
47	Deferred Taxes on Timing Differences- State		(2,044)		(2,044)
48	Deferred Taxes on State NOL		2,352	(3,498)	(1,146)
49	Excess Deferred Amortization		3,023		3,023
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(951)		(951)
53	Corporate Alternative Minimum Tax		16,721		16,721
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$14,337	($2,763)	$11,573
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$14,290	($29,893)	($15,603)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$5		$5
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$14,294	($29,893)	($15,598)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$10,187	($21,148)	($10,960)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	4,107	(8,745)	(4,638)
65	Total Income Tax Benefit / (Expense)	L63 + L64	$14,294	($29,893)	($15,598)

Line No.	Description	(1) Reference	(2) 2018	(3) 2019	(4) 2020	(5) 2021	(6) 2022	(7) Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		($85,736)	($162,524)	($249,053)	($575,746)	($108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	($12,750)	($33,376)		($11,242)	($18,122)	
14								
15								
16	Gas Percentage		-1.20%	-21.27%	163.65%	-259.39%	-38.60%	
17								
18								
19	Loss Allocable to Gas	L13 * L16	$153	$7,100		$29,160	$6,994	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						8,681
24								
25								
26	Tax Rate							21.00%
27								
28	Section 1301.1(b) Differential	L23 * L26						$1,823

PECO Gas Operations
Before The PAPUC
FPFTY Ending December 2025
($ in Thousands)
D-19 Conversion Factor

Line No.	Description	(1) Reference	(2) Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		1,329
4	Total Customer Revenue		740,896
5	Shopping Revenue		82,479
6	LPC REVENUE	L3 / (L4 + L5)	0.001614
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.003692)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.003087)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.994834
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.079487)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.915347
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.192223)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.723124
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.382888
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	27.171%
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%

Calculation of Working Capital Offset Factor

	Arrears	$ 1,000	
1	Incremental Age (Billing Date to Due Date)	22	
2	Age of Arrears at Charge-offs	189	
3	Days Remaining Until Charge-off (Age of Arrears Minus Incremental Age)	167	
4	Dollar Lag Days (Days Remaining X Dollars of Arrears)	$ 167,000	
5	Annualized Weighted Return	7.98%	PECO Exhibit MJT-1, Schedule B-7, Line 6, Column 4
6	Gross Up Factor for Taxes	37.57%	PECO Exhibit MJT-1, Schedule D-19, Line 50
7	Weighted Return (Annualized Return X Gross Up for Taxes)	11.0%	
8	Days Per Year	365	
9	Daily Return (Weighted Return / Days Per Year)	0.030%	
10	Annualizing Factor	1	
11	Annualized Working Capital per $1,000 Receivables	$ 50.23	
12	Working Capital Per $1 Receivables	$ 0.0502	
13	PECO CAP Rate Working Capital Offset	5.0%	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Michael J. Trzaska, hereby state that I am a Principal Regulatory and Rate 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 statements and exhibits listed below 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.

- PECO Statement No. 3
- PECO Exhibit MJT-1
- PECO Exhibit MJT-2
- PECO Exhibit MJT-3

- PECO Statement No. 3-R
- PECO Exhibit MJT-1 Revised
- PECO Exhibit MJT-4

Dated: August 5, 2024

Michael J. Trzaska

PECO Statement No. 4:

Direct Testimony of Caroline Fulginiti

PECO ENERGY COMPANY
STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: CAROLINE FULGINITI

SUBJECTS: OVERVIEW OF PECO ENERGY COMPANY'S ACCOUNTING PROCESSES; ALLOCATION OF COSTS BETWEEN ELECTRIC AND GAS OPERATIONS; AND GAS DIVISION DEPRECIATION CLAIMS

DATED: MARCH 28, 2024

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I. INTRODUCTION AND PURPOSE OF TESTIMONY 1

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DIRECT TESTIMONY
OF
CAROLINE FULGINITI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Caroline Fulginiti. 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 Exelon as Vice President and Assistant Controller. In that capacity, I am responsible for maintaining PECO Energy Company's ("PECO's" or the "Company's") accounting books and records under United States Generally Accepted Accounting Principles ("GAAP") and the Federal Energy Regulatory Commission's ("FERC") *Uniform System of Accounts Prescribed for Public Utilities and Licensees* and *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Federal Power Act* ("Uniform System of Accounts"). In addition, I am responsible for PECO's financial reporting to the U.S. Securities and Exchange Commission ("SEC"), the FERC and the Pennsylvania Public Utility Commission ("PUC" or "Commission").

3. Q. Please describe your educational background.

A. I received a Bachelor of Business Administration from James Madison University and Master of Professional Accountancy from Indiana University.

4. Q. Please describe your professional experience.

A. Upon graduation, I was hired as an audit associate for PricewaterhouseCoopers, LLP in Chicago. After seven years at PricewaterhouseCoopers, I began employment with Exelon Corporation in 2007. I held various roles at Exelon, including Manager of Accounting Policy & Research, Manager of Power Team Accounting and Manager of PECO Accounting prior to being promoted to Director of Property Accounting and Project Controls in 2014. In 2016, I became Director of Financial Operations for PECO, overseeing the Company's capital and operations and maintenance budgeting process. In January 2020, I became Director of Accounting at PECO. I assumed my current responsibilities as Vice President and Assistant Controller for Exelon in February 2024.

5. Q. What is the purpose of your testimony?

A. I will provide a general overview of PECO's accounting processes. I will then describe how PECO allocates common costs between its natural gas and electric operations. Finally, I will present and explain PECO's claims for accrued and annual depreciation related to the utility plant in service of PECO's Gas Division as of the end of the historic test year (December 31, 2023) ("HTY"), future test year (December 31, 2024) ("FTY") and the fully projected future test year (December 31, 2025) ("FPFTY").

6. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring PECO Exhibits CF-1, CF-2, and CF-3, which include, respectively, the results of the depreciation studies related to the original cost of PECO's gas and common plant in service at December 31, 2023, and estimated to

be in service at December 31, 2024 and December 31, 2025. I am also sponsoring PECO Exhibit CF-4, which is a service-life study performed by Gannett Fleming, Inc. ("Gannet Fleming") based upon plant balances at December 31, 2018.

II. OVERVIEW OF PECO'S ACCOUNTING PROCESSES

7. Q. How are PECO's accounting records maintained?

A. The Company's accounting records are kept in accordance with GAAP and FERC's Uniform System of Accounts, as required by the PUC's regulations at 52 Pa. Code § 57.42(a). In addition, PECO maintains a continuing property records system in accordance with PUC and FERC requirements.

8. Q. Do PECO's continuing property records accurately reflect the original cost of the property in question?

A. Yes, they do. A determination of the original cost of PECO's gas plant was made in the 1940s with the approval of the PUC. Subsequent plant additions, retirements and adjustments have been recorded on an original cost basis in accordance with GAAP, the PUC's regulations and the Uniform System of Accounts.

10. Q. Are PECO's books and records audited?

A. Yes, PECO's books and records are audited. Exelon Corporation maintains Exelon Audit Services ("EAS"), which routinely audits various aspects of PECO's operations. In addition, PECO's books and records are audited annually by its outside auditors.

In 2022, the PUC completed a Management and Operations Audit of PECO that included a review of the Company's internal audit process.[1] The PUC's review of the internal audit process resulted in no recommendations.

11. Q. How can you be sure that all property reflected in PECO's plant accounts is, in fact, used and useful?

A. As explained in the testimony of Company witness Amy E. Hamilton in PECO Statement No. 1, the assets included in PECO's rate base in this case are, or by the end of the FTY and the FPFTY will be, in service and used by PECO to provide gas service to its customers. Moreover, PECO has a process in place requiring that: (1) a record be made in the field at the time any property unit is added to service or permanently removed from service; and (2) based on the records made in the field, appropriate accounting entries be made to the Company's property accounts to add or remove, respectively, the original cost of any property unit that was added or retired. Individuals with appropriate authority must review and approve the entries that are made to record the addition and removal of property units from the Company's plant accounts. Additionally, EAS performed an audit of the controls surrounding PECO's fixed asset process in 2015, which included review of fixed asset accounting records. EAS concluded that the processes and general control environment – which includes those activities necessary to provide reasonable assurance that risks are being managed and objectives met – are effective.

[1] *See* Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (Issued July 2022).

III. ALLOCATION OF COSTS BETWEEN ELECTRIC AND GAS OPERATIONS

12. Q. Does PECO maintain separate books and records for its electric and natural gas operations?

A. Yes. Under applicable PUC and FERC regulations, PECO is required to maintain, separately, certain income statement accounts and to maintain, separately, certain balance sheet accounts for its electric and natural gas operations.

13. Q. How does the Company allocate "common plant" assets between its two divisions?

A. "Common plant" assets (i.e., facilities, such as PECO's headquarters office building in Philadelphia, that are used to provide both electric and gas service) are allocated on the basis of a three-part formula, with equal weight given to relative plant investment, total revenue, and number of customers. The allocation factors utilized for purposes of this rate filing are set forth in the applicable schedules of PECO Exhibits MJT-1, MJT-2, and MJT-3.

14. Q. Are operating expenses handled in the same fashion?

A. No, a different method is used to allocate operating expenses. The Company develops factors to allocate between gas and electric operations those operating expenses that are not directly assigned. PECO reviews these factors annually and updates them as necessary to reflect the forces driving the costs to which they apply.

15. Q. Please explain the method used to allocate non-assignable Administrative and General ("A&G") expense.

A. Expenses in this category consist of the labor and other resources of the Company's A&G departments, such as Finance, Marketing, and Accounting, that provide service to both the gas and electric divisions. Non-assignable expenses in these areas are allocated to gas operations based upon a percentage calculated by dividing: (1) the previous year's non-fuel Operating & Maintenance ("O&M") expenses that were directly assigned to gas operations, by (2) the total of all the previous year's non-fuel O&M expenses that were directly assigned to gas and electric operations.

16. Q. Please explain the method used to allocate non-assignable bad debt expense.

A. Bad debt expense associated with customer accounts receivable is allocated to gas operations based on the historical ratio of accounts receivable charged off. Although bad debt expense is allocated for accounting purposes, uncollectible accounts expense included in PECO's revenue requirement for ratemaking purposes is calculated based on the net uncollectible accounts charged off, expressed as a percentage of total tariff revenue, as explained by Company witness Michael J. Trzaska in PECO Statement No. 3.

IV. PECO GAS DIVISION DEPRECIATION CLAIMS

17. Q. Has a service-life study of PECO's gas utility plant in service been performed?

A. Yes. With the assistance of Gannett Fleming, a service-life study was performed based on PECO's plant balances at December 31, 2018, which is provided as

PECO Exhibit CF-4. The study was filed with the PUC in April 2020 at Docket No. M-2020-3020569. Prior to the Company's 2018 service-life study, a service-life study was performed in 2014 based on PECO's plant balances at December 31, 2013.

18. Q. Have you prepared exhibits presenting the results of PECO's depreciation studies?

A. Yes. PECO Exhibits CF-1, CF-2 and CF-3 reflect PECO's gas and common plant in service as of December 31, 2023, 2024, and 2025 respectively. Exhibits CF-1, CF-2, and CF-3 rely upon the service lives and depreciation rates developed in the Company's 2018 service-life study.

19. Q. What is the purpose of the depreciation study?

A. PECO is relying principally on data for a FPFTY ending December 31, 2025 to support its proposed increase in revenue requirement in this case. Accordingly, the purpose of the depreciation study is to provide the basis to calculate the estimated 2025 annual depreciation accruals related to plant in service for ratemaking purposes and, using procedures approved by the PUC, to estimate PECO's book reserve at December 31, 2025.

PECO uses the remaining-life method of depreciation, which calculates depreciation accruals designed to recover the original cost less accrued depreciation of utility plant over the estimated remaining life of that plant, by depreciable group.

20. Q. Please describe PECO Exhibits CF-1, CF-2, and CF-3.

A. PECO Exhibit CF-1 is titled "Annual Depreciation Accruals Related to Utility

Plant in Service for 2023." This exhibit includes the results of the depreciation study related to the original cost of PECO's plant in service at December 31, 2023. The exhibit also includes the detailed depreciation calculations used to determine 2024 depreciation rates, which are used in calculating the estimated 2024 Annual Depreciation Accruals shown in PECO Exhibit CF-2.

PECO Exhibit CF-2 is titled "Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024." This exhibit includes the results of the depreciation study related to the estimated original cost of PECO's plant in service at December 31, 2024. PECO Exhibit CF-2 includes PECO's FTY plant additions for gas and allocated common plant assets claimed in rate base in this case and reflects the depreciation accruals related to those additions in the column titled "2024 Estimated Annual Depreciation Accrual."

PECO Exhibit CF-3 is titled "Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025." This exhibit includes the results of the depreciation study related to the estimated original cost of PECO's plant in service at December 31, 2025. PECO Exhibit CF-3 includes PECO's FPFTY plant additions for gas and allocated common plant assets claimed in rate base in this case and reflects the depreciation accruals related to those additions in the column titled "2025 Estimated Annual Depreciation Accrual."

21. Q. Has the Commission previously approved PECO's use of the remaining-life method of depreciation?

A. Yes. In 1988, the Commission approved PECO's use of the remaining-life method in PECO's Gas Division rate proceeding at Docket No. R-870629, and

also approved PECO's adjusted book reserve as the measure of accrued depreciation for ratemaking. PECO has employed the remaining-life method in each of the Annual Depreciation Reports filed with the Commission since it adopted the remaining-life method.

22. Q. How was the accumulated depreciation recorded in the Company's book reserve ("accumulated depreciation") used in the calculation of annual depreciation?

A. The accumulated depreciation, by account, at December 31, 2023, is one of the factors used in calculating the annual depreciation accruals. The methodology used to calculate the annual depreciation accrual is consistent with the methodology described in the 2018 Depreciation Study (PECO Exhibit CF-4).

23. Q. How was the estimated accumulated depreciation at December 31, 2024 determined?

A. As shown in PECO Exhibit CF-2, the December 31, 2024 estimated accumulated depreciation was developed by: (1) adding the 2024 estimated annual depreciation accruals to the actual accumulated depreciation by account as of January 1, 2024; (2) subtracting the estimated 2024 plant retirements by account; and (3) adding 2024 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The 2024 annual depreciation accruals are estimated by adding the following three items: (1) the estimated net book value of depreciable plant by account as of December 31, 2023, multiplied by the depreciation rates shown in PECO Exhibit CF-2; (2) the 2024 estimated plant additions multiplied by the depreciation rate (using a half-year convention)

for the appropriate accounts; and (3) the 2024 estimated salvage or cost of removal multiplied by the depreciation rate (using a half-year convention) for the appropriate account.

24. Q. How was the estimated accumulated depreciation at December 31, 2025 determined?

A. As shown in PECO Exhibit CF-3, the December 31, 2025 estimated accumulated depreciation was developed by: (1) adding the 2025 estimated annual depreciation accruals to the estimated accumulated depreciation by account as of January 1, 2025; (2) subtracting the 2025 estimated plant retirements by account; and (3) adding 2025 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The 2025 annual depreciation accruals are estimated by adding the following three items: (1) the estimated net book value balance of depreciable plant by account as of December 31, 2024, multiplied by the depreciation rates shown in PECO Exhibit CF-3; (2) the 2025 estimated plant additions multiplied by the depreciation rate (using a half-year convention) for the appropriate account; and (3) the 2025 estimated salvage or cost of removal multiplied by the depreciation rate (using a half-year convention) for the appropriate account.

25. Q. Have you prepared schedules that summarize the development of the original cost of gross plant, estimated accumulated depreciation, estimated net book value of depreciable plant, and estimated annual depreciation accruals, by property account, for utility plant in service at December 31, 2025?

A. Yes. PECO Exhibit CF-3 provides this information. The original cost of gross

plant in service at December 31, 2025 was calculated by adding the estimated plant additions by account for 2025 to, and subtracting the estimated plant retirements for 2025 from, the estimated original cost of gross plant as of December 31, 2024. The estimated net book value of depreciable plant at December 31, 2025 was calculated by subtracting the estimated accumulated depreciation at December 31, 2025 from the estimated original cost of gross plant at December 31, 2025. The 2025 annual depreciation accruals were estimated by adding the following three items: (1) the estimated net book value balance of depreciable plant by account as of December 31, 2024, multiplied by the depreciation rates shown in PECO Exhibit CF-3; (2) the 2025 estimated plant additions multiplied by the depreciation rate (using a half-year convention) for the appropriate accounts; and (3) the 2025 estimated salvage or cost of removal multiplied by the depreciation rate (using a half- year convention) for the appropriate accounts.

V. CONCLUSION

26. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit CF-1:

Annual Depreciation Accruals Related to Utility Plant in Service for 2023

Annual Depreciation Accruals Related to
Utility Plant in Service for 2023

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the original cost of PECO's gas and common plant in service at December 31, 2023. The report also includes the detailed depreciation calculations used to determine 2024 depreciation rates, which are used in calculating the estimated 2024 Annual Depreciation Accruals shown in PECO Exhibit CF-2.

Note:
The system generated reports show the date for each utility account as of January 1, 2024. The balances as of December 31, 2023 are the same as the balances as of January 1, 2024.

Generation Arrangement Report

PECO Gas 375 Composite 2024

Account: PECO Gas 375 Composite
Dispersion: 50.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$240,275.77	50.00	49.50	0.9900	1.0000	$237,875.40	$4,805.52
2022	1.50	$470,708.93	50.00	48.50	0.9700	1.0000	$456,601.57	$9,414.18
2021	2.50	$906,847.43	50.00	47.50	0.9501	1.0000	$861,557.98	$18,136.95
2020	3.50	$631,975.54	50.00	46.50	0.9301	1.0000	$587,791.95	$12,639.51
2019	4.50	$43,808.94	50.00	45.51	0.9101	1.0000	$39,871.94	$876.18
2018	5.50	$743,586.92	50.00	44.51	0.8902	1.0000	$661,931.10	$14,871.74
2017	6.50	$133,516.74	50.00	43.51	0.8703	1.0000	$116,195.06	$2,670.33
2016	7.50	$135,078.02	50.00	42.52	0.8504	1.0000	$114,863.85	$2,701.56
2015	8.50	$289,156.35	50.00	41.52	0.8305	1.0000	$240,133.13	$5,783.13
2014	9.50	$85,767.42	50.00	40.53	0.8106	1.0000	$69,523.14	$1,715.35
2013	10.50	$464,798.22	50.00	39.54	0.7908	1.0000	$367,551.77	$9,295.96
2012	11.50	$364,549.18	50.00	38.55	0.7710	1.0000	$281,060.24	$7,290.98
2007	16.50	$49,885.92	50.00	33.64	0.6728	1.0000	$33,565.31	$997.72
2004	19.50	$129,057.30	50.00	30.75	0.6150	1.0000	$79,363.84	$2,581.15
2003	20.50	$925,633.96	50.00	29.79	0.5959	1.0000	$551,576.10	$18,512.68
2002	21.50	$50,149.65	50.00	28.85	0.5770	1.0000	$28,934.43	$1,002.99
2001	22.50	$194,581.67	50.00	27.91	0.5582	1.0000	$108,613.62	$3,891.63
1999	24.50	$8,943.15	50.00	26.06	0.5212	1.0000	$4,660.83	$178.86
1998	25.50	$1,573,347.17	50.00	25.15	0.5029	1.0000	$791,287.69	$31,466.94
1997	26.50	$1,388,434.92	50.00	24.25	0.4849	1.0000	$673,273.00	$27,768.70
1996	27.50	$580,187.29	50.00	23.36	0.4671	1.0000	$271,018.63	$11,603.75
1995	28.50	$409,535.36	50.00	22.48	0.4496	1.0000	$184,113.51	$8,190.71
1994	29.50	$3,302,580.25	50.00	21.61	0.4323	1.0000	$1,427,578.19	$66,051.61
1992	31.50	$27,196.22	50.00	19.92	0.3984	1.0000	$10,836.26	$543.92
1991	32.50	$23,320.58	50.00	19.10	0.3820	1.0000	$8,907.54	$466.41
1990	33.50	$50,101.91	50.00	18.29	0.3658	1.0000	$18,325.69	$1,002.04
1989	34.50	$607,780.96	50.00	17.49	0.3499	1.0000	$212,642.94	$12,155.62
1988	35.50	$313,781.34	50.00	16.71	0.3343	1.0000	$104,887.80	$6,275.63
1987	36.50	$1,129.98	50.00	15.95	0.3190	1.0000	$360.44	$22.60
1986	37.50	$8,008.81	50.00	15.20	0.3040	1.0000	$2,434.59	$160.18
1985	38.50	$167,133.13	50.00	14.46	0.2893	1.0000	$48,350.99	$3,342.66
1984	39.50	$233,206.14	50.00	13.75	0.2749	1.0000	$64,108.78	$4,664.12

Generation Arrangement Report

PECO Gas 375 Composite 2024

Account: PECO Gas 375 Composite
Dispersion: 50.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1983	40.50	$57,390.13	50.00	13.04	0.2608	1.0000	$14,966.68	$1,147.80
1982	41.50	$210,672.48	50.00	12.35	0.2469	1.0000	$52,025.33	$4,213.45
1981	42.50	$6,330.35	50.00	11.67	0.2334	1.0000	$1,477.40	$126.61
1980	43.50	$377,828.96	50.00	11.01	0.2201	1.0000	$83,168.06	$7,556.58
1979	44.50	$10,389.66	50.00	10.36	0.2072	1.0000	$2,153.19	$207.79
1978	45.50	$732.74	50.00	9.74	0.1948	1.0000	$142.76	$14.65
1975	48.50	$1,994.22	50.00	8.06	0.1611	1.0000	$321.31	$39.88
1973	50.50	$4,245.03	50.00	7.09	0.1419	1.0000	$602.30	$84.90
1972	51.50	$1,571.01	50.00	6.66	0.1332	1.0000	$209.27	$31.42
1971	52.50	$223,034.69	50.00	6.26	0.1251	1.0000	$27,902.13	$4,460.69
1966	57.50	$33,520.90	50.00	4.56	0.0912	1.0000	$3,058.38	$670.42
1965	58.50	$190,782.08	50.00	4.27	0.0854	1.0000	$16,291.18	$3,815.64
1964	59.50	$32,802.90	50.00	3.99	0.0797	1.0000	$2,615.38	$656.06
1963	60.50	$8,670.53	50.00	3.71	0.0742	1.0000	$643.50	$173.41
1962	61.50	$142,557.58	50.00	3.44	0.0688	1.0000	$9,809.83	$2,851.15
1955	68.50	$343.25	50.00	1.69	0.0338	1.0000	$11.59	$6.87
1954	69.50	$4,600.69	50.00	1.46	0.0293	1.0000	$134.78	$92.01
1943	80.50	$447.14	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1932	91.50	$37.51	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	92.50	$821.26	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	108.50	$1,143.09	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1910	113.50	$1,046.66	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$15,865,028.03	50.00	27.98	0.5594	1.0000	$8,875,330.36	$317,230.65

Remaining Life Depreciation Accrual

Account: PECO Gas 375 Composite
Scenario: PECO Gas 375 Composite 2024
Dispersion: 50.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$15,865,028.03	27.98	$340,908.80	2.148807%	3.574297%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($181,827.84)	0.50	($1,818.28)	1.000001%	
Total:	$15,865,028.03 *		$339,090.52	2.137346%	3.555233%
Average:	$15,774,114.11		$339,090.52	2.149664%	3.589447%
Grand Total:	$15,865,028.03 *		$339,090.52	2.137346%	3.555233%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3761 PA
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$20,974,151.43	70.00	69.51	0.9930	1.0000	$20,826,456.07	$299,630.73
2022	1.50	$33,880,272.85	70.00	68.52	0.9789	1.0000	$33,165,901.01	$484,003.90
2021	2.50	$61,184,396.43	70.00	67.54	0.9649	1.0000	$59,035,632.45	$874,062.81
2020	3.50	$43,688,316.56	70.00	66.56	0.9509	1.0000	$41,543,049.56	$624,118.81
2019	4.50	$41,584,571.37	70.00	65.59	0.9369	1.0000	$38,961,789.07	$594,065.31
2018	5.50	$26,162,806.22	70.00	64.61	0.9230	1.0000	$24,148,230.19	$373,754.37
2017	6.50	$12,187,230.93	70.00	63.64	0.9091	1.0000	$11,079,421.84	$174,103.30
2016	7.50	$12,991,325.00	70.00	62.67	0.8952	1.0000	$11,630,153.90	$185,590.36
2015	8.50	$13,908,928.71	70.00	61.70	0.8814	1.0000	$12,259,500.64	$198,698.98
2014	9.50	$12,372,639.84	70.00	60.73	0.8676	1.0000	$10,734,739.74	$176,752.00
2013	10.50	$4,526,391.80	70.00	59.77	0.8539	1.0000	$3,865,036.17	$64,662.74
2012	11.50	$5,350,906.27	70.00	58.81	0.8402	1.0000	$4,495,838.90	$76,441.52
2011	12.50	$8,486,622.29	70.00	57.86	0.8266	1.0000	$7,014,658.65	$121,237.46
2010	13.50	$7,284,654.55	70.00	56.91	0.8130	1.0000	$5,922,215.81	$104,066.49
2009	14.50	$7,440,029.35	70.00	55.96	0.7994	1.0000	$5,947,741.85	$106,286.13
2008	15.50	$10,195,168.06	70.00	55.02	0.7860	1.0000	$8,012,931.62	$145,645.26
2007	16.50	$6,610,607.32	70.00	54.08	0.7725	1.0000	$5,106,801.66	$94,437.25
2006	17.50	$10,017,707.09	70.00	53.14	0.7592	1.0000	$7,605,143.40	$143,110.10
2005	18.50	$8,145,618.55	70.00	52.21	0.7459	1.0000	$6,075,675.70	$116,365.98
2004	19.50	$6,935,920.44	70.00	51.29	0.7326	1.0000	$5,081,599.52	$99,084.58
2003	20.50	$3,686,464.19	70.00	50.37	0.7195	1.0000	$2,652,412.36	$52,663.77
2002	21.50	$4,818,507.59	70.00	49.45	0.7064	1.0000	$3,403,817.03	$68,835.82
2001	22.50	$10,237,661.78	70.00	48.54	0.6934	1.0000	$7,098,789.15	$146,252.31
2000	23.50	$85,853.98	70.00	47.63	0.6805	1.0000	$58,419.49	$1,226.49
1999	24.50	$15,746,946.05	70.00	46.73	0.6676	1.0000	$10,512,859.16	$224,956.37
1998	25.50	$20,503,007.13	70.00	45.84	0.6548	1.0000	$13,426,248.03	$292,900.10
1997	26.50	$33,197,201.32	70.00	44.95	0.6421	1.0000	$21,317,432.38	$474,245.73
1996	27.50	$27,371,978.62	70.00	44.07	0.6296	1.0000	$17,232,031.47	$391,028.27
1995	28.50	$27,794,594.84	70.00	43.19	0.6170	1.0000	$17,149,732.61	$397,065.64
1994	29.50	$7,885,294.37	70.00	42.32	0.6046	1.0000	$4,767,454.94	$112,647.06
1993	30.50	$11,415,469.45	70.00	41.46	0.5922	1.0000	$6,760,682.01	$163,078.13
1992	31.50	$15,109,656.36	70.00	40.60	0.5800	1.0000	$8,763,909.68	$215,852.23

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3761 PA
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$12,664,557.15	70.00	39.75	0.5679	1.0000	$7,191,957.64	$180,922.25
1990	33.50	$12,598,192.35	70.00	38.91	0.5558	1.0000	$7,002,253.84	$179,974.18
1989	34.50	$12,836,035.62	70.00	38.07	0.5439	1.0000	$6,981,174.35	$183,371.94
1988	35.50	$10,409,986.00	70.00	37.24	0.5320	1.0000	$5,538,132.69	$148,714.09
1987	36.50	$7,878,139.61	70.00	36.42	0.5203	1.0000	$4,098,692.69	$112,544.85
1986	37.50	$6,365,655.39	70.00	35.60	0.5086	1.0000	$3,237,467.87	$90,937.93
1985	38.50	$6,557,260.55	70.00	34.79	0.4971	1.0000	$3,259,358.89	$93,675.15
1984	39.50	$3,826,270.27	70.00	33.99	0.4856	1.0000	$1,858,155.82	$54,661.00
1983	40.50	$4,128,062.91	70.00	33.20	0.4743	1.0000	$1,957,881.66	$58,972.33
1982	41.50	$4,086,881.69	70.00	32.42	0.4631	1.0000	$1,892,544.83	$58,384.02
1981	42.50	$10,263,895.80	70.00	31.64	0.4519	1.0000	$4,638,740.50	$146,627.08
1980	43.50	$8,944,343.52	70.00	30.87	0.4410	1.0000	$3,944,192.69	$127,776.34
1979	44.50	$2,877,126.33	70.00	30.10	0.4301	1.0000	$1,237,326.07	$41,101.80
1978	45.50	$1,291,263.53	70.00	29.35	0.4193	1.0000	$541,450.52	$18,446.62
1977	46.50	$985,423.00	70.00	28.61	0.4087	1.0000	$402,729.68	$14,077.47
1976	47.50	$1,366,399.38	70.00	27.87	0.3981	1.0000	$544,029.39	$19,519.99
1975	48.50	$1,971,637.23	70.00	27.14	0.3878	1.0000	$764,552.65	$28,166.25
1974	49.50	$2,926,395.38	70.00	26.42	0.3775	1.0000	$1,104,666.13	$41,805.65
1973	50.50	$3,939,788.80	70.00	25.72	0.3674	1.0000	$1,447,386.17	$56,282.70
1972	51.50	$4,147,315.54	70.00	25.01	0.3573	1.0000	$1,482,005.88	$59,247.36
1971	52.50	$4,470,260.68	70.00	24.33	0.3475	1.0000	$1,553,494.41	$63,860.87
1970	53.50	$4,813,373.44	70.00	23.65	0.3378	1.0000	$1,626,046.58	$68,762.48
1969	54.50	$5,646,018.20	70.00	22.98	0.3282	1.0000	$1,853,206.40	$80,657.40
1968	55.50	$4,295,343.68	70.00	22.32	0.3188	1.0000	$1,369,534.38	$61,362.05
1967	56.50	$4,277,022.10	70.00	21.67	0.3096	1.0000	$1,323,959.87	$61,100.32
1966	57.50	$4,439,615.09	70.00	21.03	0.3005	1.0000	$1,334,028.14	$63,423.07
1965	58.50	$3,150,563.68	70.00	20.41	0.2915	1.0000	$918,404.68	$45,008.05
1964	59.50	$3,917,008.43	70.00	19.79	0.2828	1.0000	$1,107,642.24	$55,957.26
1963	60.50	$2,804,486.44	70.00	19.19	0.2742	1.0000	$768,989.21	$40,064.09
1962	61.50	$3,656,759.20	70.00	18.60	0.2658	1.0000	$971,822.44	$52,239.42
1961	62.50	$1,722,827.03	70.00	18.03	0.2575	1.0000	$443,705.70	$24,611.81
1960	63.50	$2,206,138.86	70.00	17.46	0.2495	1.0000	$550,341.33	$31,516.27

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3761 PA
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$1,749,077.94	70.00	16.91	0.2416	1.0000	$422,615.78	$24,986.83
1958	65.50	$1,586,517.56	70.00	16.37	0.2339	1.0000	$371,095.77	$22,664.54
1957	66.50	$3,575,986.53	70.00	15.85	0.2264	1.0000	$809,773.43	$51,085.52
1956	67.50	$1,312,047.07	70.00	15.34	0.2192	1.0000	$287,559.65	$18,743.53
1955	68.50	$1,248,070.38	70.00	14.84	0.2121	1.0000	$264,654.46	$17,829.58
1954	69.50	$1,388,027.09	70.00	14.36	0.2052	1.0000	$284,768.89	$19,828.96
1953	70.50	$1,020,910.27	70.00	13.89	0.1984	1.0000	$202,579.49	$14,584.43
1952	71.50	$831,394.47	70.00	13.44	0.1919	1.0000	$159,571.32	$11,877.06
1951	72.50	$911,992.34	70.00	12.99	0.1856	1.0000	$169,259.15	$13,028.46
1950	73.50	$314,742.04	70.00	12.56	0.1795	1.0000	$56,488.24	$4,496.31
1949	74.50	$301,078.41	70.00	12.15	0.1735	1.0000	$52,248.35	$4,301.12
1948	75.50	$150,032.74	70.00	11.74	0.1678	1.0000	$25,172.19	$2,143.32
1947	76.50	$325,506.46	70.00	11.35	0.1622	1.0000	$52,798.56	$4,650.09
1946	77.50	$290,583.31	70.00	10.98	0.1568	1.0000	$45,566.55	$4,151.19
1945	78.50	$55,325.34	70.00	10.61	0.1516	1.0000	$8,386.24	$790.36
1944	79.50	$68,147.97	70.00	10.26	0.1465	1.0000	$9,986.31	$973.54
1943	80.50	$10,330.87	70.00	9.91	0.1416	1.0000	$1,463.10	$147.58
1942	81.50	$17,814.14	70.00	9.58	0.1369	1.0000	$2,438.04	$254.49
1941	82.50	$8,757.59	70.00	9.26	0.1323	1.0000	$1,158.40	$125.11
1940	83.50	$6,895.44	70.00	8.94	0.1278	1.0000	$881.08	$98.51
1939	84.50	$9,545.64	70.00	8.64	0.1235	1.0000	$1,178.71	$136.37
1938	85.50	$13,221.43	70.00	8.34	0.1192	1.0000	$1,576.01	$188.88
1937	86.50	$4,497.30	70.00	8.06	0.1152	1.0000	$517.91	$64.25
1936	87.50	$798.05	70.00	7.77	0.1111	1.0000	$88.63	$11.40
1935	88.50	$2,352.38	70.00	7.49	0.1071	1.0000	$251.86	$33.61
1934	89.50	$4,163.42	70.00	7.23	0.1032	1.0000	$429.83	$59.48
1933	90.50	$4,104.06	70.00	6.95	0.0994	1.0000	$407.76	$58.63
1932	91.50	$3,214.39	70.00	6.70	0.0957	1.0000	$307.54	$45.92
1931	92.50	$31,920.53	70.00	6.43	0.0918	1.0000	$2,931.89	$456.01
1930	93.50	$95,323.06	70.00	6.18	0.0883	1.0000	$8,415.87	$1,361.76
1929	94.50	$27,932.87	70.00	5.91	0.0845	1.0000	$2,359.85	$399.04
1928	95.50	$26,728.90	70.00	5.65	0.0807	1.0000	$2,158.14	$381.84

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3761 PA
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1927	96.50	$22,709.34	70.00	5.40	0.0772	1.0000	$1,752.15	$324.42
1926	97.50	$19,557.55	70.00	5.14	0.0734	1.0000	$1,435.35	$279.39
1925	98.50	$5,565.06	70.00	4.89	0.0699	1.0000	$388.79	$79.50
1924	99.50	$4,798.67	70.00	4.62	0.0661	1.0000	$317.02	$68.55
1923	100.50	$6,084.88	70.00	4.38	0.0626	1.0000	$380.98	$86.93
1922	101.50	$697.84	70.00	4.12	0.0588	1.0000	$41.03	$9.97
1921	102.50	$1,689.29	70.00	3.85	0.0550	1.0000	$92.98	$24.13
1920	103.50	$1,749.07	70.00	3.61	0.0515	1.0000	$90.12	$24.99
1919	104.50	$258.97	70.00	3.34	0.0478	1.0000	$12.37	$3.70
1918	105.50	$70.30	70.00	3.11	0.0444	1.0000	$3.12	$1.00
1917	106.50	$166.74	70.00	2.84	0.0406	1.0000	$6.77	$2.38
1916	107.50	$323.65	70.00	2.62	0.0375	1.0000	$12.12	$4.62
1915	108.50	$21.37	70.00	2.36	0.0337	1.0000	$0.72	$0.31
1914	109.50	$4.09	70.00	2.11	0.0301	1.0000	$0.12	$0.06
1913	110.50	$4.90	70.00	1.89	0.0269	1.0000	$0.13	$0.07
1912	111.50	$3.16	70.00	1.63	0.0233	1.0000	$0.07	$0.05
1911	112.50	$8.64	70.00	1.43	0.0205	1.0000	$0.18	$0.12
1910	113.50	$0.89	70.00	1.17	0.0168	1.0000	$0.01	$0.01
1909	114.50	$1.64	70.00	1.03	0.0148	1.0000	$0.02	$0.02
1908	115.50	$1.32	70.00	0.81	0.0116	1.0000	$0.02	$0.02
1907	116.50	$1.96	70.00	0.55	0.0079	1.0000	$0.02	$0.03
1906	117.50	$1.35	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1905	118.50	$0.82	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1904	119.50	$0.98	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1903	120.50	$0.96	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1902	121.50	$0.83	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	122.50	$0.97	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	123.50	$0.98	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1899	124.50	$0.97	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1891	132.50	$0.71	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1890	133.50	$0.92	70.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3761 PA
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1880	143.50	$0.99	70.00	0.00	0.0000	0.0000	$0.00	$0.00
		$712,705,717.42	70.00	50.27	0.7182	1.0000	$511,855,804.51	$10,181,510.10

Remaining Life Depreciation Accrual

Account: PECO Gas 3761 PA
Scenario: PECO Gas Groups 2024
Dispersion: 70.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$712,705,717.42	50.27	$10,269,832.37	1.440964%	1.989136%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,822,210.52)	0.50	($20,158.65)	0.714286%	
Total:	$712,705,717.42 *		$10,249,673.72	1.438135%	1.985232%
Average:	$711,294,612.16		$10,249,673.72	1.440989%	1.990673%
Grand Total:	$712,705,717.42 *		$10,249,673.72	1.438135%	1.985232%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3762 PA
Dispersion: 60.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2022	1.50	$21,443.81	60.00	58.64	0.9774	1.0000	$20,958.97	$357.40
2011	12.50	$0.03	60.00	49.01	0.8169	1.0000	$0.02	$0.00
2009	14.50	$112.58	60.00	47.33	0.7888	1.0000	$88.81	$1.88
1971	52.50	$28,285.12	60.00	20.44	0.3407	1.0000	$9,637.34	$471.42
1970	53.50	$120,833.17	60.00	19.90	0.3317	1.0000	$40,077.10	$2,013.89
1969	54.50	$349,972.72	60.00	19.36	0.3227	1.0000	$112,951.51	$5,832.88
1968	55.50	$638,322.24	60.00	18.84	0.3140	1.0000	$200,411.67	$10,638.70
1967	56.50	$483,004.88	60.00	18.32	0.3054	1.0000	$147,513.96	$8,050.08
1966	57.50	$544,822.21	60.00	17.82	0.2970	1.0000	$161,799.31	$9,080.37
1965	58.50	$252,476.22	60.00	17.32	0.2887	1.0000	$72,889.68	$4,207.94
1964	59.50	$265,677.30	60.00	16.84	0.2806	1.0000	$74,557.88	$4,427.96
1963	60.50	$265,594.30	60.00	16.36	0.2727	1.0000	$72,427.46	$4,426.57
1962	61.50	$582,224.94	60.00	15.90	0.2649	1.0000	$154,259.44	$9,703.75
1961	62.50	$538,468.19	60.00	15.44	0.2573	1.0000	$138,574.61	$8,974.47
1960	63.50	$360,339.20	60.00	14.99	0.2499	1.0000	$90,052.07	$6,005.65
1959	64.50	$413,029.96	60.00	14.56	0.2426	1.0000	$100,216.40	$6,883.83
1958	65.50	$343,212.87	60.00	14.13	0.2355	1.0000	$80,836.87	$5,720.21
1957	66.50	$427,347.43	60.00	13.71	0.2286	1.0000	$97,681.40	$7,122.46
1956	67.50	$427,499.79	60.00	13.31	0.2218	1.0000	$94,809.07	$7,125.00
1955	68.50	$493,136.23	60.00	12.91	0.2151	1.0000	$106,091.57	$8,218.94
1954	69.50	$343,701.06	60.00	12.52	0.2086	1.0000	$71,709.35	$5,728.35
1953	70.50	$352,282.08	60.00	12.14	0.2023	1.0000	$71,265.26	$5,871.37
1952	71.50	$240,361.56	60.00	11.76	0.1961	1.0000	$47,128.83	$4,006.03
1951	72.50	$526,611.66	60.00	11.40	0.1900	1.0000	$100,061.05	$8,776.86
1950	73.50	$360,710.93	60.00	11.05	0.1841	1.0000	$66,401.85	$6,011.85
1949	74.50	$336,160.45	60.00	10.69	0.1782	1.0000	$59,917.27	$5,602.67
1948	75.50	$89,657.64	60.00	10.35	0.1726	1.0000	$15,470.76	$1,494.29
1947	76.50	$162,099.48	60.00	10.02	0.1669	1.0000	$27,061.45	$2,701.66
1946	77.50	$24,605.26	60.00	9.69	0.1615	1.0000	$3,972.92	$410.09
1945	78.50	$53,669.02	60.00	9.37	0.1561	1.0000	$8,377.68	$894.48
1944	79.50	$30,453.27	60.00	9.05	0.1508	1.0000	$4,593.76	$507.55
1943	80.50	$75,611.25	60.00	8.73	0.1456	1.0000	$11,006.29	$1,260.19

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3762 PA
Dispersion: 60.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1942	81.50	$37,958.15	60.00	8.43	0.1404	1.0000	$5,331.14	$632.64
1941	82.50	$41,392.14	60.00	8.13	0.1354	1.0000	$5,605.52	$689.87
1940	83.50	$43,004.55	60.00	7.82	0.1303	1.0000	$5,604.27	$716.74
1939	84.50	$47,184.03	60.00	7.52	0.1254	1.0000	$5,915.43	$786.40
1938	85.50	$43,893.72	60.00	7.23	0.1205	1.0000	$5,289.31	$731.56
1937	86.50	$19,085.16	60.00	6.93	0.1155	1.0000	$2,204.05	$318.09
1936	87.50	$13,734.14	60.00	6.64	0.1106	1.0000	$1,519.54	$228.90
1935	88.50	$10,293.36	60.00	6.35	0.1059	1.0000	$1,089.58	$171.56
1934	89.50	$4,142.23	60.00	6.05	0.1009	1.0000	$417.86	$69.04
1933	90.50	$8,157.22	60.00	5.76	0.0961	1.0000	$783.72	$135.95
1932	91.50	$28,281.08	60.00	5.48	0.0913	1.0000	$2,583.11	$471.35
1931	92.50	$40,522.85	60.00	5.18	0.0864	1.0000	$3,499.83	$675.38
1930	93.50	$49,263.25	60.00	4.90	0.0816	1.0000	$4,019.70	$821.05
1929	94.50	$124,217.30	60.00	4.61	0.0769	1.0000	$9,552.57	$2,070.29
1928	95.50	$126,881.30	60.00	4.32	0.0719	1.0000	$9,127.58	$2,114.69
1927	96.50	$103,432.81	60.00	4.03	0.0672	1.0000	$6,952.58	$1,723.88
1926	97.50	$142,882.20	60.00	3.76	0.0626	1.0000	$8,946.62	$2,381.37
1925	98.50	$149,302.64	60.00	3.46	0.0577	1.0000	$8,612.15	$2,488.38
1924	99.50	$91,661.70	60.00	3.18	0.0531	1.0000	$4,864.24	$1,527.70
1923	100.50	$54,714.48	60.00	2.92	0.0486	1.0000	$2,660.70	$911.91
1922	101.50	$48,392.89	60.00	2.63	0.0438	1.0000	$2,117.48	$806.55
1921	102.50	$8,809.78	60.00	2.36	0.0393	1.0000	$346.36	$146.83
1920	103.50	$5,011.38	60.00	2.11	0.0352	1.0000	$176.22	$83.52
1919	104.50	$5,150.16	60.00	1.82	0.0304	1.0000	$156.33	$85.84
1918	105.50	$20,450.76	60.00	1.57	0.0262	1.0000	$535.24	$340.85
1917	106.50	$16,179.42	60.00	1.35	0.0225	1.0000	$364.78	$269.66
1916	107.50	$14,521.63	60.00	1.07	0.0179	1.0000	$260.05	$242.03
1915	108.50	$11,599.77	60.00	0.86	0.0143	1.0000	$165.87	$193.33
1914	109.50	$36,027.33	60.00	0.78	0.0130	1.0000	$468.36	$600.46
1913	110.50	$9,300.47	60.00	0.55	0.0092	1.0000	$85.25	$155.01
1912	111.50	$28,052.27	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1911	112.50	$29,400.73	60.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3762 PA
Dispersion: 60.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1910	113.50	$10,149.98	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1909	114.50	$5,944.49	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1908	115.50	$1,724.17	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1907	116.50	$3,874.97	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1906	117.50	$14,551.02	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1905	118.50	$9,560.18	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1904	119.50	$510.19	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1903	120.50	$9,016.89	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1902	121.50	$11,758.61	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	122.50	$9,971.53	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	123.50	$780.12	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1899	124.50	$5,038.82	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1898	125.50	$1,902.30	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1897	126.50	$1,346.95	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1896	127.50	$867.48	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1895	128.50	$214.06	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1893	130.50	$1.80	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1892	131.50	$1.10	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1890	133.50	$4.02	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1880	143.50	$25.69	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1870	153.50	$0.51	60.00	0.00	0.0000	0.0000	$0.00	$0.00
1868	155.50	$1.68	60.00	0.00	0.0000	0.0000	$0.00	$0.00
		$10,651,874.31	60.00	13.49	0.2218	1.0000	$2,362,057.03	$175,119.58

Remaining Life Depreciation Accrual

Account: PECO Gas 3762 PA
Scenario: PECO Gas Groups 2024
Dispersion: 60.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$10,651,874.31	13.49	$1,218,745.33	11.441605%	7.413859%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($643,090.05)	0.50	($5,359.08)	0.833333%	
Total:	$10,651,874.31 *		$1,213,386.25	11.391293%	7.381259%
Average:	$10,330,329.29		$1,213,386.25	11.745862%	7.528518%
Grand Total:	$10,651,874.31 *		$1,213,386.25	11.391293%	7.381259%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3763 PA
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$110,457,196.77	65.00	64.51	0.9924	1.0000	$109,619,716.10	$1,699,341.49
2022	1.50	$115,763,137.73	65.00	63.52	0.9773	1.0000	$113,134,983.21	$1,780,971.35
2021	2.50	$83,570,622.29	65.00	62.54	0.9622	1.0000	$80,410,955.31	$1,285,701.88
2020	3.50	$71,855,506.53	65.00	61.56	0.9471	1.0000	$68,056,800.75	$1,105,469.33
2019	4.50	$76,414,040.82	65.00	60.59	0.9321	1.0000	$71,225,341.10	$1,175,600.63
2018	5.50	$71,658,880.74	65.00	59.61	0.9171	1.0000	$65,719,517.11	$1,102,444.32
2017	6.50	$76,511,259.44	65.00	58.64	0.9022	1.0000	$69,025,822.82	$1,177,096.30
2016	7.50	$63,829,900.61	65.00	57.67	0.8872	1.0000	$56,632,911.84	$981,998.47
2015	8.50	$55,688,934.83	65.00	56.71	0.8724	1.0000	$48,582,711.52	$856,752.84
2014	9.50	$30,356,283.08	65.00	55.74	0.8576	1.0000	$26,032,842.29	$467,019.74
2013	10.50	$37,274,346.27	65.00	54.78	0.8428	1.0000	$31,415,863.63	$573,451.48
2012	11.50	$37,652,438.65	65.00	53.83	0.8281	1.0000	$31,180,827.78	$579,268.29
2011	12.50	$29,736,957.76	65.00	52.88	0.8135	1.0000	$24,190,809.91	$457,491.66
2010	13.50	$23,553,019.07	65.00	51.93	0.7989	1.0000	$18,816,663.35	$362,354.14
2009	14.50	$21,000,504.69	65.00	50.99	0.7844	1.0000	$16,472,871.83	$323,084.69
2008	15.50	$21,625,803.69	65.00	50.05	0.7700	1.0000	$16,650,814.28	$332,704.67
2007	16.50	$14,232,771.56	65.00	49.11	0.7556	1.0000	$10,754,132.29	$218,965.72
2006	17.50	$15,921,332.55	65.00	48.18	0.7413	1.0000	$11,802,366.45	$244,943.58
2005	18.50	$16,887,482.98	65.00	47.26	0.7271	1.0000	$12,278,633.68	$259,807.43
2004	19.50	$23,088,883.74	65.00	46.34	0.7129	1.0000	$16,460,991.60	$355,213.60
2003	20.50	$13,772,983.89	65.00	45.43	0.6989	1.0000	$9,625,577.08	$211,892.06
2002	21.50	$18,787,575.79	65.00	44.52	0.6849	1.0000	$12,868,281.10	$289,039.63
2001	22.50	$36,199,039.50	65.00	43.62	0.6711	1.0000	$24,291,495.95	$556,908.30
2000	23.50	$3,816,472.37	65.00	42.72	0.6573	1.0000	$2,508,526.03	$58,714.96
1999	24.50	$5,334,534.68	65.00	41.83	0.6436	1.0000	$3,433,301.23	$82,069.76
1998	25.50	$7,848,696.10	65.00	40.95	0.6300	1.0000	$4,944,934.56	$120,749.17
1997	26.50	$12,643,293.03	65.00	40.08	0.6165	1.0000	$7,795,092.46	$194,512.20
1996	27.50	$8,973,573.86	65.00	39.21	0.6032	1.0000	$5,412,641.24	$138,054.98
1995	28.50	$10,727,187.64	65.00	38.34	0.5899	1.0000	$6,327,886.60	$165,033.66
1994	29.50	$13,458,958.30	65.00	37.49	0.5767	1.0000	$7,762,440.07	$207,060.90
1993	30.50	$9,047,105.02	65.00	36.64	0.5637	1.0000	$5,099,747.03	$139,186.23
1992	31.50	$15,747,729.01	65.00	35.80	0.5508	1.0000	$8,673,226.92	$242,272.75

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3763 PA
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$11,782,789.40	65.00	34.97	0.5379	1.0000	$6,338,249.58	$181,273.68
1990	33.50	$10,078,611.94	65.00	34.14	0.5252	1.0000	$5,293,209.78	$155,055.57
1989	34.50	$7,868,227.85	65.00	33.32	0.5126	1.0000	$4,033,506.69	$121,049.66
1988	35.50	$6,097,288.73	65.00	32.51	0.5001	1.0000	$3,049,497.90	$93,804.44
1987	36.50	$7,236,120.63	65.00	31.71	0.4878	1.0000	$3,529,913.56	$111,324.93
1986	37.50	$5,276,273.20	65.00	30.91	0.4756	1.0000	$2,509,283.59	$81,173.43
1985	38.50	$4,072,444.12	65.00	30.13	0.4635	1.0000	$1,887,605.90	$62,652.99
1984	39.50	$2,863,665.62	65.00	29.35	0.4515	1.0000	$1,293,020.46	$44,056.39
1983	40.50	$3,537,122.73	65.00	28.58	0.4397	1.0000	$1,555,320.82	$54,417.27
1982	41.50	$3,360,216.65	65.00	27.82	0.4280	1.0000	$1,438,163.76	$51,695.64
1981	42.50	$8,070,836.76	65.00	27.07	0.4165	1.0000	$3,361,129.58	$124,166.72
1980	43.50	$5,246,151.70	65.00	26.33	0.4050	1.0000	$2,124,786.45	$80,710.03
1979	44.50	$1,939,808.69	65.00	25.59	0.3938	1.0000	$763,816.65	$29,843.21
1978	45.50	$1,714,579.42	65.00	24.87	0.3826	1.0000	$656,030.67	$26,378.14
1977	46.50	$608,463.92	65.00	24.15	0.3716	1.0000	$226,111.49	$9,360.98
1976	47.50	$174,901.15	65.00	23.45	0.3608	1.0000	$63,108.31	$2,690.79
1975	48.50	($417,586.67)	65.00	22.76	0.3501	1.0000	($146,210.57)	($6,424.41)
1974	49.50	$717,786.08	65.00	22.08	0.3397	1.0000	$243,810.49	$11,042.86
1973	50.50	$475,187.89	65.00	21.41	0.3293	1.0000	$156,487.31	$7,310.58
1972	51.50	$1,945,927.32	65.00	20.75	0.3192	1.0000	$621,141.83	$29,937.34
1971	52.50	$701,859.40	65.00	20.10	0.3092	1.0000	$217,018.71	$10,797.84
1970	53.50	$578,668.08	65.00	19.46	0.2995	1.0000	$173,282.60	$8,902.59
1969	54.50	$262,733.88	65.00	18.84	0.2898	1.0000	$76,149.42	$4,042.06
1967	56.50	$6,400.98	65.00	17.63	0.2713	1.0000	$1,736.28	$98.48
1951	72.50	$26.40	65.00	10.00	0.1538	1.0000	$4.06	$0.41
		$1,237,634,958.86	65.00	54.45	0.8376	1.0000	$1,036,674,902.44	$19,040,537.83

Remaining Life Depreciation Accrual

Account: PECO Gas 3763 PA
Scenario: PECO Gas Groups 2024
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,237,634,958.86	54.45	$19,134,232.55	1.546032%	1.836693%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,756,822.70)	0.50	($13,514.02)	0.769231%	
Total:	$1,237,634,958.86 *		$19,120,718.53	1.544940%	1.835396%
Average:	$1,236,756,547.51		$19,120,718.53	1.546037%	1.836945%
Grand Total:	$1,237,634,958.86 *		$19,120,718.53	1.544940%	1.835396%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3780 PA
Dispersion: 50.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$1,057,096.60	50.00	49.55	0.9909	1.0000	$1,047,525.80	$21,141.93
2022	1.50	$1,976,121.31	50.00	48.65	0.9729	1.0000	$1,922,576.30	$39,522.43
2021	2.50	$1,041,274.50	50.00	47.75	0.9550	1.0000	$994,391.24	$20,825.49
2020	3.50	$2,039,102.68	50.00	46.86	0.9371	1.0000	$1,910,936.19	$40,782.05
2019	4.50	$690,312.89	50.00	45.97	0.9194	1.0000	$634,688.09	$13,806.26
2018	5.50	$1,900,677.36	50.00	45.09	0.9018	1.0000	$1,714,041.88	$38,013.55
2017	6.50	$446,076.45	50.00	44.22	0.8843	1.0000	$394,467.65	$8,921.53
2016	7.50	$523,387.85	50.00	43.35	0.8669	1.0000	$453,736.87	$10,467.76
2015	8.50	$582,404.94	50.00	42.48	0.8497	1.0000	$494,847.99	$11,648.10
2014	9.50	$136,845.01	50.00	41.63	0.8325	1.0000	$113,926.33	$2,736.90
2013	10.50	$520,680.39	50.00	40.77	0.8155	1.0000	$424,614.71	$10,413.61
2012	11.50	$376,546.31	50.00	39.93	0.7986	1.0000	$300,714.10	$7,530.93
2011	12.50	$1,070,492.87	50.00	39.09	0.7818	1.0000	$836,964.74	$21,409.86
2010	13.50	$147,460.59	50.00	38.26	0.7652	1.0000	$112,840.76	$2,949.21
2009	14.50	$150,430.95	50.00	37.44	0.7487	1.0000	$112,633.00	$3,008.62
2008	15.50	$362,259.91	50.00	36.62	0.7324	1.0000	$265,314.39	$7,245.20
2007	16.50	$551,466.78	50.00	35.81	0.7162	1.0000	$394,946.51	$11,029.34
2006	17.50	$156,386.23	50.00	35.01	0.7001	1.0000	$109,487.28	$3,127.72
2005	18.50	$238,733.21	50.00	34.21	0.6842	1.0000	$163,340.41	$4,774.66
2004	19.50	$275,675.17	50.00	33.42	0.6684	1.0000	$184,268.41	$5,513.50
2003	20.50	$222,908.00	50.00	32.64	0.6528	1.0000	$145,517.04	$4,458.16
2002	21.50	$142,937.13	50.00	31.87	0.6374	1.0000	$91,101.83	$2,858.74
2001	22.50	$811,217.67	50.00	31.10	0.6221	1.0000	$504,624.67	$16,224.35
2000	23.50	$246,537.10	50.00	30.35	0.6069	1.0000	$149,628.21	$4,930.74
1999	24.50	$81,174.33	50.00	29.60	0.5919	1.0000	$48,050.94	$1,623.49
1994	29.50	$50,850.23	50.00	25.98	0.5197	1.0000	$26,426.36	$1,017.00
1993	30.50	$421,783.26	50.00	25.29	0.5058	1.0000	$213,331.35	$8,435.67
1992	31.50	$950,419.43	50.00	24.60	0.4921	1.0000	$467,670.78	$19,008.39
1991	32.50	$255,190.98	50.00	23.93	0.4785	1.0000	$122,119.53	$5,103.82
1990	33.50	$404,164.83	50.00	23.26	0.4652	1.0000	$188,022.90	$8,083.30
1989	34.50	$308,593.59	50.00	22.60	0.4521	1.0000	$139,510.44	$6,171.87
1988	35.50	$490,756.32	50.00	21.96	0.4392	1.0000	$215,519.52	$9,815.13

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3780 PA
Dispersion: 50.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1987	36.50	$543,672.90	50.00	21.32	0.4264	1.0000	$231,844.70	$10,873.46
1986	37.50	$506,709.82	50.00	20.70	0.4139	1.0000	$209,747.01	$10,134.20
1985	38.50	$408,863.38	50.00	20.08	0.4016	1.0000	$164,219.76	$8,177.27
1984	39.50	$290,014.82	50.00	19.48	0.3896	1.0000	$112,981.75	$5,800.30
1983	40.50	$450,066.35	50.00	18.89	0.3777	1.0000	$170,001.14	$9,001.33
1982	41.50	$595,262.21	50.00	18.30	0.3661	1.0000	$217,924.16	$11,905.24
1981	42.50	$494,600.65	50.00	17.74	0.3547	1.0000	$175,434.99	$9,892.01
1980	43.50	$307,464.74	50.00	17.18	0.3435	1.0000	$105,623.90	$6,149.29
1979	44.50	$58,357.20	50.00	16.63	0.3326	1.0000	$19,409.52	$1,167.14
1978	45.50	$200,553.91	50.00	16.09	0.3219	1.0000	$64,557.97	$4,011.08
1977	46.50	$144,252.81	50.00	15.57	0.3114	1.0000	$44,924.75	$2,885.06
1976	47.50	$187,822.44	50.00	15.06	0.3012	1.0000	$56,573.53	$3,756.45
1975	48.50	$263,494.74	50.00	14.56	0.2912	1.0000	$76,734.25	$5,269.89
1974	49.50	$42,572.25	50.00	14.07	0.2815	1.0000	$11,982.87	$851.45
1973	50.50	$104,592.76	50.00	13.60	0.2720	1.0000	$28,445.31	$2,091.86
1972	51.50	$217,267.34	50.00	13.13	0.2627	1.0000	$57,074.21	$4,345.35
1971	52.50	$78,854.90	50.00	12.68	0.2537	1.0000	$20,001.93	$1,577.10
1970	53.50	$89,296.00	50.00	12.24	0.2449	1.0000	$21,864.43	$1,785.92
1969	54.50	$36,776.14	50.00	11.81	0.2363	1.0000	$8,689.60	$735.52
1968	55.50	$70,429.79	50.00	11.40	0.2279	1.0000	$16,054.09	$1,408.60
1967	56.50	$46,813.66	50.00	10.99	0.2198	1.0000	$10,290.87	$936.27
1966	57.50	$40,418.19	50.00	10.60	0.2119	1.0000	$8,565.85	$808.36
1965	58.50	$16,685.12	50.00	10.21	0.2042	1.0000	$3,407.84	$333.70
1964	59.50	$55,264.41	50.00	9.84	0.1968	1.0000	$10,873.86	$1,105.29
1963	60.50	$60,667.45	50.00	9.47	0.1895	1.0000	$11,495.10	$1,213.35
1962	61.50	$51,420.07	50.00	9.12	0.1824	1.0000	$9,378.03	$1,028.40
1961	62.50	$59,680.13	50.00	8.77	0.1755	1.0000	$10,471.56	$1,193.60
1960	63.50	$47,679.93	50.00	8.44	0.1687	1.0000	$8,043.98	$953.60
1959	64.50	$25,711.85	50.00	8.11	0.1621	1.0000	$4,168.19	$514.24
1958	65.50	$83,659.46	50.00	7.78	0.1557	1.0000	$13,021.89	$1,673.19
1957	66.50	$63,737.56	50.00	7.47	0.1493	1.0000	$9,517.50	$1,274.75
1956	67.50	$34,497.75	50.00	7.16	0.1431	1.0000	$4,936.79	$689.96

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3780 PA
Dispersion: 50.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1955	68.50	$56,681.86	50.00	6.85	0.1370	1.0000	$7,764.43	$1,133.64
1954	69.50	$35,420.91	50.00	6.55	0.1310	1.0000	$4,638.44	$708.42
1953	70.50	$29,633.25	50.00	6.25	0.1250	1.0000	$3,703.65	$592.67
1952	71.50	$14,698.47	50.00	5.95	0.1191	1.0000	$1,750.18	$293.97
1951	72.50	$26,799.84	50.00	5.66	0.1132	1.0000	$3,033.74	$536.00
1950	73.50	$15,095.85	50.00	5.37	0.1074	1.0000	$1,620.66	$301.92
1949	74.50	$18,708.10	50.00	5.08	0.1015	1.0000	$1,899.61	$374.16
1948	75.50	$15,497.15	50.00	4.79	0.0957	1.0000	$1,483.64	$309.94
1947	76.50	$13,177.50	50.00	4.50	0.0899	1.0000	$1,185.26	$263.55
1946	77.50	$5,887.43	50.00	4.21	0.0842	1.0000	$495.53	$117.75
1945	78.50	$9,071.91	50.00	3.92	0.0784	1.0000	$711.28	$181.44
1944	79.50	$1,822.27	50.00	3.63	0.0727	1.0000	$132.41	$36.45
1943	80.50	$1,705.98	50.00	3.35	0.0670	1.0000	$114.22	$34.12
1942	81.50	$2,548.94	50.00	3.06	0.0613	1.0000	$156.20	$50.98
1941	82.50	$3,880.18	50.00	2.78	0.0557	1.0000	$215.96	$77.60
1940	83.50	$407.22	50.00	2.51	0.0501	1.0000	$20.40	$8.14
1939	84.50	$866.72	50.00	2.23	0.0446	1.0000	$38.67	$17.33
1936	87.50	$2.95	50.00	1.44	0.0288	1.0000	$0.09	$0.06
1935	88.50	$0.95	50.00	1.19	0.0239	1.0000	$0.02	$0.02
1934	89.50	$42.89	50.00	0.96	0.0193	1.0000	$0.83	$0.86
1933	90.50	$706.27	50.00	0.76	0.0153	1.0000	$10.78	$14.13
1932	91.50	$1,944.15	50.00	0.64	0.0129	1.0000	$24.99	$38.88
1931	92.50	$1.36	50.00	0.25	0.0050	1.0000	$0.01	$0.03
1930	93.50	$1,445.02	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$86.86	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$535.44	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	96.50	$326.52	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	97.50	$202.75	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	98.50	$1.81	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	104.50	$208.31	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	106.50	$38.17	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	107.50	$74.23	50.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3780 PA
Dispersion: 50.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1913	110.50	$24.62	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1910	113.50	$32.96	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$24,564,704.44	50.00	34.29	0.6857	1.0000	$16,845,048.54	$491,234.56

Remaining Life Depreciation Accrual

Account: PECO Gas 3780 PA
Scenario: PECO Gas Groups 2024
Dispersion: 50.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$24,564,704.44	34.29	$515,827.25	2.099872%	2.916196%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($308,098.70)	0.50	($3,080.99)	1.000001%	
Total:	$24,564,704.44 *		$512,746.26	2.087329%	2.898777%
Average:	$24,410,655.09		$512,746.26	2.100502%	2.924245%
Grand Total:	$24,564,704.44 *		$512,746.26	2.087329%	2.898777%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3790 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2020	3.50	$9,376,009.49	50.00	46.57	0.9313	1.0000	$8,732,334.61	$187,520.19
2018	5.50	$12,113,232.98	50.00	44.62	0.8925	1.0000	$10,810,608.64	$242,264.66
2016	7.50	$73,310.04	50.00	42.69	0.8539	1.0000	$62,598.69	$1,466.20
2015	8.50	$519,345.06	50.00	41.74	0.8347	1.0000	$433,517.12	$10,386.90
2014	9.50	$297,609.24	50.00	40.78	0.8157	1.0000	$242,755.21	$5,952.18
2013	10.50	$528,159.53	50.00	39.84	0.7967	1.0000	$420,801.47	$10,563.19
2012	11.50	$295,658.45	50.00	38.89	0.7779	1.0000	$229,990.04	$5,913.17
2011	12.50	$264,156.87	50.00	37.96	0.7592	1.0000	$200,540.45	$5,283.14
2010	13.50	$602,368.96	50.00	37.03	0.7406	1.0000	$446,104.29	$12,047.38
2009	14.50	$1,421,084.78	50.00	36.11	0.7221	1.0000	$1,026,201.50	$28,421.70
2008	15.50	$990,091.64	50.00	35.19	0.7038	1.0000	$696,832.68	$19,801.83
2007	16.50	$1,279,683.63	50.00	34.28	0.6856	1.0000	$877,392.18	$25,593.67
2006	17.50	$1,757,865.79	50.00	33.38	0.6676	1.0000	$1,173,578.98	$35,157.32
2005	18.50	$998,204.80	50.00	32.49	0.6498	1.0000	$648,588.93	$19,964.10
2004	19.50	$4,613,251.93	50.00	31.60	0.6321	1.0000	$2,915,860.28	$92,265.04
2003	20.50	$1,182,863.99	50.00	30.73	0.6145	1.0000	$726,915.47	$23,657.28
2002	21.50	$2,196,354.45	50.00	29.86	0.5972	1.0000	$1,311,637.27	$43,927.09
2001	22.50	$6,736,818.60	50.00	29.00	0.5800	1.0000	$3,907,528.80	$134,736.37
2000	23.50	($106,637.73)	50.00	28.15	0.5630	1.0000	($60,041.97)	($2,132.75)
1999	24.50	$53,766.59	50.00	27.31	0.5463	1.0000	$29,370.33	$1,075.33
1998	25.50	$336,491.70	50.00	26.48	0.5297	1.0000	$178,226.83	$6,729.83
1997	26.50	$516,677.52	50.00	25.66	0.5133	1.0000	$265,191.43	$10,333.55
1996	27.50	$1,754,578.01	50.00	24.85	0.4971	1.0000	$872,147.30	$35,091.56
1995	28.50	$7,446.48	50.00	24.05	0.4811	1.0000	$3,582.39	$148.93
1994	29.50	$6,461,664.93	50.00	23.27	0.4653	1.0000	$3,006,707.24	$129,233.30
1992	31.50	$903,491.71	50.00	21.72	0.4344	1.0000	$392,506.35	$18,069.83
1991	32.50	$1,379,105.05	50.00	20.97	0.4193	1.0000	$578,301.66	$27,582.10
1989	34.50	$405,890.17	50.00	19.49	0.3898	1.0000	$158,235.81	$8,117.80
1988	35.50	$324,440.05	50.00	18.77	0.3755	1.0000	$121,820.88	$6,488.80
1987	36.50	$1,379.40	50.00	18.07	0.3614	1.0000	$498.48	$27.59
1986	37.50	$16,591.68	50.00	17.38	0.3475	1.0000	$5,766.22	$331.83
1985	38.50	$1,605,763.37	50.00	16.70	0.3340	1.0000	$536,298.47	$32,115.27

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3790 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1983	40.50	$9,218.07	50.00	15.39	0.3078	1.0000	$2,836.99	$184.36
1982	41.50	$318,662.52	50.00	14.76	0.2951	1.0000	$94,044.08	$6,373.25
1981	42.50	$793.85	50.00	14.14	0.2828	1.0000	$224.51	$15.88
1980	43.50	$539,840.82	50.00	13.54	0.2708	1.0000	$146,204.78	$10,796.82
1979	44.50	$25,437.98	50.00	12.96	0.2592	1.0000	$6,593.51	$508.76
1978	45.50	$80,993.97	50.00	12.40	0.2479	1.0000	$20,080.70	$1,619.88
1977	46.50	$1,535.98	50.00	11.85	0.2370	1.0000	$364.07	$30.72
1974	49.50	$3,053.02	50.00	10.33	0.2066	1.0000	$630.66	$61.06
1972	51.50	$12,081.53	50.00	9.41	0.1882	1.0000	$2,273.41	$241.63
1971	52.50	$373,915.78	50.00	8.98	0.1795	1.0000	$67,133.12	$7,478.32
1969	54.50	$51,911.78	50.00	8.17	0.1634	1.0000	$8,481.45	$1,038.24
1968	55.50	$1,005.81	50.00	7.79	0.1558	1.0000	$156.74	$20.12
1967	56.50	$4,811.95	50.00	7.43	0.1486	1.0000	$715.13	$96.24
1966	57.50	$117,090.00	50.00	7.09	0.1417	1.0000	$16,593.73	$2,341.80
1965	58.50	$144,983.09	50.00	6.76	0.1351	1.0000	$19,589.65	$2,899.66
1964	59.50	$68,071.56	50.00	6.44	0.1288	1.0000	$8,766.63	$1,361.43
1963	60.50	$50,579.24	50.00	6.14	0.1227	1.0000	$6,206.61	$1,011.58
1962	61.50	$137,405.52	50.00	5.84	0.1169	1.0000	$16,055.87	$2,748.11
1961	62.50	$28,161.47	50.00	5.56	0.1112	1.0000	$3,131.15	$563.23
1960	63.50	$5,610.02	50.00	5.28	0.1057	1.0000	$592.85	$112.20
1959	64.50	$13,299.44	50.00	5.01	0.1003	1.0000	$1,333.93	$265.99
1958	65.50	$7,161.94	50.00	4.75	0.0950	1.0000	$680.55	$143.24
1957	66.50	$161,462.11	50.00	4.49	0.0898	1.0000	$14,501.40	$3,229.24
1954	69.50	$57,430.89	50.00	3.72	0.0744	1.0000	$4,271.89	$1,148.62
1953	70.50	$21,595.85	50.00	3.46	0.0693	1.0000	$1,495.67	$431.92
1952	71.50	$41,909.50	50.00	3.21	0.0641	1.0000	$2,687.88	$838.19
1951	72.50	$327,667.29	50.00	2.95	0.0590	1.0000	$19,339.37	$6,553.35
1950	73.50	$10,899.33	50.00	2.70	0.0539	1.0000	$587.80	$217.99
1949	74.50	$8,472.09	50.00	2.44	0.0489	1.0000	$414.06	$169.44
1948	75.50	$108.78	50.00	2.19	0.0439	1.0000	$4.77	$2.18
1947	76.50	$1,478.40	50.00	1.95	0.0389	1.0000	$57.57	$29.57
1942	81.50	$70.66	50.00	0.81	0.0161	1.0000	$1.14	$1.41

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3790 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1941	82.50	$145.80	50.00	0.60	0.0120	1.0000	$1.76	$2.92
1940	83.50	$16.14	50.00	0.25	0.0050	1.0000	$0.08	$0.32
1928	95.50	$2,865.67	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	100.50	$222.34	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$61,536,689.35	50.00	33.66	0.6731	1.0000	$41,418,451.54	$1,230,672.03

Remaining Life Depreciation Accrual

Account: PECO Gas 3790 PA
Scenario: PECO Gas Groups 2024
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$61,536,689.35	33.66	$1,063,896.56	1.728882%	2.971313%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($513,420.09)	0.50	($5,134.20)	1.000000%	
Total:	$61,536,689.35 *		$1,058,762.36	1.720538%	2.956974%
Average:	$61,279,979.31		$1,058,762.36	1.727746%	2.978328%
Grand Total:	$61,536,689.35 *		$1,058,762.36	1.720538%	2.956974%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3801 PA
Dispersion: 37.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$537,502.92	37.00	36.51	0.9869	1.0000	$530,445.35	$14,527.11
2022	1.50	$739,313.77	37.00	35.59	0.9618	1.0000	$711,107.24	$19,981.45
2021	2.50	$791,348.58	37.00	34.71	0.9381	1.0000	$742,368.11	$21,387.80
2020	3.50	$252,096.77	37.00	33.87	0.9155	1.0000	$230,787.83	$6,813.43
2019	4.50	$841,831.95	37.00	33.07	0.8937	1.0000	$752,333.11	$22,752.21
2018	5.50	$121,278.07	37.00	32.29	0.8727	1.0000	$105,836.66	$3,277.79
2017	6.50	$289,488.13	37.00	31.54	0.8524	1.0000	$246,745.37	$7,824.00
2016	7.50	$943,882.38	37.00	30.81	0.8327	1.0000	$785,984.11	$25,510.33
2015	8.50	$896,637.38	37.00	30.10	0.8136	1.0000	$729,503.95	$24,233.44
2014	9.50	$2,445,389.79	37.00	29.42	0.7950	1.0000	$1,944,102.03	$66,091.62
2013	10.50	$2,683,963.30	37.00	28.75	0.7769	1.0000	$2,085,237.48	$72,539.55
2012	11.50	$2,717,045.90	37.00	28.09	0.7593	1.0000	$2,062,940.80	$73,433.67
2011	12.50	$2,728,083.26	37.00	27.45	0.7420	1.0000	$2,024,209.42	$73,731.98
2010	13.50	$2,882,516.18	37.00	26.83	0.7251	1.0000	$2,090,222.49	$77,905.84
2009	14.50	$2,468,901.60	37.00	26.22	0.7086	1.0000	$1,749,515.35	$66,727.07
2008	15.50	$3,688,173.85	37.00	25.62	0.6924	1.0000	$2,553,779.27	$99,680.37
2007	16.50	$2,878,933.00	37.00	25.03	0.6765	1.0000	$1,947,712.08	$77,809.00
2006	17.50	$3,237,849.90	37.00	24.46	0.6610	1.0000	$2,140,135.37	$87,509.46
2005	18.50	$3,627,400.91	37.00	23.89	0.6457	1.0000	$2,342,078.16	$98,037.86
2004	19.50	$2,017,495.12	37.00	23.33	0.6306	1.0000	$1,272,241.82	$54,526.90
2003	20.50	$4,380,961.87	37.00	22.79	0.6158	1.0000	$2,697,848.30	$118,404.37
2002	21.50	$4,207,674.21	37.00	22.25	0.6012	1.0000	$2,529,787.12	$113,720.92
2001	22.50	$5,683,701.31	37.00	21.71	0.5869	1.0000	$3,335,612.35	$153,613.55
2000	23.50	$1,776,644.90	37.00	21.19	0.5727	1.0000	$1,017,498.37	$48,017.43
1999	24.50	$1,000,890.50	37.00	20.67	0.5588	1.0000	$559,269.01	$27,051.09
1998	25.50	$1,340,184.41	37.00	20.16	0.5450	1.0000	$730,399.81	$36,221.20
1997	26.50	$934,762.18	37.00	19.66	0.5314	1.0000	$496,747.34	$25,263.84
1996	27.50	$526,459.20	37.00	19.17	0.5180	1.0000	$272,704.92	$14,228.63
1995	28.50	$484,294.24	37.00	18.68	0.5047	1.0000	$244,442.38	$13,089.03
1994	29.50	$172,044.98	37.00	18.19	0.4916	1.0000	$84,583.02	$4,649.86
1993	30.50	$588,074.77	37.00	17.71	0.4787	1.0000	$281,503.28	$15,893.91
1992	31.50	$490,458.02	37.00	17.24	0.4659	1.0000	$228,491.11	$13,255.62

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3801 PA
Dispersion: 37.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$658,927.12	37.00	16.77	0.4532	1.0000	$298,621.24	$17,808.84
1990	33.50	$569,897.33	37.00	16.30	0.4406	1.0000	$251,120.06	$15,402.63
1989	34.50	$524,673.55	37.00	15.84	0.4282	1.0000	$224,674.89	$14,180.37
1988	35.50	$553,166.32	37.00	15.39	0.4159	1.0000	$230,064.21	$14,950.44
1987	36.50	$479,800.21	37.00	14.94	0.4037	1.0000	$193,702.64	$12,967.57
1986	37.50	$430,197.19	37.00	14.49	0.3916	1.0000	$168,477.10	$11,626.95
1985	38.50	$422,545.06	37.00	14.05	0.3797	1.0000	$160,420.54	$11,420.14
1984	39.50	$355,495.26	37.00	13.61	0.3678	1.0000	$130,740.18	$9,607.98
1983	40.50	$326,137.70	37.00	13.17	0.3560	1.0000	$116,102.69	$8,814.53
1982	41.50	$19,250.40	37.00	12.74	0.3443	1.0000	$6,627.97	$520.28
1972	51.50	$152,514.72	37.00	8.58	0.2319	1.0000	$35,373.20	$4,122.02
1971	52.50	$112,520.65	37.00	8.18	0.2211	1.0000	$24,877.79	$3,041.10
1970	53.50	$64,682.13	37.00	7.78	0.2103	1.0000	$13,603.88	$1,748.17
1969	54.50	$221,181.07	37.00	7.38	0.1996	1.0000	$44,143.91	$5,977.87
1968	55.50	$346,861.40	37.00	6.99	0.1889	1.0000	$65,530.39	$9,374.63
1967	56.50	$387,880.00	37.00	6.60	0.1783	1.0000	$69,172.56	$10,483.24
1966	57.50	$401,775.58	37.00	6.21	0.1678	1.0000	$67,403.26	$10,858.80
1965	58.50	$359,322.76	37.00	5.82	0.1573	1.0000	$56,511.69	$9,711.43
1964	59.50	$271,348.83	37.00	5.43	0.1468	1.0000	$39,843.51	$7,333.75
1963	60.50	$222,857.86	37.00	5.05	0.1365	1.0000	$30,417.12	$6,023.19
1962	61.50	$164,345.44	37.00	4.67	0.1261	1.0000	$20,723.87	$4,441.77
1961	62.50	$142,255.82	37.00	4.29	0.1158	1.0000	$16,476.44	$3,844.75
1960	63.50	$81,490.46	37.00	3.91	0.1056	1.0000	$8,606.84	$2,202.44
1959	64.50	$65,325.73	37.00	3.53	0.0954	1.0000	$6,230.48	$1,765.56
1958	65.50	$31,455.42	37.00	3.15	0.0852	1.0000	$2,681.36	$850.15
1957	66.50	$55,322.99	37.00	2.78	0.0752	1.0000	$4,159.76	$1,495.22
1956	67.50	$22,452.60	37.00	2.41	0.0651	1.0000	$1,461.27	$606.83
1955	68.50	$21,523.56	37.00	2.04	0.0551	1.0000	$1,185.74	$581.72
1954	69.50	$10,073.98	37.00	1.67	0.0452	1.0000	$455.37	$272.27
1953	70.50	$11,639.29	37.00	1.31	0.0355	1.0000	$413.53	$314.58
1952	71.50	$3,507.39	37.00	0.95	0.0256	1.0000	$89.73	$94.79
1951	72.50	$1,566.97	37.00	0.59	0.0159	1.0000	$24.93	$42.35

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3801 PA
Dispersion: 37.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1950	73.50	$963.44	37.00	0.25	0.0068	1.0000	$6.52	$26.04
1949	74.50	$148.43	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	75.50	$63.48	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	76.50	$13.79	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	77.50	$1.95	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	78.50	$1.20	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	79.50	$1.54	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	80.50	$1.78	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	81.50	$1.65	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1941	82.50	$1.96	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1940	83.50	$1.37	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1939	84.50	$1.22	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1938	85.50	$1.46	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	86.50	$1.80	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1936	87.50	$1.71	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	88.50	$1.49	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1934	89.50	$1.56	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	90.50	$0.58	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1932	91.50	$0.97	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	92.50	$0.85	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	93.50	($215.92)	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$1.80	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$1.54	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	96.50	$0.94	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	97.50	$0.98	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	98.50	$0.99	37.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	99.50	($736.87)	37.00	0.00	0.0000	0.0000	$0.00	$0.00
		$65,867,543.83	37.00	23.49	0.6349	1.0000	$41,816,117.67	$1,780,222.75

Remaining Life Depreciation Accrual

Account: PECO Gas 3801 PA
Scenario: PECO Gas Groups 2024
Dispersion: 37.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$65,867,543.83	23.49	$3,656,648.89	5.551519%	4.257264%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,515,288.74)	0.50	($20,476.87)	1.351351%	
Total:	$65,867,543.83 *		$3,636,172.02	5.520431%	4.233424%
Average:	$65,109,899.46		$3,636,172.02	5.584668%	4.271099%
Grand Total:	$65,867,543.83 *		$3,636,172.02	5.520431%	4.233424%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3802 PA
Dispersion: 56.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$85,074,184.26	56.00	55.51	0.9912	1.0000	$84,325,756.78	$1,519,181.86
2022	1.50	$111,365,993.71	56.00	54.52	0.9737	1.0000	$108,432,297.63	$1,988,678.46
2021	2.50	$79,501,787.82	56.00	53.54	0.9561	1.0000	$76,014,922.62	$1,419,674.78
2020	3.50	$70,610,757.98	56.00	52.57	0.9387	1.0000	$66,280,417.24	$1,260,906.39
2019	4.50	$80,333,920.30	56.00	51.59	0.9213	1.0000	$74,008,505.42	$1,434,534.29
2018	5.50	$65,611,646.50	56.00	50.62	0.9039	1.0000	$59,306,251.69	$1,171,636.54
2017	6.50	$50,366,122.71	56.00	49.65	0.8866	1.0000	$44,653,835.74	$899,395.05
2016	7.50	$43,915,837.34	56.00	48.68	0.8694	1.0000	$38,178,293.44	$784,211.38
2015	8.50	$35,611,813.32	56.00	47.72	0.8522	1.0000	$30,347,587.35	$635,925.24
2014	9.50	$20,367,089.26	56.00	46.76	0.8351	1.0000	$17,008,123.91	$363,698.02
2013	10.50	$24,837,148.74	56.00	45.81	0.8181	1.0000	$20,318,198.94	$443,520.51
2012	11.50	$23,585,365.21	56.00	44.86	0.8011	1.0000	$18,894,444.33	$421,167.24
2011	12.50	$19,720,221.59	56.00	43.92	0.7843	1.0000	$15,466,078.23	$352,146.81
2010	13.50	$18,075,290.64	56.00	42.98	0.7675	1.0000	$13,873,046.10	$322,773.05
2009	14.50	$14,925,800.88	56.00	42.05	0.7509	1.0000	$11,207,060.30	$266,532.16
2008	15.50	$12,833,922.25	56.00	41.12	0.7343	1.0000	$9,423,877.53	$229,177.18
2007	16.50	$12,319,801.21	56.00	40.20	0.7179	1.0000	$8,843,914.80	$219,996.45
2006	17.50	$11,313,856.65	56.00	39.29	0.7015	1.0000	$7,936,995.72	$202,033.15
2005	18.50	$13,265,051.20	56.00	38.38	0.6853	1.0000	$9,090,658.06	$236,875.91
2004	19.50	$10,962,644.47	56.00	37.48	0.6692	1.0000	$7,336,336.56	$195,761.51
2003	20.50	$10,817,769.49	56.00	36.58	0.6532	1.0000	$7,066,526.33	$193,174.46
2002	21.50	$13,673,746.52	56.00	35.70	0.6374	1.0000	$8,715,935.68	$244,174.04
2001	22.50	$22,410,322.83	56.00	34.82	0.6217	1.0000	$13,932,886.77	$400,184.34
2000	23.50	$6,215,979.69	56.00	33.94	0.6061	1.0000	$3,767,797.16	$110,999.64
1999	24.50	$9,569,904.77	56.00	33.08	0.5907	1.0000	$5,653,097.17	$170,891.16
1998	25.50	$9,181,321.80	56.00	32.22	0.5754	1.0000	$5,283,242.28	$163,952.18
1997	26.50	$10,619,611.87	56.00	31.38	0.5603	1.0000	$5,950,578.13	$189,635.93
1996	27.50	$5,298,899.84	56.00	30.54	0.5454	1.0000	$2,889,817.63	$94,623.21
1995	28.50	$5,078,889.01	56.00	29.71	0.5305	1.0000	$2,694,547.04	$90,694.45
1994	29.50	$11,136,279.74	56.00	28.89	0.5159	1.0000	$5,744,816.91	$198,862.14
1993	30.50	$16,541,123.55	56.00	28.08	0.5014	1.0000	$8,293,581.11	$295,377.21
1992	31.50	$22,966,914.94	56.00	27.28	0.4871	1.0000	$11,186,201.00	$410,123.48

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3802 PA
Dispersion: 56.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$23,661,910.15	56.00	26.48	0.4729	1.0000	$11,189,475.37	$422,534.11
1990	33.50	$17,339,396.70	56.00	25.70	0.4589	1.0000	$7,956,803.14	$309,632.08
1989	34.50	$15,300,685.52	56.00	24.92	0.4451	1.0000	$6,809,693.44	$273,226.53
1988	35.50	$14,254,068.77	56.00	24.16	0.4315	1.0000	$6,149,952.12	$254,536.94
1987	36.50	$15,677,367.89	56.00	23.41	0.4180	1.0000	$6,553,057.45	$279,953.00
1986	37.50	$11,716,618.70	56.00	22.66	0.4047	1.0000	$4,741,967.29	$209,225.33
1985	38.50	$11,996,835.49	56.00	21.93	0.3916	1.0000	$4,698,453.52	$214,229.21
1984	39.50	$8,352,585.85	56.00	21.21	0.3788	1.0000	$3,163,546.24	$149,153.32
1983	40.50	$9,269,653.04	56.00	20.50	0.3661	1.0000	$3,393,906.58	$165,529.52
1982	41.50	$10,000,036.66	56.00	19.81	0.3537	1.0000	$3,536,753.28	$178,572.08
1981	42.50	$12,460,763.29	56.00	19.12	0.3414	1.0000	$4,254,506.81	$222,513.63
1980	43.50	$12,070,382.82	56.00	18.45	0.3294	1.0000	$3,976,157.18	$215,542.55
1979	44.50	$9,410,510.30	56.00	17.79	0.3177	1.0000	$2,989,602.63	$168,044.83
1978	45.50	$3,909,311.11	56.00	17.15	0.3062	1.0000	$1,196,891.43	$69,809.13
1977	46.50	$2,544,947.46	56.00	16.51	0.2949	1.0000	$750,472.70	$45,445.49
1976	47.50	$2,671,645.47	56.00	15.90	0.2839	1.0000	$758,391.91	$47,707.95
1975	48.50	$1,497,136.55	56.00	15.29	0.2731	1.0000	$408,878.72	$26,734.58
1974	49.50	$1,157,209.69	56.00	14.71	0.2627	1.0000	$303,985.28	$20,664.46
1973	50.50	$1,164,517.31	56.00	14.14	0.2525	1.0000	$294,046.64	$20,794.95
1972	51.50	$5,276,551.97	56.00	13.59	0.2426	1.0000	$1,280,120.75	$94,224.14
1971	52.50	$3,660,175.58	56.00	13.05	0.2330	1.0000	$852,804.82	$65,360.28
1970	53.50	$2,692,773.49	56.00	12.53	0.2237	1.0000	$602,321.63	$48,085.24
1969	54.50	$1,479,178.37	56.00	12.02	0.2147	1.0000	$317,622.11	$26,413.90
1968	55.50	$525,156.20	56.00	11.54	0.2060	1.0000	$108,199.15	$9,377.79
1967	56.50	$348,884.58	56.00	11.07	0.1976	1.0000	$68,953.53	$6,230.08
1966	57.50	$133,827.83	56.00	10.61	0.1896	1.0000	$25,367.08	$2,389.78
1951	72.50	$486.99	56.00	5.54	0.0990	1.0000	$48.19	$8.70
		$1,146,681,637.87	56.00	42.90	0.7661	1.0000	$878,507,608.62	$20,476,457.82

Remaining Life Depreciation Accrual

Account: PECO Gas 3802 PA
Scenario: PECO Gas Groups 2024
Dispersion: 56.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,146,681,637.87	42.90	$19,670,388.98	1.715419%	2.330823%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($4,395,199.17)	0.50	($39,242.85)	0.892857%	
Total:	$1,146,681,637.87 *		$19,631,146.13	1.711996%	2.326173%
Average:	$1,144,484,038.28		$19,631,146.13	1.715284%	2.332246%
Grand Total:	$1,146,681,637.87 *		$19,631,146.13	1.711996%	2.326173%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3810 PA
Dispersion: 40.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$4,046,455.27	40.00	39.51	0.9877	1.0000	$3,996,648.78	$101,161.38
2022	1.50	$3,206,612.91	40.00	38.53	0.9631	1.0000	$3,088,394.35	$80,165.32
2021	2.50	$3,218,753.83	40.00	37.55	0.9387	1.0000	$3,021,357.40	$80,468.85
2020	3.50	$4,499,003.79	40.00	36.57	0.9143	1.0000	$4,113,446.80	$112,475.09
2019	4.50	$2,116,528.29	40.00	35.60	0.8900	1.0000	$1,883,806.37	$52,913.21
2018	5.50	$1,291,922.11	40.00	34.64	0.8659	1.0000	$1,118,680.81	$32,298.05
2017	6.50	$1,993,524.59	40.00	33.68	0.8419	1.0000	$1,678,367.74	$49,838.11
2016	7.50	$3,231,131.61	40.00	32.72	0.8181	1.0000	$2,643,250.86	$80,778.29
2015	8.50	$3,953,020.39	40.00	31.77	0.7944	1.0000	$3,140,179.33	$98,825.51
2014	9.50	$1,942,576.46	40.00	30.83	0.7709	1.0000	$1,497,437.31	$48,564.41
2013	10.50	$1,993,698.58	40.00	29.90	0.7475	1.0000	$1,490,372.61	$49,842.46
2012	11.50	$1,259,658.68	40.00	28.98	0.7244	1.0000	$912,523.27	$31,491.47
2011	12.50	$1,201,339.94	40.00	28.06	0.7015	1.0000	$842,777.40	$30,033.50
2010	13.50	$1,183,508.61	40.00	27.15	0.6789	1.0000	$803,428.30	$29,587.72
2009	14.50	$1,056,966.77	40.00	26.26	0.6564	1.0000	$693,833.46	$26,424.17
2008	15.50	$1,858,674.35	40.00	25.37	0.6343	1.0000	$1,178,878.24	$46,466.86
2007	16.50	$887,659.07	40.00	24.49	0.6124	1.0000	$543,574.06	$22,191.48
2006	17.50	$710,350.63	40.00	23.63	0.5907	1.0000	$419,619.26	$17,758.77
2005	18.50	$1,589,824.16	40.00	22.78	0.5694	1.0000	$905,247.46	$39,745.60
2004	19.50	$507,230.87	40.00	21.93	0.5483	1.0000	$278,134.24	$12,680.77
2003	20.50	$1,118,131.05	40.00	21.10	0.5276	1.0000	$589,938.93	$27,953.28
2002	21.50	$2,281,802.07	40.00	20.29	0.5072	1.0000	$1,157,236.16	$57,045.05
2001	22.50	$19,890,851.04	40.00	19.48	0.4871	1.0000	$9,688,179.04	$497,271.28
2000	23.50	$4,385.68	40.00	18.69	0.4673	1.0000	$2,049.29	$109.64
1999	24.50	$1,358,808.60	40.00	17.91	0.4479	1.0000	$608,543.67	$33,970.22
1998	25.50	$988,473.60	40.00	17.15	0.4287	1.0000	$423,795.46	$24,711.84
1997	26.50	$2,108,439.67	40.00	16.40	0.4100	1.0000	$864,524.48	$52,710.99
1996	27.50	$1,490,901.50	40.00	15.67	0.3917	1.0000	$583,923.97	$37,272.54
1995	28.50	$1,012,243.13	40.00	14.95	0.3737	1.0000	$378,298.89	$25,306.08
1994	29.50	$1,313,953.02	40.00	14.25	0.3561	1.0000	$467,961.14	$32,848.83
1993	30.50	$1,441,414.94	40.00	13.56	0.3391	1.0000	$488,719.11	$36,035.37
1992	31.50	$1,317,697.06	40.00	12.89	0.3224	1.0000	$424,777.16	$32,942.43

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3810 PA
Dispersion: 40.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$1,337,950.72	40.00	12.25	0.3062	1.0000	$409,673.38	$33,448.77
1990	33.50	$1,207,697.75	40.00	11.62	0.2905	1.0000	$350,793.49	$30,192.44
1989	34.50	$1,009,549.01	40.00	11.01	0.2753	1.0000	$277,942.28	$25,238.73
1988	35.50	$973,798.89	40.00	10.43	0.2606	1.0000	$253,810.64	$24,344.97
1987	36.50	$972,388.17	40.00	9.86	0.2466	1.0000	$239,774.69	$24,309.70
1986	37.50	$789,695.73	40.00	9.32	0.2330	1.0000	$184,036.38	$19,742.39
1985	38.50	$998,518.48	40.00	8.81	0.2201	1.0000	$219,821.69	$24,962.96
1984	39.50	$423,845.31	40.00	8.31	0.2078	1.0000	$88,072.46	$10,596.13
1983	40.50	$393,456.50	40.00	7.84	0.1961	1.0000	$77,149.99	$9,836.41
1982	41.50	$493,578.97	40.00	7.40	0.1849	1.0000	$91,278.99	$12,339.47
1981	42.50	$999,495.15	40.00	6.98	0.1744	1.0000	$174,302.63	$24,987.38
1980	43.50	$1,549,151.40	40.00	6.58	0.1644	1.0000	$254,694.11	$38,728.78
1979	44.50	$1,384,239.53	40.00	6.20	0.1550	1.0000	$214,518.19	$34,605.99
1978	45.50	$141,563.27	40.00	5.84	0.1461	1.0000	$20,678.00	$3,539.08
1977	46.50	$132,985.90	40.00	5.50	0.1376	1.0000	$18,301.87	$3,324.65
1976	47.50	$200,150.63	40.00	5.19	0.1297	1.0000	$25,952.75	$5,003.77
1975	48.50	$127,500.43	40.00	4.88	0.1220	1.0000	$15,559.93	$3,187.51
1974	49.50	$161,670.44	40.00	4.59	0.1148	1.0000	$18,566.39	$4,041.76
1973	50.50	$311,291.97	40.00	4.31	0.1078	1.0000	$33,558.40	$7,782.30
1972	51.50	$682,000.29	40.00	4.05	0.1011	1.0000	$68,969.69	$17,050.01
1971	52.50	$432,722.79	40.00	3.78	0.0945	1.0000	$40,873.53	$10,818.07
1970	53.50	$501,851.96	40.00	3.52	0.0881	1.0000	$44,196.99	$12,546.30
1969	54.50	$595,922.33	40.00	3.26	0.0815	1.0000	$48,590.33	$14,898.06
1968	55.50	$372,964.75	40.00	3.01	0.0753	1.0000	$28,067.05	$9,324.12
1967	56.50	$95,474.73	40.00	2.75	0.0687	1.0000	$6,562.75	$2,386.87
1966	57.50	$398,565.66	40.00	2.50	0.0625	1.0000	$24,907.93	$9,964.14
1965	58.50	$289,253.71	40.00	2.24	0.0560	1.0000	$16,194.23	$7,231.34
1964	59.50	$174,556.81	40.00	1.99	0.0499	1.0000	$8,702.66	$4,363.92
1963	60.50	$137,475.45	40.00	1.74	0.0434	1.0000	$5,972.91	$3,436.89
1962	61.50	$47,366.70	40.00	1.50	0.0376	1.0000	$1,780.69	$1,184.17
1961	62.50	$25,626.45	40.00	1.26	0.0314	1.0000	$804.92	$640.66
1960	63.50	$75,275.16	40.00	1.04	0.0261	1.0000	$1,962.44	$1,881.88

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3810 PA
Dispersion: 40.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$80,331.01	40.00	0.81	0.0202	1.0000	$1,625.65	$2,008.28
1958	65.50	$61,047.37	40.00	0.63	0.0157	1.0000	$961.01	$1,526.18
1957	66.50	$94,002.65	40.00	0.35	0.0087	1.0000	$822.42	$2,350.07
1956	67.50	$91,831.36	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	68.50	$66,770.23	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	69.50	$74,754.05	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	70.50	$84,098.93	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1952	71.50	$70,451.66	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1951	72.50	$56,877.23	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	73.50	$34,056.48	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1949	74.50	$15,681.27	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	75.50	$13,512.76	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	76.50	$6,468.91	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	77.50	$4,309.56	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	78.50	$2,059.84	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	79.50	$1,279.35	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	80.50	$2,382.01	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	81.50	$6,320.40	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1941	82.50	$3,368.31	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1940	83.50	$3,205.54	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1939	84.50	$2,196.69	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1938	85.50	$1,498.86	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	86.50	$1,437.36	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1936	87.50	$438.37	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	88.50	$602.37	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1934	89.50	$140.83	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	90.50	$535.73	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1932	91.50	$214.41	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	92.50	$504.72	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	93.50	$1,078.38	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$1,430.19	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$1,258.34	40.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3810 PA
Dispersion: 40.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1927	96.50	$1,437.80	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	97.50	$1,041.60	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	98.50	$817.48	40.00	0.00	0.0000	0.0000	$0.00	$0.00
		$94,300,569.36	40.00	22.70	0.5641	1.0000	$53,197,386.79	$2,343,712.71

Remaining Life Depreciation Accrual

Account: PECO Gas 3810 PA
Scenario: PECO Gas Groups 2024
Dispersion: 40.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$94,300,569.36	22.70	$2,063,188.47	2.187885%	4.405691%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,589,168.80)	0.50	($32,364.61)	1.250000%	
Total:	$94,300,569.36 *		$2,030,823.86	2.153565%	4.336581%
Average:	$93,005,984.96		$2,030,823.86	2.183541%	4.459871%
Grand Total:	$94,300,569.36 *		$2,030,823.86	2.153565%	4.336581%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3811 PA
Dispersion: 20.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$1,582,314.52	20.00	19.50	0.9750	1.0000	$1,542,756.66	$79,115.73
2022	1.50	$1,325,779.66	20.00	18.50	0.9250	1.0000	$1,226,365.08	$66,288.98
2021	2.50	$926,955.19	20.00	17.50	0.8751	1.0000	$811,203.30	$46,347.76
2020	3.50	$486,321.88	20.00	16.51	0.8256	1.0000	$401,498.54	$24,316.09
2019	4.50	$567,384.88	20.00	15.53	0.7767	1.0000	$440,679.30	$28,369.24
2018	5.50	$697,964.64	20.00	14.58	0.7288	1.0000	$508,687.16	$34,898.23
2017	6.50	$3,559,826.33	20.00	13.65	0.6823	1.0000	$2,428,963.40	$177,991.32
2016	7.50	$6,551,872.83	20.00	12.75	0.6376	1.0000	$4,177,249.16	$327,593.64
2015	8.50	$23,792,671.15	20.00	11.90	0.5948	1.0000	$14,151,483.77	$1,189,633.56
2014	9.50	$32,663,594.09	20.00	11.08	0.5542	1.0000	$18,100,969.73	$1,633,179.70
2013	10.50	$2,270,274.80	20.00	10.32	0.5158	1.0000	$1,171,016.68	$113,513.74
		$74,424,959.97	20.00	12.08	0.6041	1.0000	$44,960,872.77	$3,721,248.00

Remaining Life Depreciation Accrual

Account: PECO Gas 3811 PA
Scenario: PECO Gas Groups 2024
Dispersion: 20.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$74,424,959.97	12.08	$3,602,778.17	4.840820%	8.276636%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,262,181.79)	0.50	($31,554.54)	2.500000%	
Total:	$74,424,959.97 *		$3,571,223.63	4.798422%	8.204146%
Average:	$73,793,869.08		$3,571,223.63	4.839458%	8.324840%
Grand Total:	$74,424,959.97 *		$3,571,223.63	4.798422%	8.204146%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3820 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$15,731,328.13	50.00	49.51	0.9901	1.0000	$15,576,363.10	$314,626.56
2022	1.50	$22,533,605.78	50.00	48.53	0.9705	1.0000	$21,868,916.38	$450,672.12
2021	2.50	$18,854,657.65	50.00	47.54	0.9509	1.0000	$17,928,827.49	$377,093.15
2020	3.50	$12,390,820.15	50.00	46.57	0.9313	1.0000	$11,540,174.71	$247,816.40
2019	4.50	$10,999,451.81	50.00	45.59	0.9119	1.0000	$10,030,124.50	$219,989.04
2018	5.50	$10,305,495.59	50.00	44.62	0.8925	1.0000	$9,197,270.44	$206,109.91
2017	6.50	$7,510,953.71	50.00	43.66	0.8731	1.0000	$6,558,081.44	$150,219.07
2016	7.50	$7,265,700.31	50.00	42.69	0.8539	1.0000	$6,204,107.25	$145,314.01
2015	8.50	$6,449,834.00	50.00	41.74	0.8347	1.0000	$5,383,922.34	$128,996.68
2014	9.50	$4,268,955.54	50.00	40.78	0.8157	1.0000	$3,482,120.32	$85,379.11
2013	10.50	$5,166,898.56	50.00	39.84	0.7967	1.0000	$4,116,632.13	$103,337.97
2012	11.50	$4,317,306.30	50.00	38.89	0.7779	1.0000	$3,358,393.60	$86,346.13
2011	12.50	$6,700,232.54	50.00	37.96	0.7592	1.0000	$5,086,627.69	$134,004.65
2010	13.50	$3,407,466.28	50.00	37.03	0.7406	1.0000	$2,523,512.03	$68,149.33
2009	14.50	$3,433,547.23	50.00	36.11	0.7221	1.0000	$2,479,451.86	$68,670.94
2008	15.50	$2,705,759.18	50.00	35.19	0.7038	1.0000	$1,904,330.21	$54,115.18
2007	16.50	$2,911,871.47	50.00	34.28	0.6856	1.0000	$1,996,472.57	$58,237.43
2006	17.50	$2,914,318.99	50.00	33.38	0.6676	1.0000	$1,945,645.42	$58,286.38
2005	18.50	$3,556,073.38	50.00	32.49	0.6498	1.0000	$2,310,577.77	$71,121.47
2004	19.50	$2,071,214.35	50.00	31.60	0.6321	1.0000	$1,309,135.45	$41,424.29
2003	20.50	$2,199,771.61	50.00	30.73	0.6145	1.0000	$1,351,844.37	$43,995.43
2002	21.50	$3,565,476.05	50.00	29.86	0.5972	1.0000	$2,129,260.73	$71,309.52
2001	22.50	$5,301,340.27	50.00	29.00	0.5800	1.0000	$3,074,914.29	$106,026.81
2000	23.50	$759,047.08	50.00	28.15	0.5630	1.0000	$427,378.55	$15,180.94
1999	24.50	$3,246,217.31	50.00	27.31	0.5463	1.0000	$1,773,266.32	$64,924.35
1998	25.50	$13,173,969.77	50.00	26.48	0.5297	1.0000	$6,977,749.89	$263,479.40
1997	26.50	$9,256,511.36	50.00	25.66	0.5133	1.0000	$4,751,024.30	$185,130.23
1996	27.50	$3,988,298.17	50.00	24.85	0.4971	1.0000	$1,982,461.56	$79,765.96
1995	28.50	$5,187,411.50	50.00	24.05	0.4811	1.0000	$2,495,589.20	$103,748.23
1994	29.50	$4,030,958.09	50.00	23.27	0.4653	1.0000	$1,875,663.78	$80,619.16
1993	30.50	$3,835,768.33	50.00	22.49	0.4498	1.0000	$1,725,192.49	$76,715.37
1992	31.50	$3,526,480.26	50.00	21.72	0.4344	1.0000	$1,532,018.38	$70,529.61

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3820 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$5,024,374.88	50.00	20.97	0.4193	1.0000	$2,106,876.74	$100,487.50
1990	33.50	$3,159,323.65	50.00	20.22	0.4045	1.0000	$1,277,839.70	$63,186.47
1989	34.50	$2,467,107.16	50.00	19.49	0.3898	1.0000	$961,798.88	$49,342.14
1988	35.50	$2,468,130.65	50.00	18.77	0.3755	1.0000	$926,734.71	$49,362.61
1987	36.50	$2,958,571.21	50.00	18.07	0.3614	1.0000	$1,069,143.15	$59,171.42
1986	37.50	$2,672,243.93	50.00	17.38	0.3475	1.0000	$928,703.38	$53,444.88
1985	38.50	$2,937,195.93	50.00	16.70	0.3340	1.0000	$980,974.98	$58,743.92
1984	39.50	$1,752,734.81	50.00	16.04	0.3207	1.0000	$562,142.32	$35,054.70
1983	40.50	$1,910,401.47	50.00	15.39	0.3078	1.0000	$587,952.94	$38,208.03
1982	41.50	$1,738,759.45	50.00	14.76	0.2951	1.0000	$513,144.87	$34,775.19
1981	42.50	$2,427,939.90	50.00	14.14	0.2828	1.0000	$686,638.77	$48,558.80
1980	43.50	$2,916,141.20	50.00	13.54	0.2708	1.0000	$789,776.84	$58,322.82
1979	44.50	$1,088,005.60	50.00	12.96	0.2592	1.0000	$282,010.23	$21,760.11
1978	45.50	$514,459.38	50.00	12.40	0.2479	1.0000	$127,549.05	$10,289.19
1977	46.50	$340,140.20	50.00	11.85	0.2370	1.0000	$80,622.06	$6,802.80
1976	47.50	$290,576.43	50.00	11.32	0.2265	1.0000	$65,813.32	$5,811.53
1975	48.50	$341,474.08	50.00	10.82	0.2163	1.0000	$73,874.96	$6,829.48
1974	49.50	$399,173.62	50.00	10.33	0.2066	1.0000	$82,456.73	$7,983.47
1973	50.50	$629,650.53	50.00	9.86	0.1972	1.0000	$124,154.77	$12,593.01
1972	51.50	$598,317.05	50.00	9.41	0.1882	1.0000	$112,586.92	$11,966.34
1971	52.50	$615,320.62	50.00	8.98	0.1795	1.0000	$110,475.12	$12,306.41
1970	53.50	$417,880.92	50.00	8.56	0.1713	1.0000	$71,574.41	$8,357.62
1969	54.50	$423,743.48	50.00	8.17	0.1634	1.0000	$69,232.07	$8,474.87
1968	55.50	$345,669.48	50.00	7.79	0.1558	1.0000	$53,865.73	$6,913.39
1967	56.50	$278,129.98	50.00	7.43	0.1486	1.0000	$41,334.44	$5,562.60
1966	57.50	$198,289.71	50.00	7.09	0.1417	1.0000	$28,101.17	$3,965.79
1965	58.50	$232,710.27	50.00	6.76	0.1351	1.0000	$31,443.07	$4,654.21
1964	59.50	$158,939.29	50.00	6.44	0.1288	1.0000	$20,469.07	$3,178.79
1963	60.50	$115,160.49	50.00	6.14	0.1227	1.0000	$14,131.42	$2,303.21
1962	61.50	$114,867.48	50.00	5.84	0.1169	1.0000	$13,422.30	$2,297.35
1961	62.50	$42,509.98	50.00	5.56	0.1112	1.0000	$4,726.49	$850.20
1960	63.50	$81,750.75	50.00	5.28	0.1057	1.0000	$8,639.21	$1,635.02

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3820 PA
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$42,435.52	50.00	5.01	0.1003	1.0000	$4,256.27	$848.71
1958	65.50	$46,757.47	50.00	4.75	0.0950	1.0000	$4,443.03	$935.15
1957	66.50	$43,436.56	50.00	4.49	0.0898	1.0000	$3,901.17	$868.73
1956	67.50	$37,351.05	50.00	4.23	0.0846	1.0000	$3,161.76	$747.02
1955	68.50	$45,555.52	50.00	3.98	0.0795	1.0000	$3,622.15	$911.11
1954	69.50	$51,381.90	50.00	3.72	0.0744	1.0000	$3,821.95	$1,027.64
1953	70.50	$31,693.17	50.00	3.46	0.0693	1.0000	$2,194.98	$633.86
1952	71.50	$33,887.66	50.00	3.21	0.0641	1.0000	$2,173.40	$677.75
1951	72.50	$17,487.07	50.00	2.95	0.0590	1.0000	$1,032.11	$349.74
1950	73.50	$28,394.69	50.00	2.70	0.0539	1.0000	$1,531.31	$567.89
1949	74.50	$22,720.81	50.00	2.44	0.0489	1.0000	$1,110.45	$454.42
1948	75.50	$6,831.20	50.00	2.19	0.0439	1.0000	$299.68	$136.62
1947	76.50	$8,163.34	50.00	1.95	0.0389	1.0000	$317.88	$163.27
1945	78.50	$32.88	50.00	1.47	0.0294	1.0000	$0.97	$0.66
1944	79.50	$2,301.25	50.00	1.24	0.0248	1.0000	$57.02	$46.03
1943	80.50	$5,276.60	50.00	1.02	0.0203	1.0000	$107.34	$105.53
1942	81.50	$1,790.72	50.00	0.81	0.0161	1.0000	$28.86	$35.81
1941	82.50	$946.93	50.00	0.60	0.0120	1.0000	$11.40	$18.94
1940	83.50	$2,084.66	50.00	0.25	0.0050	1.0000	$10.42	$41.69
1939	84.50	$2,472.42	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1938	85.50	$3,018.73	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	86.50	$488.13	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1936	87.50	$230.56	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	88.50	$86.39	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1934	89.50	$17.07	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	90.50	$16.26	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$251,661,292.89	50.00	35.31	0.7063	1.0000	$177,737,342.55	$5,033,099.27

Remaining Life Depreciation Accrual

Account: PECO Gas 3820 PA
Scenario: PECO Gas Groups 2024
Dispersion: 50.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$251,661,292.89	35.31	$4,990,488.33	1.983018%	2.831762%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,762,007.17)	0.50	($17,620.07)	1.000000%	
Total:	$251,661,292.89 *		$4,972,868.26	1.976016%	2.821764%
Average:	$250,780,289.30		$4,972,868.26	1.982958%	2.835941%
Grand Total:	$251,661,292.89 *		$4,972,868.26	1.976016%	2.821764%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3870 PA
Dispersion: 22.00 - S1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2016	7.50	$19,055.77	22.00	14.96	0.6801	1.0000	$12,959.26	$866.17
2014	9.50	$199,116.02	22.00	13.36	0.6071	1.0000	$120,892.35	$9,050.73
2009	14.50	$71,854.62	22.00	9.97	0.4532	1.0000	$32,564.90	$3,266.12
2008	15.50	$340,655.95	22.00	9.40	0.4271	1.0000	$145,480.79	$15,484.36
2007	16.50	$35,681.43	22.00	8.85	0.4023	1.0000	$14,354.36	$1,621.88
2006	17.50	$30,551.79	22.00	8.33	0.3788	1.0000	$11,573.90	$1,388.72
2005	18.50	$2,280.86	22.00	7.85	0.3566	1.0000	$813.46	$103.68
2004	19.50	$7,999.43	22.00	7.38	0.3356	1.0000	$2,684.58	$363.61
2003	20.50	$386.07	22.00	6.94	0.3157	1.0000	$121.87	$17.55
2002	21.50	$412.51	22.00	6.53	0.2967	1.0000	$122.39	$18.75
1998	25.50	$0.43	22.00	5.05	0.2295	1.0000	$0.10	$0.02
1991	32.50	$1,085,691.19	22.00	2.98	0.1355	1.0000	$147,127.51	$49,349.60
1990	33.50	$87,966.45	22.00	2.72	0.1236	1.0000	$10,869.32	$3,998.48
1988	35.50	$78,479.19	22.00	2.21	0.1004	1.0000	$7,880.78	$3,567.24
1987	36.50	$2,782.50	22.00	1.96	0.0891	1.0000	$248.00	$126.48
1985	38.50	$87,074.72	22.00	1.46	0.0666	1.0000	$5,795.93	$3,957.94
1982	41.50	$8,416.09	22.00	0.75	0.0340	1.0000	$286.02	$382.55
1969	54.50	$3,890.94	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	55.50	$4,402.06	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	57.50	$7,136.95	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	58.50	$12,579.66	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	59.50	$752.97	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	61.50	$9,811.52	22.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	69.50	$937.85	22.00	0.00	0.0000	0.0000	$0.00	$0.00
		$2,097,916.97	22.00	5.49	0.2449	1.0000	$513,775.52	$93,563.86

Remaining Life Depreciation Accrual

Account: PECO Gas 3870 PA
Scenario: PECO Gas Groups 2024
Dispersion: 22.00 - S1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$2,097,916.97	5.49	$100,919.60	4.810467%	18.211039%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($368,784.69)	0.50	($8,381.47)	2.272727%	
Total:	$2,097,916.97 *		$92,538.13	4.410953%	16.698594%
Average:	$1,913,524.63		$92,538.13	4.836004%	25.025534%
Grand Total:	$2,097,916.97 *		$92,538.13	4.410953%	16.698594%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas 390 Composite 2024

Account: PECO Gas 390 Composite
Dispersion: 45.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$935,090.30	45.00	44.55	0.9899	1.0000	$925,686.10	$20,779.78
2021	2.50	$335,663.53	45.00	42.75	0.9500	1.0000	$318,879.87	$7,459.19
2020	3.50	$566,150.37	45.00	41.86	0.9302	1.0000	$526,649.13	$12,581.12
2019	4.50	$392,728.36	45.00	40.98	0.9106	1.0000	$357,616.49	$8,727.30
2018	5.50	$1,893,244.22	45.00	40.10	0.8911	1.0000	$1,687,072.96	$42,072.09
2017	6.50	$492,410.38	45.00	39.23	0.8717	1.0000	$429,256.67	$10,942.45
2016	7.50	$18,202.55	45.00	38.36	0.8525	1.0000	$15,518.11	$404.50
2015	8.50	$694,511.94	45.00	37.51	0.8335	1.0000	$578,853.42	$15,433.60
2014	9.50	$38,316.39	45.00	36.66	0.8146	1.0000	$31,211.01	$851.48
2006	17.50	$883,357.10	45.00	30.12	0.6693	1.0000	$591,226.20	$19,630.16
2005	18.50	$919,501.62	45.00	29.34	0.6520	1.0000	$599,472.08	$20,433.37
2004	19.50	$10,125.00	45.00	28.57	0.6348	1.0000	$6,427.37	$225.00
2003	20.50	$30,649.72	45.00	27.80	0.6178	1.0000	$18,935.96	$681.10
1995	28.50	$165,033.14	45.00	22.04	0.4898	1.0000	$80,834.86	$3,667.40
1994	29.50	$17,548.67	45.00	21.37	0.4748	1.0000	$8,332.05	$389.97
1992	31.50	$1,774,500.25	45.00	20.05	0.4456	1.0000	$790,708.86	$39,433.34
1991	32.50	$2,699.55	45.00	19.41	0.4314	1.0000	$1,164.50	$59.99
1989	34.50	$115,814.54	45.00	18.17	0.4037	1.0000	$46,750.96	$2,573.66
1987	36.50	$30,078.97	45.00	16.97	0.3771	1.0000	$11,342.17	$668.42
1986	37.50	$85,238.31	45.00	16.39	0.3642	1.0000	$31,043.36	$1,894.18
1985	38.50	$3,688.27	45.00	15.82	0.3516	1.0000	$1,296.63	$81.96
1984	39.50	$4,312.39	45.00	15.27	0.3392	1.0000	$1,462.96	$95.83
1983	40.50	$5,111.74	45.00	14.72	0.3272	1.0000	$1,672.67	$113.59
1982	41.50	$14,593.03	45.00	14.20	0.3155	1.0000	$4,603.89	$324.29
1981	42.50	$3,490.23	45.00	13.68	0.3040	1.0000	$1,061.16	$77.56
1979	44.50	$19,192.50	45.00	12.69	0.2820	1.0000	$5,412.47	$426.50
1978	45.50	$1,448.28	45.00	12.22	0.2714	1.0000	$393.14	$32.18
1977	46.50	$12,694.47	45.00	11.75	0.2612	1.0000	$3,315.56	$282.10
1976	47.50	$26,857.40	45.00	11.30	0.2512	1.0000	$6,746.17	$596.83
1975	48.50	$90,069.62	45.00	10.87	0.2415	1.0000	$21,752.11	$2,001.55
1974	49.50	$1,032.19	45.00	10.44	0.2321	1.0000	$239.57	$22.94
1973	50.50	$4,866.88	45.00	10.03	0.2230	1.0000	$1,085.15	$108.15

Generation Arrangement Report

PECO Gas 390 Composite 2024

Account: PECO Gas 390 Composite
Dispersion: 45.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1972	51.50	$42,168.48	45.00	9.64	0.2141	1.0000	$9,028.83	$937.08
1971	52.50	$3,414.51	45.00	9.25	0.2055	1.0000	$701.78	$75.88
1970	53.50	$105.53	45.00	8.87	0.1972	1.0000	$20.81	$2.35
1969	54.50	$1,482.53	45.00	8.51	0.1891	1.0000	$280.33	$32.95
1968	55.50	$868.44	45.00	8.15	0.1812	1.0000	$157.38	$19.30
1966	57.50	$451.55	45.00	7.48	0.1662	1.0000	$75.03	$10.03
1965	58.50	$4,980.19	45.00	7.15	0.1589	1.0000	$791.29	$110.67
1964	59.50	$221.12	45.00	6.83	0.1518	1.0000	$33.56	$4.91
1963	60.50	$4,977.86	45.00	6.52	0.1448	1.0000	$720.89	$110.62
1962	61.50	$30,452.14	45.00	6.21	0.1381	1.0000	$4,203.98	$676.71
1961	62.50	$527.79	45.00	5.91	0.1313	1.0000	$69.31	$11.73
1960	63.50	$10,573.24	45.00	5.61	0.1247	1.0000	$1,318.11	$234.96
1958	65.50	$36.82	45.00	5.03	0.1117	1.0000	$4.11	$0.82
1957	66.50	$4,681.57	45.00	4.73	0.1052	1.0000	$492.34	$104.03
1956	67.50	$628.92	45.00	4.44	0.0987	1.0000	$62.06	$13.98
1955	68.50	$531.02	45.00	4.15	0.0922	1.0000	$48.96	$11.80
1953	70.50	$1,746.80	45.00	3.58	0.0795	1.0000	$138.83	$38.82
1952	71.50	$148,181.49	45.00	3.29	0.0731	1.0000	$10,825.35	$3,292.92
1951	72.50	$131,398.32	45.00	3.00	0.0667	1.0000	$8,758.98	$2,919.96
1950	73.50	$8,174.22	45.00	2.71	0.0603	1.0000	$493.02	$181.65
1949	74.50	$63,061.68	45.00	2.45	0.0543	1.0000	$3,426.45	$1,401.37
1948	75.50	$141,323.54	45.00	2.17	0.0482	1.0000	$6,805.97	$3,140.52
1947	76.50	$167,797.08	45.00	1.89	0.0421	1.0000	$7,058.96	$3,728.82
1945	78.50	$555.06	45.00	1.36	0.0302	1.0000	$16.76	$12.33
1944	79.50	$2,504.83	45.00	1.13	0.0252	1.0000	$63.00	$55.66
1943	80.50	$34.03	45.00	0.90	0.0201	1.0000	$0.68	$0.76
1942	81.50	$330.51	45.00	0.71	0.0158	1.0000	$5.23	$7.34
1941	82.50	$101.53	45.00	0.60	0.0133	1.0000	$1.35	$2.26
1940	83.50	$547.84	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1939	84.50	$82.12	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	86.50	$145.04	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1934	89.50	$592.01	45.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Gas 390 Composite 2024

Account: PECO Gas 390 Composite
Dispersion: 45.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1933	90.50	$379.04	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1932	91.50	$887.18	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	92.50	$12,389.42	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	93.50	$63,129.70	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$18,857.47	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$14,929.46	45.00	0.00	0.0000	0.0000	$0.00	$0.00
		$10,471,471.99	45.00	31.11	0.6839	1.0000	$7,161,626.95	$230,211.84

Remaining Life Depreciation Accrual

Account: PECO Gas 390 Composite
Scenario: PECO Gas 390 Composite 2024
Dispersion: 45.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$10,471,471.99	31.11	$227,762.03	2.175072%	3.214519%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($271,002.21)	0.50	($3,011.14)	1.111113%	
Total:	$10,471,471.99 *		$224,750.89	2.146316%	3.172021%
Average:	$10,335,970.89		$224,750.89	2.174454%	3.233865%
Grand Total:	$10,471,471.99 *		$224,750.89	2.146316%	3.172021%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3912 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$60,132.16	15.00	14.50	0.9667	1.0000	$58,127.75	$4,008.81
2022	1.50	$147,789.23	15.00	13.50	0.9000	1.0000	$133,010.31	$9,852.62
2021	2.50	$5,904.45	15.00	12.50	0.8333	1.0000	$4,920.38	$393.63
2020	3.50	$9,720.92	15.00	11.50	0.7667	1.0000	$7,452.71	$648.06
2017	6.50	$228,283.50	15.00	8.50	0.5667	1.0000	$129,360.65	$15,218.90
2013	10.50	$62,557.53	15.00	4.50	0.3000	1.0000	$18,767.26	$4,170.50
2012	11.50	$1,193.88	15.00	3.50	0.2333	1.0000	$278.57	$79.59
		$515,581.67	15.00	10.24	0.6826	1.0000	$351,917.62	$34,372.11

Remaining Life Depreciation Accrual

Account: PECO Gas 3912 PA
Scenario: PECO Gas Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$515,581.67	10.24	$35,351.16	6.856558%	9.767090%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$515,581.67 *		$35,351.16	6.856558%	9.767090%
Average:	$515,581.67		$35,351.16	6.856558%	9.767090%
Grand Total:	$515,581.67 *		$35,351.16	6.856558%	9.767090%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas 391.3 Composite 2024

Account: PECO Gas 3913 PA
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$241,862.97	5.00	4.50	0.9000	1.0000	$217,676.67	$48,372.59
2022	1.50	$375,177.51	5.00	3.50	0.7000	1.0000	$262,624.26	$75,035.50
2021	2.50	$172,035.02	5.00	2.50	0.5000	1.0000	$86,017.51	$34,407.00
2020	3.50	$1,892,315.62	5.00	1.50	0.3000	1.0000	$567,694.69	$378,463.12
2019	4.50	$28,982.37	5.00	0.50	0.1000	1.0000	$2,898.24	$5,796.47
		$2,710,373.49	5.00	2.10	0.4195	1.0000	$1,136,911.36	$542,074.70

Remaining Life Depreciation Accrual

Account: PECO Gas 3913 PA
Scenario: PECO Gas 391.3 Composite 2024
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$2,710,373.49	2.10	$531,854.52	19.622924%	47.679601%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($28,982.37)	0.50	($2,898.24)	10.000010%	
Total:	$2,710,373.49 *		$528,956.28	19.515992%	47.419780%
Average:	$2,695,882.31		$528,956.28	19.620897%	48.043920%
Grand Total:	$2,710,373.49 *		$528,956.28	19.515992%	47.419780%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3940 PA
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$1,062,151.27	20.00	19.50	0.9750	1.0000	$1,035,597.49	$53,107.56
2022	1.50	$846,470.41	20.00	18.50	0.9250	1.0000	$782,985.13	$42,323.52
2021	2.50	$764,050.78	20.00	17.50	0.8750	1.0000	$668,544.43	$38,202.54
2020	3.50	$1,492,439.37	20.00	16.50	0.8250	1.0000	$1,231,262.48	$74,621.97
2019	4.50	$1,181,048.85	20.00	15.50	0.7750	1.0000	$915,312.86	$59,052.44
2018	5.50	$1,408,789.74	20.00	14.50	0.7250	1.0000	$1,021,372.56	$70,439.49
2017	6.50	$1,330,543.22	20.00	13.50	0.6750	1.0000	$898,116.67	$66,527.16
2016	7.50	$822,798.03	20.00	12.50	0.6250	1.0000	$514,248.77	$41,139.90
2015	8.50	$626,101.96	20.00	11.50	0.5750	1.0000	$360,008.63	$31,305.10
2014	9.50	$429,896.26	20.00	10.50	0.5250	1.0000	$225,695.54	$21,494.81
2013	10.50	$492,497.32	20.00	9.50	0.4750	1.0000	$233,936.23	$24,624.87
2012	11.50	$352,323.30	20.00	8.50	0.4250	1.0000	$149,737.40	$17,616.17
2011	12.50	$476,038.52	20.00	7.50	0.3750	1.0000	$178,514.45	$23,801.93
2010	13.50	$896,247.89	20.00	6.50	0.3250	1.0000	$291,280.56	$44,812.39
2009	14.50	$907,863.63	20.00	5.50	0.2750	1.0000	$249,662.50	$45,393.18
2008	15.50	$738,136.57	20.00	4.50	0.2250	1.0000	$166,080.73	$36,906.83
2007	16.50	$460,766.21	20.00	3.50	0.1750	1.0000	$80,634.09	$23,038.31
2006	17.50	$520,392.52	20.00	2.50	0.1250	1.0000	$65,049.07	$26,019.63
2005	18.50	$324,274.22	20.00	1.50	0.0750	1.0000	$24,320.57	$16,213.71
2004	19.50	$100,164.19	20.00	0.50	0.0250	1.0000	$2,504.10	$5,008.21
		$15,232,994.26	20.00	11.94	0.5971	1.0000	$9,094,864.24	$761,649.71

Remaining Life Depreciation Accrual

Account: PECO Gas 3940 PA
Scenario: PECO Gas Groups 2024
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$15,232,994.26	11.94	$769,675.26	5.052685%	8.374503%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($100,164.19)	0.50	($2,504.10)	2.499995%	
Total:	$15,232,994.26 *		$767,171.16	5.036247%	8.347257%
Average:	$15,182,912.17		$767,171.16	5.052859%	8.392992%
Grand Total:	$15,232,994.26 *		$767,171.16	5.036247%	8.347257%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3970 PA
Dispersion: 5.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$299,783.75	5.00	4.51	0.9022	1.0000	$270,459.05	$59,956.75
2022	1.50	$809,319.95	5.00	3.57	0.7132	1.0000	$577,233.81	$161,863.99
2021	2.50	$169,951.33	5.00	2.69	0.5389	1.0000	$91,581.30	$33,990.27
2020	3.50	$474,819.59	5.00	1.92	0.3849	1.0000	$182,773.78	$94,963.92
2017	6.50	$931,770.56	5.00	0.61	0.1216	1.0000	$113,343.37	$186,354.11
2016	7.50	$271,314.51	5.00	0.45	0.0901	1.0000	$24,433.06	$54,262.90
2013	10.50	$88,065.36	5.00	0.00	0.0000	0.0000	$0.00	$0.00
2012	11.50	$2,365,733.80	5.00	0.00	0.0000	0.0000	$0.00	$0.00
		$5,410,758.85	5.00	2.13	0.2328	1.0000	$1,259,824.36	$591,391.94

Remaining Life Depreciation Accrual

Account: PECO Gas 3970 PA
Scenario: PECO Gas Groups 2024
Dispersion: 5.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$5,410,758.85	2.13	$464,846.78	8.591157%	46.942406%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,247,906.56)	0.50	($124,790.66)	10.000000%	
Total:	$5,410,758.85 *		$340,056.12	6.284814%	34.340461%
Average:	$4,786,805.57		$340,056.12	7.104030%	92.836462%
Grand Total:	$5,410,758.85 *		$340,056.12	6.284814%	34.340461%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Gas Groups 2024

Account: PECO Gas 3980 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2017	6.50	$97,067.44	15.00	8.50	0.5667	1.0000	$55,004.88	$6,471.16
2015	8.50	$30,200.00	15.00	6.50	0.4333	1.0000	$13,086.67	$2,013.33
		$127,267.44	15.00	8.03	0.5350	1.0000	$68,091.55	$8,484.50

Remaining Life Depreciation Accrual

Account: PECO Gas 3980 PA
Scenario: PECO Gas Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$127,267.44	8.03	$8,296.81	6.519193%	12.460424%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$127,267.44 *		$8,296.81	6.519193%	12.460424%
Average:	$127,267.44		$8,296.81	6.519193%	12.460424%
Grand Total:	$127,267.44 *		$8,296.81	6.519193%	12.460424%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$33,473,165.09	55.00	54.63	0.9932	1.0000	$33,247,078.34	$608,603.00
2022	1.50	$26,231,713.27	55.00	53.89	0.9798	1.0000	$25,701,740.29	$476,940.24
2021	2.50	$14,945,857.59	55.00	53.15	0.9664	1.0000	$14,444,096.31	$271,742.87
2020	3.50	$20,443,382.53	55.00	52.42	0.9531	1.0000	$19,485,565.82	$371,697.86
2019	4.50	$15,786,924.26	55.00	51.70	0.9399	1.0000	$14,838,637.11	$287,034.99
2018	5.50	$7,526,824.12	55.00	50.97	0.9268	1.0000	$6,975,732.46	$136,851.35
2017	6.50	$11,786,114.15	55.00	50.25	0.9137	1.0000	$10,768,940.21	$214,292.98
2016	7.50	$3,535,634.02	55.00	49.54	0.9007	1.0000	$3,184,491.58	$64,284.25
2015	8.50	$3,524,290.56	55.00	48.83	0.8878	1.0000	$3,128,706.69	$64,078.01
2014	9.50	$4,672,130.45	55.00	48.12	0.8749	1.0000	$4,087,531.95	$84,947.83
2013	10.50	$6,479,129.37	55.00	47.41	0.8621	1.0000	$5,585,395.46	$117,802.35
2012	11.50	$4,737,124.82	55.00	46.71	0.8493	1.0000	$4,023,214.34	$86,129.54
2011	12.50	$2,807,741.74	55.00	46.01	0.8366	1.0000	$2,348,941.90	$51,049.85
2010	13.50	$23,784,418.93	55.00	45.32	0.8240	1.0000	$19,597,280.58	$432,443.98
2009	14.50	$13,010,855.37	55.00	44.63	0.8114	1.0000	$10,556,674.67	$236,561.01
2008	15.50	$6,657,810.34	55.00	43.94	0.7988	1.0000	$5,318,540.98	$121,051.10
2007	16.50	$4,705,608.60	55.00	43.25	0.7863	1.0000	$3,700,244.27	$85,556.52
2006	17.50	$172,301.52	55.00	42.57	0.7739	1.0000	$133,345.92	$3,132.75
2005	18.50	$1,307,544.40	55.00	41.88	0.7615	1.0000	$995,727.74	$23,773.53
2004	19.50	$2,314,335.66	55.00	41.21	0.7492	1.0000	$1,733,888.98	$42,078.83
2003	20.50	$21,962,509.57	55.00	40.53	0.7369	1.0000	$16,184,479.01	$399,318.36
2002	21.50	$2,685,959.20	55.00	39.86	0.7247	1.0000	$1,946,456.95	$48,835.62
2001	22.50	$815,059.23	55.00	39.19	0.7125	1.0000	$580,736.90	$14,819.26
2000	23.50	$417,130.00	55.00	38.52	0.7004	1.0000	$292,159.31	$7,584.18
1999	24.50	$1,817,757.87	55.00	37.86	0.6884	1.0000	$1,251,260.42	$33,050.14
1998	25.50	$40,860,513.08	55.00	37.20	0.6764	1.0000	$27,638,006.48	$742,918.42
1997	26.50	$5,090,081.78	55.00	36.55	0.6645	1.0000	$3,382,365.08	$92,546.94
1996	27.50	$2,961,881.86	55.00	35.90	0.6527	1.0000	$1,933,140.17	$53,852.40
1995	28.50	$21,344,897.25	55.00	35.25	0.6409	1.0000	$13,680,533.88	$388,089.04
1994	29.50	$3,045,571.17	55.00	34.61	0.6293	1.0000	$1,916,463.94	$55,374.02
1993	30.50	$6,536,534.74	55.00	33.97	0.6177	1.0000	$4,037,684.07	$118,846.09
1992	31.50	$4,055,727.37	55.00	33.34	0.6062	1.0000	$2,458,701.44	$73,740.50

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$2,461,687.57	55.00	32.72	0.5948	1.0000	$1,464,306.27	$44,757.96
1990	33.50	$1,630,818.18	55.00	32.10	0.5835	1.0000	$951,658.46	$29,651.24
1989	34.50	$425,645.00	55.00	31.48	0.5724	1.0000	$243,618.60	$7,739.00
1988	35.50	$1,621,992.40	55.00	30.87	0.5612	1.0000	$910,342.35	$29,490.77
1987	36.50	$1,843,461.39	55.00	30.27	0.5503	1.0000	$1,014,427.53	$33,517.48
1986	37.50	$891,755.86	55.00	29.67	0.5394	1.0000	$481,018.38	$16,213.74
1985	38.50	$583,726.08	55.00	29.07	0.5286	1.0000	$308,576.04	$10,613.20
1984	39.50	$1,747,807.13	55.00	28.49	0.5180	1.0000	$905,292.03	$31,778.31
1983	40.50	$1,107,195.78	55.00	27.91	0.5074	1.0000	$561,794.07	$20,130.83
1982	41.50	$293,436.25	55.00	27.33	0.4970	1.0000	$145,832.17	$5,335.20
1981	42.50	$1,008,275.15	55.00	26.77	0.4867	1.0000	$490,680.36	$18,332.28
1980	43.50	$325,585.69	55.00	26.20	0.4764	1.0000	$155,120.60	$5,919.74
1979	44.50	$74,022.35	55.00	25.65	0.4663	1.0000	$34,519.48	$1,345.86
1978	45.50	$358,408.13	55.00	25.10	0.4563	1.0000	$163,557.75	$6,516.51
1977	46.50	$145,548.13	55.00	24.56	0.4465	1.0000	$64,983.41	$2,646.33
1976	47.50	$91,976.05	55.00	24.02	0.4367	1.0000	$40,169.86	$1,672.29
1975	48.50	$74,766.72	55.00	23.49	0.4271	1.0000	$31,933.51	$1,359.39
1974	49.50	$74,462.49	55.00	22.97	0.4176	1.0000	$31,094.60	$1,353.86
1973	50.50	$9,578.53	55.00	22.45	0.4082	1.0000	$3,909.71	$174.16
1972	51.50	$25,138,086.51	55.00	21.94	0.3989	1.0000	$10,027,195.13	$457,056.12
1971	52.50	$13,150.86	55.00	21.43	0.3897	1.0000	$5,125.17	$239.11
1970	53.50	$4,026,826.49	55.00	20.94	0.3807	1.0000	$1,532,841.50	$73,215.03
1969	54.50	$20,156.13	55.00	20.44	0.3717	1.0000	$7,492.25	$366.48
1968	55.50	$3,016,555.59	55.00	19.96	0.3629	1.0000	$1,094,615.22	$54,846.47
1967	56.50	$588,794.05	55.00	19.48	0.3541	1.0000	$208,517.16	$10,705.35
1966	57.50	$8,710.80	55.00	19.00	0.3455	1.0000	$3,009.80	$158.38
1965	58.50	$230,964.86	55.00	18.54	0.3370	1.0000	$77,842.43	$4,199.36
1964	59.50	$448.18	55.00	18.07	0.3286	1.0000	$147.29	$8.15
1963	60.50	$102,934.00	55.00	17.62	0.3203	1.0000	$32,974.15	$1,871.53
1962	61.50	$13,782.07	55.00	17.17	0.3122	1.0000	$4,302.25	$250.58
1961	62.50	$798,747.44	55.00	16.72	0.3041	1.0000	$242,880.66	$14,522.68
1960	63.50	$41,170.32	55.00	16.29	0.2961	1.0000	$12,190.96	$748.55

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$506,068.46	55.00	15.85	0.2882	1.0000	$145,867.16	$9,201.24
1958	65.50	$114,683.49	55.00	15.43	0.2805	1.0000	$32,165.07	$2,085.15
1957	66.50	$45,395.83	55.00	15.00	0.2728	1.0000	$12,383.80	$825.38
1956	67.50	$1,379,385.77	55.00	14.59	0.2652	1.0000	$365,840.23	$25,079.74
1955	68.50	$35,386.50	55.00	14.18	0.2578	1.0000	$9,120.93	$643.39
1954	69.50	$1,992.49	55.00	13.77	0.2504	1.0000	$498.85	$36.23
1953	70.50	$73,915.73	55.00	13.37	0.2431	1.0000	$17,967.57	$1,343.92
1952	71.50	$63,925.13	55.00	12.97	0.2359	1.0000	$15,079.17	$1,162.28
1951	72.50	$16,504.21	55.00	12.58	0.2288	1.0000	$3,776.08	$300.08
1950	73.50	$3,326.06	55.00	12.20	0.2218	1.0000	$737.67	$60.47
1949	74.50	$56,408.83	55.00	11.82	0.2149	1.0000	$12,119.95	$1,025.62
1948	75.50	$238.29	55.00	11.44	0.2080	1.0000	$49.57	$4.33
1947	76.50	$293.41	55.00	11.07	0.2013	1.0000	$59.06	$5.33
1946	77.50	$1,117.60	55.00	10.70	0.1946	1.0000	$217.52	$20.32
1944	79.50	$394,951.08	55.00	9.99	0.1816	1.0000	$71,720.49	$7,180.93
1942	81.50	$3,689.29	55.00	9.29	0.1688	1.0000	$622.86	$67.08
1941	82.50	$1,241.54	55.00	8.94	0.1626	1.0000	$201.87	$22.57
1938	85.50	$8,310.34	55.00	7.94	0.1443	1.0000	$1,199.39	$151.10
1937	86.50	$121.50	55.00	7.61	0.1384	1.0000	$16.82	$2.21
1933	90.50	$25.47	55.00	6.35	0.1155	1.0000	$2.94	$0.46
1931	92.50	$403.82	55.00	5.74	0.1043	1.0000	$42.13	$7.34
1930	93.50	$122.02	55.00	5.44	0.0989	1.0000	$12.07	$2.22
1927	96.50	$13,978.16	55.00	4.55	0.0827	1.0000	$1,156.59	$254.15
1925	98.50	$5,336.67	55.00	3.96	0.0720	1.0000	$384.50	$97.03
1924	99.50	$5,737.55	55.00	3.67	0.0667	1.0000	$382.51	$104.32
1922	101.50	$232.91	55.00	3.06	0.0557	1.0000	$12.97	$4.23
1914	109.50	$1,588.23	55.00	0.52	0.0095	1.0000	$15.15	$28.88
1892	131.50	$59.47	55.00	0.00	0.0000	0.0000	$0.00	$0.00
		$371,001,445.94	55.00	42.56	0.7739	1.0000	$287,101,385.33	$6,745,479.75

Remaining Life Depreciation Accrual

Account: PECO Common 390 Composite
Scenario: PECO Common 390 Composite 2024
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$371,001,445.94	42.56	$6,929,864.62	1.867881%	2.349511%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,374,318.12)	0.50	($30,675.62)	0.909091%	
Total:	$371,001,445.94 *		$6,899,189.00	1.859612%	2.339111%
Average:	$369,314,286.88		$6,899,189.00	1.868108%	2.352568%
Grand Total:	$371,001,445.94 *		$6,899,189.00	1.859612%	2.339111%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3911 PA
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2019	4.50	$100,572.80	10.00	5.50	0.5500	1.0000	$55,315.04	$10,057.28
		$100,572.80	10.00	5.50	0.5500	1.0000	$55,315.04	$10,057.28

Remaining Life Depreciation Accrual

Account: PECO Common 3911 PA
Scenario: PECO Common Groups 2024
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$100,572.80	5.50	$13,629.47	13.551841%	18.181818%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$100,572.80 *		$13,629.47	13.551841%	18.181818%
Average:	$100,572.80		$13,629.47	13.551841%	18.181818%
Grand Total:	$100,572.80 *		$13,629.47	13.551841%	18.181818%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3912 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$78,661.44	15.00	14.50	0.9667	1.0000	$76,039.39	$5,244.10
2022	1.50	$2,311,205.85	15.00	13.50	0.9000	1.0000	$2,080,085.27	$154,080.39
2021	2.50	$398,753.73	15.00	12.50	0.8333	1.0000	$332,294.78	$26,583.58
2020	3.50	$4,458,491.59	15.00	11.50	0.7667	1.0000	$3,418,176.89	$297,232.77
2019	4.50	$5,306,661.15	15.00	10.50	0.7000	1.0000	$3,714,662.81	$353,777.41
2018	5.50	$1,835,238.77	15.00	9.50	0.6333	1.0000	$1,162,317.89	$122,349.25
2017	6.50	$6,381,677.35	15.00	8.50	0.5667	1.0000	$3,616,283.83	$425,445.16
2016	7.50	$2,471,622.59	15.00	7.50	0.5000	1.0000	$1,235,811.30	$164,774.84
2015	8.50	$765,681.81	15.00	6.50	0.4333	1.0000	$331,795.45	$51,045.45
2014	9.50	$269,581.12	15.00	5.50	0.3667	1.0000	$98,846.41	$17,972.07
2013	10.50	$551,666.18	15.00	4.50	0.3000	1.0000	$165,499.85	$36,777.75
2012	11.50	$264,226.94	15.00	3.50	0.2333	1.0000	$61,652.95	$17,615.13
2011	12.50	$486,527.93	15.00	2.50	0.1667	1.0000	$81,087.99	$32,435.20
2010	13.50	$953,124.79	15.00	1.50	0.1000	1.0000	$95,312.48	$63,541.65
2009	14.50	$68,987.13	15.00	0.50	0.0333	1.0000	$2,299.57	$4,599.14
		$26,602,108.37	15.00	9.29	0.6192	1.0000	$16,472,166.84	$1,773,473.89

Remaining Life Depreciation Accrual

Account: PECO Common 3912 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$26,602,108.37	9.29	$2,284,519.85	8.587740%	10.766488%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($68,987.13)	0.50	($2,299.57)	3.333332%	
Total:	$26,602,108.37 *		$2,282,220.28	8.579095%	10.755650%
Average:	$26,567,614.81		$2,282,220.28	8.590234%	10.773163%
Grand Total:	$26,602,108.37 *		$2,282,220.28	8.579095%	10.755650%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common 391.3 Composite 2024

Account: PECO Common 3913 Composite
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$11,521,553.83	5.00	4.50	0.9000	1.0000	$10,369,398.45	$2,304,310.77
2022	1.50	$10,320,951.33	5.00	3.50	0.7000	1.0000	$7,224,665.93	$2,064,190.27
2021	2.50	$7,175,681.06	5.00	2.50	0.5000	1.0000	$3,587,840.53	$1,435,136.21
2020	3.50	$7,191,339.89	5.00	1.50	0.3000	1.0000	$2,157,401.97	$1,438,267.98
2019	4.50	$8,646,094.27	5.00	0.50	0.1000	1.0000	$864,609.43	$1,729,218.85
2018	5.50	$65,435.00	5.00	0.00	0.0000	0.0000	$0.00	$0.00
2012	11.50	($2,682.00)	5.00	0.00	0.0000	0.0000	$0.00	$0.00
		$44,918,373.38	5.00	2.70	0.5388	1.0000	$24,203,916.30	$8,971,124.08

Remaining Life Depreciation Accrual

Account: PECO Common 3913 Composite
Scenario: PECO Common 391.3 Composite 2024
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$44,918,373.38	2.70	$9,048,288.38	20.143847%	37.064767%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($8,646,094.27)	0.50	($864,609.43)	10.000000%	
Total:	$44,918,373.38 *		$8,183,678.95	18.219001%	33.523042%
Average:	$40,595,326.25		$8,183,678.95	20.159165%	40.737005%
Grand Total:	$44,918,373.38 *		$8,183,678.95	18.219001%	33.523042%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3921 PA
Dispersion: 6.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2017	6.50	$2,306.80	6.00	1.76	0.2929	1.0000	$675.59	$384.47
2015	8.50	$752.09	6.00	1.30	0.2174	1.0000	$163.47	$125.35
2002	21.50	$64,490.53	6.00	0.00	0.0000	0.0000	$0.00	$0.00
		$67,549.42	6.00	1.65	0.0124	1.0000	$839.07	$509.82

Remaining Life Depreciation Accrual

Account: PECO Common 3921 PA
Scenario: PECO Common Groups 2024
Dispersion: 6.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$67,549.42	1.65	($2,075.84)	-3.073064%	60.759875%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,258.68)	0.50	($104.89)	8.333333%	
Total:	$67,549.42 *		($2,180.73)	-3.228343%	63.830012%
Average:	$66,920.08		($2,180.73)	-3.258703%	53.901004%
Grand Total:	$67,549.42 *		($2,180.73)	-3.228343%	63.830012%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3922 PA
Dispersion: 12.00 - S4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$6,093,630.90	12.00	11.50	0.9583	1.0000	$5,839,729.60	$507,802.58
2022	1.50	$3,765,352.71	12.00	10.50	0.8750	1.0000	$3,294,683.61	$313,779.39
2021	2.50	$6,684,602.07	12.00	9.50	0.7917	1.0000	$5,291,976.62	$557,050.17
2020	3.50	$3,531,877.71	12.00	8.50	0.7083	1.0000	$2,501,746.70	$294,323.14
2019	4.50	$4,314,339.78	12.00	7.50	0.6250	1.0000	$2,696,534.26	$359,528.32
2018	5.50	$2,383,578.77	12.00	6.50	0.5419	1.0000	$1,291,610.86	$198,631.56
2017	6.50	$3,254,130.17	12.00	5.52	0.4598	1.0000	$1,496,296.86	$271,177.51
2016	7.50	$5,519,175.80	12.00	4.57	0.3811	1.0000	$2,103,362.01	$459,931.32
2015	8.50	$4,207,764.81	12.00	3.71	0.3095	1.0000	$1,302,101.89	$350,647.07
2014	9.50	$4,266,553.67	12.00	2.98	0.2480	1.0000	$1,058,085.54	$355,546.14
2013	10.50	$1,480,427.12	12.00	2.37	0.1979	1.0000	$292,917.28	$123,368.93
2012	11.50	$51,459.17	12.00	1.90	0.1586	1.0000	$8,159.11	$4,288.26
2010	13.50	$1,034,775.31	12.00	1.26	0.1047	1.0000	$108,390.22	$86,231.28
2009	14.50	($73,442.95)	12.00	1.04	0.0865	1.0000	($6,352.97)	($6,120.25)
2008	15.50	($84,042.38)	12.00	0.87	0.0721	1.0000	($6,058.19)	($7,003.53)
2007	16.50	($5,936.57)	12.00	0.74	0.0613	1.0000	($364.04)	($494.71)
2006	17.50	($17,794.82)	12.00	0.63	0.0527	1.0000	($937.64)	($1,482.90)
2005	18.50	($5,237.68)	12.00	0.54	0.0451	1.0000	($236.09)	($436.47)
		$46,401,213.59	12.00	7.05	0.5877	1.0000	$27,271,645.63	$3,866,767.80

Remaining Life Depreciation Accrual

Account: PECO Common 3922 PA
Scenario: PECO Common Groups 2024
Dispersion: 12.00 - S4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$46,401,213.59	7.05	$3,523,474.48	7.593496%	14.178712%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,874,115.55)	0.50	($78,088.15)	4.166667%	
Total:	$46,401,213.59 *		$3,445,386.33	7.425207%	13.864479%
Average:	$45,464,155.82		$3,445,386.33	7.578248%	14.407765%
Grand Total:	$46,401,213.59 *		$3,445,386.33	7.425207%	13.864479%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3923 PA
Dispersion: 14.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$13,479,643.77	14.00	13.50	0.9643	1.0000	$12,998,644.28	$962,831.70
2022	1.50	$8,442,335.45	14.00	12.50	0.8930	1.0000	$7,539,292.42	$603,023.96
2021	2.50	$9,812,135.57	14.00	11.51	0.8219	1.0000	$8,065,058.43	$700,866.83
2020	3.50	$5,257,912.78	14.00	10.52	0.7512	1.0000	$3,949,941.43	$375,565.20
2019	4.50	$13,483,377.98	14.00	9.54	0.6812	1.0000	$9,184,860.60	$963,098.43
2018	5.50	$4,552,920.78	14.00	8.57	0.6123	1.0000	$2,787,531.08	$325,208.63
2017	6.50	$7,617,326.79	14.00	7.63	0.5449	1.0000	$4,151,013.47	$544,094.77
2016	7.50	$9,193,523.00	14.00	6.72	0.4799	1.0000	$4,411,718.37	$656,680.21
2015	8.50	$3,476,528.53	14.00	5.85	0.4178	1.0000	$1,452,346.24	$248,323.47
2014	9.50	$10,095,457.91	14.00	5.03	0.3591	1.0000	$3,625,510.89	$721,104.14
2013	10.50	$7,243,874.33	14.00	4.26	0.3043	1.0000	$2,204,402.91	$517,419.60
2012	11.50	$2,913,595.85	14.00	3.55	0.2533	1.0000	$738,085.17	$208,113.99
2011	12.50	$3,620,081.35	14.00	2.89	0.2062	1.0000	$746,293.89	$258,577.24
2010	13.50	$5,767,850.51	14.00	2.31	0.1652	1.0000	$953,094.40	$411,989.32
2009	14.50	$1,442,949.26	14.00	1.86	0.1326	1.0000	$191,319.74	$103,067.80
2008	15.50	$1,991,682.37	14.00	1.50	0.1072	1.0000	$213,445.32	$142,263.03
2006	17.50	($211.56)	14.00	0.95	0.0681	1.0000	($14.41)	($15.11)
2004	19.50	($176,825.88)	14.00	0.54	0.0389	1.0000	($6,870.46)	($12,630.42)
1997	26.50	$200,155.65	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	29.50	$141,407.95	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	31.50	($345,713.56)	14.00	0.00	0.0000	0.0000	$0.00	$0.00
		$108,210,008.83	14.00	8.18	0.5841	1.0000	$63,205,673.79	$7,729,582.77

Remaining Life Depreciation Accrual

Account: PECO Common 3923 PA
Scenario: PECO Common Groups 2024
Dispersion: 14.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$108,210,008.83	8.18	$7,311,901.39	6.757140%	12.229255%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($4,803,891.16)	0.50	($171,567.54)	3.571429%	
Total:	$108,210,008.83 *		$7,140,333.85	6.598589%	11.942306%
Average:	$105,808,063.25		$7,140,333.85	6.748383%	12.442142%
Grand Total:	$108,210,008.83 *		$7,140,333.85	6.598589%	11.942306%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3924 PA
Dispersion: 11.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$142,055.76	11.00	10.50	0.9546	1.0000	$135,611.18	$12,914.16
2009	14.50	$57,897.77	11.00	3.44	0.3127	1.0000	$18,106.11	$5,263.43
2002	21.50	$44,306.19	11.00	1.84	0.1673	1.0000	$7,414.07	$4,027.84
1995	28.50	$177,146.57	11.00	0.59	0.0541	1.0000	$9,579.26	$16,104.23
		$421,406.29	11.00	4.46	0.4051	1.0000	$170,710.62	$38,309.66

Remaining Life Depreciation Accrual

Account: PECO Common 3924 PA
Scenario: PECO Common Groups 2024
Dispersion: 11.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$421,406.29	4.46	$19,409.07	4.605785%	22.441289%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($182,249.82)	0.50	($8,284.08)	4.545453%	
Total:	$421,406.29 *		$11,124.99	2.639968%	12.863012%
Average:	$330,281.38		$11,124.99	3.368337%	-239.933341%
Grand Total:	$421,406.29 *		$11,124.99	2.639968%	12.863012%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3925 PA
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$401,515.30	14.00	13.52	0.9655	1.0000	$387,650.94	$28,679.66
2022	1.50	$124,663.73	14.00	12.58	0.8984	1.0000	$112,003.70	$8,904.55
2021	2.50	$238,124.45	14.00	11.69	0.8351	1.0000	$198,855.54	$17,008.89
2020	3.50	$243,537.12	14.00	10.87	0.7761	1.0000	$189,015.47	$17,395.51
2019	4.50	$32,124.54	14.00	10.10	0.7217	1.0000	$23,185.62	$2,294.61
2018	5.50	$369,084.30	14.00	9.41	0.6720	1.0000	$248,024.13	$26,363.16
2017	6.50	$666,229.90	14.00	8.79	0.6278	1.0000	$418,231.35	$47,587.85
2016	7.50	$850,547.86	14.00	8.25	0.5894	1.0000	$501,337.29	$60,753.42
2015	8.50	$445,680.25	14.00	7.79	0.5566	1.0000	$248,050.86	$31,834.30
2014	9.50	$303,236.60	14.00	7.39	0.5280	1.0000	$160,106.80	$21,659.76
2013	10.50	$70,130.41	14.00	7.04	0.5028	1.0000	$35,263.84	$5,009.31
2012	11.50	$98,806.05	14.00	6.72	0.4802	1.0000	$47,449.30	$7,057.58
2011	12.50	$45,336.50	14.00	6.43	0.4594	1.0000	$20,826.61	$3,238.32
2010	13.50	$308,073.67	14.00	6.15	0.4396	1.0000	$135,434.90	$22,005.26
2009	14.50	$7,165.37	14.00	5.89	0.4205	1.0000	$3,013.08	$511.81
2008	15.50	($265,209.35)	14.00	5.62	0.4017	1.0000	($106,522.20)	($18,943.52)
2007	16.50	$589,268.67	14.00	5.36	0.3830	1.0000	$225,670.54	$42,090.62
2006	17.50	$50,554.48	14.00	5.10	0.3644	1.0000	$18,424.22	$3,611.03
2005	18.50	$23,623.28	14.00	4.85	0.3461	1.0000	$8,177.13	$1,687.38
2004	19.50	$9,379.42	14.00	4.59	0.3282	1.0000	$3,078.24	$669.96
2003	20.50	$23,049.70	14.00	4.35	0.3107	1.0000	$7,160.84	$1,646.41
2002	21.50	$174,201.67	14.00	4.11	0.2937	1.0000	$51,164.71	$12,442.98
2001	22.50	$3,706.93	14.00	3.88	0.2773	1.0000	$1,027.87	$264.78
2000	23.50	$67,159.32	14.00	3.66	0.2614	1.0000	$17,556.49	$4,797.09
1997	26.50	$232,446.39	14.00	3.04	0.2173	1.0000	$50,502.01	$16,603.31
1996	27.50	$180,164.09	14.00	2.85	0.2036	1.0000	$36,687.10	$12,868.86
1995	28.50	$71,710.56	14.00	2.67	0.1907	1.0000	$13,672.25	$5,122.18
1994	29.50	($36,535.68)	14.00	2.49	0.1781	1.0000	($6,506.42)	($2,609.69)
1988	35.50	$9,324.38	14.00	1.57	0.1123	1.0000	$1,047.03	$666.03
1978	45.50	$14,407.27	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	47.50	$1,544.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	48.50	$25,351.71	14.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3925 PA
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1974	49.50	$814.23	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$67,709.54	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	51.50	$4,524.32	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	52.50	$6,644.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	53.50	$27,731.60	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	54.50	$11,345.85	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	55.50	$54,611.08	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	56.50	$23,398.38	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	57.50	$3,152.61	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	60.50	$1,026.82	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	61.50	$972.68	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	62.50	$3,539.00	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	63.50	$5,673.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
		$5,589,547.50	14.00	8.00	0.5456	1.0000	$3,049,589.28	$381,221.42

Remaining Life Depreciation Accrual

Account: PECO Common 3925 PA
Scenario: PECO Common Groups 2024
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$5,589,547.50	8.00	$277,884.41	4.971501%	12.500747%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($457,450.74)	0.50	($16,337.53)	3.571429%	
Total:	$5,589,547.50 *		$261,546.88	4.679214%	11.765796%
Average:	$5,360,822.13		$261,546.88	4.878858%	13.115266%
Grand Total:	$5,589,547.50 *		$261,546.88	4.679214%	11.765796%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3926 PA
Dispersion: 15.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$92,545.00	15.00	14.50	0.9667	1.0000	$89,464.11	$6,169.67
2022	1.50	$200,469.85	15.00	13.52	0.9010	1.0000	$180,629.34	$13,364.66
2021	2.50	$382,589.00	15.00	12.56	0.8375	1.0000	$320,425.66	$25,505.93
2020	3.50	$880,312.65	15.00	11.65	0.7769	1.0000	$683,877.44	$58,687.51
2019	4.50	$10,000.00	15.00	10.79	0.7191	1.0000	$7,191.28	$666.67
2018	5.50	$118,132.30	15.00	9.97	0.6644	1.0000	$78,482.81	$7,875.49
2016	7.50	$125,532.09	15.00	8.54	0.5696	1.0000	$71,503.64	$8,368.81
2015	8.50	$200,945.00	15.00	7.98	0.5318	1.0000	$106,858.77	$13,396.33
2014	9.50	$322,483.80	15.00	7.50	0.5002	1.0000	$161,294.11	$21,498.92
2012	11.50	$248,450.64	15.00	6.77	0.4513	1.0000	$112,115.54	$16,563.38
2011	12.50	$5,537.55	15.00	6.48	0.4318	1.0000	$2,391.13	$369.17
2010	13.50	$280,071.99	15.00	6.21	0.4143	1.0000	$116,030.85	$18,671.47
2009	14.50	$231,325.16	15.00	5.97	0.3979	1.0000	$92,042.82	$15,421.68
2008	15.50	($7,679.32)	15.00	5.73	0.3819	1.0000	($2,932.60)	($511.95)
2007	16.50	$218,596.62	15.00	5.49	0.3659	1.0000	$79,987.04	$14,573.11
2006	17.50	$906,063.59	15.00	5.25	0.3497	1.0000	$316,886.63	$60,404.24
2005	18.50	$310,885.69	15.00	5.00	0.3332	1.0000	$103,589.30	$20,725.71
2003	20.50	$75,707.23	15.00	4.50	0.2998	1.0000	$22,696.29	$5,047.15
2002	21.50	$1,162,784.26	15.00	4.25	0.2831	1.0000	$329,167.90	$77,518.95
1996	27.50	$28,685.34	15.00	2.86	0.1909	1.0000	$5,474.81	$1,912.36
1995	28.50	$70,184.76	15.00	2.65	0.1770	1.0000	$12,421.25	$4,678.98
1994	29.50	$20,914.19	15.00	2.45	0.1635	1.0000	$3,419.96	$1,394.28
1993	30.50	$27,544.80	15.00	2.25	0.1502	1.0000	$4,138.29	$1,836.32
1992	31.50	$6,119.39	15.00	2.06	0.1374	1.0000	$840.78	$407.96
1983	40.50	$2,890.72	15.00	0.15	0.0100	1.0000	$28.91	$192.71
1974	49.50	$3,888.93	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$3,536.26	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	51.50	$17,323.55	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	58.50	$84,406.50	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	61.50	$57.56	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	77.50	$920.22	15.00	0.00	0.0000	0.0000	$0.00	$0.00
		$6,031,225.32	15.00	7.34	0.4805	1.0000	$2,898,026.03	$394,739.49

01/07/2024

Remaining Life Depreciation Accrual

Account: PECO Common 3926 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$6,031,225.32	7.34	$224,069.85	3.715163%	13.620978%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($598,032.91)	0.50	($19,934.43)	3.333333%	
Total:	$6,031,225.32 *		$204,135.42	3.384643%	12.409184%
Average:	$5,732,208.87		$204,135.42	3.561200%	15.165870%
Grand Total:	$6,031,225.32 *		$204,135.42	3.384643%	12.409184%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3927 PA
Dispersion: 8.00 - L4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$4,224,204.73	8.00	7.50	0.9375	1.0000	$3,960,191.88	$528,025.59
2022	1.50	$1,448,573.64	8.00	6.50	0.8125	1.0000	$1,176,966.06	$181,071.71
2021	2.50	$5,222,906.86	8.00	5.50	0.6876	1.0000	$3,591,149.95	$652,863.36
2020	3.50	$2,101,106.06	8.00	4.52	0.5650	1.0000	$1,187,143.19	$262,638.26
2019	4.50	$10,476,557.91	8.00	3.61	0.4507	1.0000	$4,721,866.82	$1,309,569.74
2018	5.50	$4,451,531.94	8.00	2.79	0.3482	1.0000	$1,549,851.53	$556,441.49
2017	6.50	$1,995,253.94	8.00	2.11	0.2636	1.0000	$525,964.98	$249,406.74
		$29,920,135.08	8.00	4.47	0.5586	1.0000	$16,713,134.42	$3,740,016.89

Remaining Life Depreciation Accrual

Account: PECO Common 3927 PA
Scenario: PECO Common Groups 2024
Dispersion: 8.00 - L4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$29,920,135.08	4.47	$3,728,943.92	12.462992%	22.377713%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,736,284.79)	0.50	($108,517.80)	6.250000%	
Total:	$29,920,135.08 *		$3,620,426.12	12.100300%	21.726488%
Average:	$29,051,992.69		$3,620,426.12	12.461886%	22.920605%
Grand Total:	$29,920,135.08 *		$3,620,426.12	12.100300%	21.726488%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3930 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$121,632.00	15.00	14.50	0.9667	1.0000	$117,577.60	$8,108.80
2021	2.50	$272,946.64	15.00	12.50	0.8333	1.0000	$227,455.53	$18,196.44
2019	4.50	$196,774.10	15.00	10.50	0.7000	1.0000	$137,741.87	$13,118.27
2018	5.50	$463,423.36	15.00	9.50	0.6333	1.0000	$293,501.46	$30,894.89
2017	6.50	$785.81	15.00	8.50	0.5667	1.0000	$445.29	$52.39
2016	7.50	$115,923.80	15.00	7.50	0.5000	1.0000	$57,961.90	$7,728.25
2015	8.50	$770.40	15.00	6.50	0.4333	1.0000	$333.84	$51.36
2014	9.50	$770.40	15.00	5.50	0.3667	1.0000	$282.48	$51.36
2013	10.50	$46,416.68	15.00	4.50	0.3000	1.0000	$13,925.00	$3,094.45
2011	12.50	$5,183.04	15.00	2.50	0.1667	1.0000	$863.84	$345.54
2010	13.50	$60,242.00	15.00	1.50	0.1000	1.0000	$6,024.20	$4,016.13
2009	14.50	$54,743.00	15.00	0.50	0.0333	1.0000	$1,824.77	$3,649.53
		$1,339,611.23	15.00	9.61	0.6404	1.0000	$857,937.79	$89,307.42

Remaining Life Depreciation Accrual

Account: PECO Common 3930 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,339,611.23	9.61	$100,461.91	7.499333%	10.409545%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($54,743.00)	0.50	($1,824.77)	3.333339%	
Total:	$1,339,611.23 *		$98,637.14	7.363117%	10.220468%
Average:	$1,312,239.73		$98,637.14	7.516701%	10.518797%
Grand Total:	$1,339,611.23 *		$98,637.14	7.363117%	10.220468%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3942 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2018	5.50	$952,765.21	15.00	9.50	0.6333	1.0000	$603,417.97	$63,517.68
2016	7.50	$2,088.50	15.00	7.50	0.5000	1.0000	$1,044.25	$139.23
2014	9.50	$55,267.65	15.00	5.50	0.3667	1.0000	$20,264.81	$3,684.51
		$1,010,121.36	15.00	9.28	0.6185	1.0000	$624,727.02	$67,341.42

Remaining Life Depreciation Accrual

Account: PECO Common 3942 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,010,121.36	9.28	$69,378.41	6.868324%	10.779336%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,010,121.36 *		$69,378.41	6.868324%	10.779336%
Average:	$1,010,121.36		$69,378.41	6.868324%	10.779336%
Grand Total:	$1,010,121.36 *		$69,378.41	6.868324%	10.779336%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3943 PA
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$34,175.67	20.00	19.50	0.9750	1.0000	$33,321.28	$1,708.78
2022	1.50	$80,643.65	20.00	18.50	0.9250	1.0000	$74,595.38	$4,032.18
2021	2.50	$168,062.80	20.00	17.50	0.8750	1.0000	$147,054.95	$8,403.14
2020	3.50	$35,598.30	20.00	16.50	0.8250	1.0000	$29,368.60	$1,779.92
2019	4.50	$15,709.23	20.00	15.50	0.7750	1.0000	$12,174.65	$785.46
2018	5.50	$102,889.01	20.00	14.50	0.7250	1.0000	$74,594.53	$5,144.45
2017	6.50	$171,250.58	20.00	13.50	0.6750	1.0000	$115,594.14	$8,562.53
2016	7.50	$424,469.01	20.00	12.50	0.6250	1.0000	$265,293.13	$21,223.45
2015	8.50	$83,948.79	20.00	11.50	0.5750	1.0000	$48,270.55	$4,197.44
2014	9.50	$126,931.56	20.00	10.50	0.5250	1.0000	$66,639.07	$6,346.58
2013	10.50	$60,134.71	20.00	9.50	0.4750	1.0000	$28,563.99	$3,006.74
2012	11.50	$22,052.17	20.00	8.50	0.4250	1.0000	$9,372.17	$1,102.61
2011	12.50	$50,175.40	20.00	7.50	0.3750	1.0000	$18,815.78	$2,508.77
2010	13.50	$73,469.80	20.00	6.50	0.3250	1.0000	$23,877.69	$3,673.49
2008	15.50	$12,963.09	20.00	4.50	0.2250	1.0000	$2,916.70	$648.15
2007	16.50	$21,453.01	20.00	3.50	0.1750	1.0000	$3,754.28	$1,072.65
2006	17.50	$3,478.87	20.00	2.50	0.1250	1.0000	$434.86	$173.94
2004	19.50	$54,167.87	20.00	0.50	0.0250	1.0000	$1,354.20	$2,708.39
		$1,541,573.52	20.00	12.40	0.6201	1.0000	$955,995.93	$77,078.68

Remaining Life Depreciation Accrual

Account: PECO Common 3943 PA
Scenario: PECO Common Groups 2024
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,541,573.52	12.40	$76,247.62	4.946090%	8.062657%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($54,167.87)	0.50	($1,354.20)	2.500006%	
Total:	$1,541,573.52 *		$74,893.42	4.858245%	7.919460%
Average:	$1,514,489.59		$74,893.42	4.945126%	8.152956%
Grand Total:	$1,541,573.52 *		$74,893.42	4.858245%	7.919460%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3961 PA
Dispersion: 12.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2002	21.50	$93,979.86	12.00	0.90	0.0753	1.0000	$7,074.20	$7,831.66
1998	25.50	$35,800.78	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	37.50	$5,472.23	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	42.50	$6,017.00	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	43.50	$3,955.00	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	46.50	$11,826.57	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$28,014.86	12.00	0.00	0.0000	0.0000	$0.00	$0.00
		$185,066.30	12.00	0.90	0.0382	1.0000	$7,074.20	$7,831.66

Remaining Life Depreciation Accrual

Account: PECO Common 3961 PA
Scenario: PECO Common Groups 2024
Dispersion: 12.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$185,066.30	0.90	$101.58	0.054888%	100.000000%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($60,015.78)	0.50	($2,500.66)	4.166671%	
Total:	$185,066.30 *		($2,399.08)	-1.296335%	2361.764127%
Average:	$155,058.41		($2,399.08)	-1.547210%	8.021986%
Grand Total:	$185,066.30 *		($2,399.08)	-1.296335%	2361.764127%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3970 PA
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$12,675,460.89	20.00	19.50	0.9750	1.0000	$12,358,574.37	$633,773.04
2022	1.50	$13,546,160.99	20.00	18.50	0.9250	1.0000	$12,530,198.92	$677,308.05
2021	2.50	$3,484,206.74	20.00	17.50	0.8750	1.0000	$3,048,774.97	$174,210.34
2020	3.50	$32,862,198.64	20.00	16.51	0.8253	1.0000	$27,121,422.64	$1,643,109.93
2019	4.50	$17,853,340.73	20.00	15.52	0.7762	1.0000	$13,857,356.04	$892,667.04
2018	5.50	$18,280,188.44	20.00	14.56	0.7279	1.0000	$13,306,288.56	$914,009.42
2017	6.50	$221,177.09	20.00	13.61	0.6807	1.0000	$150,557.28	$11,058.85
2016	7.50	$422,148.93	20.00	12.69	0.6347	1.0000	$267,944.17	$21,107.45
2015	8.50	$1,444,889.14	20.00	11.80	0.5900	1.0000	$852,542.83	$72,244.46
2014	9.50	$1,088,927.83	20.00	10.94	0.5470	1.0000	$595,600.67	$54,446.39
2013	10.50	$34,614.16	20.00	10.12	0.5060	1.0000	$17,513.64	$1,730.71
2012	11.50	$745,044.85	20.00	9.36	0.4679	1.0000	$348,607.84	$37,252.24
2008	15.50	$1,390,836.04	20.00	7.12	0.3559	1.0000	$494,999.39	$69,541.80
2007	16.50	$6,682,064.26	20.00	6.78	0.3388	1.0000	$2,263,627.04	$334,103.21
2006	17.50	$7,909,519.60	20.00	6.50	0.3251	1.0000	$2,571,593.96	$395,475.98
2005	18.50	$50,000.00	20.00	6.28	0.3142	1.0000	$15,709.60	$2,500.00
2003	20.50	$614,915.20	20.00	5.93	0.2966	1.0000	$182,356.28	$30,745.76
2002	21.50	$50,892.16	20.00	5.77	0.2883	1.0000	$14,670.05	$2,544.61
2001	22.50	$122,375.76	20.00	5.58	0.2792	1.0000	$34,171.14	$6,118.79
1999	24.50	$1,031,170.51	20.00	5.16	0.2581	1.0000	$266,175.61	$51,558.53
1998	25.50	$7,398,704.24	20.00	4.92	0.2461	1.0000	$1,820,533.26	$369,935.21
1997	26.50	$794,445.38	20.00	4.67	0.2335	1.0000	$185,541.59	$39,722.27
		$128,703,281.58	20.00	14.34	0.7172	1.0000	$92,304,759.85	$6,435,164.08

Remaining Life Depreciation Accrual

Account: PECO Common 3970 PA
Scenario: PECO Common Groups 2024
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$128,703,281.58	14.34	$6,279,780.15	4.879270%	6.971649%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,396,767.30)	0.50	($84,919.18)	2.500000%	
Total:	$128,703,281.58 *		$6,194,860.97	4.813289%	6.877374%
Average:	$127,004,897.93		$6,194,860.97	4.877655%	7.009539%
Grand Total:	$128,703,281.58 *		$6,194,860.97	4.813289%	6.877374%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3980 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2017	6.50	$57,233.54	15.00	8.50	0.5667	1.0000	$32,432.34	$3,815.57
2015	8.50	$16,773.27	15.00	6.50	0.4333	1.0000	$7,268.42	$1,118.22
2014	9.50	$497,037.52	15.00	5.50	0.3667	1.0000	$182,247.09	$33,135.83
2012	11.50	$67,989.42	15.00	3.50	0.2333	1.0000	$15,864.20	$4,532.63
2011	12.50	$22,622.02	15.00	2.50	0.1667	1.0000	$3,770.34	$1,508.13
2010	13.50	$511,435.53	15.00	1.50	0.1000	1.0000	$51,143.55	$34,095.70
2009	14.50	$18,269.07	15.00	0.50	0.0333	1.0000	$608.97	$1,217.94
		$1,191,360.37	15.00	3.69	0.2462	1.0000	$293,334.90	$79,424.02

Remaining Life Depreciation Accrual

Account: PECO Common 3980 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,191,360.37	3.69	$92,455.40	7.760490%	27.076225%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($18,269.07)	0.50	($608.97)	3.333339%	
Total:	$1,191,360.37 *		$91,846.43	7.709374%	26.897884%
Average:	$1,182,225.84		$91,846.43	7.768941%	27.637211%
Grand Total:	$1,191,360.37 *		$91,846.43	7.709374%	26.897884%

* Excluding 2024 Retirements

PECO Exhibit CF-2:

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024

PECO Exhibit CF-2

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the estimated original cost of PECO's gas and common plant in service at December 31, 2024.

Estimated Annual Depreciation Accruals Related to Utility Plant In Service for 2024

Utility Account	2018 Service Life Study - Average Service Life	2018 Service Life Study - Dispersion Curve	2024 Depreciation Rate	Original Cost of Gross Plant - January 1, 2024	2024 Estimated Plant Additions	2024 Estimated Plant Retirements	Estimated Original Cost of Gross Plant - December 31, 2024	Accumulated Book Reserve - January 1, 2024	2024 Estimated Annual Depreciation Accrual	2024 Estimated Plant Retirements	2024 - Estimated Cost of (Removal) / Salvage	Estimated Accumulated Book Reserve - December 31, 2024	Estimated Depreciable Plant Net Book Value - December 31, 2024
PECO Gas 303 Intangible Plant **(Note A)**	-	-	-	19,925,640	2,021,825	(4,793,260)	17,154,205	11,058,569	3,655,203	(4,793,260)	-	9,920,512	7,233,693
PECO Gas 305 Structures & Improvements **(Note B)**	2035	-	-	1,225,274	-	-	1,225,274	873,901	30,554	-	-	904,455	320,819
PECO Gas 311 Liquefied Pet. Gas Equipment **(Note B)**	2035	-	-	14,333,838	-	-	14,333,838	12,724,561	139,937	-	-	12,864,498	1,469,340
PECO Gas 361 Structures & Improvements **(Note B)**	2042	-	-	15,046,615	-	(57,224)	14,989,391	7,581,411	401,431	(57,224)	-	7,925,618	7,063,773
PECO Gas 362 Gas Holders **(Note B)**	2042	-	-	7,083,540	-	-	7,083,540	6,898,123	10,023	-	-	6,908,146	175,394
PECO Gas 363 Purification Equipment **(Note B)**	2042	-	-	1,329,879	-	-	1,329,879	870,052	24,856	-	-	894,908	434,971
PECO Gas 3631 Liquefaction Equipment **(Note B)**	2042	-	-	9,958,189	-	-	9,958,189	7,072,311	155,993	-	-	7,228,304	2,729,885
PECO Gas 3632 Vaporizing Equipment **(Note B)**	2042	-	-	63,789,495	20,828,847	-	84,618,342	1,977,571	3,437,975	-	(809,354)	4,606,192	80,012,150
PECO Gas 3633 Compressor Equipment **(Note B)**	2042	-	-	14,130,891	5,202,862	(1,289,923)	18,043,830	(1,832,538)	917,589	(1,289,923)	(193,950)	(2,398,822)	20,442,652
PECO Gas 3634 Measuring & Regulating Equipment **(Note B)**	2042	-	-	10,407,592	5,421,300	-	15,828,892	1,219,396	530,269	-	(140,366)	1,609,299	14,219,593
PECO Gas 3635 Other Equipment **(Note B)**	2042	-	-	10,606,090	1,167,484	(153,284)	11,620,290	5,466,167	290,946	(153,284)	(126,159)	5,477,670	6,142,620
PECO Gas 375 Structures & Improvements	50	R4	3.57%	15,865,030	495,790	(36,145)	16,324,675	6,304,506	340,840	(36,145)	(43,039)	6,566,162	9,758,513
PECO Gas 3761 Steel Mains	70	R3	1.99%	712,705,717	44,351,471	(5,024,861)	752,032,327	194,902,254	10,660,724	(5,024,861)	(3,400,835)	197,137,282	554,895,045
PECO Gas 3762 Cast Iron Mains **(Note B)**	2035	-	-	10,651,874	-	(940,294)	9,711,580	(6,530,217)	1,178,173	(940,294)	(2,145,581)	(8,437,919)	18,149,499
PECO Gas 3763 Plastic Mains	65	R3	1.84%	1,237,634,959	127,689,035	(2,771,742)	1,362,552,252	195,511,664	20,295,779	(2,771,742)	(575,140)	212,460,561	1,150,091,691
PECO Gas 378 Measure & Regulate Station Equipment	50	R2	2.92%	24,564,707	841,615	(110,087)	25,296,235	6,572,971	525,125	(110,087)	(750,477)	6,237,532	19,058,703
PECO Gas 379 City Gate Check Stations	50	R3	2.97%	61,536,689	6,625	(41,025)	61,502,289	25,731,091	1,049,594	(41,025)	-	26,739,660	34,762,629
PECO Gas 3801 Steel Services	37	S0	4.26%	65,867,544	-	(4,312,691)	61,554,853	(20,657,598)	3,594,606	(4,312,691)	(3,277,000)	(24,652,683)	86,207,536
PECO Gas 3802 Plastic Services	56	R3	2.33%	1,146,681,638	108,460,903	(1,858,589)	1,253,283,952	302,561,921	20,593,862	(1,858,589)	(806,601)	320,490,593	932,793,359
PECO Gas 381 Meters	40	R3	4.41%	94,300,569	4,035,369	(458,234)	97,877,704	47,470,497	2,065,067	(458,234)	(210,391)	48,866,939	49,010,765
PECO Gas 3811 Meter Modules	20	S2	8.28%	74,424,960	1,559,575	-	75,984,535	30,895,463	3,485,016	-	(659)	34,379,820	41,604,715
PECO Gas 382 Meter Installations	50	R3	2.83%	251,661,292	20,632,685	(841,312)	271,452,665	75,428,700	5,156,514	(841,312)	(2,087,919)	77,655,983	193,796,682
PECO Gas 387 Other Equipment	22	S1.5	18.21%	2,097,917	-	(6,802)	2,091,115	1,543,750	92,908	(6,802)	-	1,629,856	461,259
PECO Gas 390 Structures & Improvements	45	R2	3.21%	10,471,471	520,626	(2,903)	10,989,194	3,360,451	230,079	(2,903)	(36,109)	3,551,518	7,437,676
PECO Gas 3912 Furniture & Fixtures	15	SQ	9.77%	515,582	-	-	515,582	153,640	33,812	-	-	187,452	328,130
PECO Gas 3913 Computers	5	SQ	47.68%	2,710,373	328,553	(1,050,202)	1,988,724	1,580,114	433,133	(1,050,202)	(7,363)	955,682	1,033,042
PECO Gas 394 Tools & Equipment	20	SQ	8.37%	15,270,654	944,353	(278,029)	15,936,978	6,057,585	751,983	(278,029)	-	6,531,539	9,405,439
PECO Gas 397 Communication Equipment	5	R3	46.94%	5,410,759	488,449	(300,887)	5,598,321	4,420,510	382,454	(300,887)	(69,835)	4,432,242	1,166,079
PECO Gas 398 Miscellaneous Equipment	15	SQ	12.46%	127,264	-	-	127,264	60,682	7,839	-	-	68,521	58,743
PECO Gas 399.1 Asset Retirement Costs	-	-	-	130,200	-	(2,794)	127,406	43,638	9,549	(2,794)	-	50,393	77,013
PECO Gas 388 ARO Costs Distribution Plt				884,264	-	(88)	884,176	605,630	1,442	(88)	-	606,984	277,192
Gas Subtotal				**3,901,350,506**	**344,997,367**	**(24,330,376)**	**4,222,017,497**	**929,926,776**	**80,483,275**	**(24,330,376)**	**(14,680,778)**	**971,398,897**	**3,250,618,600**
Common Plant Allocated to Gas **(Note C)**				254,069,788	60,532,906	(41,424,222)	273,178,472	106,812,486	20,693,238	(41,424,222)	(974,869)	85,106,633	188,071,839
Depreciable Total				4,155,420,294	405,530,273	(65,754,598)	4,495,195,969	1,036,739,262	101,176,513	(65,754,598)	(15,655,647)	1,056,505,530	3,438,690,439

Fleet Depreciation **(Note D)**	(3,598,441)
ARC Amortization **(Note E)**	(30,693)
Adjusted 2024 estimated annual depreciation accrual	**97,547,379**
	Note F

Notes:

Note A: Intangible Plant is amortized based on the service lives estimated at the time the plant is placed into service. The amortization rates for Intangible Plant are weighted based on the relative amount of underlying plant booked to the Intangible Plant accounts.

Note B: The Liquified Natural Gas Plant, Liquified Petroleum Gas Plant and Cast Iron Mains are depreciated using a terminal date and as a result do not have an average service life or dispersion curve.

Note C: Common Plant allocated to Gas relates to various Common Plant utility accounts identified in the 2018 Electric Distribution, General and Common Depreciation Study. The Common Plant amounts are allocated to Gas plant based on the Common Allocation Factor determined each year.

Note D: Included in the 2024 Estimated Annual Depreciation Accrual column for the Common Plant allocated to Gas row is $3.6 million relating to PECO Fleet. Depreciation associated with Fleet is excluded from depreciation expense and directly assigned to the functional O&M and capital accounts based on use.

Note E: Asset Retirement Costs (ARC) are depreciable plant, but the ARC depreciation expense is not included in the revenue requirements calculation and not included in the claim for the current proceeding.

Note F: Agrees to Gas depreciation expense included in the revenue requirements calculation in Exhibit MJT-2, Schedule D-17, Column 13 Depr on Existing Assets + Adds (Function), Row 105

PECO Exhibit CF-3:

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025

PECO Exhibit CF-3

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the estimated original cost of PECO's gas and common plant in service at December 31, 2025.

Estimated Annual Depreciation Accruals Related to Utility Plant In Service for 2025

Utility Account	2018 Service Life Study - Average Service Life	2018 Service Life Study - Dispersion Curve	2025 Depreciation Rate	Original Cost of Gross Plant - January 1, 2025	2025 Estimated Plant Additions	2025 Estimated Plant Retirements	Estimated Original Cost of Gross Plant - December 31, 2025	Accumulated Book Reserve - January 1, 2025	2025 Estimated Annual Depreciation Accrual	2025 Estimated Plant Retirements	2025 - Estimated Cost of (Removal) / Salvage	Estimated Accumulated Book Reserve - December 31, 2025	Estimated Depreciable Plant Net Book Value - December 31, 2025
PECO Gas 303 Intangible Plant **(Note A)**	-	-	-	17,154,205	4,798,509	(5,596,803)	16,355,911	9,920,512	3,694,589	(5,596,803)	-	8,018,298	8,337,613
PECO Gas 305 Structures & Improvements **(Note B)**	2035	-	-	1,225,274	-	-	1,225,274	904,455	30,554	-	-	935,009	290,265
PECO Gas 311 Liquefied Pet. Gas Equipment **(Note B)**	2035	-	-	14,333,838	-	-	14,333,838	12,864,498	139,937	-	-	13,004,435	1,329,403
PECO Gas 361 Structures & Improvements **(Note B)**	2042	-	-	14,989,391	-	(57,224)	14,932,167	7,925,618	401,431	(57,224)	-	8,269,825	6,662,342
PECO Gas 362 Gas Holders **(Note B)**	2042	-	-	7,083,540	-	-	7,083,540	6,908,146	10,023	-	-	6,918,169	165,371
PECO Gas 363 Purification Equipment **(Note B)**	2042	-	-	1,329,879	-	-	1,329,879	894,908	24,856	-	-	919,764	410,115
PECO Gas 3631 Liquefaction Equipment **(Note B)**	2042	-	-	9,958,189	-	-	9,958,189	7,228,304	155,993	-	-	7,384,297	2,573,892
PECO Gas 3632 Vaporizing Equipment **(Note B)**	2042	-	-	84,618,342	19,836,074	-	104,454,416	4,606,192	3,964,650	-	(809,354)	7,761,488	96,692,928
PECO Gas 3633 Compressor Equipment **(Note B)**	2042	-	-	18,043,830	5,208,603	(1,289,923)	21,962,510	(2,398,822)	1,053,993	(1,289,923)	(193,950)	(2,828,702)	24,791,212
PECO Gas 3634 Measuring & Regulating Equipment **(Note B)**	2042	-	-	15,828,892	5,427,216	-	21,256,108	1,609,299	670,839	-	(140,366)	2,139,772	19,116,336
PECO Gas 3635 Other Equipment **(Note B)**	2042	-	-	11,620,290	1,168,860	(153,284)	12,635,866	5,477,670	323,642	(153,284)	(126,159)	5,521,869	7,113,997
PECO Gas 375 Structures & Improvements	50	R4	3.54%	16,324,675	496,363	(36,145)	16,784,893	6,566,162	354,460	(36,145)	(43,039)	6,841,438	9,943,455
PECO Gas 3761 Steel Mains	70	R3	1.99%	752,032,327	126,449,470	(5,024,861)	873,456,936	197,137,282	13,430,816	(5,024,861)	(3,400,835)	202,142,402	671,314,534
PECO Gas 3762 Cast Iron Mains **(Note B)**	2035	-	7.41%	9,711,580	-	(940,294)	8,771,286	(8,437,919)	1,178,173	(940,294)	(2,145,581)	(10,345,621)	19,116,907
PECO Gas 3763 Plastic Mains	65	R3	1.84%	1,362,552,252	127,827,739	(2,771,742)	1,487,608,249	212,460,561	23,591,869	(2,771,742)	(575,140)	232,705,548	1,254,902,701
PECO Gas 378 Measure & Regulate Station Equipment	50	R2	2.92%	25,296,235	843,309	(110,087)	26,029,457	6,237,532	565,365	(110,087)	(750,477)	5,942,333	20,087,124
PECO Gas 379 City Gate Check Stations	50	R3	2.97%	61,502,289	6,625	(41,025)	61,467,889	26,739,660	1,049,761	(41,025)	-	27,748,396	33,719,493
PECO Gas 3801 Steel Services	37	S0	4.26%	61,554,853	-	(4,312,691)	57,242,162	(24,652,683)	3,615,728	(4,312,691)	(3,277,000)	(28,626,646)	85,868,808
PECO Gas 3802 Plastic Services	56	R3	2.33%	1,253,283,952	108,580,604	(1,858,589)	1,360,005,967	320,490,593	23,417,288	(1,858,589)	(806,601)	341,242,691	1,018,763,276
PECO Gas 381 Meters	40	R3	4.41%	97,877,704	4,039,885	(458,234)	101,459,355	48,866,939	2,172,378	(458,234)	(210,391)	50,370,692	51,088,663
PECO Gas 3811 Meter Modules	20	S2	8.28%	75,984,535	1,561,234	-	77,545,769	34,379,820	3,524,451	-	(659)	37,903,612	39,642,157
PECO Gas 382 Meter Installations	50	R3	2.83%	271,452,665	20,656,851	(841,312)	291,268,204	77,655,983	5,730,775	(841,312)	(2,087,919)	80,457,527	210,810,677
PECO Gas 387 Other Equipment	22	S1.5	18.21%	2,091,115	-	(6,802)	2,084,313	1,629,856	92,908	(6,802)	-	1,715,962	368,351
PECO Gas 390 Structures & Improvements	45	R2	3.21%	10,989,194	521,219	(2,903)	11,507,510	3,551,518	244,150	(2,903)	(36,109)	3,756,656	7,750,854
PECO Gas 3912 Furniture & Fixtures	15	SQ	9.77%	515,582	-	-	515,582	187,452	33,812	-	-	221,264	294,318
PECO Gas 3913 Computers	5	SQ	47.68%	1,988,724	328,910	(1,050,202)	1,267,432	955,682	441,624	(1,050,202)	(7,363)	339,741	927,691
PECO Gas 394 Tools & Equipment	20	SQ	8.37%	15,936,978	945,357	(278,029)	16,604,306	6,531,539	775,851	(278,029)	-	7,029,361	9,574,945
PECO Gas 397 Communication Equipment	5	R3	46.94%	5,598,321	489,042	(300,887)	5,786,476	4,432,242	396,565	(300,887)	(69,835)	4,458,085	1,328,391
PECO Gas 398 Miscellaneous Equipment	15	SQ	12.46%	127,264	-	-	127,264	68,521	7,839	-	-	76,360	50,904
PECO Gas 399.1 Asset Retirement Costs	-	-	-	127,406	-	(2,794)	124,612	50,393	9,549	(2,794)	-	57,148	67,464
PECO Gas 388 ARO Costs Distribution Plt				884,176	-	(88)	884,088	606,984	1,442	(88)	-	608,338	275,750
Gas Subtotal				**4,222,017,497**	**429,185,870**	**(25,133,919)**	**4,626,069,448**	**971,398,897**	**91,105,311**	**(25,133,919)**	**(14,680,778)**	**1,022,689,511**	**3,603,379,937**
Common Plant Allocated to Gas **(Note C)**				273,178,472	22,650,023	(7,562,906)	288,265,589	85,106,633	23,151,528	(7,562,906)	(974,869)	99,720,386	188,545,203
											-		
Depreciable Total				**4,495,195,969**	**451,835,893**	**(32,696,825)**	**4,914,335,037**	**1,056,505,530**	**114,256,839**	**(32,696,825)**	**(15,655,647)**	**1,122,409,897**	**3,791,925,140**

Fleet Depreciation (Note D)	(4,168,589)
ARC Amortization (Note E)	(30,693)
Adjusted 2025 estimated annual depreciation accrual	110,057,557
	Note F

Notes:

Note A: Intangible Plant is amortized based on the service lives estimated at the time the plant is placed into service. The amortization rates for Intangible Plant are weighted based on the relative amount of underlying plant booked to the Intangible Plant accounts.

Note B: The Liquified Natural Gas Plant, Liquified Petroleum Gas Plant and Cast Iron Mains are depreciated using a terminal date and as a result do not have an average service life or dispersion curve.

Note C: Common Plant allocated to Gas relates to various Common Plant utility accounts identified in the 2018 Electric Distribution, General and Common Depreciation Study. The Common Plant amounts are allocated to Gas plant based on the Common Allocation Factor determined each year.

Note D: Included in the 2025 Estimated Annual Depreciation Accrual column for the Common Plant allocated to Gas row is $4.2 million relating to PECO Fleet. Depreciation associated with Fleet is excluded from depreciation expense and directly assigned to the functional O&M and capital accounts based on use.

Note E: Asset Retirement Costs (ARC) are depreciable plant, but the ARC depreciation expense is not included in the revenue requirements calculation and not included in the claim for the current proceeding.

Note F: Agrees to Gas depreciation expense included in the revenue requirements calculation in Exhibit MJT-1, Schedule D-17, Column 13 Depr on Existing Assets + Adds (Function), Row 98

PECO Exhibit CF-4:

2018 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2018

PECO ENERGY COMPANY

PHILADELPHIA, PENNSYLVANIA

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AS OF DECEMBER 31, 2018

Prepared by:



*Excellence Delivered **As Promised***

PECO ENERGY COMPANY

Philadelphia, Pennsylvania

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AS OF DECEMBER 31, 2018

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Valley Forge, Pennsylvania

Gannett Fleming

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March 31, 2020

PECO Energy Company
2301 Market Street
Philadelphia, PA 19101

Attention Mr. Scott Bailey
Vice President and Controller

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of PECO Energy Company (PECO) as of December 31, 2018. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the service life estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

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PECO ENERGY COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to PECO Energy Company's ("PECO" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to PECO's gas plant as of December 31, 2018. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life for each depreciable group of assets.

The most significant change since the previous depreciation study as of December 31, 2013 is related to increased life span at the West Conshohocken Liquefied Natural Gas (LNG) Plant from 60 years to 70 years which resulted in a decrease in depreciation expense.

Several other Gas Plant accounts experienced relatively small increases in estimated service lives. The two largest Gas Distribution plant accounts with increased service lives were Accounts 379, Measuring and Regulating Station Equipment – City Gate Stations and 380.2, Services – Plastic. The service life estimate was lengthened from 48 to 50 years for M&R Station Equipment at City Gate Stations and 55 to 56 years for Plastic Services. There were no Gas Plant accounts where the proposed service life estimates decreased in this report.

PECO's current depreciation rates are based on service life estimates approved in the most recent service life study filed in March 2015.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of December 31, 2018 as summarized on Table 1 in Part VI of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense for gas plant of $49.006 million when applied to depreciable plant balances as of December 31, 2018. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, PROPOSED ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2018	ACCRUAL RATE	ACCRUAL AMOUNT
(1)	(2)	(3)=(4)/(2)	(4)
GAS PLANT			
Production Plant	15,655,999	1.37	214,046
Storage Plant	62,939,167	2.36	1,484,601
Distribution Plant	2,565,579,017	1.78	45,669,498
General Plant	27,882,995	5.87	1,637,825
Total Gas Plant	**2,672,057,178**	**1.83**	**49,005,970**

PART I. INTRODUCTION

PECO ENERGY COMPANY

DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the gas plant depreciation study for PECO Energy Company ("PECO"). The purpose of the study is to determine the appropriate survivor curve estimate for each plant account and to calculate the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas plant as of December 31, 2018. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to gas plant in service as of December 31, 2018.

The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2018, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the gas industry, including knowledge of service life estimates used for other gas companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life studies. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents a discussion of the method used by PECO for the recovery of net salvage. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group

depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, and Part VIII, Detailed Depreciation Calculations presents the detailed tabulations of annual and accrued depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization

accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use in this study. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life Estimates

The service life estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and estimates of future experience yielded estimated survivor curves from which the average service lives were derived.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through discussions with operating and management personnel and was incorporated in the interpretation and extrapolation of the statistical life analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves,

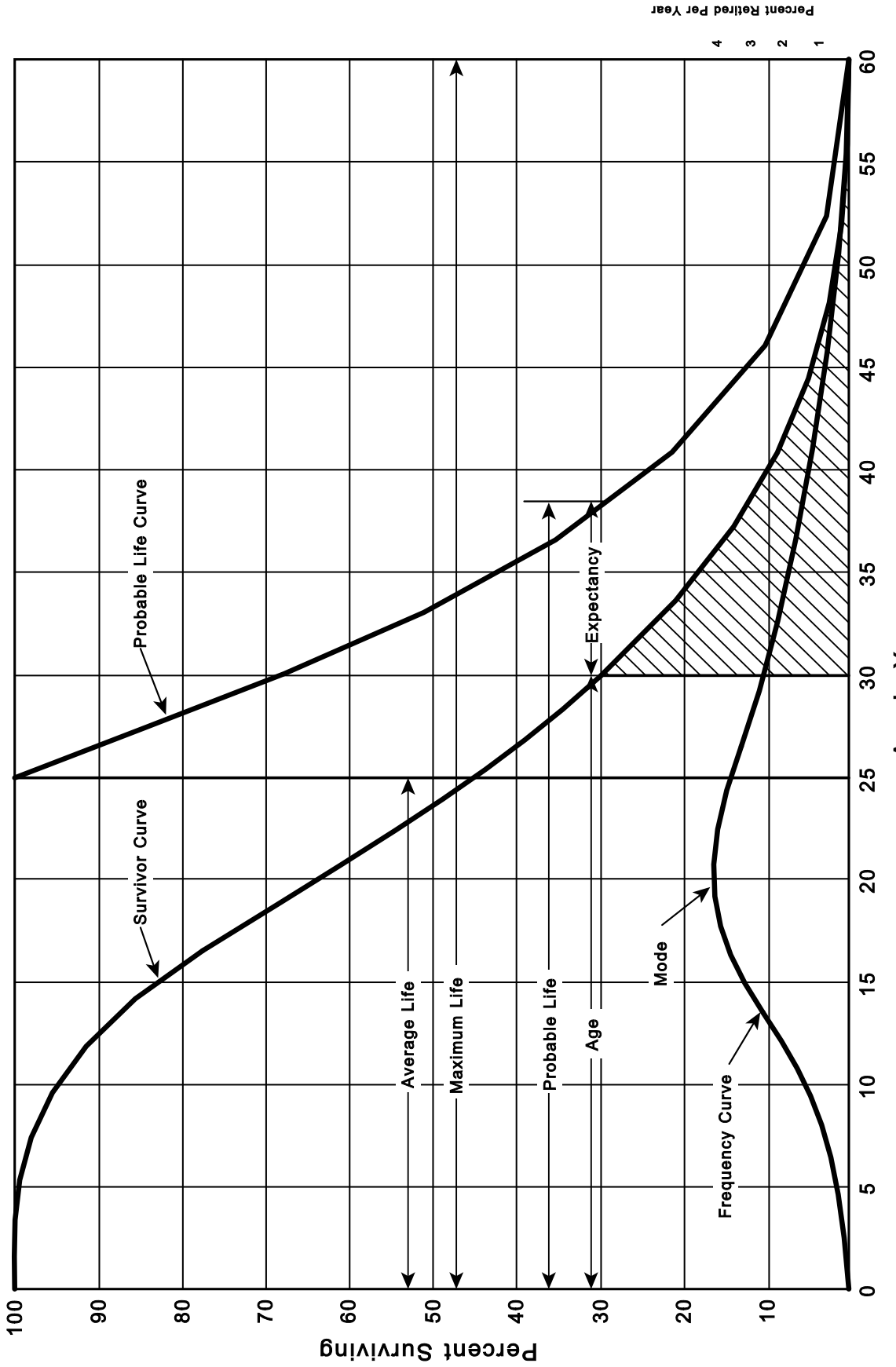


Figure 1. A Typical Survivor Curve and Derived Curves

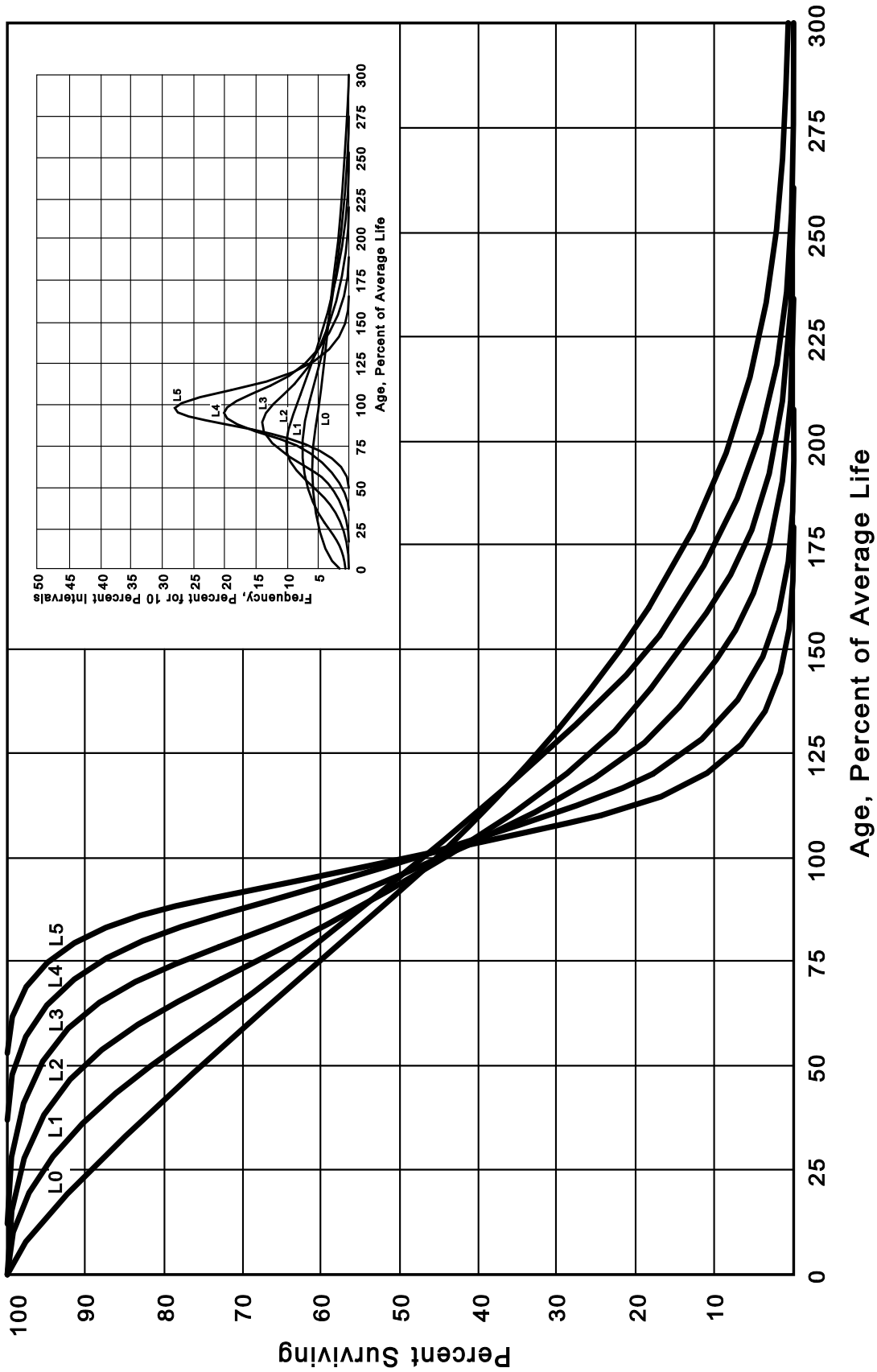


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

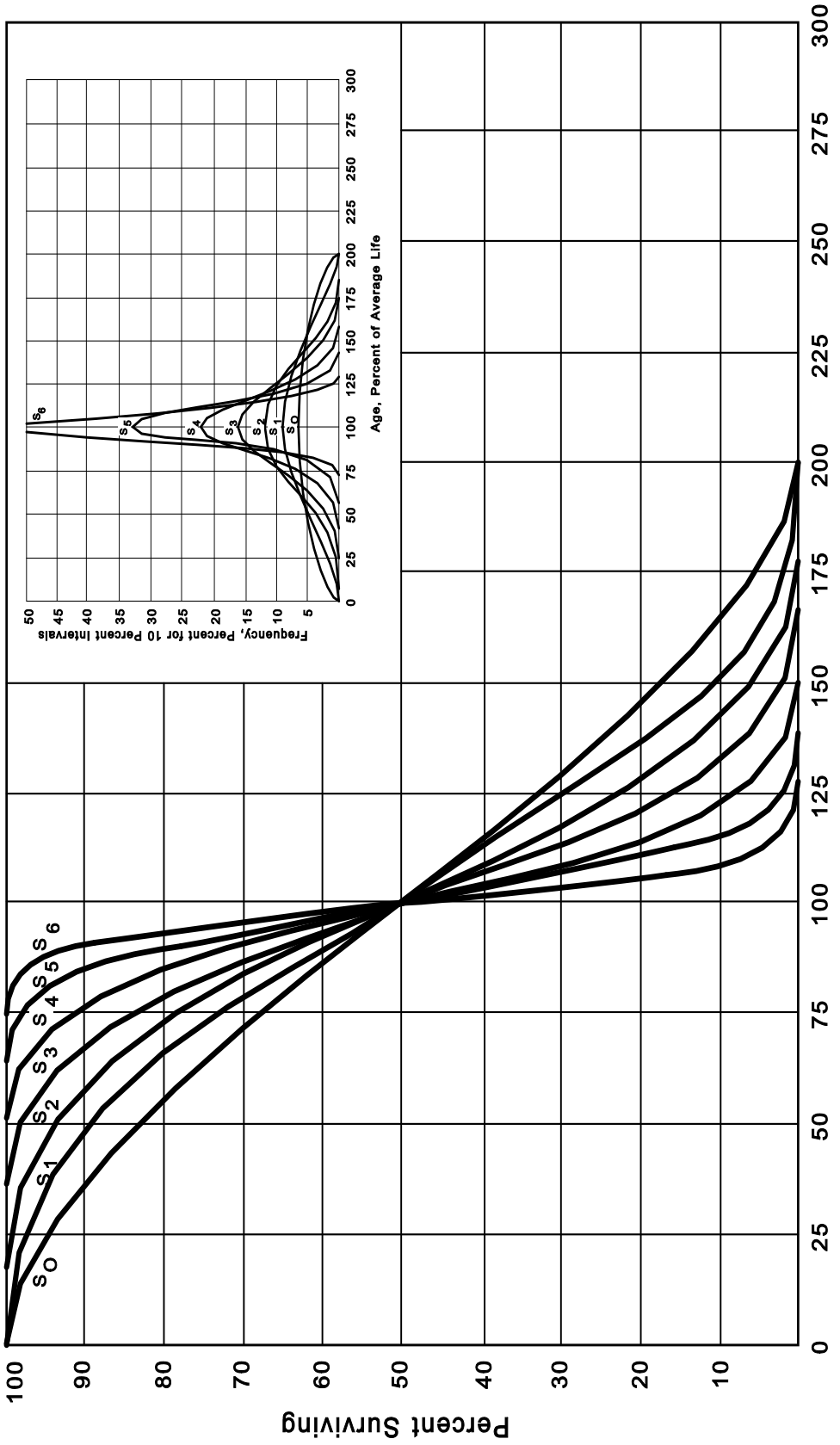


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

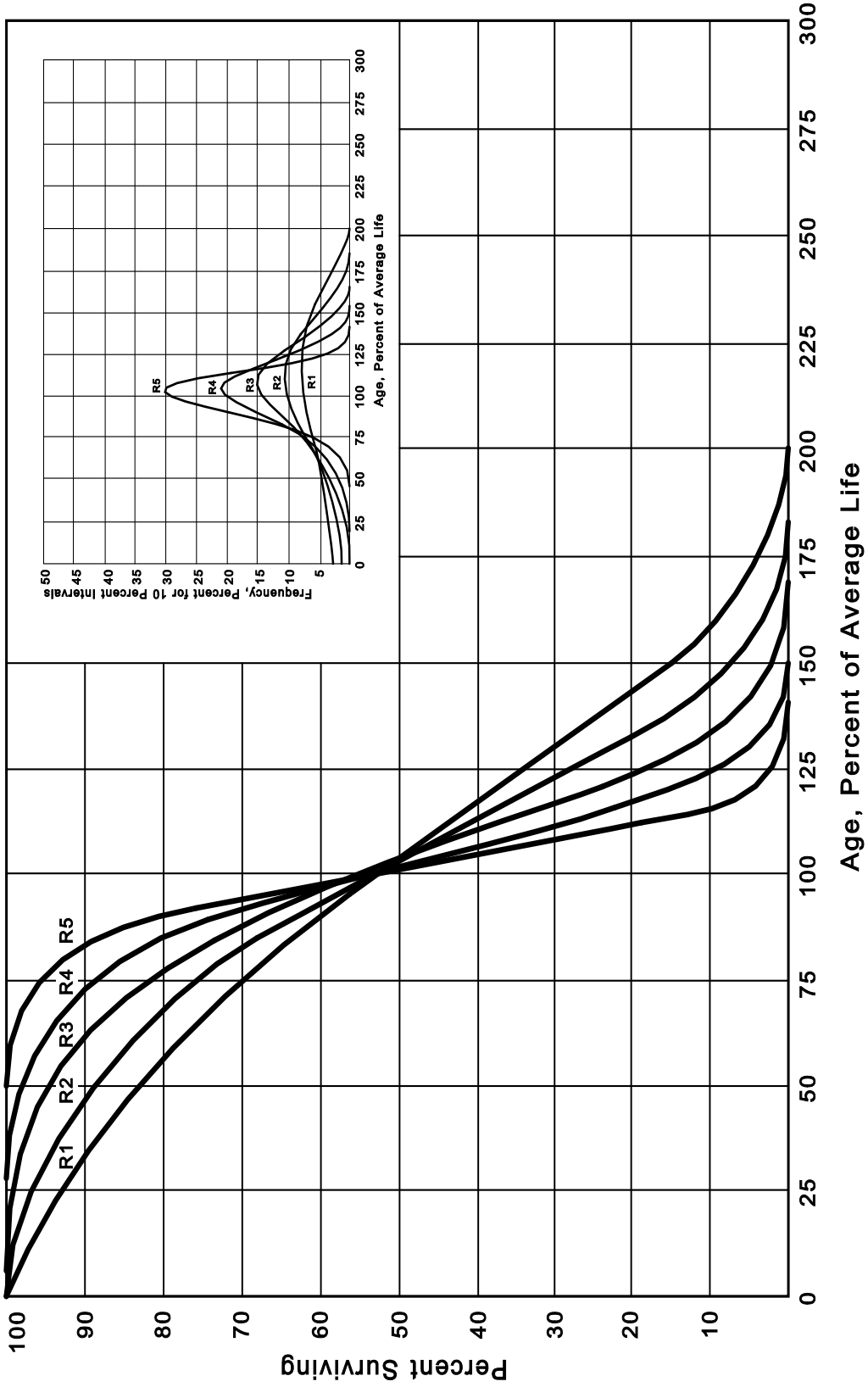


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

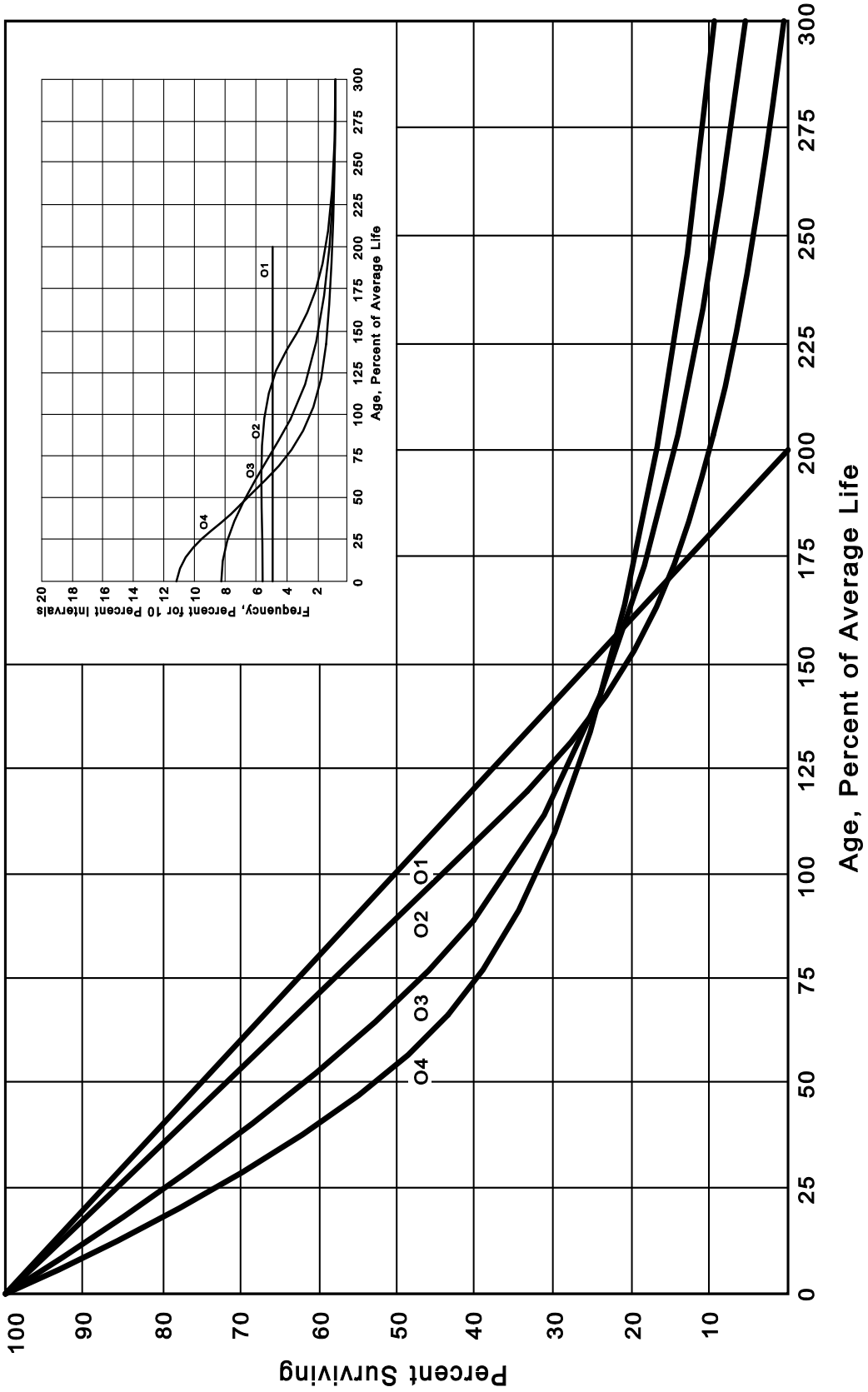


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Robley, Supra Note 1.
[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

A hypothetical property group is used to illustrate the retirement rate method. This property group is observed for the experience band 2009-2018 during which there were placements during the years 2004-2018. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12 In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2004 were retired in 2009. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2009 retirements of 2004 installations and ending with the 2018 retirements of the 2013 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018

Placement Band 2004-2018

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2004	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2005	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2006	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2007	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2008	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2009	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2010		5	11	12	13	14	15	16	18	20	113	7½-8½
2011			6	12	13	15	16	17	19	19	124	6½-7½
2012				6	13	15	16	17	19	19	131	5½-6½
2013					7	14	16	17	19	20	143	4½-5½
2014						8	18	20	22	23	146	3½-4½
2015							9	20	22	25	150	2½-3½
2016								11	23	25	151	1½-2½
2017									11	24	153	½-1½
2018										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 Placement Band 2004-2018

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2004	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2005	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2006	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2007	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2008	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2009	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2010		-	-	-	-	-	-	-	-	-	6	7½-8½
2011			-	-	-	-	-	-	-	-	-	6½-7½
2012				-	-	-	-	(12)[b]	-	-	-	5½-6½
2013					-	-	-	-	22[a]	-	-	4½-5½
2014						-	-	(19)[b]	-	-	10	3½-4½
2015							-	-	-	-	-	2½-3½
2016								-	-	(102)[c]	(121)	1½-2½
2017									-	-	-	½-1½
2018											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year

[b] Transfer Affecting Exposures at End of Year

[c] Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2009 through 2018 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2014 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018

Placement Band 2004-2018

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2004	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2005	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2006	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2007	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2008	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2009	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2010		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2011			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2012				580[a]	574	561	546	530	501	482	3,057	5½-6½
2013					660[a]	653	639	623	628	609	3,789	4½-5½
2014						750[a]	742	724	685	663	4,332	3½-4½
2015							850[a]	841	821	799	4,955	2½-3½
2016								960[a]	949	926	5,719	1½-2½
2017									1,080[a]	1,069	6,579	½-1½
2018										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2009-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16**,** is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2009-2018 Placement Band 2004-2018

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

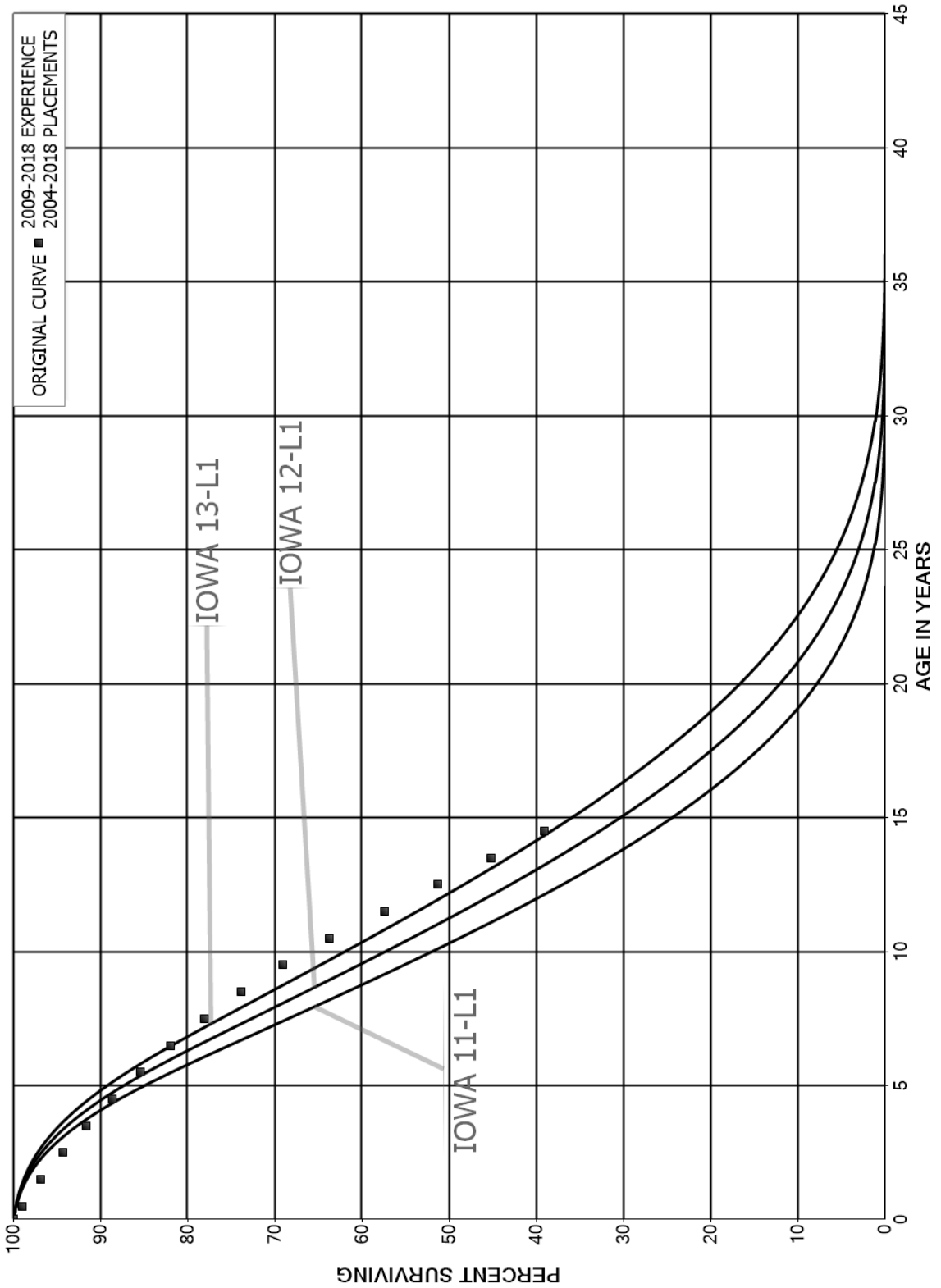


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

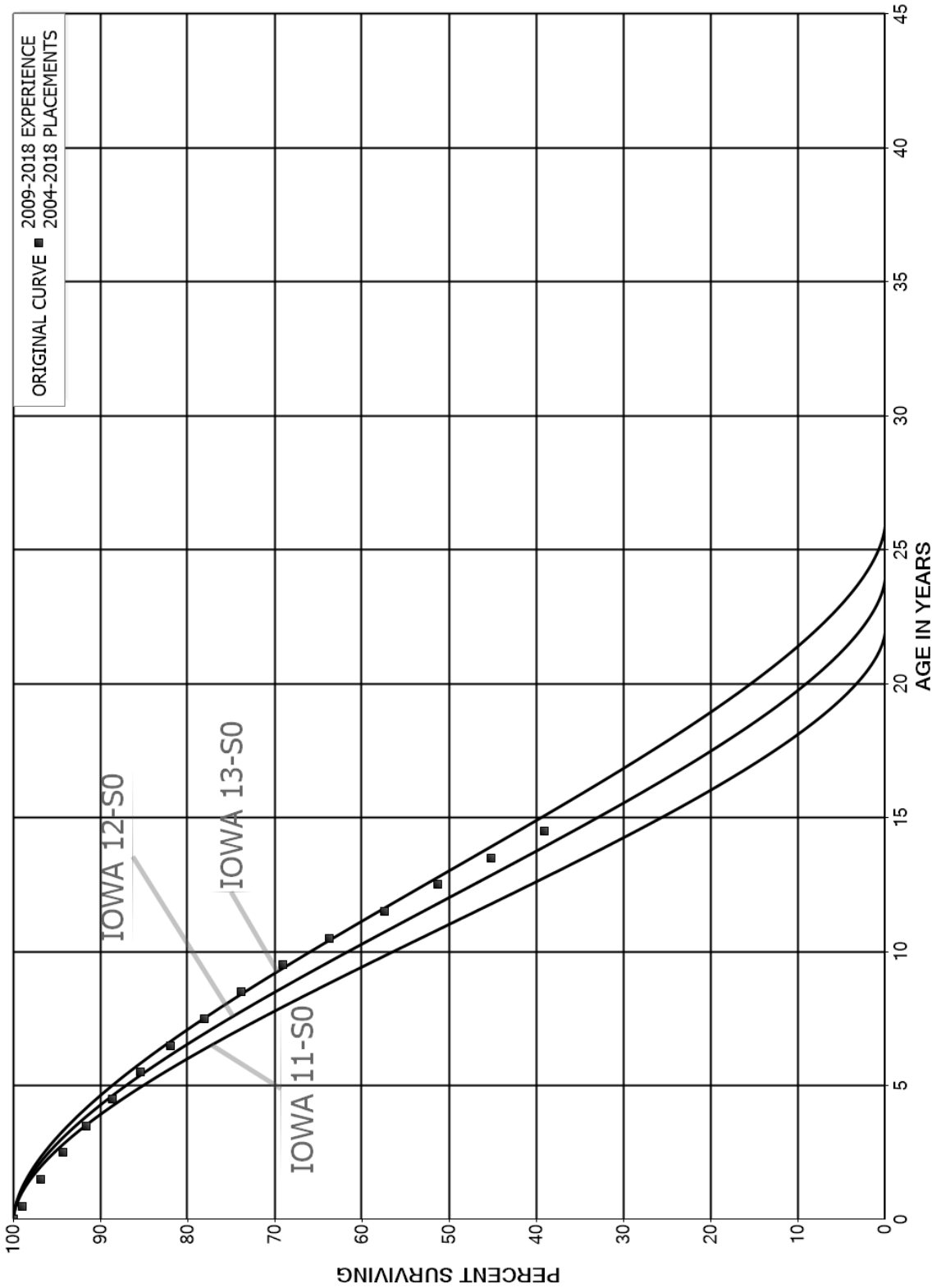


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

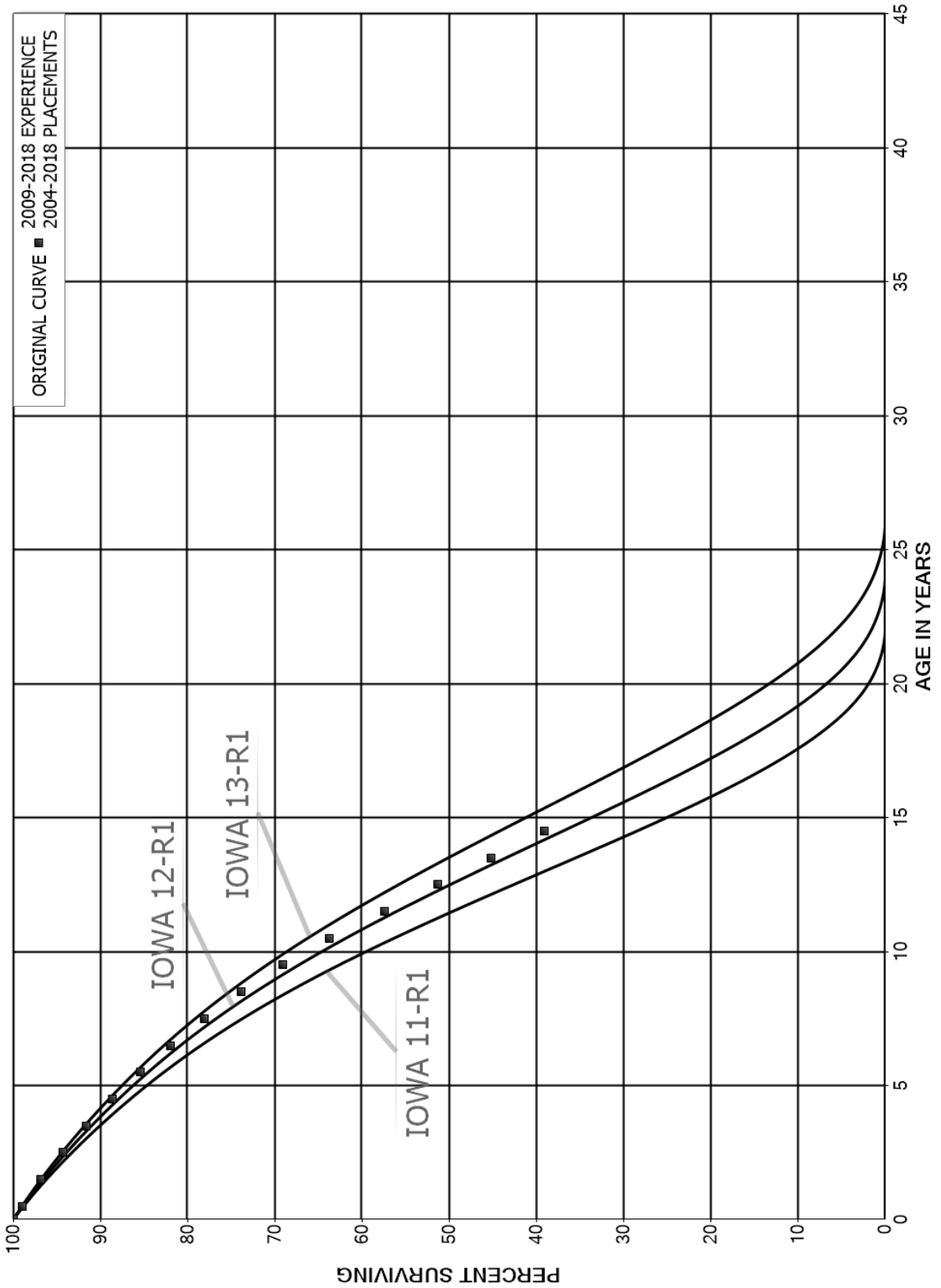
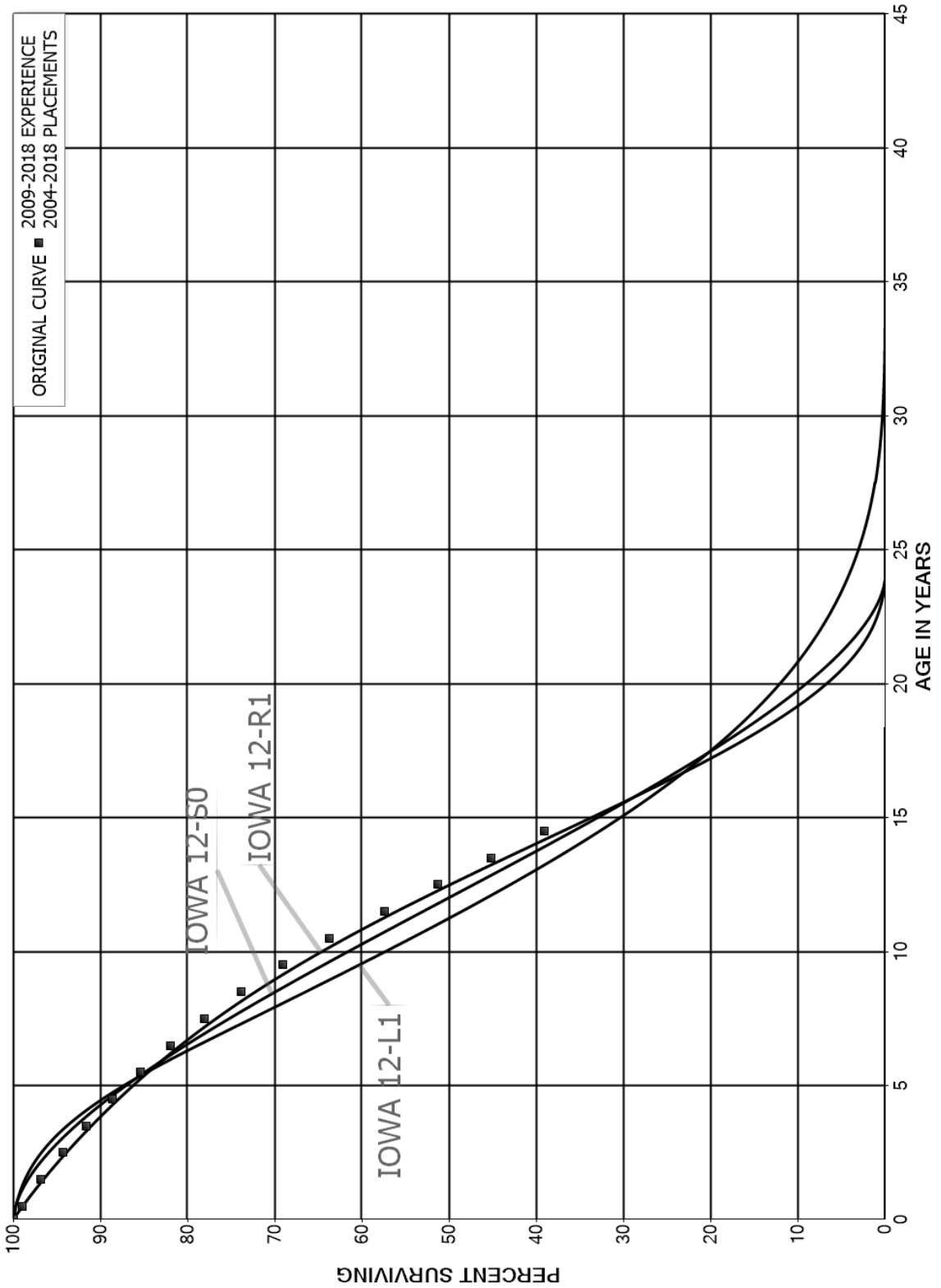


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, a field trip was conducted for the study. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trips.

July 24, 2019
- West Conshohocken Liquefied Natural Gas Plant
- West Conshohocken Gas Operations Center
- West Conshohocken District Regulator Station (Front St and Moorhead Ave)
- Oreland City Gate Station
- Center Point City Gate Station
- Skippack City Gate Station
- Tilghman Street LPG Plant

September 10, 2014
- West Conshohocken Liquefied Natural Gas Plant
- West Conshohocken Gas Operations Center
- King of Prussia Gas Operations Center (Backup)
- Planebrook City Gate Station
- Tilghman Street LPG Plant

September 24, 2014
- Plymouth Service Center

September 26, 2014
- PECO Energy Headquarters Building – 2301 Market Street

LIFE ANALYSIS

The retirement rate method of life analysis is an actuarial method of developing survivor curves using the average rates at which property is retired from each depreciable group. The method involves the analysis of historical retirements of property of various ages, in relation to the property units exposed to retirement at those same ages. Application of this method requires an extensive compilation of historical aged retirement data as well as related plant accounting data including additions, acquisitions, sales and transfers. Plant accounting data for the years 1975 through 2018 were available to study. The life analyses were performed using Gannett Fleming's depreciation software programs. The actuarial data may or may not produce a complete life cycle of experience. A complete life cycle is indicated by the life table reaching zero percent surviving for the last age interval shown on the life table. The curve-fitting portion of Gannett Fleming's depreciation software program matches the stub survivor curves (i.e., from the original life tables) with each member of the Iowa curve family. The curve-fitting results are based on a least squares solution of the differences between the stub curve and the Iowa curve. Survivor data developed by the actuarial analysis and set forth on the original life table are graphed and compared visually and statistically with the Iowa curves. There are two distinct steps in the estimation of service lives and retirement dispersions which must be recognized in the interpretation of the service life analysis results. The first step, *life analysis*, refers to the application of statistical procedures to determine life and dispersion indications based solely on past experience. The second step, *life estimation*, refers to the exercise of informed judgment in making sound estimates of service lives and retirement dispersions. Life estimation incorporates known historical experience, estimated historical trends and estimated future trends or events in order to define complete patterns of estimated service life characteristics. The results of the life analyses,

performed as the first step, are only one of the relevant factors to be considered during the decision making process of life estimation.

LIFE ESTIMATION

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of PECO's property accounting data; current Company policies and outlook as determined during conversations with engineering management and other technical subject matters experts from the company's operations, facilities and IT departments; and the survivor curve estimates from previous studies of this company and other gas companies.

For several of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in reasonable indications of the survivor patterns experienced. These accounts represent 61 percent of depreciable gas plant studied. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

Account No.	Account Description
GAS PLANT	
OTHER STORAGE PLANT	
363	Purification Equipment
363.3	Compressor Equipment
DISTRIBUTION PLANT	
375	Structures and Improvements
376.1	Mains – Steel
376.2	Mains – Cast Iron
379	Measuring and Regulating Station Equipment – City Gate
380.1	Services – Steel
380.2	Services – Plastic
382	Meter Installations

Account 376.1, Mains - Steel, is the third largest plant account and is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged retirement and other plant accounting data were compiled for the years 1975 through 2018. These data were coded in the course of the Companies' normal recordkeeping according to plant account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The data were analyzed by the retirement rate method of life analysis. The survivor curve chart for the account is presented on page VII-23 and the life tables for the experience band plotted on the chart follows it. Multiple experience band and placement band combinations were analyzed and reviewed for each account.

The estimated Iowa 70-R3 is a good fit of the more significant portion of the observed data, i.e., through approximately age 65. The range of service life estimates for mains in other gas companies is 50 to 70 years. The estimate resulting from the previous service life study was the 70-R3. The 70-R3 estimate is based on the statistical analysis for the period 1975-2018. More recent experience also was considered including the period 2009-2018. The Company has accelerated the rate of replacement for its bare steel mains. In 2011, PECO announced plans to accelerate the replacement of its bare steel mains. In 2013, the company filed its initial Long Term Infrastructure Improvement Plan (LTIIP) with the Pennsylvania Public Utility Commission (PaPUC) that expressly stated plans to replace all existing bare steel mains within 34 years by 2047. In 2015, the company filed a modified LTIIP with the PaPUC which further accelerated the replacement rate of bare steel, so that all bare steel mains will be replaced over a 20 year period ending in 2035. Bare steel mains were placed into

service predominantly from the 1920's through 1960 with some additional bare steel mains added in the 1960's. Starting in 1971, regulations prohibited the installation of bare steel mains. Steel mains installed subsequent to 1970 are coated, and cathodically-protected. There are 283 miles of bare steel mains remaining in service as of December 31, 2018 and 2,889 miles of coated steel mains. While the miles of bare steel mains in service is a small percent of the total miles of Account 376.1, Mains - Steel, the remaining investment in bare steel mains represents an even smaller percent of the total investment in steel mains. The plans to accelerate replacement of bare steel mains should result in higher retirement ratios for older assets than had occurred in the past, which is consistent with recent trends, shown by the 2009-2018 experience band and the estimated 70-R3 survivor curve. Discussions with company management indicated no reason to deviate further from the statistical indications. Based on all of these considerations, the 70-R3 estimate is most representative of future experience for this account.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other gas companies.

The selected amortization periods for certain other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization." The General Plant accounts subject to amortization accounting comprise approximately 1 percent of the depreciable and amortizable plant included in this report.

Generally, the survivor curve estimates for the remainder of the accounts were based on judgments which considered the nature of the plant and equipment, a review of available historical retirement data, discussions with engineering management and other technical subject matter experts and a general knowledge of the service lives for similar equipment in other gas companies.

A couple other gas plant accounts affected by the company's plans to accelerate the replacement of older infrastructure assets include Accounts 376.2 – Mains – Cast Iron and 380.1, Services – Steel. In the company's most recent LTIIP filing submitted in 2015, all cast iron mains, in addition to the bare steel mains, will be replaced by 2035 and all bare steel services will be replaced by 2022. As a result of company plans to accelerate the replacement of these assets, forecasted retirements were determined based on company plans set forth in the LTIIP and incorporated with experienced retirements. A life analyses was performed for Account 376.2 using forecasted retirements through 2035 for cast iron mains. The life indications show increasing rates of retirements for older vintages of cast iron mains and steel services. The proposed survivor curve estimates for these two accounts reflect these expectations.

Life Span Estimates

The life span method is appropriate for certain gas facilities in which all assets at the facility are expected to be retired concurrently upon the final retirement of the facility. The life span estimates for these facilities were based on current Company policies and outlook as determined during field review, discussions with management and the range of estimates from other gas utility companies.

The range of life spans for other similar gas facilities varies widely from company to company and is dependent on numerous economic factors other than just the physical condition of the facility. The operation of these types of facilities is largely due to the continued economic attractiveness compared with alternative supply and storage options. The life span estimate for PECO's Tilghman Street LPG plant is 51 years and the estimate for its West Conshohocken LNG plant is 70 years. These estimates are at the upper end of the industry range and are based on the attained age of the facilities, the Company's current and continuing maintenance practices and planned investments.

A table with shows the life span estimates by generating unit is presented below.

GAS FACILITY	IN-SERVICE YEAR	PROBABLE RETIREMENT YEAR	LIFE SPAN
Tilghman Street LPG Plant	1984	2035	51
West Conshohocken LNG Plant	1972	2042	70

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

Net Salvage Considerations

Inasmuch as this report relates primarily to Pennsylvania rate regulation practices, under which experienced costs of negative net salvage (i.e., primarily removal costs) are amortized after their occurrence, no adjustments for expected salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for individual accounts. The annual provision for recovering negative net salvage in Pennsylvania typically is based on the amortization of experienced net salvage over a five year period. However, PECO had requested in their 1989 rate case (Docket R-891364) to amortize experienced negative net salvage over the account's remaining life. The Pennsylvania Public Utility Commission (PA PUC) granted PECO's request and the company has been utilizing this method since 1989.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000 \left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2018, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2018, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable utility plant in service. The accounts and their amortization periods are as follows:

ACCT	TITLE	AMORTIZATION PERIOD, YEARS
Gas		
391,	Office Furniture and Equipment	
391.2	Furniture and Fixtures	15
391.3	Computers	5
394,	Tools, Shop and Garage Equipment	20
398,	Miscellaneous Equipment	15

For the purpose of calculating annual amortization amounts as of December 31, 2018, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book

reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual accrual rates and amounts resulting from an updated service life study are the principal results of this report. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions. The annual depreciation accrual rates are applicable specifically to the gas plant in service as of December 31, 2018.

DESCRIPTION OF SUMMARY TABULATIONS

Table 1 presents summary results of the study as applied to the original cost of gas plant at December 31, 2018. The summary table sets forth for each account the estimated survivor curve, the plant and reserve balance, the future accruals, the composite remaining life and the annual depreciation accrual rates for gross and net plant and the annual depreciation accrual amount. The summary schedule is presented on page VI-4 of this report.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience. For accounts in which the historical service life indications were indeterminate or not indicative of the expected survivor characteristics, only the estimated smooth survivor curve is shown and not the original stub curve.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2018 are presented in account sequence starting on page VIII-2 of the supporting documents. The tables indicate the estimated survivor curve for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

PECO ENERGY COMPANY
GAS PLANT

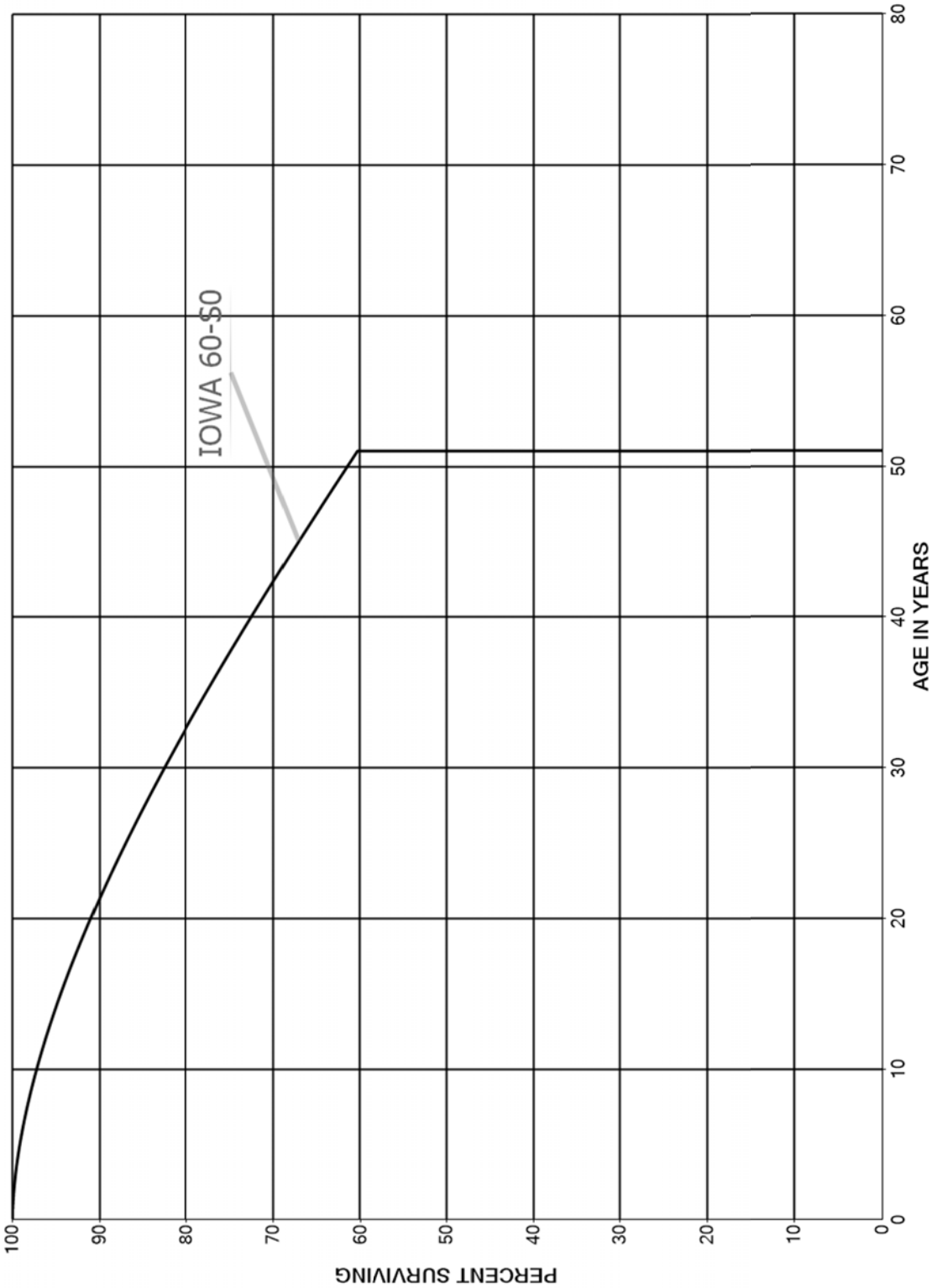
TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT DECEMBER 31, 2018

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE		ORIGINAL COST AT 12/31/2018	BOOK RESERVE AT 12/31/2018	FUTURE ACCRUALS (NET PLANT)	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%) GROSS PLANT	CALCULATED ANNUAL ACCRUAL RATE (%) NET PLANT
(1)		(2)	(3)		(4)	(5)	(6)=(4)-(5)	(7)	(8)	(9)=(8)/(4)	(10)=(8)/(6)
DEPRECIABLE PLANT											
PRODUCTION PLANT											
305	STRUCTURES AND IMPROVEMENTS	6-2035	60 - S0	*	1,322,161	755,217	566,944	15.6	36,447	2.76	6.43
311	LIQUEFIED PETROLEUM GAS EQUIPMENT	6-2035	40 - S3	*	14,333,838	11,956,964	2,376,874	13.4	177,599	1.24	7.47
TOTAL PRODUCTION PLANT					**15,655,999**	**12,712,181**	**2,943,818**		**214,046**	**1.37**	**7.27**
STORAGE AND PROCESSING PLANT											
361	STRUCTURES AND IMPROVEMENTS	6-2042	110 - R1	*	13,822,226	5,743,237	8,078,989	22.7	355,357	2.57	4.40
362	GAS HOLDERS	6-2042	SQUARE		7,083,540	6,835,440	248,100	23.5	10,558	0.15	4.26
363	PURIFICATION EQUIPMENT	6-2042	50 - L3	*	1,329,879	712,683	617,196	22.5	27,449	2.06	4.45
363.1	LIQUEFACTION EQUIPMENT	6-2042	40 - L3	*	9,958,189	6,057,558	3,900,631	20.1	194,188	1.95	4.98
363.2	VAPORIZING EQUIPMENT	6-2042	45 - L2.5	*	15,670,588	3,079,846	12,590,742	22.7	554,362	3.54	4.40
363.3	COMPRESSOR EQUIPMENT	6-2042	30 - R2.5	*	5,824,142	1,334,512	4,489,630	20.3	220,841	3.79	4.92
363.4	MEASURING AND REGULATING EQUIPMENT	6-2042	45 - L2.5	*	1,547,673	976,097	571,576	21.0	27,261	1.76	4.77
363.5	OTHER EQUIPMENT	6-2042	45 - L2.5	*	7,702,930	5,689,957	2,012,973	21.3	94,585	1.23	4.70
TOTAL STORAGE AND PROCESSING PLANT					**62,939,167**	**30,429,330**	**32,509,837**		**1,484,601**	**2.36**	**4.57**
DISTRIBUTION PLANT											
375	STRUCTURES AND IMPROVEMENTS		50 - R4		13,652,505	5,097,563	8,554,942	27.8	308,229	2.26	3.60
376.1	MAINS - STEEL		70 - R3		532,104,163	187,362,763	344,741,400	47.9	7,201,094	1.35	2.09
376.2	MAINS - CAST IRON	12-2035	60 - R2	*	15,228,174	4,485,659	10,742,516	9.6	1,123,368	7.38	10.46
376.3	MAINS - PLASTIC		65 - R3		784,932,347	134,702,696	650,229,651	53.9	12,058,283	1.54	1.85
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		50 - R2		18,155,129	7,519,627	10,635,502	34.2	310,951	1.71	2.92
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		50 - R3		52,858,184	21,016,873	31,841,311	38.6	824,257	1.56	2.59
380.1	SERVICES - STEEL		37 - S0		98,308,943	5,802,220	92,506,723	23.1	3,996,994	4.07	4.32
380.2	SERVICES - PLASTIC		56 - R3		725,985,131	232,525,725	493,459,406	42.2	11,701,593	1.61	2.37
381	METERS		40 - R3		79,054,279	40,753,346	38,300,932	26.7	1,435,880	1.82	3.75
381.1	METER MODULES		20 - S2		67,155,256	13,578,611	53,576,645	16.1	3,320,787	4.94	6.20
382	METER INSTALLATIONS		50 - R3		176,026,583	64,850,693	111,175,890	34.7	3,199,728	1.82	2.88
387	OTHER EQUIPMENT		22 - S1.5		2,118,323	951,673	1,166,650	6.2	188,334	8.89	16.14
TOTAL DISTRIBUTION PLANT					**2,565,579,017**	**718,647,450**	**1,846,931,568**		**45,669,498**	**1.78**	**2.47**
GENERAL PLANT											
390	STRUCTURES AND IMPROVEMENTS		45 - R2		8,177,511	2,659,265	5,518,246	31.9	173,257	2.12	3.14
391.2	OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES		15 - SQ		328,620	53,922	274,698	12.7	21,616	6.58	7.87
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		5 - SQ		3,179,992	960,211	2,219,781	4.3	515,822	16.22	23.24
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ		11,413,903	4,101,283	7,312,620	12.8	572,301	5.01	7.83
397	COMMUNICATION EQUIPMENT - SCADA HW & SW		5 - R3		4,614,171	3,417,378	1,196,793	3.5	346,495	7.51	28.95
398	MISCELLANEOUS EQUIPMENT		15 - SQ		168,798	60,173	108,625	13.0	8,334	4.94	7.67
TOTAL GENERAL PLANT					**27,882,995**	**11,252,232**	**16,630,762**		**1,637,825**	**5.87**	**9.85**
TOTAL DEPRECIABLE PLANT					**2,672,057,178**	**773,041,193**	**1,899,015,986**		**49,005,970**	**1.83**	**2.58**
NONDEPRECIABLE AND ACCOUNTS NOT STUDIED											
302	FRANCHISES AND CONSENTS				50,033	0					
303	MISCELLANEOUS INTANGIBLE PLANT**				16,664,207	11,564,885					
360	LAND AND LAND RIGHTS				15,923	0					
374	LAND AND LAND RIGHTS				3,651,337	0					
388	DISTRIBUTION ARO COSTS				1,401,921	286,237					
399.1	GENERAL ARO COSTS				145,154	20,051					
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED					**21,928,575**	**11,871,173**					
TOTAL GAS PLANT					**2,693,985,754**	**784,912,366**					

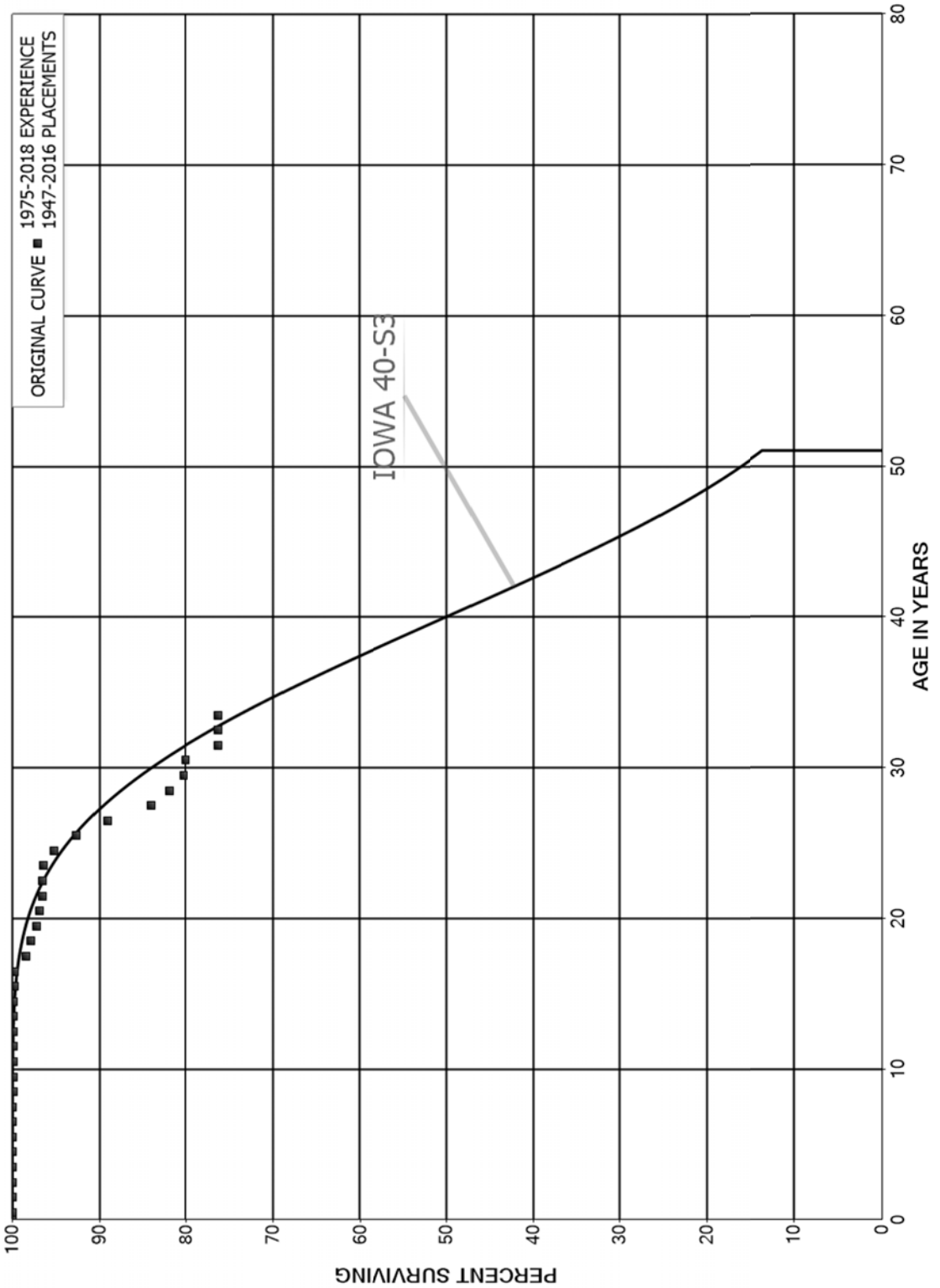
* Interim Survivor Curve
** Miscellaneous Intangible Plant is individually depreciated over 5 years.

PART VII. SERVICE LIFE STATISTICS

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 305 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 311 LIQUEFIED PETROLEUM GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

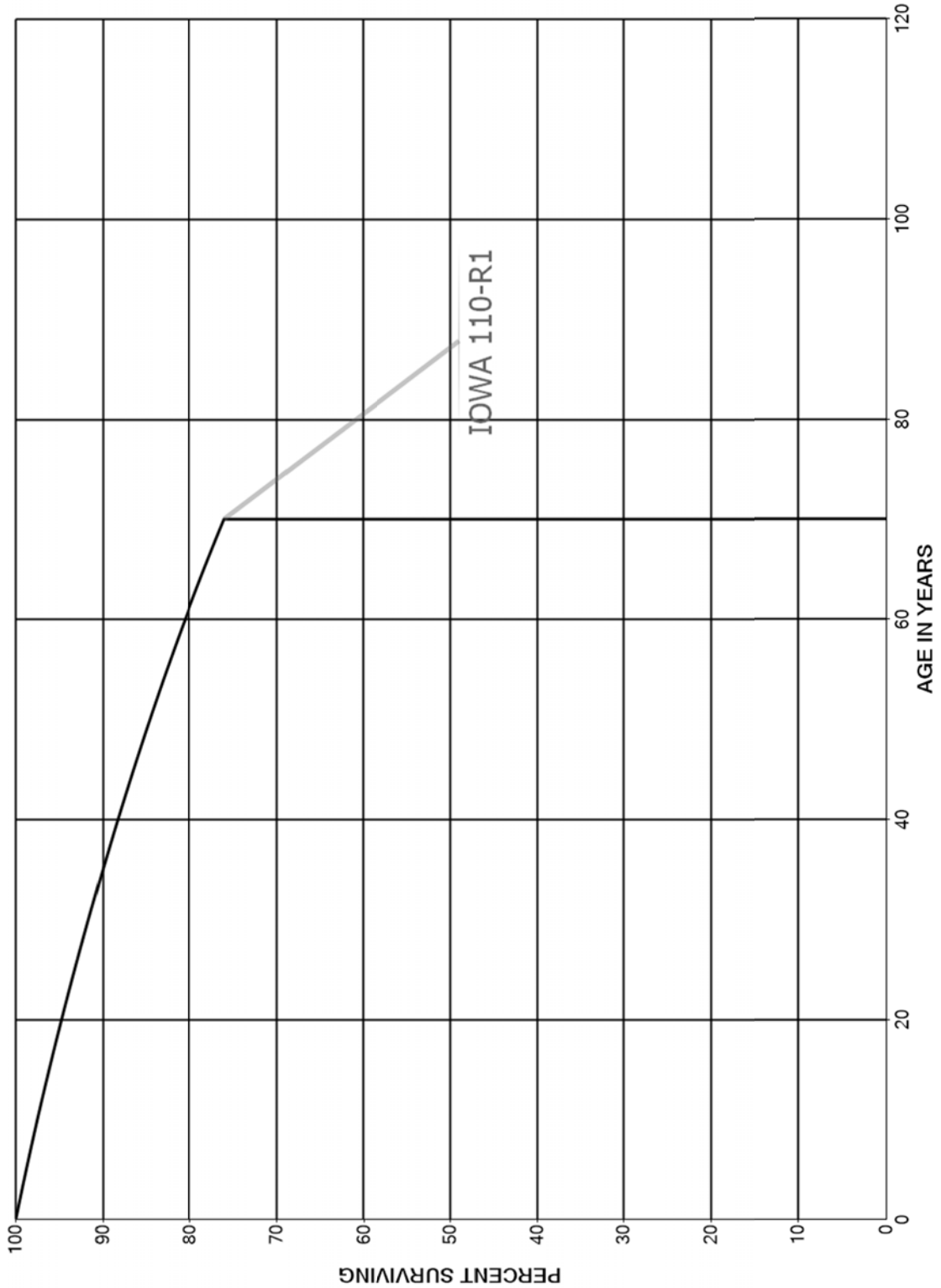
ACCOUNT 311 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

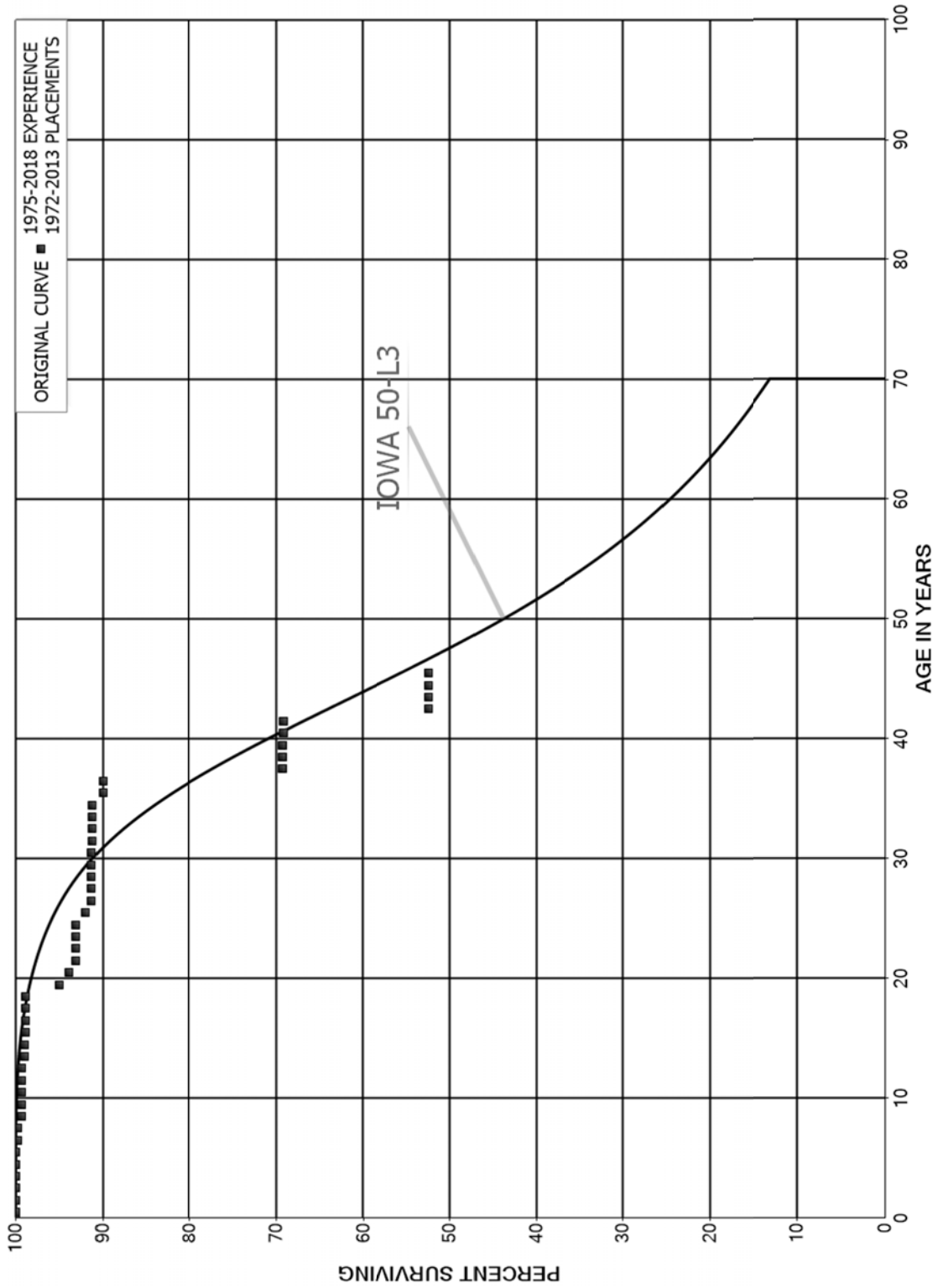
PLACEMENT BAND 1947-2016 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,908,341		0.0000	1.0000	100.00
0.5	14,908,341	101	0.0000	1.0000	100.00
1.5	14,908,240	1,809	0.0001	0.9999	100.00
2.5	14,874,441	527	0.0000	1.0000	99.99
3.5	14,873,914		0.0000	1.0000	99.98
4.5	14,873,914	5,237	0.0004	0.9996	99.98
5.5	14,868,677		0.0000	1.0000	99.95
6.5	14,614,484		0.0000	1.0000	99.95
7.5	14,008,234	9,234	0.0007	0.9993	99.95
8.5	13,444,975	15	0.0000	1.0000	99.88
9.5	13,444,960	6	0.0000	1.0000	99.88
10.5	13,444,954		0.0000	1.0000	99.88
11.5	13,462,205		0.0000	1.0000	99.88
12.5	13,626,465		0.0000	1.0000	99.88
13.5	13,626,465		0.0000	1.0000	99.88
14.5	13,626,465	16,223	0.0012	0.9988	99.88
15.5	13,607,065	4,494	0.0003	0.9997	99.76
16.5	13,647,723	178,217	0.0131	0.9869	99.73
17.5	13,469,506	87,157	0.0065	0.9935	98.43
18.5	13,677,286	81,455	0.0060	0.9940	97.79
19.5	13,981,466	54,209	0.0039	0.9961	97.21
20.5	14,272,442	45,206	0.0032	0.9968	96.83
21.5	14,227,236	179	0.0000	1.0000	96.53
22.5	14,202,275	26,870	0.0019	0.9981	96.52
23.5	14,333,395	165,841	0.0116	0.9884	96.34
24.5	12,949,128	361,379	0.0279	0.9721	95.23
25.5	6,370,475	244,416	0.0384	0.9616	92.57
26.5	6,450,371	361,620	0.0561	0.9439	89.02
27.5	6,094,125	152,738	0.0251	0.9749	84.03
28.5	5,941,388	121,903	0.0205	0.9795	81.92
29.5	5,810,163	12,485	0.0021	0.9979	80.24
30.5	5,797,678	270,029	0.0466	0.9534	80.07
31.5	5,510,532	1,272	0.0002	0.9998	76.34
32.5	5,509,260		0.0000	1.0000	76.32
33.5	5,509,260	197,823	0.0359	0.9641	76.32
34.5	7,856	7,856	1.0000		73.58
35.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 361 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363 PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363 PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2013 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,188,124		0.0000	1.0000	100.00
0.5	1,190,668		0.0000	1.0000	100.00
1.5	1,190,668		0.0000	1.0000	100.00
2.5	1,498,886	1,476	0.0010	0.9990	100.00
3.5	1,497,410		0.0000	1.0000	99.90
4.5	1,497,410		0.0000	1.0000	99.90
5.5	1,106,646	1,363	0.0012	0.9988	99.90
6.5	1,105,282		0.0000	1.0000	99.78
7.5	1,105,282	4,988	0.0045	0.9955	99.78
8.5	1,100,294		0.0000	1.0000	99.33
9.5	1,100,294	421	0.0004	0.9996	99.33
10.5	727,970		0.0000	1.0000	99.29
11.5	727,970		0.0000	1.0000	99.29
12.5	585,407	2,349	0.0040	0.9960	99.29
13.5	583,058		0.0000	1.0000	98.89
14.5	583,058	265	0.0005	0.9995	98.89
15.5	582,793		0.0000	1.0000	98.85
16.5	582,793		0.0000	1.0000	98.85
17.5	431,694	187	0.0004	0.9996	98.85
18.5	431,507	16,866	0.0391	0.9609	98.80
19.5	401,854	4,908	0.0122	0.9878	94.94
20.5	396,946	2,925	0.0074	0.9926	93.78
21.5	394,021		0.0000	1.0000	93.09
22.5	394,021		0.0000	1.0000	93.09
23.5	394,021		0.0000	1.0000	93.09
24.5	394,021	4,850	0.0123	0.9877	93.09
25.5	389,171	2,938	0.0076	0.9924	91.95
26.5	386,232		0.0000	1.0000	91.25
27.5	386,232		0.0000	1.0000	91.25
28.5	386,232	7	0.0000	1.0000	91.25
29.5	326,788		0.0000	1.0000	91.25
30.5	294,870	200	0.0007	0.9993	91.25
31.5	294,670		0.0000	1.0000	91.19
32.5	294,670	29	0.0001	0.9999	91.19
33.5	294,641		0.0000	1.0000	91.18
34.5	294,641	3,884	0.0132	0.9868	91.18
35.5	290,757	128	0.0004	0.9996	89.98
36.5	290,629	66,694	0.2295	0.7705	89.94
37.5	223,935		0.0000	1.0000	69.30
38.5	223,935		0.0000	1.0000	69.30

PECO ENERGY COMPANY
GAS PLANT

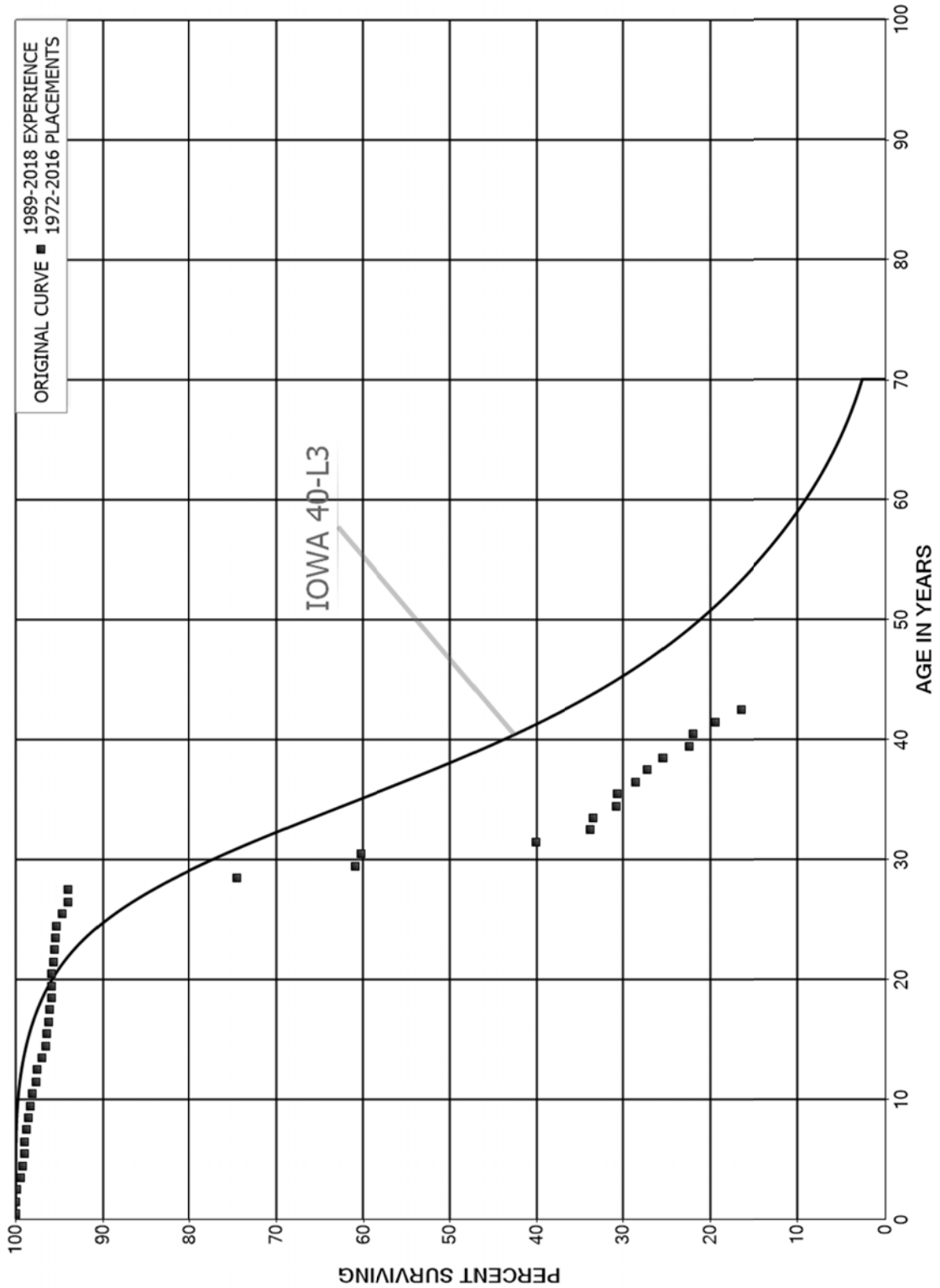
ACCOUNT 363 PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2013 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	223,935	446	0.0020	0.9980	69.30
40.5	222,954		0.0000	1.0000	69.16
41.5	222,954	54,082	0.2426	0.7574	69.16
42.5	168,872		0.0000	1.0000	52.38
43.5	168,872		0.0000	1.0000	52.38
44.5	167,385		0.0000	1.0000	52.38
45.5	167,385		0.0000	1.0000	52.38
46.5					52.38

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363.1 LIQUEFACTION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.1 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,941,504		0.0000	1.0000	100.00
0.5	9,941,504	3,329	0.0003	0.9997	100.00
1.5	9,938,175	9,092	0.0009	0.9991	99.97
2.5	9,417,046	50,384	0.0054	0.9946	99.88
3.5	8,939,591	10,733	0.0012	0.9988	99.34
4.5	8,928,858	22,640	0.0025	0.9975	99.22
5.5	8,480,592	3,700	0.0004	0.9996	98.97
6.5	8,154,413	16,814	0.0021	0.9979	98.93
7.5	8,138,581	18,075	0.0022	0.9978	98.72
8.5	7,612,599	13,931	0.0018	0.9982	98.50
9.5	7,598,668	19,707	0.0026	0.9974	98.32
10.5	7,655,541	31,872	0.0042	0.9958	98.07
11.5	7,623,669	15,061	0.0020	0.9980	97.66
12.5	7,608,608	36,341	0.0048	0.9952	97.47
13.5	7,853,954	40,276	0.0051	0.9949	97.00
14.5	7,816,247	11,370	0.0015	0.9985	96.50
15.5	4,325,511	9,038	0.0021	0.9979	96.36
16.5	4,896,552	5,548	0.0011	0.9989	96.16
17.5	4,330,725	7,717	0.0018	0.9982	96.05
18.5	4,323,008	633	0.0001	0.9999	95.88
19.5	4,028,749	3,121	0.0008	0.9992	95.87
20.5	2,266,202	5,014	0.0022	0.9978	95.79
21.5	2,261,189	1,055	0.0005	0.9995	95.58
22.5	2,171,240	3,422	0.0016	0.9984	95.54
23.5	2,149,376	1,933	0.0009	0.9991	95.39
24.5	2,147,443	16,372	0.0076	0.9924	95.30
25.5	2,131,071	14,546	0.0068	0.9932	94.57
26.5	2,116,526	632	0.0003	0.9997	93.93
27.5	2,106,208	435,722	0.2069	0.7931	93.90
28.5	1,670,486	302,378	0.1810	0.8190	74.48
29.5	1,368,108	16,403	0.0120	0.9880	60.99
30.5	1,351,704	453,928	0.3358	0.6642	60.26
31.5	897,777	141,231	0.1573	0.8427	40.03
32.5	756,545	7,657	0.0101	0.9899	33.73
33.5	748,888	60,083	0.0802	0.9198	33.39
34.5	688,805	2,559	0.0037	0.9963	30.71
35.5	683,187	47,128	0.0690	0.9310	30.59
36.5	636,059	28,183	0.0443	0.9557	28.48
37.5	607,508	41,583	0.0684	0.9316	27.22
38.5	561,220	66,509	0.1185	0.8815	25.36

PECO ENERGY COMPANY
GAS PLANT

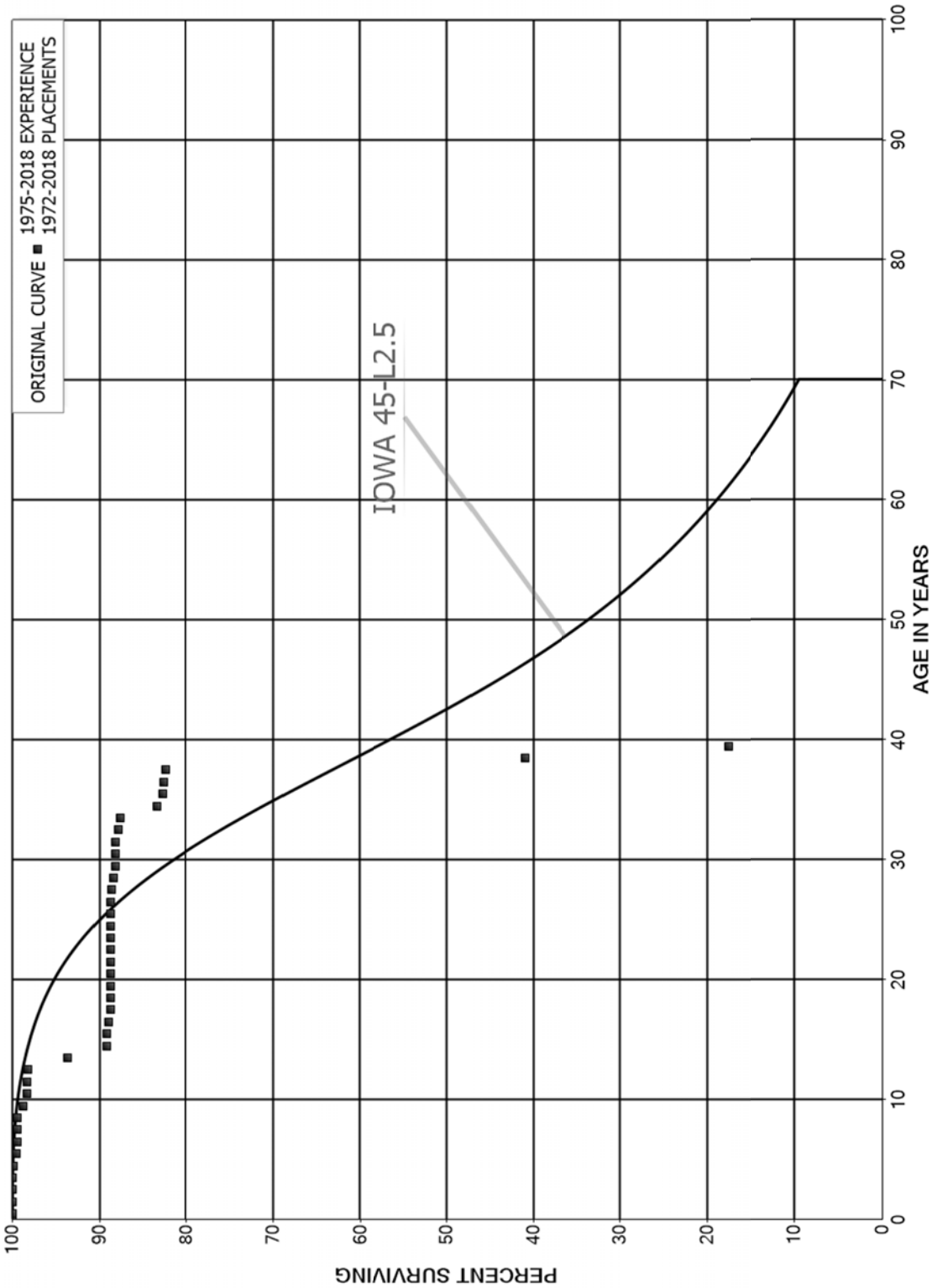
ACCOUNT 363.1 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2016 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	494,711	8,212	0.0166	0.9834	22.35
40.5	465,508	54,765	0.1176	0.8824	21.98
41.5	410,744	63,922	0.1556	0.8444	19.40
42.5	346,822	78	0.0002	0.9998	16.38
43.5	89,461	11,835	0.1323	0.8677	16.37
44.5	77,233	13,392	0.1734	0.8266	14.21
45.5	63,841		0.0000	1.0000	11.74
46.5					11.74

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363.2 VAPORIZING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.2 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,804,830	1,090	0.0001	0.9999	100.00
0.5	6,368,118	2,954	0.0005	0.9995	99.99
1.5	4,670,220	124	0.0000	1.0000	99.95
2.5	5,311,561		0.0000	1.0000	99.94
3.5	5,311,561	7,965	0.0015	0.9985	99.94
4.5	5,303,595	15,781	0.0030	0.9970	99.79
5.5	5,287,814	6,992	0.0013	0.9987	99.50
6.5	5,280,822		0.0000	1.0000	99.37
7.5	5,280,822		0.0000	1.0000	99.37
8.5	3,430,387	22,381	0.0065	0.9935	99.37
9.5	3,331,561	16,417	0.0049	0.9951	98.72
10.5	2,153,134		0.0000	1.0000	98.23
11.5	2,153,134	253	0.0001	0.9999	98.23
12.5	1,949,331	90,712	0.0465	0.9535	98.22
13.5	1,718,346	82,346	0.0479	0.9521	93.65
14.5	1,636,001		0.0000	1.0000	89.16
15.5	1,636,001	3,968	0.0024	0.9976	89.16
16.5	1,632,033	3,520	0.0022	0.9978	88.94
17.5	1,426,285		0.0000	1.0000	88.75
18.5	1,426,285		0.0000	1.0000	88.75
19.5	1,426,285		0.0000	1.0000	88.75
20.5	1,426,285		0.0000	1.0000	88.75
21.5	680,568		0.0000	1.0000	88.75
22.5	680,568	30	0.0000	1.0000	88.75
23.5	680,538	108	0.0002	0.9998	88.75
24.5	656,136	16	0.0000	1.0000	88.73
25.5	656,120		0.0000	1.0000	88.73
26.5	656,120	483	0.0007	0.9993	88.73
27.5	655,637	2,215	0.0034	0.9966	88.67
28.5	653,422	1,194	0.0018	0.9982	88.37
29.5	652,229		0.0000	1.0000	88.21
30.5	652,229		0.0000	1.0000	88.21
31.5	652,229	2,520	0.0039	0.9961	88.21
32.5	649,709	1,461	0.0022	0.9978	87.87
33.5	648,248	31,829	0.0491	0.9509	87.67
34.5	616,419	4,716	0.0077	0.9923	83.36
35.5	611,070	1,043	0.0017	0.9983	82.73
36.5	608,286	1,253	0.0021	0.9979	82.58
37.5	607,033	305,037	0.5025	0.4975	82.41
38.5	301,996	172,887	0.5725	0.4275	41.00

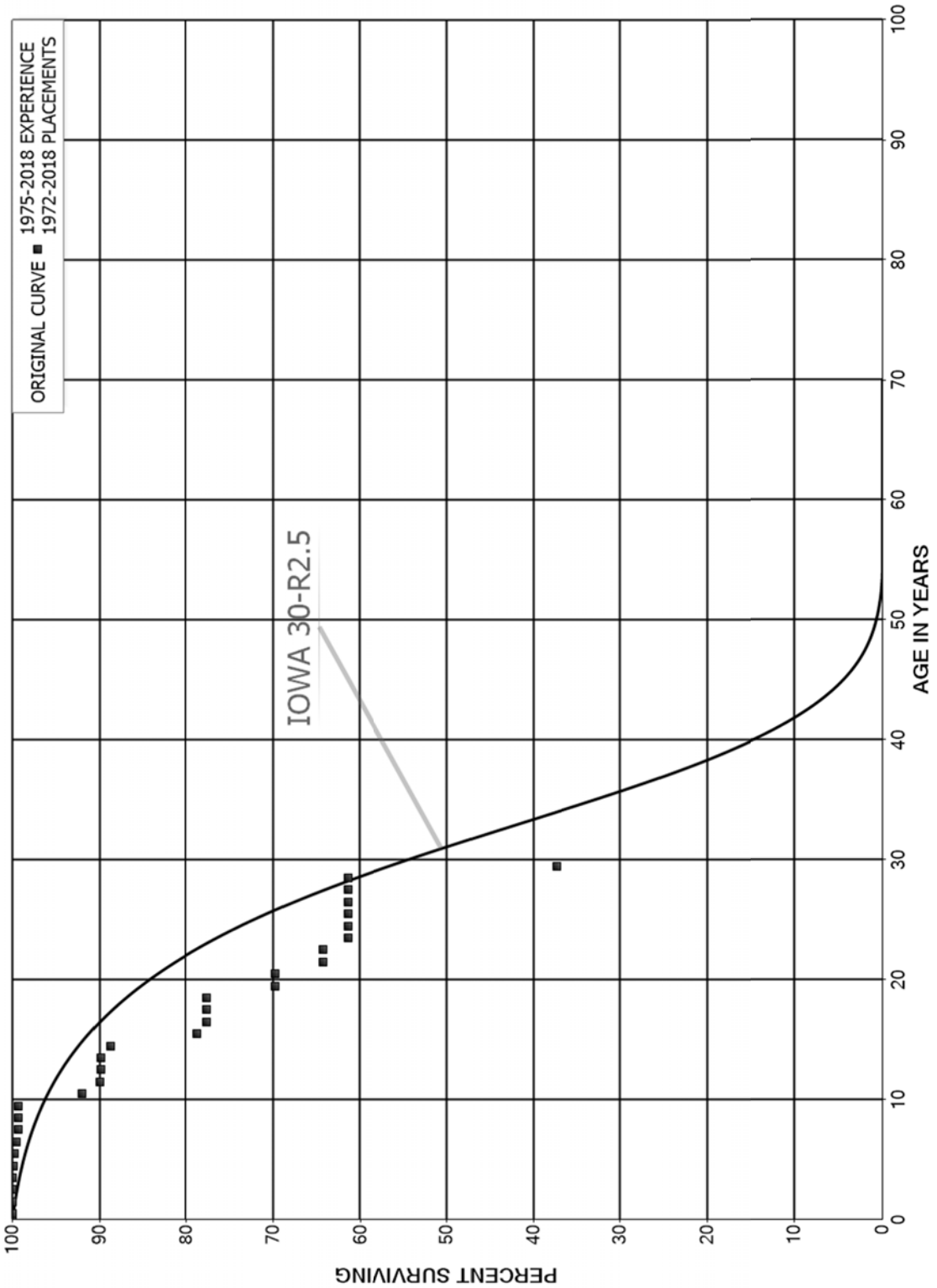
PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.2 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2018			EXPERIENCE BAND 1975-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	129,109		0.0000	1.0000	17.53
40.5	128,094		0.0000	1.0000	17.53
41.5	128,094		0.0000	1.0000	17.53
42.5	128,094		0.0000	1.0000	17.53
43.5	128,094		0.0000	1.0000	17.53
44.5	127,657		0.0000	1.0000	17.53
45.5	127,380		0.0000	1.0000	17.53
46.5					17.53

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363.3 COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

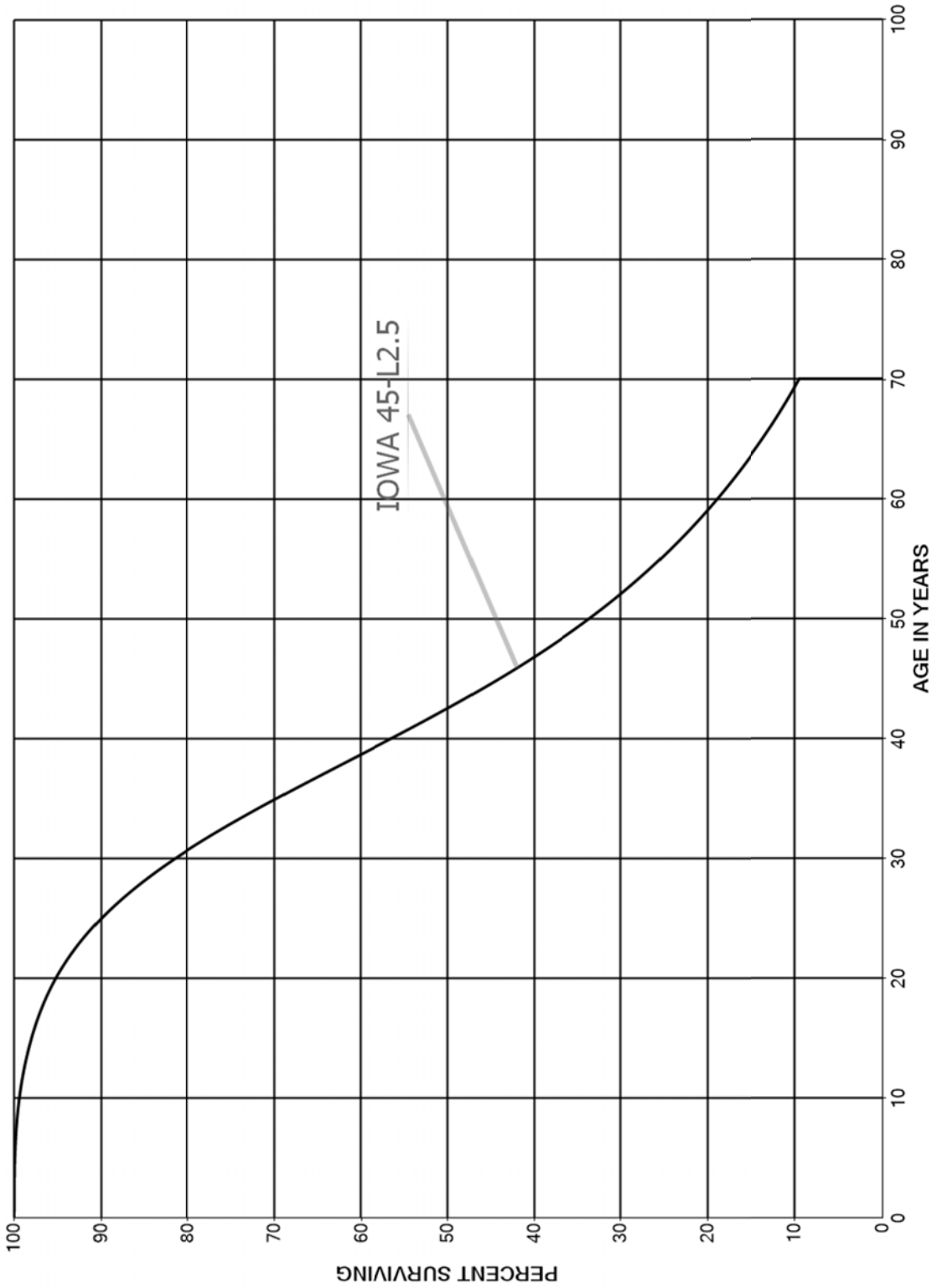
ACCOUNT 363.3 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

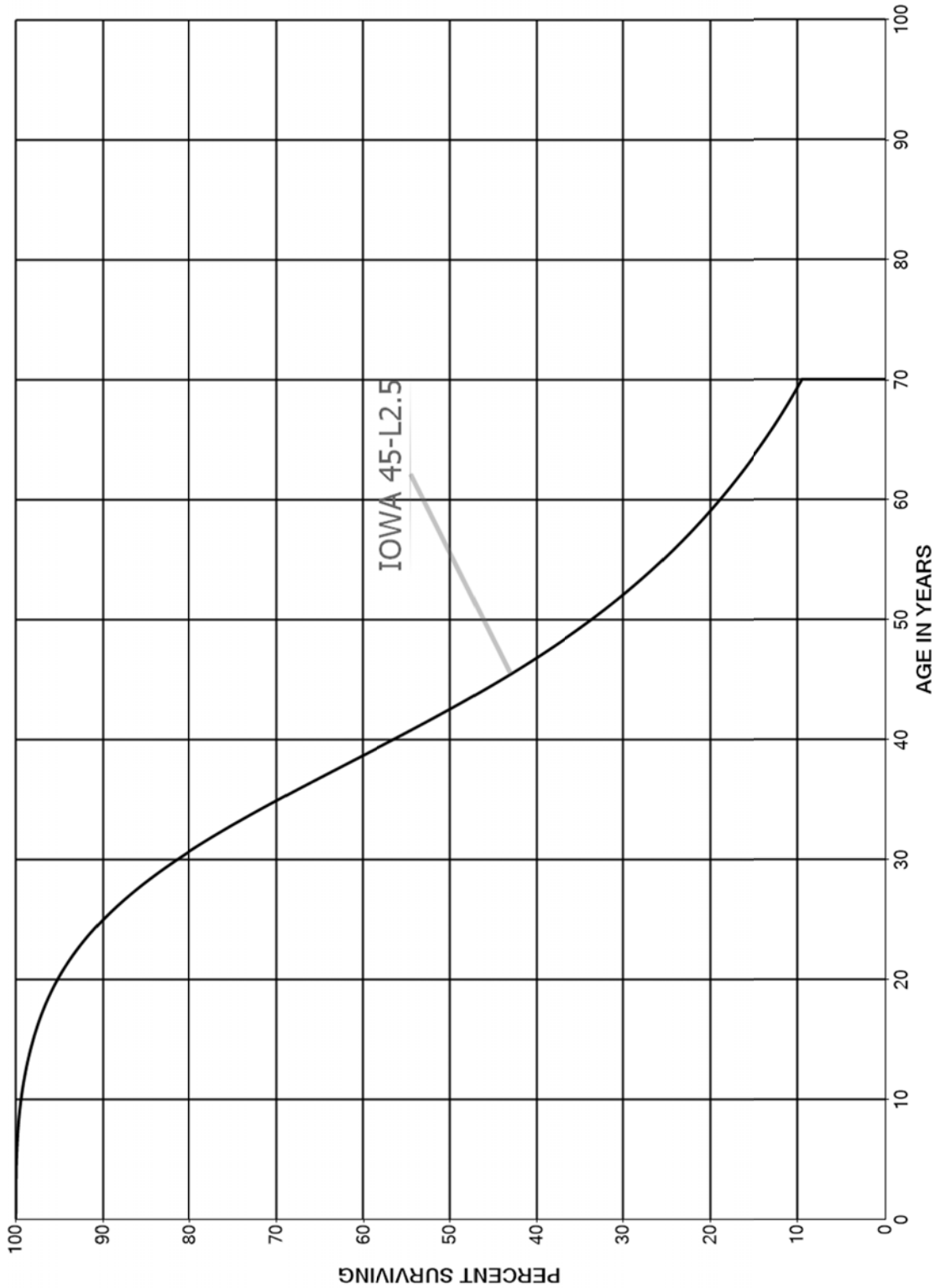
PLACEMENT BAND 1972-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,316,148		0.0000	1.0000	100.00
0.5	4,474,888		0.0000	1.0000	100.00
1.5	3,979,145	93	0.0000	1.0000	100.00
2.5	2,410,296	98	0.0000	1.0000	100.00
3.5	2,410,198	4,705	0.0020	0.9980	99.99
4.5	2,405,494	1,196	0.0005	0.9995	99.80
5.5	2,404,298	7,007	0.0029	0.9971	99.75
6.5	2,357,174	3,238	0.0014	0.9986	99.46
7.5	2,133,140	632	0.0003	0.9997	99.32
8.5	2,036,436		0.0000	1.0000	99.29
9.5	2,036,436	149,913	0.0736	0.9264	99.29
10.5	1,886,523	41,076	0.0218	0.9782	91.98
11.5	1,845,447	2,091	0.0011	0.9989	89.98
12.5	1,783,277	111	0.0001	0.9999	89.88
13.5	1,783,166	22,073	0.0124	0.9876	89.87
14.5	1,761,093	198,995	0.1130	0.8870	88.76
15.5	1,562,098	21,962	0.0141	0.9859	78.73
16.5	339,214		0.0000	1.0000	77.62
17.5	225,305	120	0.0005	0.9995	77.62
18.5	225,185	22,930	0.1018	0.8982	77.58
19.5	201,815		0.0000	1.0000	69.68
20.5	132,455	10,296	0.0777	0.9223	69.68
21.5	122,160		0.0000	1.0000	64.27
22.5	122,160	5,472	0.0448	0.9552	64.27
23.5	116,688		0.0000	1.0000	61.39
24.5	116,688		0.0000	1.0000	61.39
25.5	116,688		0.0000	1.0000	61.39
26.5	116,688		0.0000	1.0000	61.39
27.5	116,688		0.0000	1.0000	61.39
28.5	116,688	45,738	0.3920	0.6080	61.39
29.5	70,950	70,950	1.0000		37.33
30.5					

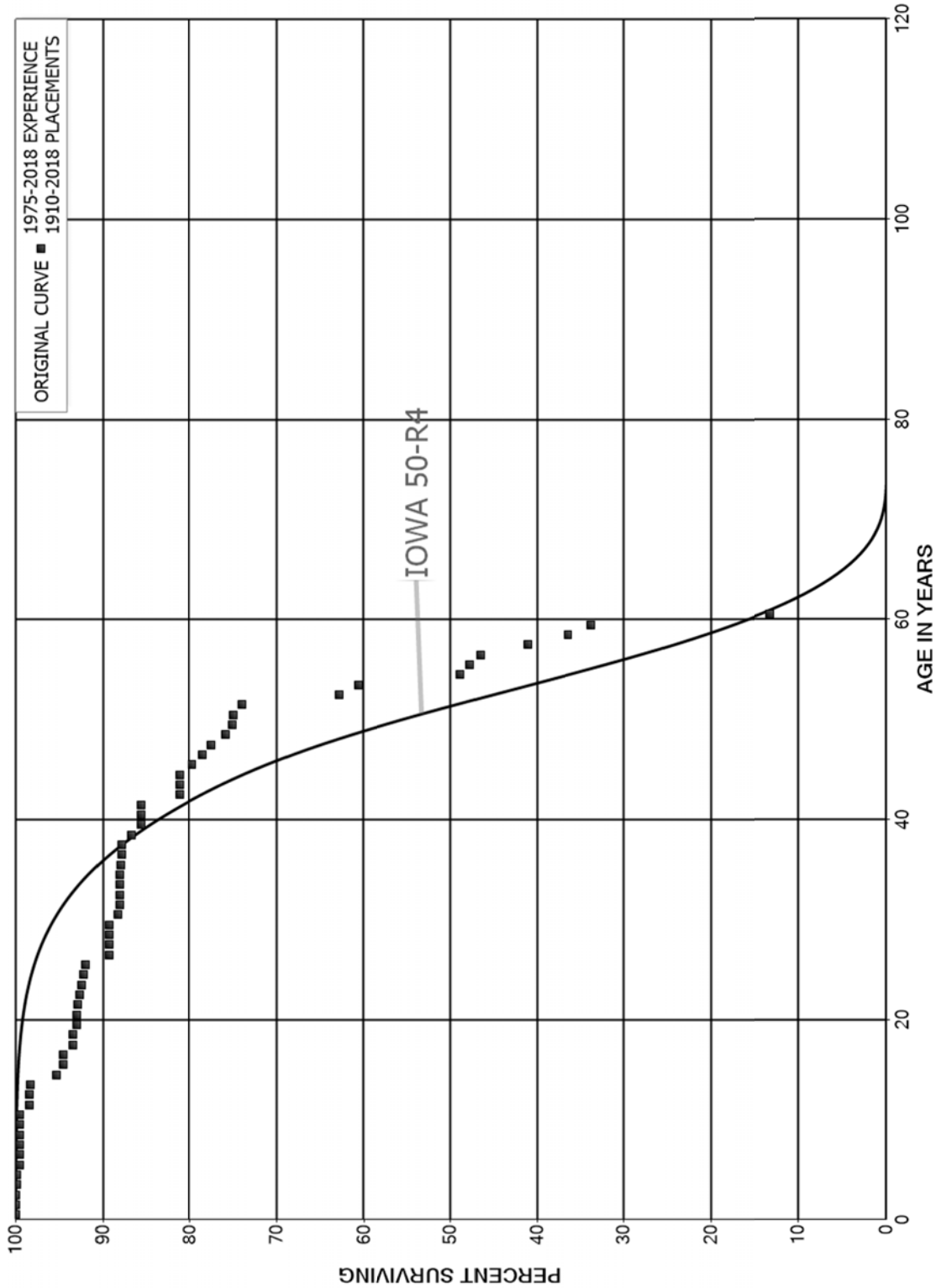
PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363.4 MEASURING AND REGULATING EQUIPMENT
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 363.5 OTHER EQUIPMENT
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,215,828		0.0000	1.0000	100.00
0.5	15,458,681		0.0000	1.0000	100.00
1.5	15,426,899		0.0000	1.0000	100.00
2.5	15,261,019	23,282	0.0015	0.9985	100.00
3.5	15,184,652	1,616	0.0001	0.9999	99.85
4.5	15,097,269	49,887	0.0033	0.9967	99.84
5.5	13,649,225	2,263	0.0002	0.9998	99.51
6.5	13,282,413		0.0000	1.0000	99.49
7.5	13,282,413		0.0000	1.0000	99.49
8.5	13,384,914		0.0000	1.0000	99.49
9.5	13,604,803		0.0000	1.0000	99.49
10.5	13,649,979	156,513	0.0115	0.9885	99.49
11.5	13,472,256		0.0000	1.0000	98.35
12.5	13,340,852	11,428	0.0009	0.9991	98.35
13.5	12,520,494	377,161	0.0301	0.9699	98.27
14.5	11,968,658	102,884	0.0086	0.9914	95.31
15.5	10,949,283	377	0.0000	1.0000	94.49
16.5	10,898,756	130,830	0.0120	0.9880	94.48
17.5	10,577,394		0.0000	1.0000	93.35
18.5	10,723,859	49,563	0.0046	0.9954	93.35
19.5	10,693,753		0.0000	1.0000	92.92
20.5	9,235,454	5,228	0.0006	0.9994	92.92
21.5	7,851,977	18,253	0.0023	0.9977	92.86
22.5	7,263,918	24,028	0.0033	0.9967	92.65
23.5	6,857,525	16,212	0.0024	0.9976	92.34
24.5	3,564,393	4,612	0.0013	0.9987	92.12
25.5	3,573,862	104,471	0.0292	0.9708	92.00
26.5	3,556,072		0.0000	1.0000	89.32
27.5	3,540,333	524	0.0001	0.9999	89.32
28.5	3,513,585	1,775	0.0005	0.9995	89.30
29.5	2,888,120	32,834	0.0114	0.9886	89.26
30.5	2,541,768	3,605	0.0014	0.9986	88.24
31.5	2,537,963		0.0000	1.0000	88.12
32.5	2,530,696		0.0000	1.0000	88.12
33.5	2,269,785		0.0000	1.0000	88.12
34.5	2,036,725	3,665	0.0018	0.9982	88.12
35.5	1,976,348	2,517	0.0013	0.9987	87.96
36.5	1,763,159	543	0.0003	0.9997	87.85
37.5	1,756,519	22,154	0.0126	0.9874	87.82
38.5	1,356,537	17,309	0.0128	0.9872	86.71

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,326,133		0.0000	1.0000	85.61
40.5	1,325,400		0.0000	1.0000	85.61
41.5	1,325,624	67,994	0.0513	0.9487	85.61
42.5	1,269,032	1,145	0.0009	0.9991	81.21
43.5	1,266,714		0.0000	1.0000	81.14
44.5	1,269,406	21,670	0.0171	0.9829	81.14
45.5	1,244,771	19,264	0.0155	0.9845	79.76
46.5	1,223,936	15,538	0.0127	0.9873	78.52
47.5	987,065	21,383	0.0217	0.9783	77.52
48.5	966,586	10,487	0.0108	0.9892	75.85
49.5	956,099	676	0.0007	0.9993	75.02
50.5	960,395	13,122	0.0137	0.9863	74.97
51.5	947,346	142,123	0.1500	0.8500	73.95
52.5	796,325	28,057	0.0352	0.9648	62.85
53.5	575,715	111,702	0.1940	0.8060	60.64
54.5	423,232	10,186	0.0241	0.9759	48.87
55.5	404,376	10,382	0.0257	0.9743	47.70
56.5	251,436	29,240	0.1163	0.8837	46.47
57.5	223,124	25,661	0.1150	0.8850	41.07
58.5	197,464	14,081	0.0713	0.9287	36.34
59.5	184,526	112,214	0.6081	0.3919	33.75
60.5	94,082	7,582	0.0806	0.9194	13.23
61.5	122,210	1,724	0.0141	0.9859	12.16
62.5	120,486	3,753	0.0312	0.9688	11.99
63.5	116,390	263	0.0023	0.9977	11.62
64.5	112,572	483	0.0043	0.9957	11.59
65.5	112,090	742	0.0066	0.9934	11.54
66.5	111,348	551	0.0050	0.9950	11.46
67.5	110,797	146	0.0013	0.9987	11.41
68.5	110,651	679	0.0061	0.9939	11.39
69.5	109,972		0.0000	1.0000	11.32
70.5	109,972	234	0.0021	0.9979	11.32
71.5	109,738		0.0000	1.0000	11.30
72.5	109,738		0.0000	1.0000	11.30
73.5	109,738	3,220	0.0293	0.9707	11.30
74.5	106,518	225	0.0021	0.9979	10.97
75.5	105,846	8,144	0.0769	0.9231	10.94
76.5	97,702		0.0000	1.0000	10.10
77.5	97,702	2,692	0.0276	0.9724	10.10
78.5	95,010	1,280	0.0135	0.9865	9.82

PECO ENERGY COMPANY
GAS PLANT

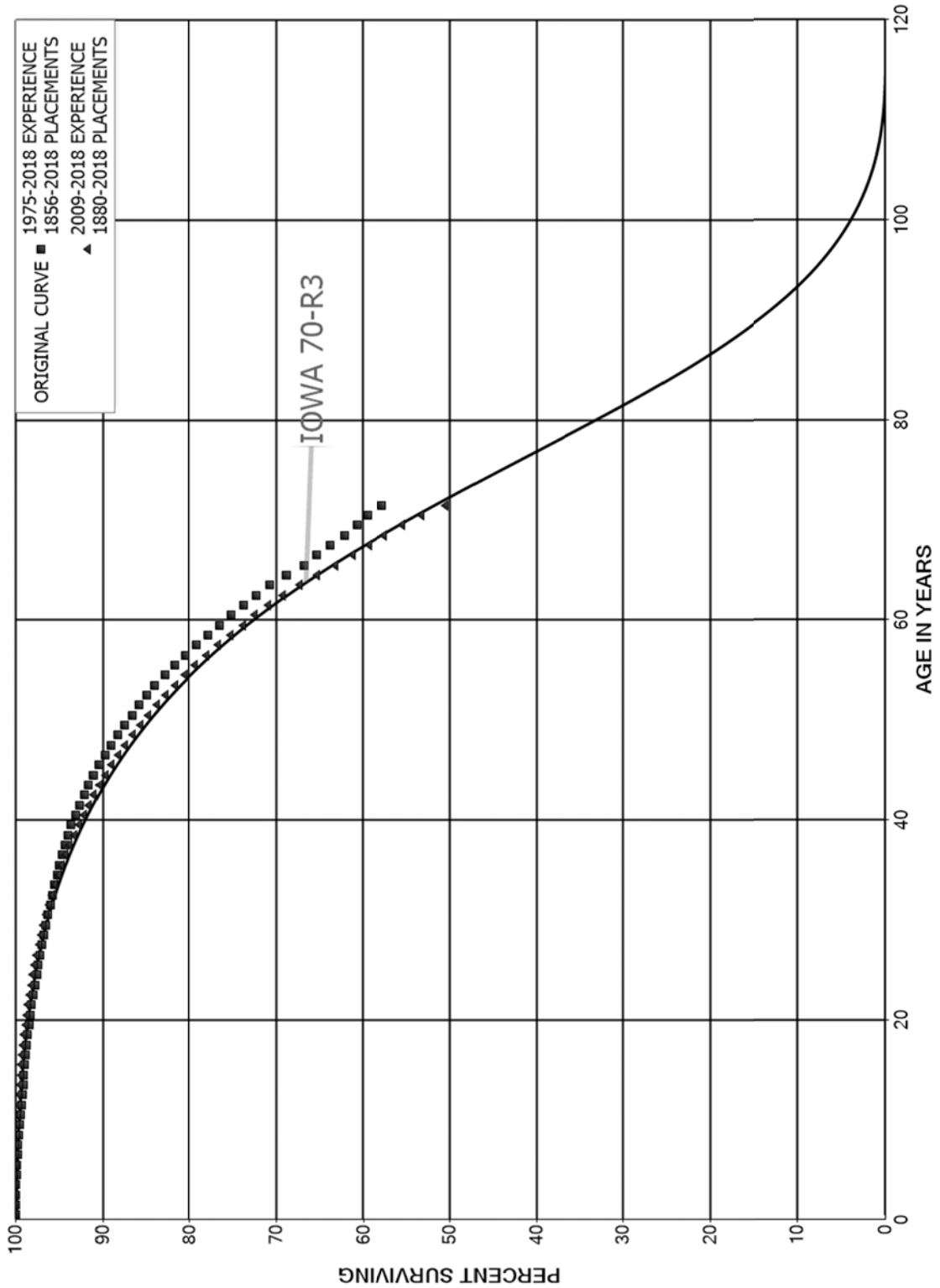
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	93,731		0.0000	1.0000	9.69
80.5	93,731	1,701	0.0181	0.9819	9.69
81.5	92,030	904	0.0098	0.9902	9.51
82.5	91,126		0.0000	1.0000	9.42
83.5	91,126	4,972	0.0546	0.9454	9.42
84.5	86,154	73	0.0008	0.9992	8.91
85.5	86,080	24,624	0.2861	0.7139	8.90
86.5	61,419		0.0000	1.0000	6.35
87.5	60,598		0.0000	1.0000	6.35
88.5	60,598		0.0000	1.0000	6.35
89.5	60,598		0.0000	1.0000	6.35
90.5	60,598	928	0.0153	0.9847	6.35
91.5	59,670		0.0000	1.0000	6.26
92.5	59,670		0.0000	1.0000	6.26
93.5	59,670	21,770	0.3648	0.6352	6.26
94.5	37,899	35,710	0.9422	0.0578	3.97
95.5	2,190		0.0000	1.0000	0.23
96.5	2,190		0.0000	1.0000	0.23
97.5	2,190		0.0000	1.0000	0.23
98.5	2,190		0.0000	1.0000	0.23
99.5	2,190		0.0000	1.0000	0.23
100.5	2,190		0.0000	1.0000	0.23
101.5	2,190		0.0000	1.0000	0.23
102.5	2,190		0.0000	1.0000	0.23
103.5	1,047		0.0000	1.0000	0.23
104.5	1,047		0.0000	1.0000	0.23
105.5	1,047		0.0000	1.0000	0.23
106.5	1,047		0.0000	1.0000	0.23
107.5	1,047		0.0000	1.0000	0.23
108.5					0.23

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 376.1 MAINS - STEEL
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1856-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	452,517,067	33,063	0.0001	0.9999	100.00
0.5	432,851,651	139,008	0.0003	0.9997	99.99
1.5	424,112,179	146,460	0.0003	0.9997	99.96
2.5	416,549,481	136,573	0.0003	0.9997	99.93
3.5	408,044,563	240,998	0.0006	0.9994	99.89
4.5	401,602,115	120,732	0.0003	0.9997	99.83
5.5	404,262,554	204,010	0.0005	0.9995	99.80
6.5	404,735,081	340,117	0.0008	0.9992	99.75
7.5	401,893,071	251,384	0.0006	0.9994	99.67
8.5	400,310,666	280,240	0.0007	0.9993	99.61
9.5	296,288,778	330,152	0.0011	0.9989	99.54
10.5	308,131,070	294,885	0.0010	0.9990	99.43
11.5	334,218,932	431,419	0.0013	0.9987	99.33
12.5	355,555,203	323,651	0.0009	0.9991	99.20
13.5	377,704,178	354,446	0.0009	0.9991	99.11
14.5	373,723,415	404,917	0.0011	0.9989	99.02
15.5	372,396,222	369,045	0.0010	0.9990	98.91
16.5	369,855,879	463,045	0.0013	0.9987	98.82
17.5	364,815,231	426,885	0.0012	0.9988	98.69
18.5	366,800,424	603,457	0.0016	0.9984	98.58
19.5	352,862,707	474,686	0.0013	0.9987	98.41
20.5	334,330,701	514,741	0.0015	0.9985	98.28
21.5	302,405,342	510,878	0.0017	0.9983	98.13
22.5	275,846,126	548,441	0.0020	0.9980	97.96
23.5	248,841,790	544,835	0.0022	0.9978	97.77
24.5	241,031,190	463,543	0.0019	0.9981	97.56
25.5	229,623,050	443,587	0.0019	0.9981	97.37
26.5	214,101,629	465,952	0.0022	0.9978	97.18
27.5	201,727,138	448,482	0.0022	0.9978	96.97
28.5	189,141,401	491,582	0.0026	0.9974	96.75
29.5	175,593,707	395,995	0.0023	0.9977	96.50
30.5	164,673,582	517,971	0.0031	0.9969	96.28
31.5	156,040,861	428,977	0.0027	0.9973	95.98
32.5	149,087,996	401,784	0.0027	0.9973	95.72
33.5	141,920,618	382,762	0.0027	0.9973	95.46
34.5	137,620,606	400,035	0.0029	0.9971	95.20
35.5	132,958,445	389,554	0.0029	0.9971	94.92
36.5	128,358,555	535,129	0.0042	0.9958	94.65
37.5	117,047,613	436,265	0.0037	0.9963	94.25
38.5	107,183,870	351,071	0.0033	0.9967	93.90

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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	103,865,239	552,591	0.0053	0.9947	93.59
40.5	101,979,874	581,558	0.0057	0.9943	93.10
41.5	100,394,015	501,999	0.0050	0.9950	92.56
42.5	98,492,753	530,906	0.0054	0.9946	92.10
43.5	96,202,698	517,552	0.0054	0.9946	91.60
44.5	93,970,817	733,694	0.0078	0.9922	91.11
45.5	89,405,500	683,619	0.0076	0.9924	90.40
46.5	84,662,036	606,439	0.0072	0.9928	89.71
47.5	79,581,930	699,200	0.0088	0.9912	89.07
48.5	74,101,284	678,091	0.0092	0.9908	88.28
49.5	67,360,475	689,885	0.0102	0.9898	87.48
50.5	61,968,805	542,436	0.0088	0.9912	86.58
51.5	56,760,241	565,335	0.0100	0.9900	85.82
52.5	51,227,763	560,447	0.0109	0.9891	84.97
53.5	47,080,295	695,365	0.0148	0.9852	84.04
54.5	41,866,209	548,153	0.0131	0.9869	82.80
55.5	38,020,244	580,152	0.0153	0.9847	81.71
56.5	33,044,248	527,438	0.0160	0.9840	80.47
57.5	30,466,124	505,512	0.0166	0.9834	79.18
58.5	27,343,640	464,433	0.0170	0.9830	77.87
59.5	24,766,651	452,304	0.0183	0.9817	76.55
60.5	22,293,945	413,818	0.0186	0.9814	75.15
61.5	17,421,412	349,625	0.0201	0.9799	73.75
62.5	15,407,169	341,386	0.0222	0.9778	72.27
63.5	13,476,993	344,859	0.0256	0.9744	70.67
64.5	11,245,727	335,977	0.0299	0.9701	68.86
65.5	9,457,710	201,772	0.0213	0.9787	66.81
66.5	8,114,622	191,676	0.0236	0.9764	65.38
67.5	6,671,021	174,456	0.0262	0.9738	63.84
68.5	6,061,518	143,473	0.0237	0.9763	62.17
69.5	5,509,354	107,188	0.0195	0.9805	60.70
70.5	5,181,803	147,696	0.0285	0.9715	59.51
71.5	4,505,956	78,416	0.0174	0.9826	57.82
72.5	3,954,137	65,618	0.0166	0.9834	56.81
73.5	3,786,199	180,284	0.0476	0.9524	55.87
74.5	3,544,525	63,469	0.0179	0.9821	53.21
75.5	3,504,561	72,432	0.0207	0.9793	52.26
76.5	3,396,898	78,422	0.0231	0.9769	51.18
77.5	3,300,028	89,355	0.0271	0.9729	49.99
78.5	3,195,665	109,998	0.0344	0.9656	48.64

PECO ENERGY COMPANY
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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	3,064,667	136,155	0.0444	0.9556	46.97
80.5	2,897,865	139,635	0.0482	0.9518	44.88
81.5	2,746,778	158,231	0.0576	0.9424	42.72
82.5	2,586,493	146,621	0.0567	0.9433	40.26
83.5	2,447,778	146,889	0.0600	0.9400	37.97
84.5	2,296,716	162,090	0.0706	0.9294	35.70
85.5	2,122,351	171,216	0.0807	0.9193	33.18
86.5	1,938,655	172,038	0.0887	0.9113	30.50
87.5	1,665,260	155,896	0.0936	0.9064	27.79
88.5	1,146,233	106,881	0.0932	0.9068	25.19
89.5	931,670	93,018	0.0998	0.9002	22.84
90.5	729,650	68,319	0.0936	0.9064	20.56
91.5	574,706	50,078	0.0871	0.9129	18.64
92.5	438,438	36,484	0.0832	0.9168	17.01
93.5	372,981	28,765	0.0771	0.9229	15.60
94.5	335,343	29,815	0.0889	0.9111	14.39
95.5	278,210	27,902	0.1003	0.8997	13.11
96.5	245,549	19,482	0.0793	0.9207	11.80
97.5	213,151	18,220	0.0855	0.9145	10.86
98.5	181,895	13,190	0.0725	0.9275	9.93
99.5	168,431	17,553	0.1042	0.8958	9.21
100.5	150,354	11,376	0.0757	0.9243	8.25
101.5	135,834	10,277	0.0757	0.9243	7.63
102.5	119,482	8,728	0.0731	0.9269	7.05
103.5	108,686	13,807	0.1270	0.8730	6.54
104.5	106,051	16,181	0.1526	0.8474	5.71
105.5	89,466	16,123	0.1802	0.8198	4.84
106.5	72,753	17,438	0.2397	0.7603	3.96
107.5	53,321	7,493	0.1405	0.8595	3.01
108.5	45,708	7,004	0.1532	0.8468	2.59
109.5	38,609	5,232	0.1355	0.8645	2.19
110.5	33,318	2,813	0.0844	0.9156	1.90
111.5	30,487	1,870	0.0613	0.9387	1.74
112.5	28,575	1,553	0.0543	0.9457	1.63
113.5	27,020	1,592	0.0589	0.9411	1.54
114.5	25,426	3,151	0.1239	0.8761	1.45
115.5	22,273	3,148	0.1413	0.8587	1.27
116.5	19,120	2,291	0.1198	0.8802	1.09
117.5	16,828	1,365	0.0811	0.9189	0.96
118.5	29,423	2,060	0.0700	0.9300	0.88

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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	27,362	5,912	0.2161	0.7839	0.82
120.5	21,450	2,152	0.1003	0.8997	0.64
121.5	19,298	101	0.0053	0.9947	0.58
122.5	19,197	40	0.0021	0.9979	0.58
123.5	19,156	848	0.0443	0.9557	0.57
124.5	18,308	315	0.0172	0.9828	0.55
125.5	17,993	1,392	0.0774	0.9226	0.54
126.5	16,601	768	0.0463	0.9537	0.50
127.5	15,832	547	0.0346	0.9654	0.47
128.5	15,284	1,805	0.1181	0.8819	0.46
129.5	13,479	2,800	0.2077	0.7923	0.40
130.5	10,679	160	0.0150	0.9850	0.32
131.5	10,519	109	0.0104	0.9896	0.32
132.5	10,410	20	0.0019	0.9981	0.31
133.5	10,390	4	0.0004	0.9996	0.31
134.5	10,385	1	0.0001	0.9999	0.31
135.5	10,384		0.0000	1.0000	0.31
136.5	10,384		0.0000	1.0000	0.31
137.5	10,384		0.0000	1.0000	0.31
138.5	10,383		0.0000	1.0000	0.31
139.5	10,383		0.0000	1.0000	0.31
140.5	10,383		0.0000	1.0000	0.31
141.5	10,383		0.0000	1.0000	0.31
142.5	10,383		0.0000	1.0000	0.31
143.5	10,383	9,723	0.9364	0.0636	0.31
144.5	660		0.0000	1.0000	0.02
145.5	660	1	0.0009	0.9991	0.02
146.5	659	57	0.0870	0.9130	0.02
147.5	602	602	1.0000		0.02
148.5					

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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1880-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	109,361,484	2,992	0.0000	1.0000	100.00
0.5	95,740,366	11,816	0.0001	0.9999	100.00
1.5	88,991,479	20,516	0.0002	0.9998	99.98
2.5	86,413,714	23,785	0.0003	0.9997	99.96
3.5	80,385,365	25,967	0.0003	0.9997	99.93
4.5	74,951,724	26,913	0.0004	0.9996	99.90
5.5	74,277,701	30,216	0.0004	0.9996	99.87
6.5	74,235,751	33,094	0.0004	0.9996	99.83
7.5	76,207,478	35,396	0.0005	0.9995	99.78
8.5	68,992,506	37,105	0.0005	0.9995	99.73
9.5	77,606,445	44,950	0.0006	0.9994	99.68
10.5	88,383,495	57,254	0.0006	0.9994	99.62
11.5	115,823,567	76,596	0.0007	0.9993	99.56
12.5	133,880,232	101,029	0.0008	0.9992	99.49
13.5	154,299,927	131,760	0.0009	0.9991	99.42
14.5	155,318,227	150,086	0.0010	0.9990	99.33
15.5	163,311,618	172,991	0.0011	0.9989	99.24
16.5	173,938,543	198,293	0.0011	0.9989	99.13
17.5	176,608,388	215,757	0.0012	0.9988	99.02
18.5	189,303,357	254,108	0.0013	0.9987	98.90
19.5	186,672,641	279,916	0.0015	0.9985	98.77
20.5	176,598,476	292,411	0.0017	0.9983	98.62
21.5	151,127,965	265,505	0.0018	0.9982	98.45
22.5	129,745,415	243,007	0.0019	0.9981	98.28
23.5	108,178,068	211,172	0.0020	0.9980	98.10
24.5	104,041,037	223,378	0.0021	0.9979	97.91
25.5	96,636,161	223,159	0.0023	0.9977	97.70
26.5	85,363,328	212,530	0.0025	0.9975	97.47
27.5	83,365,164	221,449	0.0027	0.9973	97.23
28.5	80,008,523	227,199	0.0028	0.9972	96.97
29.5	69,703,533	213,714	0.0031	0.9969	96.69
30.5	60,172,280	201,782	0.0034	0.9966	96.40
31.5	52,905,956	192,235	0.0036	0.9964	96.07
32.5	47,632,770	174,315	0.0037	0.9963	95.72
33.5	42,867,930	166,595	0.0039	0.9961	95.37
34.5	42,069,316	178,090	0.0042	0.9958	95.00
35.5	42,133,006	198,498	0.0047	0.9953	94.60
36.5	42,509,034	218,727	0.0051	0.9949	94.16
37.5	36,767,759	196,817	0.0054	0.9946	93.67
38.5	32,894,349	184,210	0.0056	0.9944	93.17

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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1880-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	36,536,485	216,325	0.0059	0.9941	92.65
40.5	40,226,773	251,260	0.0062	0.9938	92.10
41.5	44,256,963	292,446	0.0066	0.9934	91.52
42.5	48,094,924	340,318	0.0071	0.9929	90.92
43.5	49,678,041	364,103	0.0073	0.9927	90.28
44.5	51,269,991	404,200	0.0079	0.9921	89.61
45.5	50,298,704	429,247	0.0085	0.9915	88.91
46.5	50,272,257	448,371	0.0089	0.9911	88.15
47.5	47,264,578	464,662	0.0098	0.9902	87.36
48.5	44,556,660	456,077	0.0102	0.9898	86.50
49.5	40,267,843	444,533	0.0110	0.9890	85.62
50.5	37,330,133	416,536	0.0112	0.9888	84.67
51.5	37,364,007	452,080	0.0121	0.9879	83.73
52.5	33,867,562	434,872	0.0128	0.9872	82.72
53.5	31,782,451	438,665	0.0138	0.9862	81.65
54.5	29,081,906	447,756	0.0154	0.9846	80.53
55.5	27,118,550	450,609	0.0166	0.9834	79.29
56.5	23,725,428	414,083	0.0175	0.9825	77.97
57.5	22,865,519	414,300	0.0181	0.9819	76.61
58.5	20,337,804	392,557	0.0193	0.9807	75.22
59.5	18,378,529	353,572	0.0192	0.9808	73.77
60.5	16,310,159	347,361	0.0213	0.9787	72.35
61.5	12,224,398	281,810	0.0231	0.9769	70.81
62.5	10,977,084	292,500	0.0266	0.9734	69.18
63.5	9,178,960	285,639	0.0311	0.9689	67.33
64.5	7,150,449	228,522	0.0320	0.9680	65.24
65.5	5,491,887	168,458	0.0307	0.9693	63.15
66.5	4,230,494	134,520	0.0318	0.9682	61.22
67.5	2,865,289	87,051	0.0304	0.9696	59.27
68.5	2,351,409	83,514	0.0355	0.9645	57.47
69.5	1,881,009	77,981	0.0415	0.9585	55.43
70.5	1,629,452	82,315	0.0505	0.9495	53.13
71.5	1,035,118	59,060	0.0571	0.9429	50.45
72.5	466,462	22,648	0.0486	0.9514	47.57
73.5	353,240	18,192	0.0515	0.9485	45.26
74.5	244,841	12,855	0.0525	0.9475	42.93
75.5	241,811	13,375	0.0553	0.9447	40.67
76.5	221,915	12,473	0.0562	0.9438	38.42
77.5	432,800	25,576	0.0591	0.9409	36.26
78.5	1,255,816	66,849	0.0532	0.9468	34.12

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ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1880-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,436,461	94,027	0.0655	0.9345	32.30
80.5	1,594,548	101,661	0.0638	0.9362	30.19
81.5	1,723,330	124,292	0.0721	0.9279	28.27
82.5	1,836,485	122,118	0.0665	0.9335	26.23
83.5	1,788,797	127,441	0.0712	0.9288	24.48
84.5	1,720,983	141,775	0.0824	0.9176	22.74
85.5	1,657,030	152,099	0.0918	0.9082	20.87
86.5	1,508,210	154,472	0.1024	0.8976	18.95
87.5	1,296,472	146,732	0.1132	0.8868	17.01
88.5	831,618	94,542	0.1137	0.8863	15.08
89.5	635,427	73,229	0.1152	0.8848	13.37
90.5	455,523	54,624	0.1199	0.8801	11.83
91.5	329,167	42,692	0.1297	0.8703	10.41
92.5	239,228	30,129	0.1259	0.8741	9.06
93.5	195,832	21,904	0.1119	0.8881	7.92
94.5	152,243	20,038	0.1316	0.8684	7.03
95.5	108,897	15,306	0.1406	0.8594	6.11
96.5	96,773	14,971	0.1547	0.8453	5.25
97.5	99,173	14,463	0.1458	0.8542	4.44
98.5	73,923	11,209	0.1516	0.8484	3.79
99.5	63,269	11,702	0.1850	0.8150	3.22
100.5	52,904	9,840	0.1860	0.8140	2.62
101.5	40,686	8,749	0.2150	0.7850	2.13
102.5	28,745	6,343	0.2207	0.7793	1.67
103.5	20,507	5,542	0.2702	0.7298	1.30
104.5	14,738	4,966	0.3369	0.6631	0.95
105.5	9,852	2,851	0.2894	0.7106	0.63
106.5	11,254	3,649	0.3243	0.6757	0.45
107.5	6,011	1,608	0.2675	0.7325	0.30
108.5	10,415	3,757	0.3607	0.6393	0.22
109.5	11,868	4,567	0.3848	0.6152	0.14
110.5	7,242	2,813	0.3883	0.6117	0.09
111.5	4,412	1,849	0.4191	0.5809	0.05
112.5	2,520	1,226	0.4863	0.5137	0.03
113.5	1,292	714	0.5522	0.4478	0.02
114.5	578	357	0.6182	0.3818	0.01
115.5	219	173	0.7893	0.2107	0.00
116.5	40	34	0.8508	0.1492	0.00
117.5	1,673	927	0.5539	0.4461	0.00
118.5	1,634	794	0.4856	0.5144	0.00

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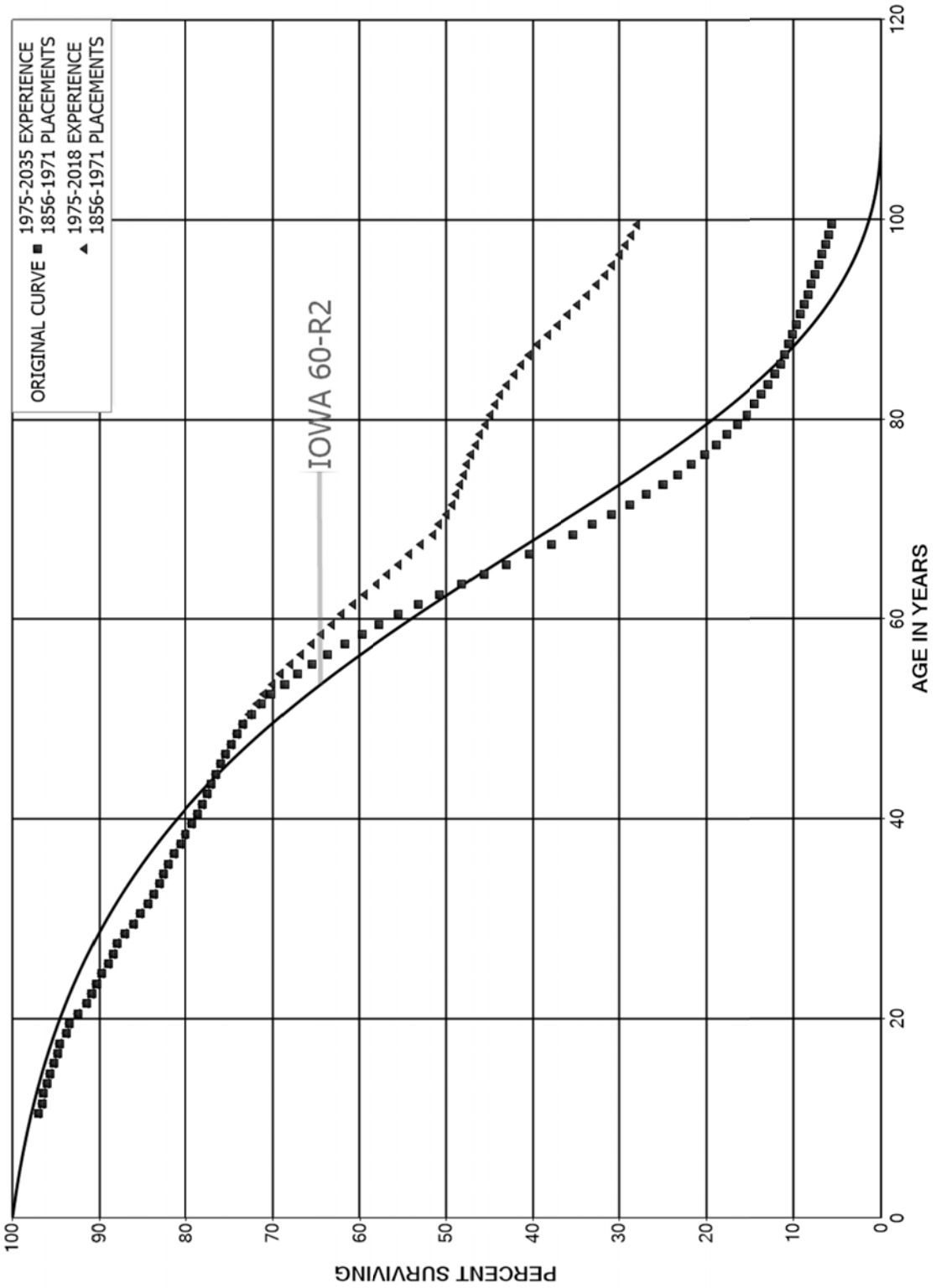
ACCOUNT 376.1 MAINS - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1880-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	840	433	0.5152	0.4848	0.00
120.5	407	271	0.6664	0.3336	0.00
121.5	136	101	0.7468	0.2532	0.00
122.5	34	26	0.7456	0.2544	0.00
123.5	9	6	0.6914	0.3086	0.00
124.5	3	1	0.3963	0.6037	0.00
125.5	2		0.0000	1.0000	0.00
126.5	2		0.0000	1.0000	0.00
127.5	1		0.0000	1.0000	0.00
128.5	985	545	0.5536	0.4464	0.00
129.5	440	178	0.4049	0.5951	0.00
130.5	262	160	0.6134	0.3866	0.00
131.5	101	75	0.7388	0.2612	0.00
132.5	26	20	0.7612	0.2388	0.00
133.5	6	4	0.6894	0.3106	0.00
134.5	2	1	0.4949	0.5051	0.00
135.5	1		0.0000	1.0000	0.00
136.5	1		0.0000	1.0000	0.00
137.5	1		0.0000	1.0000	0.00
138.5					0.00

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ORIGINAL LIFE TABLE

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2035

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0					
0.5					
1.5					
2.5					
3.5	87,209		0.0000		
4.5	367,620	1,012	0.0028		
5.5	1,025,668		0.0000		
6.5	2,146,570	7,675	0.0036		
7.5	2,973,369	4,745	0.0016		
8.5	4,026,414	26,337	0.0065		
9.5	4,562,420	7,286	0.0016		
10.5	5,230,234	23,822	0.0046	0.9954	97.00
11.5	5,826,518	8,587	0.0015	0.9985	96.56
12.5	7,040,525	30,531	0.0043	0.9957	96.42
13.5	8,202,748	37,376	0.0046	0.9954	96.00
14.5	9,059,036	38,622	0.0043	0.9957	95.56
15.5	10,014,186	40,806	0.0041	0.9959	95.15
16.5	10,792,340	26,153	0.0024	0.9976	94.77
17.5	11,857,146	95,436	0.0080	0.9920	94.54
18.5	12,742,595	53,887	0.0042	0.9958	93.77
19.5	13,946,073	150,287	0.0108	0.9892	93.38
20.5	14,653,082	161,456	0.0110	0.9890	92.37
21.5	15,506,016	82,810	0.0053	0.9947	91.35
22.5	16,041,542	109,430	0.0068	0.9932	90.87
23.5	16,901,255	97,495	0.0058	0.9942	90.25
24.5	17,921,227	161,481	0.0090	0.9910	89.73
25.5	18,426,409	106,756	0.0058	0.9942	88.92
26.5	18,528,685	107,130	0.0058	0.9942	88.40
27.5	18,745,798	174,680	0.0093	0.9907	87.89
28.5	18,669,240	206,238	0.0110	0.9890	87.07
29.5	18,584,500	176,612	0.0095	0.9905	86.11
30.5	18,472,292	200,506	0.0109	0.9891	85.29
31.5	18,421,030	135,097	0.0073	0.9927	84.37
32.5	18,366,312	154,407	0.0084	0.9916	83.75
33.5	18,334,963	92,681	0.0051	0.9949	83.04
34.5	18,366,093	129,827	0.0071	0.9929	82.62
35.5	18,358,425	131,950	0.0072	0.9928	82.04
36.5	18,354,264	188,862	0.0103	0.9897	81.45
37.5	18,214,904	116,001	0.0064	0.9936	80.61
38.5	18,158,092	179,560	0.0099	0.9901	80.10

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ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2035

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,024,910	152,462	0.0085	0.9915	79.31
40.5	17,916,021	139,751	0.0078	0.9922	78.64
41.5	17,800,951	108,071	0.0061	0.9939	78.02
42.5	17,771,489	121,564	0.0068	0.9932	77.55
43.5	17,781,168	113,638	0.0064	0.9936	77.02
44.5	17,851,479	137,521	0.0077	0.9923	76.53
45.5	18,060,859	134,417	0.0074	0.9926	75.94
46.5	18,344,658	158,256	0.0086	0.9914	75.37
47.5	18,464,961	156,097	0.0085	0.9915	74.72
48.5	18,700,146	185,453	0.0099	0.9901	74.09
49.5	18,914,568	245,555	0.0130	0.9870	73.35
50.5	18,968,660	286,665	0.0151	0.9849	72.40
51.5	18,849,611	307,315	0.0163	0.9837	71.31
52.5	18,717,334	398,805	0.0213	0.9787	70.15
53.5	18,361,159	383,415	0.0209	0.9791	68.65
54.5	18,001,453	459,014	0.0255	0.9745	67.22
55.5	17,563,828	476,640	0.0271	0.9729	65.50
56.5	17,140,507	525,891	0.0307	0.9693	63.73
57.5	16,676,257	547,479	0.0328	0.9672	61.77
58.5	16,191,810	560,683	0.0346	0.9654	59.74
59.5	15,717,336	592,916	0.0377	0.9623	57.67
60.5	15,232,631	638,599	0.0419	0.9581	55.50
61.5	14,647,573	671,522	0.0458	0.9542	53.17
62.5	14,092,200	703,834	0.0499	0.9501	50.73
63.5	13,504,600	711,487	0.0527	0.9473	48.20
64.5	12,868,577	743,858	0.0578	0.9422	45.66
65.5	12,144,875	726,806	0.0598	0.9402	43.02
66.5	11,425,731	739,057	0.0647	0.9353	40.45
67.5	10,701,228	715,688	0.0669	0.9331	37.83
68.5	10,046,207	635,510	0.0633	0.9367	35.30
69.5	9,458,789	634,545	0.0671	0.9329	33.07
70.5	8,834,132	593,097	0.0671	0.9329	30.85
71.5	8,292,490	565,881	0.0682	0.9318	28.78
72.5	7,793,510	541,402	0.0695	0.9305	26.81
73.5	7,332,138	503,002	0.0686	0.9314	24.95
74.5	6,870,557	457,261	0.0666	0.9334	23.24
75.5	6,463,304	436,136	0.0675	0.9325	21.69
76.5	6,075,248	407,429	0.0671	0.9329	20.23
77.5	5,685,028	383,686	0.0675	0.9325	18.87
78.5	5,320,662	361,293	0.0679	0.9321	17.60

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ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2035

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,972,900	323,227	0.0650	0.9350	16.40
80.5	4,649,673	283,874	0.0611	0.9389	15.34
81.5	4,368,356	254,758	0.0583	0.9417	14.40
82.5	4,124,608	232,856	0.0565	0.9435	13.56
83.5	3,901,283	232,065	0.0595	0.9405	12.80
84.5	3,687,496	179,508	0.0487	0.9513	12.03
85.5	3,507,989	149,770	0.0427	0.9573	11.45
86.5	3,361,318	139,726	0.0416	0.9584	10.96
87.5	3,221,592	139,523	0.0433	0.9567	10.50
88.5	3,082,069	130,265	0.0423	0.9577	10.05
89.5	2,955,995	135,334	0.0458	0.9542	9.62
90.5	2,820,661	130,147	0.0461	0.9539	9.18
91.5	2,690,514	133,754	0.0497	0.9503	8.76
92.5	2,556,760	130,992	0.0512	0.9488	8.32
93.5	2,434,437	129,133	0.0530	0.9470	7.90
94.5	2,311,172	122,068	0.0528	0.9472	7.48
95.5	2,189,104	121,866	0.0557	0.9443	7.08
96.5	2,067,238	116,495	0.0564	0.9436	6.69
97.5	1,950,743	112,780	0.0578	0.9422	6.31
98.5	1,837,963	111,486	0.0607	0.9393	5.95
99.5	1,731,791	113,508	0.0655	0.9345	5.59
100.5	1,618,283	114,848	0.0710	0.9290	5.22
101.5	1,503,435	115,943	0.0771	0.9229	4.85
102.5	1,387,493	115,398	0.0832	0.9168	4.48
103.5	1,275,086	114,056	0.0894	0.9106	4.10
104.5	1,170,169	111,412	0.0952	0.9048	3.74
105.5	1,058,757	107,564	0.1016	0.8984	3.38
106.5	963,719	99,132	0.1029	0.8971	3.04
107.5	864,587	86,263	0.0998	0.9002	2.73
108.5	778,324	79,237	0.1018	0.8982	2.45
109.5	701,762	69,251	0.0987	0.9013	2.20
110.5	632,511	58,046	0.0918	0.9082	1.99
111.5	574,465	49,955	0.0870	0.9130	1.80
112.5	524,511	44,952	0.0857	0.9143	1.65
113.5	479,558	41,695	0.0869	0.9131	1.51
114.5	445,440	40,165	0.0902	0.9098	1.37
115.5	405,276	39,392	0.0972	0.9028	1.25
116.5	365,883	38,419	0.1050	0.8950	1.13
117.5	327,464	35,433	0.1082	0.8918	1.01
118.5	307,266	32,235	0.1049	0.8951	0.90

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ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2035

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	275,030	29,910	0.1088	0.8912	0.81
120.5	245,120	25,125	0.1025	0.8975	0.72
121.5	227,216	26,131	0.1150	0.8850	0.65
122.5	201,086	21,396	0.1064	0.8936	0.57
123.5	177,579	17,582	0.0990	0.9010	0.51
124.5	159,997	15,538	0.0971	0.9029	0.46
125.5	144,459	13,957	0.0966	0.9034	0.42
126.5	128,018	12,996	0.1015	0.8985	0.38
127.5	115,022	13,323	0.1158	0.8842	0.34
128.5	101,699	12,928	0.1271	0.8729	0.30
129.5	88,771	11,748	0.1323	0.8677	0.26
130.5	74,397	8,318	0.1118	0.8882	0.23
131.5	66,574	8,821	0.1325	0.8675	0.20
132.5	57,753	6,570	0.1138	0.8862	0.17
133.5	51,183	5,143	0.1005	0.8995	0.15
134.5	46,039	4,113	0.0893	0.9107	0.14
135.5	41,926	4,136	0.0986	0.9014	0.13
136.5	37,479	2,123	0.0567	0.9433	0.11
137.5	35,356	3,411	0.0965	0.9035	0.11
138.5	31,945	3,187	0.0998	0.9002	0.10
139.5	28,758	4,088	0.1422	0.8578	0.09
140.5	24,486	3,465	0.1415	0.8585	0.07
141.5	21,021	1,719	0.0818	0.9182	0.06
142.5	19,302	1,040	0.0539	0.9461	0.06
143.5	19,000	1,926	0.1014	0.8986	0.06
144.5	17,074	1,296	0.0759	0.9241	0.05
145.5	15,779	681	0.0431	0.9569	0.05
146.5	14,885	196	0.0132	0.9868	0.04
147.5	14,688	1,253	0.0853	0.9147	0.04
148.5	13,435	1,627	0.1211	0.8789	0.04
149.5	11,809	2,512	0.2127	0.7873	0.04
150.5	9,296	594	0.0639	0.9361	0.03
151.5	8,178	2,079	0.2542	0.7458	0.03
152.5	6,099	3,440	0.5640	0.4360	0.02
153.5	2,659	1,333	0.5013	0.4987	0.01
154.5	1,326	375	0.2832	0.7168	0.00
155.5	951	698	0.7348	0.2652	0.00
156.5	252	232	0.9220	0.0780	0.00
157.5	20	19	0.9436	0.0564	0.00
158.5	1	0	0.1171	0.8829	0.00

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2035

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	1	0	0.1327	0.8673	0.00
160.5	1	0	0.1529	0.8471	0.00
161.5	1	0	0.1806	0.8194	0.00
162.5	1	0	0.2203	0.7797	0.00
163.5	0	0	0.2826	0.7174	0.00
164.5	0	0	0.3939	0.6061	0.00
165.5	0	0	0.5000	0.5000	0.00
166.5	0	0	1.0000		0.00
167.5					

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0					
0.5					
1.5					
2.5					
3.5	87,209		0.0000		
4.5	367,620	1,012	0.0028		
5.5	1,025,668		0.0000		
6.5	2,146,570	7,675	0.0036		
7.5	2,973,369	4,745	0.0016		
8.5	4,026,414	26,337	0.0065		
9.5	4,562,420	7,286	0.0016		
10.5	5,230,234	23,822	0.0046	0.9954	97.00
11.5	5,826,518	8,587	0.0015	0.9985	96.56
12.5	7,040,525	30,531	0.0043	0.9957	96.42
13.5	8,202,748	37,376	0.0046	0.9954	96.00
14.5	9,059,036	38,622	0.0043	0.9957	95.56
15.5	10,014,186	40,806	0.0041	0.9959	95.15
16.5	10,792,340	26,153	0.0024	0.9976	94.77
17.5	11,857,146	95,436	0.0080	0.9920	94.54
18.5	12,742,595	53,887	0.0042	0.9958	93.77
19.5	13,946,073	150,287	0.0108	0.9892	93.38
20.5	14,653,082	161,456	0.0110	0.9890	92.37
21.5	15,506,016	82,810	0.0053	0.9947	91.35
22.5	16,041,542	109,430	0.0068	0.9932	90.87
23.5	16,901,255	97,495	0.0058	0.9942	90.25
24.5	17,921,227	161,481	0.0090	0.9910	89.73
25.5	18,426,409	106,756	0.0058	0.9942	88.92
26.5	18,528,685	107,130	0.0058	0.9942	88.40
27.5	18,745,798	174,680	0.0093	0.9907	87.89
28.5	18,669,240	206,238	0.0110	0.9890	87.07
29.5	18,584,500	176,612	0.0095	0.9905	86.11
30.5	18,472,292	200,506	0.0109	0.9891	85.29
31.5	18,421,030	135,097	0.0073	0.9927	84.37
32.5	18,366,312	154,407	0.0084	0.9916	83.75
33.5	18,334,963	92,681	0.0051	0.9949	83.04
34.5	18,366,093	129,827	0.0071	0.9929	82.62
35.5	18,358,425	131,950	0.0072	0.9928	82.04
36.5	18,354,264	188,862	0.0103	0.9897	81.45
37.5	18,214,904	116,001	0.0064	0.9936	80.61
38.5	18,158,092	179,560	0.0099	0.9901	80.10

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,024,910	152,462	0.0085	0.9915	79.31
40.5	17,916,021	139,751	0.0078	0.9922	78.64
41.5	17,800,951	108,071	0.0061	0.9939	78.02
42.5	17,771,489	121,564	0.0068	0.9932	77.55
43.5	17,781,168	113,638	0.0064	0.9936	77.02
44.5	17,851,479	137,521	0.0077	0.9923	76.53
45.5	18,060,859	134,417	0.0074	0.9926	75.94
46.5	18,344,658	158,256	0.0086	0.9914	75.37
47.5	18,434,047	154,279	0.0084	0.9916	74.72
48.5	18,515,147	174,464	0.0094	0.9906	74.10
49.5	18,274,261	207,136	0.0113	0.9887	73.40
50.5	17,556,311	200,573	0.0114	0.9886	72.57
51.5	16,909,290	185,101	0.0109	0.9891	71.74
52.5	16,175,189	234,000	0.0145	0.9855	70.95
53.5	15,624,203	197,457	0.0126	0.9874	69.92
54.5	15,031,974	248,439	0.0165	0.9835	69.04
55.5	14,414,800	243,116	0.0169	0.9831	67.90
56.5	13,453,363	246,977	0.0184	0.9816	66.75
57.5	12,527,047	224,978	0.0180	0.9820	65.53
58.5	11,851,344	207,961	0.0175	0.9825	64.35
59.5	11,133,048	205,103	0.0184	0.9816	63.22
60.5	10,561,954	222,892	0.0211	0.9789	62.06
61.5	9,759,113	218,550	0.0224	0.9776	60.75
62.5	9,029,686	213,979	0.0237	0.9763	59.39
63.5	8,209,158	179,115	0.0218	0.9782	57.98
64.5	7,621,309	184,822	0.0243	0.9757	56.72
65.5	6,904,307	144,451	0.0209	0.9791	55.34
66.5	6,432,638	164,433	0.0256	0.9744	54.18
67.5	5,603,042	148,754	0.0265	0.9735	52.80
68.5	4,821,276	63,893	0.0133	0.9867	51.40
69.5	4,370,290	79,919	0.0183	0.9817	50.71
70.5	4,180,561	52,584	0.0126	0.9874	49.79
71.5	3,962,738	37,238	0.0094	0.9906	49.16
72.5	3,952,972	33,388	0.0084	0.9916	48.70
73.5	3,926,738	36,092	0.0092	0.9908	48.29
74.5	3,890,220	31,477	0.0081	0.9919	47.84
75.5	3,810,909	34,817	0.0091	0.9909	47.46
76.5	3,773,076	38,195	0.0101	0.9899	47.02
77.5	3,694,491	38,958	0.0105	0.9895	46.55
78.5	3,611,882	50,125	0.0139	0.9861	46.06

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	3,506,614	44,903	0.0128	0.9872	45.42
80.5	3,397,120	44,268	0.0130	0.9870	44.84
81.5	3,329,392	42,103	0.0126	0.9874	44.25
82.5	3,277,571	51,472	0.0157	0.9843	43.69
83.5	3,216,989	69,283	0.0215	0.9785	43.01
84.5	3,157,995	56,240	0.0178	0.9822	42.08
85.5	3,089,390	66,579	0.0216	0.9784	41.33
86.5	2,988,098	79,910	0.0267	0.9733	40.44
87.5	2,848,548	83,240	0.0292	0.9708	39.36
88.5	2,686,286	82,080	0.0306	0.9694	38.21
89.5	2,422,358	78,525	0.0324	0.9676	37.04
90.5	2,154,784	66,505	0.0309	0.9691	35.84
91.5	1,942,344	63,989	0.0329	0.9671	34.73
92.5	1,671,636	54,822	0.0328	0.9672	33.59
93.5	1,411,262	43,367	0.0307	0.9693	32.49
94.5	1,227,953	31,113	0.0253	0.9747	31.49
95.5	1,113,961	29,740	0.0267	0.9733	30.69
96.5	1,004,132	23,699	0.0236	0.9764	29.87
97.5	966,342	22,954	0.0238	0.9762	29.17
98.5	934,061	22,641	0.0242	0.9758	28.47
99.5	908,073	25,373	0.0279	0.9721	27.78
100.5	852,236	26,018	0.0305	0.9695	27.01
101.5	799,445	26,008	0.0325	0.9675	26.18
102.5	748,492	24,723	0.0330	0.9670	25.33
103.5	702,962	24,206	0.0344	0.9656	24.49
104.5	629,329	21,624	0.0344	0.9656	23.65
105.5	591,215	21,455	0.0363	0.9637	22.84
106.5	536,348	21,264	0.0396	0.9604	22.01
107.5	465,146	16,578	0.0356	0.9644	21.14
108.5	430,679	17,084	0.0397	0.9603	20.38
109.5	405,893	18,648	0.0459	0.9541	19.58
110.5	384,154	19,862	0.0517	0.9483	18.68
111.5	357,141	19,927	0.0558	0.9442	17.71
112.5	309,497	18,170	0.0587	0.9413	16.72
113.5	272,110	18,493	0.0680	0.9320	15.74
114.5	259,930	17,717	0.0682	0.9318	14.67
115.5	222,645	16,343	0.0734	0.9266	13.67
116.5	179,202	14,284	0.0797	0.9203	12.67
117.5	140,186	11,636	0.0830	0.9170	11.66
118.5	139,009	9,732	0.0700	0.9300	10.69

PECO ENERGY COMPANY
GAS PLANT

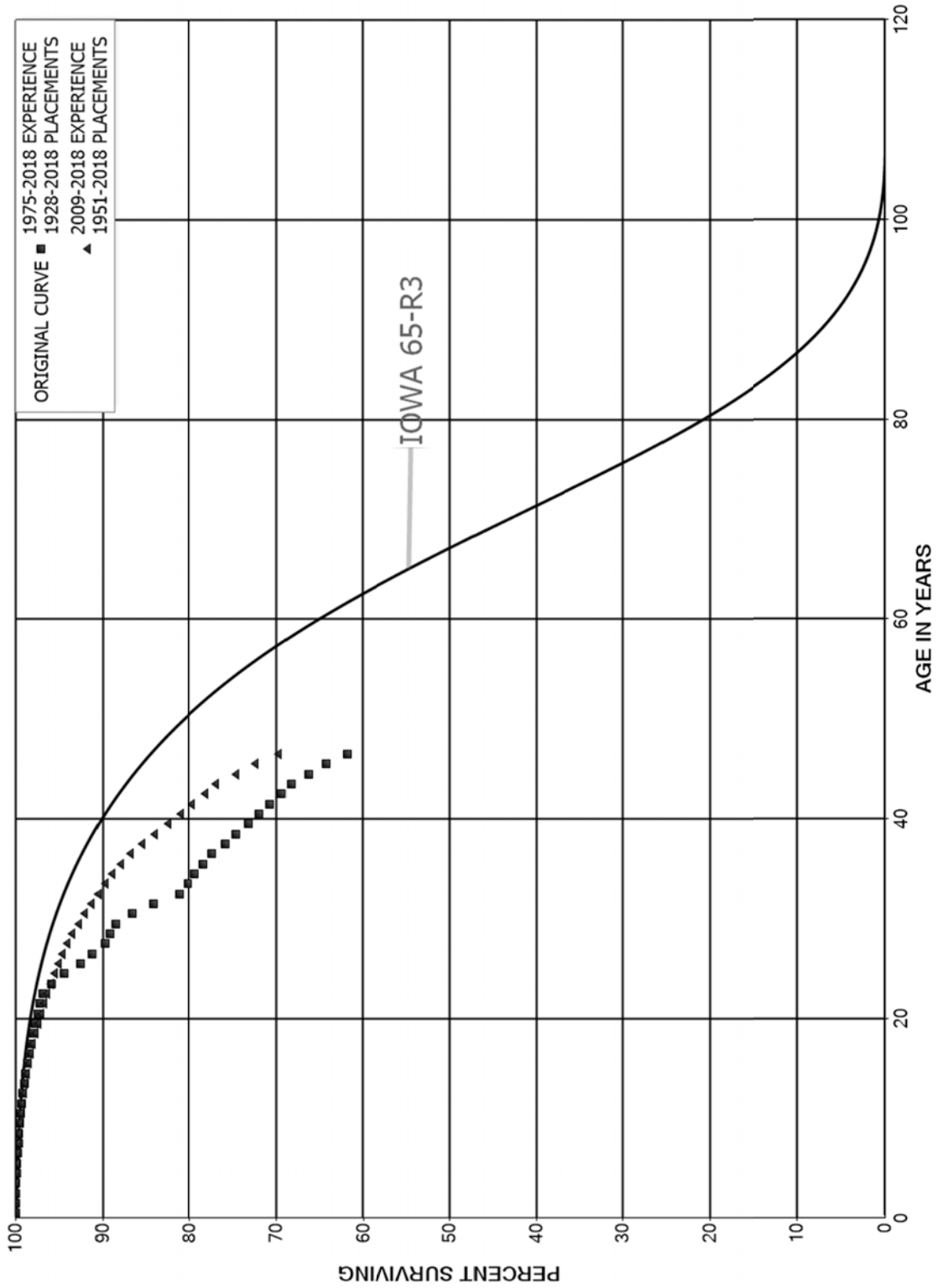
ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-1971 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	113,816	7,965	0.0700	0.9300	9.94
120.5	96,906	4,053	0.0418	0.9582	9.25
121.5	94,052	8,150	0.0867	0.9133	8.86
122.5	80,508	4,068	0.0505	0.9495	8.09
123.5	72,023	2,821	0.0392	0.9608	7.68
124.5	69,203	3,714	0.0537	0.9463	7.38
125.5	64,798	3,144	0.0485	0.9515	6.99
126.5	58,498	2,754	0.0471	0.9529	6.65
127.5	54,691	3,201	0.0585	0.9415	6.33
128.5	50,250	3,154	0.0628	0.9372	5.96
129.5	47,096	3,605	0.0765	0.9235	5.59
130.5	40,865	1,305	0.0319	0.9681	5.16
131.5	40,055	1,882	0.0470	0.9530	5.00
132.5	38,173	782	0.0205	0.9795	4.76
133.5	37,391	950	0.0254	0.9746	4.66
134.5	36,441	1,374	0.0377	0.9623	4.55
135.5	35,067	1,678	0.0479	0.9521	4.37
136.5	33,078	575	0.0174	0.9826	4.16
137.5	32,503	2,389	0.0735	0.9265	4.09
138.5	30,089	2,518	0.0837	0.9163	3.79
139.5	27,571	3,736	0.1355	0.8645	3.47
140.5	23,651	3,248	0.1373	0.8627	3.00
141.5	20,403	1,503	0.0737	0.9263	2.59
142.5	18,900	864	0.0457	0.9543	2.40
143.5	18,774	1,789	0.0953	0.9047	2.29
144.5	16,985	1,221	0.0719	0.9281	2.07
145.5	15,764	679	0.0431	0.9569	1.92
146.5	14,871	195	0.0131	0.9869	1.84
147.5	14,676	1,251	0.0853	0.9147	1.82
148.5	13,424	1,625	0.1211	0.8789	1.66
149.5	11,799	2,511	0.2128	0.7872	1.46
150.5	9,287	592	0.0638	0.9362	1.15
151.5	8,170	2,078	0.2543	0.7457	1.08
152.5	6,092	3,438	0.5644	0.4356	0.80
153.5	2,654	1,331	0.5016	0.4984	0.35
154.5	1,323	374	0.2826	0.7174	0.17
155.5	949	698	0.7358	0.2642	0.13
156.5	251	232	0.9265	0.0735	0.03
157.5	18	18	1.0000		0.00
158.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 376.3 MAINS - PLASTIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	794,627,763	45,075	0.0001	0.9999	100.00
0.5	729,501,564	179,531	0.0002	0.9998	99.99
1.5	656,305,397	195,164	0.0003	0.9997	99.97
2.5	597,950,102	243,712	0.0004	0.9996	99.94
3.5	545,104,696	280,016	0.0005	0.9995	99.90
4.5	516,660,621	246,617	0.0005	0.9995	99.85
5.5	480,843,639	314,246	0.0007	0.9993	99.80
6.5	443,959,152	317,799	0.0007	0.9993	99.74
7.5	414,393,777	375,741	0.0009	0.9991	99.66
8.5	390,542,970	383,017	0.0010	0.9990	99.57
9.5	334,331,003	323,890	0.0010	0.9990	99.48
10.5	318,231,904	355,487	0.0011	0.9989	99.38
11.5	313,530,927	347,132	0.0011	0.9989	99.27
12.5	306,293,705	519,576	0.0017	0.9983	99.16
13.5	298,396,463	559,583	0.0019	0.9981	98.99
14.5	274,334,572	486,500	0.0018	0.9982	98.80
15.5	259,750,557	563,117	0.0022	0.9978	98.63
16.5	240,125,965	577,614	0.0024	0.9976	98.42
17.5	202,756,955	486,901	0.0024	0.9976	98.18
18.5	198,392,841	512,618	0.0026	0.9974	97.94
19.5	192,545,665	528,693	0.0027	0.9973	97.69
20.5	184,012,444	532,624	0.0029	0.9971	97.42
21.5	170,698,917	622,027	0.0036	0.9964	97.14
22.5	160,877,650	1,557,813	0.0097	0.9903	96.79
23.5	148,283,118	2,181,719	0.0147	0.9853	95.85
24.5	132,194,358	2,719,764	0.0206	0.9794	94.44
25.5	120,165,776	1,696,638	0.0141	0.9859	92.50
26.5	102,217,352	1,607,841	0.0157	0.9843	91.19
27.5	88,415,364	524,627	0.0059	0.9941	89.75
28.5	77,405,984	600,671	0.0078	0.9922	89.22
29.5	68,589,696	1,465,482	0.0214	0.9786	88.53
30.5	60,728,006	1,739,451	0.0286	0.9714	86.64
31.5	51,356,535	1,797,720	0.0350	0.9650	84.16
32.5	43,975,288	545,501	0.0124	0.9876	81.21
33.5	39,126,502	406,540	0.0104	0.9896	80.20
34.5	35,685,881	435,088	0.0122	0.9878	79.37
35.5	31,472,074	409,703	0.0130	0.9870	78.40
36.5	27,442,860	562,856	0.0205	0.9795	77.38
37.5	18,110,774	290,875	0.0161	0.9839	75.79
38.5	12,094,840	223,549	0.0185	0.9815	74.58

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,734,459	163,618	0.0168	0.9832	73.20
40.5	7,632,146	131,942	0.0173	0.9827	71.97
41.5	6,776,926	123,323	0.0182	0.9818	70.72
42.5	6,333,493	106,886	0.0169	0.9831	69.44
43.5	6,226,607	182,179	0.0293	0.9707	68.27
44.5	5,367,824	163,337	0.0304	0.9696	66.27
45.5	4,564,217	168,871	0.0370	0.9630	64.25
46.5	1,969,318	84,569	0.0429	0.9571	61.87
47.5	1,066,958	40,260	0.0377	0.9623	59.22
48.5	342,065	12,499	0.0365	0.9635	56.98
49.5	13,267	409	0.0308	0.9692	54.90
50.5	12,858	641	0.0499	0.9501	53.21
51.5	1,286		0.0000	1.0000	50.56
52.5	1,286		0.0000	1.0000	50.56
53.5	1,286	1	0.0005	0.9995	50.56
54.5	1,285	3	0.0023	0.9977	50.53
55.5	1,282	2	0.0019	0.9981	50.42
56.5	1,280	3	0.0020	0.9980	50.32
57.5	1,277	8	0.0060	0.9940	50.22
58.5	1,270	7	0.0055	0.9945	49.92
59.5	1,263	5	0.0037	0.9963	49.64
60.5	1,258	8	0.0066	0.9934	49.46
61.5	1,250	6	0.0044	0.9956	49.13
62.5	1,244	3	0.0027	0.9973	48.91
63.5	1,241	5	0.0038	0.9962	48.78
64.5	1,236	21	0.0172	0.9828	48.60
65.5	1,215	10	0.0083	0.9917	47.76
66.5	1,205	7	0.0056	0.9944	47.36
67.5	1,149		0.0000	1.0000	47.10
68.5	1,149		0.0000	1.0000	47.10
69.5	1,149	770	0.6700	0.3300	47.10
70.5	379		0.0000	1.0000	15.54
71.5	379		0.0000	1.0000	15.54
72.5	379		0.0000	1.0000	15.54
73.5	379		0.0000	1.0000	15.54
74.5	379	44	0.1148	0.8852	15.54
75.5	336	336	1.0000		13.76
76.5					

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	441,173,894	33,281	0.0001	0.9999	100.00
0.5	394,529,250	105,886	0.0003	0.9997	99.99
1.5	333,649,453	137,957	0.0004	0.9996	99.97
2.5	287,853,743	136,659	0.0005	0.9995	99.92
3.5	249,606,621	138,213	0.0006	0.9994	99.88
4.5	242,840,685	159,507	0.0007	0.9993	99.82
5.5	219,471,050	165,123	0.0008	0.9992	99.76
6.5	201,238,378	171,653	0.0009	0.9991	99.68
7.5	208,694,668	211,114	0.0010	0.9990	99.60
8.5	188,888,049	225,242	0.0012	0.9988	99.50
9.5	173,072,558	214,009	0.0012	0.9988	99.38
10.5	159,434,235	198,326	0.0012	0.9988	99.25
11.5	158,163,105	224,010	0.0014	0.9986	99.13
12.5	151,327,678	255,633	0.0017	0.9983	98.99
13.5	145,383,649	255,062	0.0018	0.9982	98.82
14.5	135,983,215	315,278	0.0023	0.9977	98.65
15.5	131,231,489	321,865	0.0025	0.9975	98.42
16.5	128,612,353	353,896	0.0028	0.9972	98.18
17.5	104,153,951	309,122	0.0030	0.9970	97.91
18.5	110,767,634	366,739	0.0033	0.9967	97.62
19.5	113,687,041	397,974	0.0035	0.9965	97.30
20.5	112,035,895	391,719	0.0035	0.9965	96.95
21.5	106,961,662	404,127	0.0038	0.9962	96.62
22.5	103,287,960	413,572	0.0040	0.9960	96.25
23.5	96,444,395	436,068	0.0045	0.9955	95.87
24.5	85,373,451	403,345	0.0047	0.9953	95.43
25.5	79,763,156	390,843	0.0049	0.9951	94.98
26.5	67,069,359	373,221	0.0056	0.9944	94.52
27.5	64,147,992	422,931	0.0066	0.9934	93.99
28.5	59,591,002	451,770	0.0076	0.9924	93.37
29.5	53,323,895	438,994	0.0082	0.9918	92.66
30.5	48,691,962	402,840	0.0083	0.9917	91.90
31.5	41,486,588	330,843	0.0080	0.9920	91.14
32.5	36,022,047	316,455	0.0088	0.9912	90.41
33.5	31,402,307	264,037	0.0084	0.9916	89.62
34.5	29,133,450	323,400	0.0111	0.9889	88.86
35.5	25,825,210	330,685	0.0128	0.9872	87.88
36.5	24,905,543	401,050	0.0161	0.9839	86.75
37.5	16,769,850	279,950	0.0167	0.9833	85.36
38.5	11,654,415	220,799	0.0189	0.9811	83.93

PECO ENERGY COMPANY
GAS PLANT

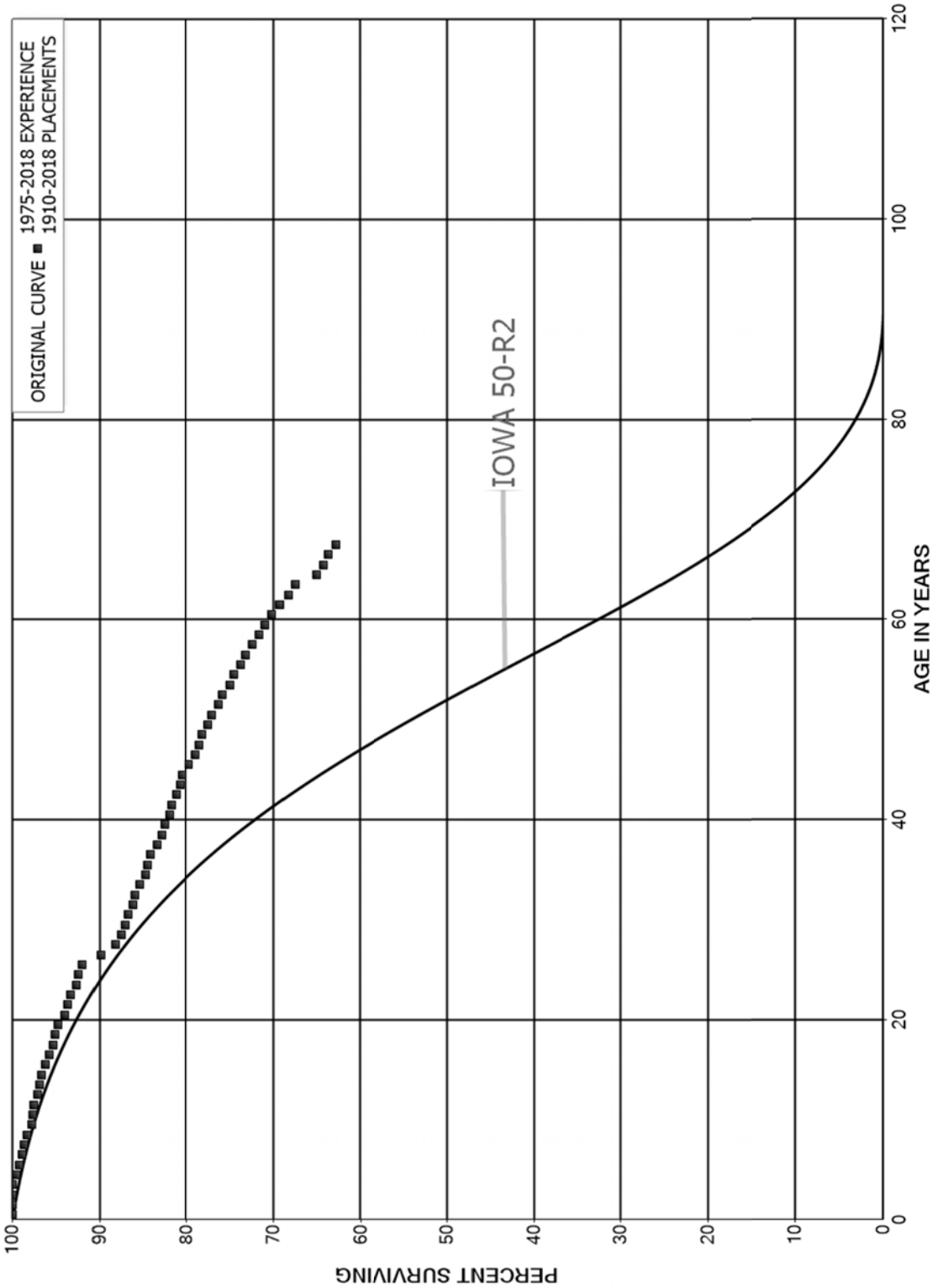
ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1951-2018 EXPERIENCE BAND 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,717,703	163,068	0.0168	0.9832	82.34
40.5	7,615,940	131,460	0.0173	0.9827	80.96
41.5	6,776,790	123,323	0.0182	0.9818	79.56
42.5	6,333,356	106,886	0.0169	0.9831	78.11
43.5	6,226,471	182,179	0.0293	0.9707	76.80
44.5	5,367,688	163,337	0.0304	0.9696	74.55
45.5	4,564,081	168,871	0.0370	0.9630	72.28
46.5	1,968,032	84,569	0.0430	0.9570	69.61
47.5	1,065,672	40,260	0.0378	0.9622	66.61
48.5	340,779	12,499	0.0367	0.9633	64.10
49.5	11,981	409	0.0341	0.9659	61.75
50.5	11,572	641	0.0554	0.9446	59.64
51.5					56.34
52.5					
53.5					
54.5					
55.5					
56.5					
57.5	128	8	0.0599		
58.5	120	7	0.0575		
59.5	113	5	0.0413		
60.5	109	8	0.0767		
61.5	100	6	0.0551		
62.5	95	3	0.0353		
63.5	91	5	0.0519		
64.5	87	21	0.2455		
65.5	65	10	0.1538		
66.5	55	7	0.1210		
67.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,239,362	1	0.0000	1.0000	100.00
0.5	15,463,361	436	0.0000	1.0000	100.00
1.5	15,387,330	792	0.0001	0.9999	100.00
2.5	15,153,201	6,781	0.0004	0.9996	99.99
3.5	14,678,860	61,965	0.0042	0.9958	99.95
4.5	14,610,173	49,290	0.0034	0.9966	99.53
5.5	14,101,588	49,201	0.0035	0.9965	99.19
6.5	13,780,154	36,486	0.0026	0.9974	98.84
7.5	12,775,646	45,024	0.0035	0.9965	98.58
8.5	12,643,767	58,934	0.0047	0.9953	98.23
9.5	12,465,518	19,383	0.0016	0.9984	97.78
10.5	12,186,628	15,642	0.0013	0.9987	97.62
11.5	11,724,690	49,872	0.0043	0.9957	97.50
12.5	11,629,422	31,082	0.0027	0.9973	97.08
13.5	11,466,556	28,259	0.0025	0.9975	96.82
14.5	11,236,307	43,495	0.0039	0.9961	96.59
15.5	11,009,115	58,663	0.0053	0.9947	96.21
16.5	10,948,461	46,541	0.0043	0.9957	95.70
17.5	10,208,821	27,330	0.0027	0.9973	95.29
18.5	10,017,617	30,004	0.0030	0.9970	95.04
19.5	10,046,376	90,272	0.0090	0.9910	94.75
20.5	10,023,795	35,777	0.0036	0.9964	93.90
21.5	10,042,970	33,745	0.0034	0.9966	93.57
22.5	10,055,644	63,309	0.0063	0.9937	93.25
23.5	10,059,309	35,181	0.0035	0.9965	92.67
24.5	10,027,837	38,920	0.0039	0.9961	92.34
25.5	9,600,020	221,911	0.0231	0.9769	91.98
26.5	8,456,560	162,294	0.0192	0.9808	89.86
27.5	8,070,177	54,538	0.0068	0.9932	88.13
28.5	7,608,240	40,158	0.0053	0.9947	87.54
29.5	7,270,802	25,338	0.0035	0.9965	87.07
30.5	6,754,123	47,407	0.0070	0.9930	86.77
31.5	6,153,958	17,938	0.0029	0.9971	86.16
32.5	5,619,772	31,324	0.0056	0.9944	85.91
33.5	5,188,500	41,460	0.0080	0.9920	85.43
34.5	4,861,252	13,818	0.0028	0.9972	84.75
35.5	4,387,415	19,920	0.0045	0.9955	84.51
36.5	3,738,201	34,829	0.0093	0.9907	84.12
37.5	3,184,315	20,131	0.0063	0.9937	83.34
38.5	2,855,560	10,415	0.0036	0.9964	82.81

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,787,698	17,462	0.0063	0.9937	82.51
40.5	2,561,226	9,553	0.0037	0.9963	82.00
41.5	2,404,457	15,940	0.0066	0.9934	81.69
42.5	2,198,484	10,869	0.0049	0.9951	81.15
43.5	1,902,746	6,937	0.0036	0.9964	80.75
44.5	1,870,272	17,437	0.0093	0.9907	80.45
45.5	1,736,364	15,556	0.0090	0.9910	79.70
46.5	1,495,190	9,719	0.0065	0.9935	78.99
47.5	1,404,063	6,243	0.0044	0.9956	78.47
48.5	1,303,606	10,578	0.0081	0.9919	78.13
49.5	1,252,651	6,271	0.0050	0.9950	77.49
50.5	1,172,142	12,182	0.0104	0.9896	77.10
51.5	1,106,906	6,948	0.0063	0.9937	76.30
52.5	1,052,978	11,328	0.0108	0.9892	75.82
53.5	1,022,184	6,986	0.0068	0.9932	75.01
54.5	949,209	9,147	0.0096	0.9904	74.50
55.5	866,769	7,221	0.0083	0.9917	73.78
56.5	797,484	8,725	0.0109	0.9891	73.16
57.5	720,385	7,222	0.0100	0.9900	72.36
58.5	654,841	6,668	0.0102	0.9898	71.64
59.5	619,453	6,444	0.0104	0.9896	70.91
60.5	512,760	6,451	0.0126	0.9874	70.17
61.5	433,242	6,221	0.0144	0.9856	69.29
62.5	385,307	4,489	0.0117	0.9883	68.29
63.5	314,403	11,425	0.0363	0.9637	67.50
64.5	264,326	3,203	0.0121	0.9879	65.04
65.5	224,691	1,744	0.0078	0.9922	64.26
66.5	205,469	2,866	0.0139	0.9861	63.76
67.5	169,332	1,904	0.0112	0.9888	62.87
68.5	146,924	1,353	0.0092	0.9908	62.16
69.5	124,283	1,696	0.0136	0.9864	61.59
70.5	99,917	1,353	0.0135	0.9865	60.75
71.5	83,184	839	0.0101	0.9899	59.92
72.5	74,734	897	0.0120	0.9880	59.32
73.5	62,688	915	0.0146	0.9854	58.61
74.5	59,465	1,725	0.0290	0.9710	57.75
75.5	55,250	1,307	0.0237	0.9763	56.08
76.5	49,411	1,367	0.0277	0.9723	54.75
77.5	40,330	1,602	0.0397	0.9603	53.24
78.5	34,588	1,449	0.0419	0.9581	51.12

PECO ENERGY COMPANY
GAS PLANT

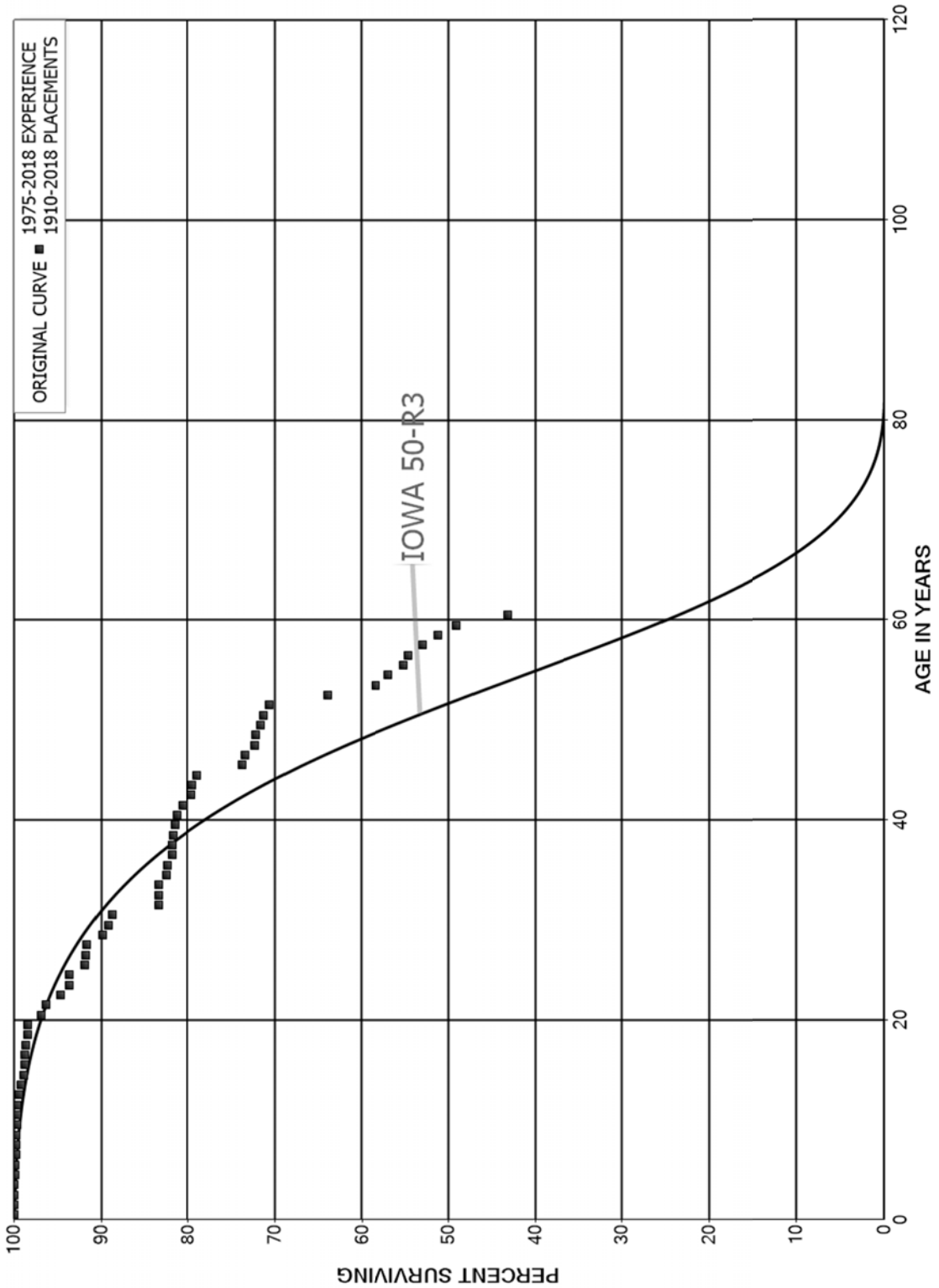
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	30,264	688	0.0227	0.9773	48.98
80.5	29,575	639	0.0216	0.9784	47.87
81.5	28,936	2,591	0.0895	0.9105	46.83
82.5	25,913	1,816	0.0701	0.9299	42.64
83.5	23,905	2,071	0.0866	0.9134	39.65
84.5	21,673	1,362	0.0628	0.9372	36.22
85.5	18,839	2,344	0.1244	0.8756	33.94
86.5	14,525	1,302	0.0896	0.9104	29.72
87.5	12,910	1,422	0.1101	0.8899	27.05
88.5	8,301	1,003	0.1208	0.8792	24.07
89.5	6,643	915	0.1377	0.8623	21.17
90.5	4,694	429	0.0914	0.9086	18.25
91.5	3,633	177	0.0487	0.9513	16.58
92.5	3,061	823	0.2689	0.7311	15.78
93.5	1,888	79	0.0420	0.9580	11.53
94.5	1,809	98	0.0544	0.9456	11.05
95.5	1,710	151	0.0884	0.9116	10.45
96.5	1,559	198	0.1269	0.8731	9.52
97.5	1,361	82	0.0604	0.9396	8.32
98.5	1,279	116	0.0906	0.9094	7.81
99.5	758	155	0.2045	0.7955	7.11
100.5	603	18	0.0306	0.9694	5.65
101.5	506	65	0.1280	0.8720	5.48
102.5	273	48	0.1776	0.8224	4.78
103.5	224	5	0.0212	0.9788	3.93
104.5	220	0	0.0020	0.9980	3.85
105.5	162	77	0.4730	0.5270	3.84
106.5	85	6	0.0650	0.9350	2.02
107.5	80	0	0.0011	0.9989	1.89
108.5					1.89

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
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ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	52,477,689	102	0.0000	1.0000	100.00
0.5	39,842,340	2,180	0.0001	0.9999	100.00
1.5	39,834,159	19,960	0.0005	0.9995	99.99
2.5	39,805,306	8,213	0.0002	0.9998	99.94
3.5	39,770,261	28,583	0.0007	0.9993	99.92
4.5	39,448,739	6,306	0.0002	0.9998	99.85
5.5	38,969,423	43,101	0.0011	0.9989	99.84
6.5	38,631,851	11,902	0.0003	0.9997	99.73
7.5	38,371,398	8,981	0.0002	0.9998	99.69
8.5	38,096,610	6,941	0.0002	0.9998	99.67
9.5	36,893,413	3,574	0.0001	0.9999	99.65
10.5	36,018,551	8,996	0.0002	0.9998	99.64
11.5	35,193,940	86,818	0.0025	0.9975	99.62
12.5	33,543,478	58,505	0.0017	0.9983	99.37
13.5	32,522,267	110,761	0.0034	0.9966	99.20
14.5	27,779,843	29,522	0.0011	0.9989	98.86
15.5	26,584,414	21,965	0.0008	0.9992	98.76
16.5	24,375,408	17,984	0.0007	0.9993	98.68
17.5	17,825,213	28,799	0.0016	0.9984	98.60
18.5	18,014,957	462	0.0000	1.0000	98.44
19.5	18,184,283	293,784	0.0162	0.9838	98.44
20.5	17,749,630	102,527	0.0058	0.9942	96.85
21.5	17,156,559	295,731	0.0172	0.9828	96.29
22.5	15,168,599	164,098	0.0108	0.9892	94.63
23.5	15,464,200	3,361	0.0002	0.9998	93.61
24.5	8,974,273	166,228	0.0185	0.9815	93.59
25.5	8,842,220	14,305	0.0016	0.9984	91.85
26.5	7,983,531	6,063	0.0008	0.9992	91.70
27.5	6,608,531	132,603	0.0201	0.9799	91.64
28.5	6,477,660	46,537	0.0072	0.9928	89.80
29.5	6,028,199	25,444	0.0042	0.9958	89.15
30.5	5,678,315	341,505	0.0601	0.9399	88.77
31.5	5,335,639	3,843	0.0007	0.9993	83.44
32.5	5,315,413	848	0.0002	0.9998	83.38
33.5	3,688,054	39,310	0.0107	0.9893	83.36
34.5	3,653,833	2,871	0.0008	0.9992	82.47
35.5	3,641,764	23,922	0.0066	0.9934	82.41
36.5	3,299,220	1,557	0.0005	0.9995	81.87
37.5	3,296,868	6,048	0.0018	0.9982	81.83
38.5	2,750,979	6,866	0.0025	0.9975	81.68

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,718,576	7,613	0.0028	0.9972	81.48
40.5	2,629,969	21,366	0.0081	0.9919	81.25
41.5	2,607,129	30,228	0.0116	0.9884	80.59
42.5	2,577,212	3,400	0.0013	0.9987	79.65
43.5	2,593,032	21,101	0.0081	0.9919	79.55
44.5	2,568,926	169,767	0.0661	0.9339	78.90
45.5	2,399,159	8,279	0.0035	0.9965	73.69
46.5	2,390,737	38,605	0.0161	0.9839	73.43
47.5	1,980,747	2,652	0.0013	0.9987	72.25
48.5	1,978,797	15,290	0.0077	0.9923	72.15
49.5	1,912,444	8,074	0.0042	0.9958	71.59
50.5	1,903,365	18,660	0.0098	0.9902	71.29
51.5	1,884,492	175,876	0.0933	0.9067	70.59
52.5	1,591,616	140,007	0.0880	0.9120	64.00
53.5	1,282,324	29,943	0.0234	0.9766	58.37
54.5	1,184,215	37,534	0.0317	0.9683	57.01
55.5	1,096,101	12,561	0.0115	0.9885	55.20
56.5	946,135	27,304	0.0289	0.9711	54.57
57.5	890,669	29,946	0.0336	0.9664	53.00
58.5	855,199	35,877	0.0420	0.9580	51.21
59.5	806,068	96,332	0.1195	0.8805	49.06
60.5	702,573	17,940	0.0255	0.9745	43.20
61.5	523,171	3,053	0.0058	0.9942	42.10
62.5	520,118	794	0.0015	0.9985	41.85
63.5	519,324	8	0.0000	1.0000	41.79
64.5	463,521	226	0.0005	0.9995	41.79
65.5	441,699	106	0.0002	0.9998	41.77
66.5	399,684	1,821	0.0046	0.9954	41.76
67.5	70,195	5,077	0.0723	0.9277	41.57
68.5	54,219	43	0.0008	0.9992	38.56
69.5	45,704	74	0.0016	0.9984	38.53
70.5	45,521	14	0.0003	0.9997	38.47
71.5	44,029	1	0.0000	1.0000	38.46
72.5	44,028		0.0000	1.0000	38.46
73.5	44,028		0.0000	1.0000	38.46
74.5	44,028	61	0.0014	0.9986	38.46
75.5	43,966	595	0.0135	0.9865	38.40
76.5	43,301	19,220	0.4439	0.5561	37.88
77.5	23,935	854	0.0357	0.9643	21.07
78.5	23,064	218	0.0095	0.9905	20.32

PECO ENERGY COMPANY
GAS PLANT

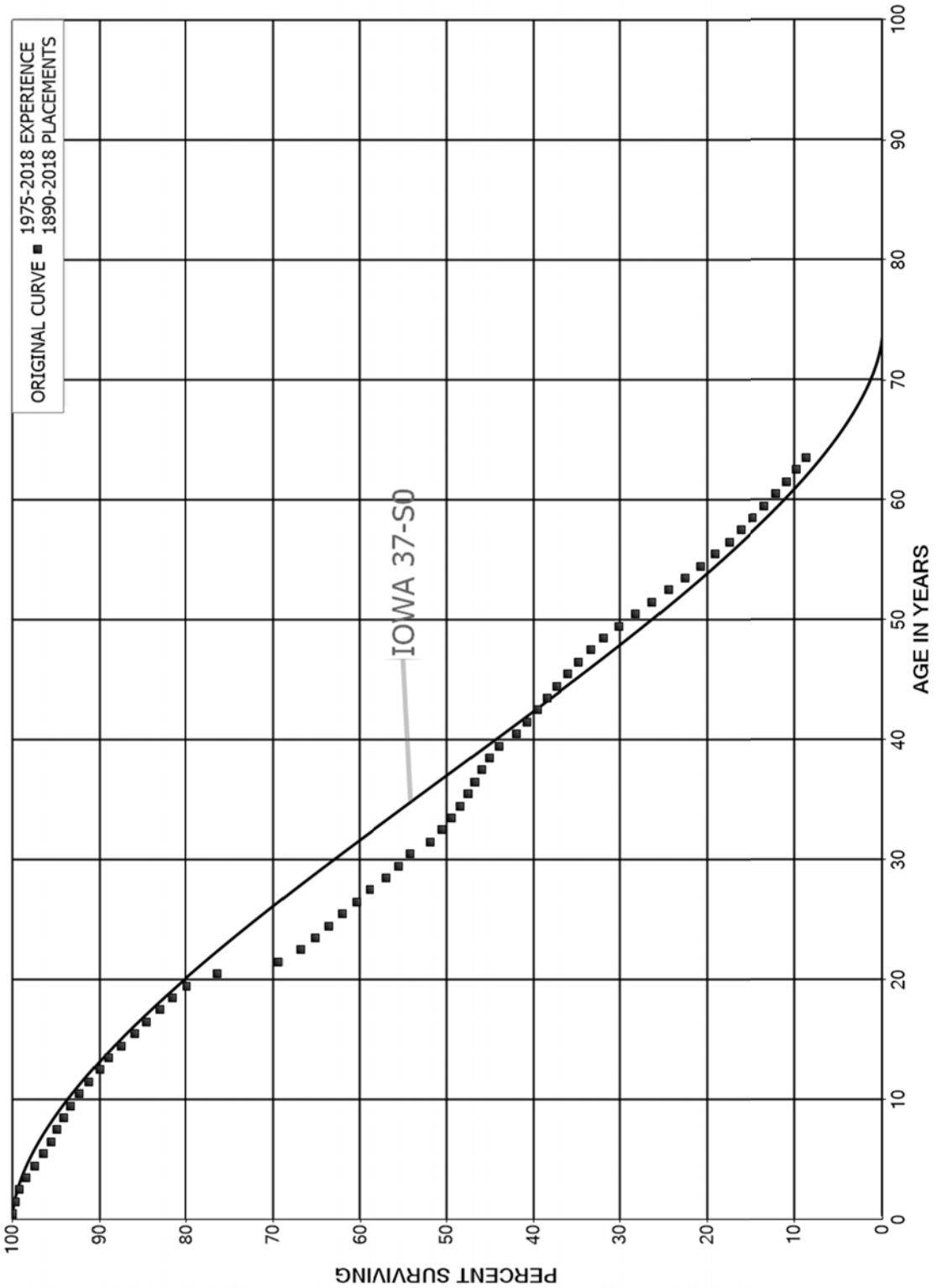
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	22,846		0.0000	1.0000	20.12
80.5	22,846	3,731	0.1633	0.8367	20.12
81.5	19,115	1,686	0.0882	0.9118	16.84
82.5	17,429	5,135	0.2946	0.7054	15.35
83.5	12,294	1,316	0.1070	0.8930	10.83
84.5	10,978	4,338	0.3952	0.6048	9.67
85.5	6,640	1,767	0.2661	0.7339	5.85
86.5	4,873	18	0.0037	0.9963	4.29
87.5	4,855		0.0000	1.0000	4.28
88.5	4,855		0.0000	1.0000	4.28
89.5	4,855		0.0000	1.0000	4.28
90.5	1,989		0.0000	1.0000	4.28
91.5	1,989	86	0.0431	0.9569	4.28
92.5	1,904	46	0.0240	0.9760	4.09
93.5	1,858		0.0000	1.0000	3.99
94.5	1,858		0.0000	1.0000	3.99
95.5	1,636		0.0000	1.0000	3.99
96.5	1,636		0.0000	1.0000	3.99
97.5	1,636	1,636	1.0000		3.99
98.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 380.1 SERVICES - STEEL
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.1 SERVICES - STEEL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	113,741,377	52,970	0.0005	0.9995	100.00
0.5	110,653,408	351,734	0.0032	0.9968	99.95
1.5	107,230,257	465,255	0.0043	0.9957	99.64
2.5	104,100,115	872,372	0.0084	0.9916	99.20
3.5	101,591,578	1,046,703	0.0103	0.9897	98.37
4.5	98,250,598	923,768	0.0094	0.9906	97.36
5.5	94,818,155	874,238	0.0092	0.9908	96.44
6.5	92,067,530	743,529	0.0081	0.9919	95.55
7.5	89,806,132	669,598	0.0075	0.9925	94.78
8.5	87,966,017	718,698	0.0082	0.9918	94.08
9.5	81,494,673	899,896	0.0110	0.9890	93.31
10.5	79,202,191	925,789	0.0117	0.9883	92.28
11.5	77,551,218	1,014,838	0.0131	0.9869	91.20
12.5	74,763,129	918,385	0.0123	0.9877	90.00
13.5	71,620,120	1,164,089	0.0163	0.9837	88.90
14.5	68,853,448	1,156,705	0.0168	0.9832	87.45
15.5	62,187,756	961,530	0.0155	0.9845	85.98
16.5	56,483,637	1,067,625	0.0189	0.9811	84.66
17.5	48,489,217	829,507	0.0171	0.9829	83.06
18.5	45,810,652	948,118	0.0207	0.9793	81.63
19.5	44,060,535	1,945,028	0.0441	0.9559	79.94
20.5	40,145,811	3,698,212	0.0921	0.9079	76.42
21.5	35,310,455	1,300,067	0.0368	0.9632	69.38
22.5	33,601,658	831,453	0.0247	0.9753	66.82
23.5	32,306,831	781,295	0.0242	0.9758	65.17
24.5	31,513,136	761,410	0.0242	0.9758	63.59
25.5	30,184,107	783,747	0.0260	0.9740	62.06
26.5	28,823,098	770,486	0.0267	0.9733	60.44
27.5	27,259,946	851,193	0.0312	0.9688	58.83
28.5	25,658,739	659,538	0.0257	0.9743	56.99
29.5	24,249,973	581,044	0.0240	0.9760	55.53
30.5	22,914,281	1,009,935	0.0441	0.9559	54.20
31.5	21,236,458	535,643	0.0252	0.9748	51.81
32.5	20,123,336	455,316	0.0226	0.9774	50.50
33.5	19,021,935	360,169	0.0189	0.9811	49.36
34.5	18,137,103	327,271	0.0180	0.9820	48.42
35.5	17,314,756	305,570	0.0176	0.9824	47.55
36.5	16,956,670	291,475	0.0172	0.9828	46.71
37.5	16,702,634	324,505	0.0194	0.9806	45.91
38.5	16,406,894	409,727	0.0250	0.9750	45.02

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.1 SERVICES - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,023,394	704,900	0.0440	0.9560	43.89
40.5	15,342,291	435,937	0.0284	0.9716	41.96
41.5	14,921,757	445,511	0.0299	0.9701	40.77
42.5	14,497,819	408,561	0.0282	0.9718	39.55
43.5	14,120,018	430,123	0.0305	0.9695	38.44
44.5	13,757,673	474,933	0.0345	0.9655	37.27
45.5	13,350,113	470,231	0.0352	0.9648	35.98
46.5	12,758,614	514,777	0.0403	0.9597	34.71
47.5	12,158,330	555,781	0.0457	0.9543	33.31
48.5	11,597,568	635,448	0.0548	0.9452	31.79
49.5	10,632,293	659,284	0.0620	0.9380	30.05
50.5	9,336,758	627,674	0.0672	0.9328	28.18
51.5	8,045,410	576,038	0.0716	0.9284	26.29
52.5	6,737,833	538,322	0.0799	0.9201	24.41
53.5	5,456,906	422,198	0.0774	0.9226	22.46
54.5	4,546,690	368,497	0.0810	0.9190	20.72
55.5	3,776,138	326,150	0.0864	0.9136	19.04
56.5	3,114,853	247,790	0.0796	0.9204	17.40
57.5	2,579,245	203,303	0.0788	0.9212	16.01
58.5	2,264,948	206,471	0.0912	0.9088	14.75
59.5	1,916,811	190,791	0.0995	0.9005	13.41
60.5	1,637,337	162,781	0.0994	0.9006	12.07
61.5	1,345,862	140,923	0.1047	0.8953	10.87
62.5	1,148,922	132,352	0.1152	0.8848	9.73
63.5	953,310	111,660	0.1171	0.8829	8.61
64.5	826,132	103,218	0.1249	0.8751	7.60
65.5	686,774	86,878	0.1265	0.8735	6.65
66.5	587,238	79,946	0.1361	0.8639	5.81
67.5	497,684	71,593	0.1439	0.8561	5.02
68.5	416,740	53,307	0.1279	0.8721	4.30
69.5	359,284	50,276	0.1399	0.8601	3.75
70.5	306,142	25,996	0.0849	0.9151	3.22
71.5	281,611	21,897	0.0778	0.9222	2.95
72.5	262,898	20,760	0.0790	0.9210	2.72
73.5	243,516	20,990	0.0862	0.9138	2.51
74.5	224,626	25,418	0.1132	0.8868	2.29
75.5	210,306	22,276	0.1059	0.8941	2.03
76.5	189,808	32,398	0.1707	0.8293	1.82
77.5	157,436	20,362	0.1293	0.8707	1.51
78.5	137,179	21,549	0.1571	0.8429	1.31

PECO ENERGY COMPANY
GAS PLANT

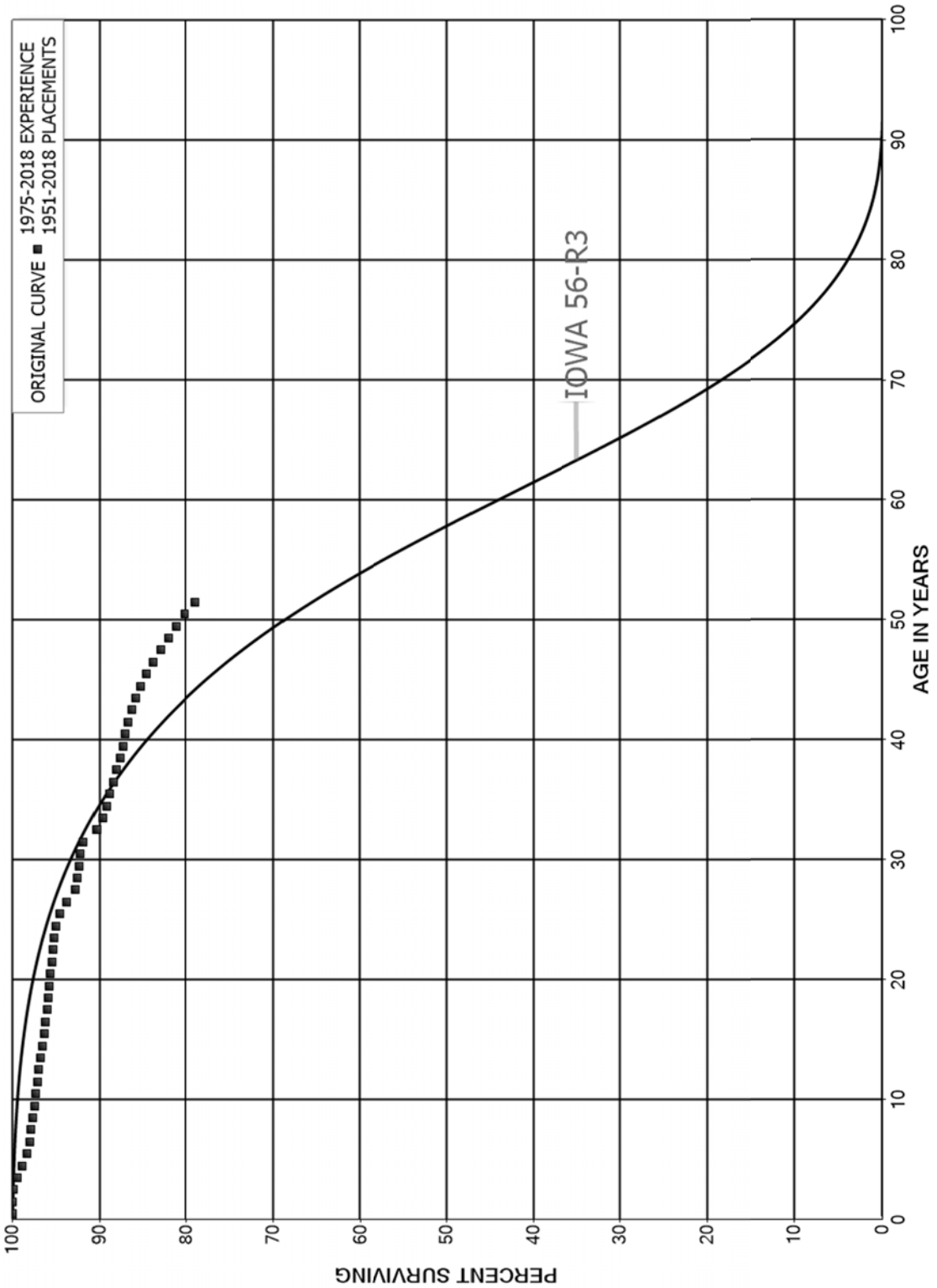
ACCOUNT 380.1 SERVICES - STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	115,802	24,462	0.2112	0.7888	1.11
80.5	91,349	17,521	0.1918	0.8082	0.87
81.5	73,843	16,126	0.2184	0.7816	0.70
82.5	57,780	9,791	0.1695	0.8305	0.55
83.5	47,989	9,122	0.1901	0.8099	0.46
84.5	41,150	6,448	0.1567	0.8433	0.37
85.5	34,702	4,923	0.1419	0.8581	0.31
86.5	29,779	2,823	0.0948	0.9052	0.27
87.5	26,956	2,689	0.0997	0.9003	0.24
88.5	24,267	3,277	0.1350	0.8650	0.22
89.5	20,990	6,268	0.2986	0.7014	0.19
90.5	14,723	3,655	0.2482	0.7518	0.13
91.5	11,068	3,569	0.3224	0.6776	0.10
92.5	7,499	1,276	0.1702	0.8298	0.07
93.5	6,223	941	0.1512	0.8488	0.06
94.5	5,282	805	0.1523	0.8477	0.05
95.5	4,478	292	0.0651	0.9349	0.04
96.5	4,186	738	0.1763	0.8237	0.04
97.5	3,448	521	0.1510	0.8490	0.03
98.5	2,927	448	0.1531	0.8469	0.03
99.5	2,479	429	0.1730	0.8270	0.02
100.5	2,050	24	0.0116	0.9884	0.02
101.5	2,026	15	0.0074	0.9926	0.02
102.5	2,011	54	0.0271	0.9729	0.02
103.5	1,957	682	0.3487	0.6513	0.02
104.5	1,274	617	0.4842	0.5158	0.01
105.5	657	126	0.1919	0.8081	0.01
106.5	531	12	0.0221	0.9779	0.00
107.5	519	27	0.0515	0.9485	0.00
108.5	493	2	0.0033	0.9967	0.00
109.5	491	1	0.0022	0.9978	0.00
110.5	490		0.0000	1.0000	0.00
111.5	490		0.0000	1.0000	0.00
112.5	490	490	1.0000		0.00
113.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 380.2 SERVICES - PLASTIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.2 SERVICES - PLASTIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	732,713,875	71,911	0.0001	0.9999	100.00
0.5	663,910,221	402,037	0.0006	0.9994	99.99
1.5	619,697,144	729,371	0.0012	0.9988	99.93
2.5	583,558,222	2,446,047	0.0042	0.9958	99.81
3.5	550,913,067	2,882,404	0.0052	0.9948	99.39
4.5	531,377,337	3,293,771	0.0062	0.9938	98.87
5.5	506,347,700	1,310,522	0.0026	0.9974	98.26
6.5	483,275,374	1,071,229	0.0022	0.9978	98.01
7.5	463,698,591	909,233	0.0020	0.9980	97.79
8.5	445,226,645	844,968	0.0019	0.9981	97.60
9.5	402,724,908	703,959	0.0017	0.9983	97.41
10.5	397,394,520	722,801	0.0018	0.9982	97.24
11.5	392,211,308	683,601	0.0017	0.9983	97.07
12.5	385,557,629	696,237	0.0018	0.9982	96.90
13.5	376,647,823	760,753	0.0020	0.9980	96.72
14.5	364,871,849	754,860	0.0021	0.9979	96.53
15.5	353,243,692	618,052	0.0017	0.9983	96.33
16.5	338,877,392	530,951	0.0016	0.9984	96.16
17.5	315,805,340	502,935	0.0016	0.9984	96.01
18.5	309,047,154	465,011	0.0015	0.9985	95.85
19.5	298,949,138	447,186	0.0015	0.9985	95.71
20.5	289,256,069	425,202	0.0015	0.9985	95.57
21.5	278,131,410	425,189	0.0015	0.9985	95.43
22.5	272,365,069	399,197	0.0015	0.9985	95.28
23.5	266,844,829	446,926	0.0017	0.9983	95.14
24.5	255,160,841	1,170,193	0.0046	0.9954	94.98
25.5	237,289,370	2,103,858	0.0089	0.9911	94.55
26.5	211,979,946	2,260,004	0.0107	0.9893	93.71
27.5	185,796,463	344,457	0.0019	0.9981	92.71
28.5	167,907,514	358,270	0.0021	0.9979	92.54
29.5	152,056,037	320,207	0.0021	0.9979	92.34
30.5	137,288,994	462,051	0.0034	0.9966	92.14
31.5	120,922,556	1,972,564	0.0163	0.9837	91.83
32.5	107,052,342	863,324	0.0081	0.9919	90.34
33.5	93,993,723	508,051	0.0054	0.9946	89.61
34.5	84,985,896	318,811	0.0038	0.9962	89.12
35.5	75,221,610	333,553	0.0044	0.9956	88.79
36.5	64,683,277	279,826	0.0043	0.9957	88.40
37.5	51,666,699	211,164	0.0041	0.9959	88.01
38.5	39,092,135	142,585	0.0036	0.9964	87.65

PECO ENERGY COMPANY
GAS PLANT

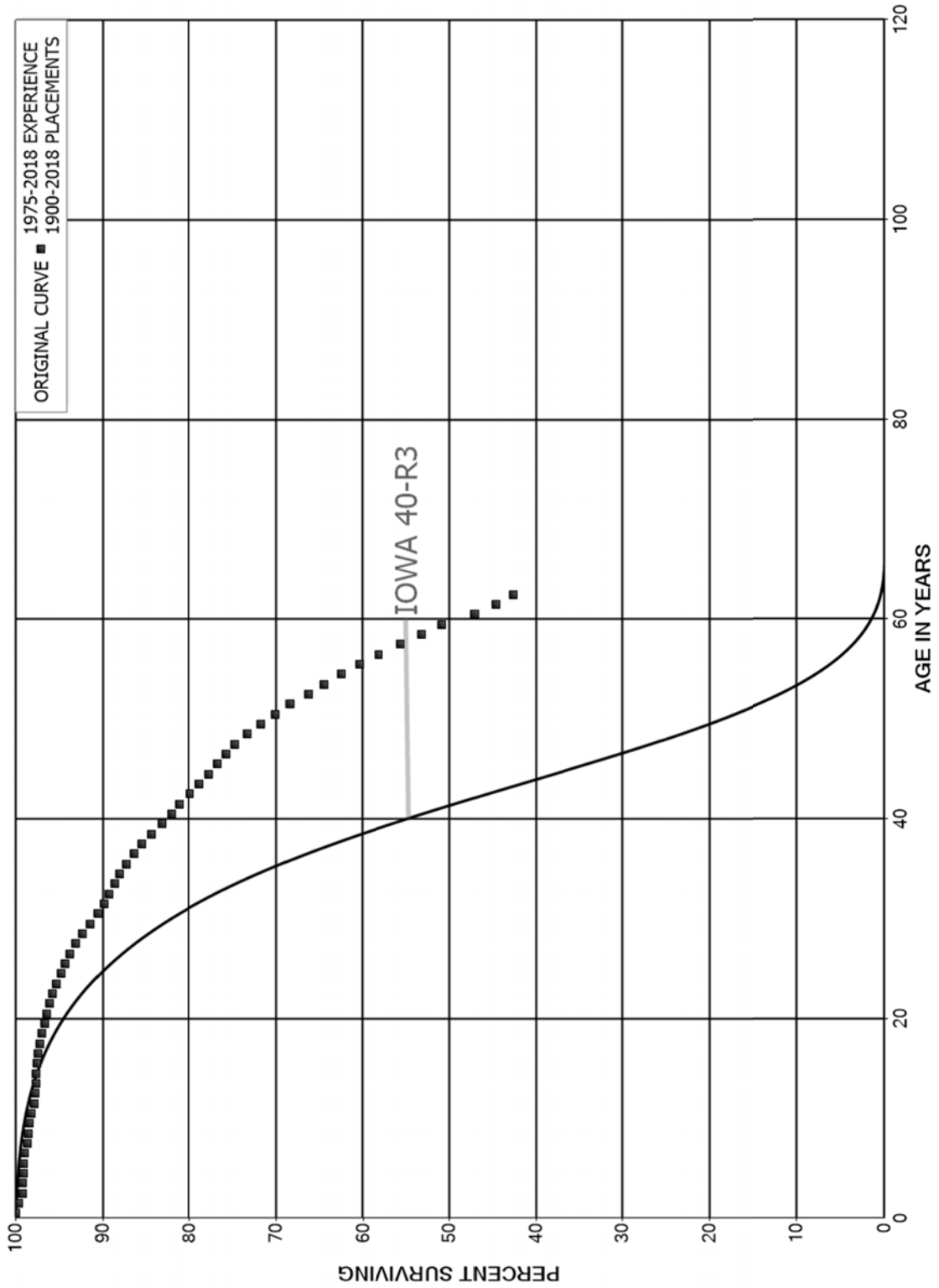
ACCOUNT 380.2 SERVICES - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1951-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,290,905	105,390	0.0036	0.9964	87.33
40.5	25,164,129	99,092	0.0039	0.9961	87.02
41.5	22,441,202	96,486	0.0043	0.9957	86.68
42.5	19,582,940	101,958	0.0052	0.9948	86.30
43.5	17,929,689	121,293	0.0068	0.9932	85.85
44.5	16,605,707	138,419	0.0083	0.9917	85.27
45.5	15,252,420	139,618	0.0092	0.9908	84.56
46.5	9,584,214	101,794	0.0106	0.9894	83.79
47.5	5,628,296	59,669	0.0106	0.9894	82.90
48.5	2,715,198	27,167	0.0100	0.9900	82.02
49.5	1,109,654	14,405	0.0130	0.9870	81.20
50.5	530,863	7,531	0.0142	0.9858	80.15
51.5	147,798	1,965	0.0133	0.9867	79.01
52.5	992		0.0000	1.0000	77.96
53.5	992	132	0.1332	0.8668	77.96
54.5	860	25	0.0296	0.9704	67.57
55.5	835	29	0.0348	0.9652	65.57
56.5	805	8	0.0099	0.9901	63.29
57.5	797	4	0.0045	0.9955	62.66
58.5	794	5	0.0059	0.9941	62.38
59.5	789	4	0.0045	0.9955	62.01
60.5	786	18	0.0226	0.9774	61.73
61.5	768	17	0.0216	0.9784	60.33
62.5	751	26	0.0341	0.9659	59.03
63.5	726	36	0.0493	0.9507	57.02
64.5	690	33	0.0482	0.9518	54.21
65.5	657	22	0.0338	0.9662	51.59
66.5	634	20	0.0313	0.9687	49.85
67.5					48.29

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 381 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	76,163,805	58,625	0.0008	0.9992	100.00
0.5	74,728,315	205,465	0.0027	0.9973	99.92
1.5	72,890,809	327,560	0.0045	0.9955	99.65
2.5	70,136,562	46,139	0.0007	0.9993	99.20
3.5	66,643,149	41,538	0.0006	0.9994	99.14
4.5	65,280,094	40,379	0.0006	0.9994	99.07
5.5	64,020,766	72,427	0.0011	0.9989	99.01
6.5	63,154,739	177,157	0.0028	0.9972	98.90
7.5	61,848,030	82,508	0.0013	0.9987	98.62
8.5	61,055,140	62,951	0.0010	0.9990	98.49
9.5	60,252,826	108,623	0.0018	0.9982	98.39
10.5	58,347,521	228,372	0.0039	0.9961	98.21
11.5	57,491,329	59,777	0.0010	0.9990	97.83
12.5	56,856,578	36,658	0.0006	0.9994	97.73
13.5	55,397,665	44,477	0.0008	0.9992	97.66
14.5	55,065,173	56,053	0.0010	0.9990	97.58
15.5	54,094,172	80,502	0.0015	0.9985	97.49
16.5	51,901,658	99,053	0.0019	0.9981	97.34
17.5	32,120,916	85,427	0.0027	0.9973	97.15
18.5	32,266,096	76,251	0.0024	0.9976	96.90
19.5	31,014,193	81,759	0.0026	0.9974	96.67
20.5	30,167,306	96,228	0.0032	0.9968	96.41
21.5	28,235,603	127,077	0.0045	0.9955	96.10
22.5	26,895,264	122,122	0.0045	0.9955	95.67
23.5	26,022,085	126,997	0.0049	0.9951	95.24
24.5	24,760,932	129,165	0.0052	0.9948	94.77
25.5	23,308,414	145,276	0.0062	0.9938	94.28
26.5	22,021,051	145,307	0.0066	0.9934	93.69
27.5	20,613,365	173,300	0.0084	0.9916	93.07
28.5	19,276,585	195,471	0.0101	0.9899	92.29
29.5	18,091,569	176,492	0.0098	0.9902	91.35
30.5	16,948,096	112,613	0.0066	0.9934	90.46
31.5	15,881,126	103,904	0.0065	0.9935	89.86
32.5	15,054,269	102,677	0.0068	0.9932	89.27
33.5	13,990,388	103,063	0.0074	0.9926	88.67
34.5	13,505,448	105,318	0.0078	0.9922	88.01
35.5	13,028,564	135,368	0.0104	0.9896	87.33
36.5	12,411,036	131,978	0.0106	0.9894	86.42
37.5	11,279,561	144,706	0.0128	0.9872	85.50
38.5	9,560,604	142,497	0.0149	0.9851	84.40

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,014,379	103,541	0.0129	0.9871	83.14
40.5	7,768,030	82,640	0.0106	0.9894	82.07
41.5	7,559,586	114,520	0.0151	0.9849	81.20
42.5	7,241,836	105,136	0.0145	0.9855	79.97
43.5	7,019,829	93,689	0.0133	0.9867	78.81
44.5	6,786,647	86,961	0.0128	0.9872	77.75
45.5	6,404,477	87,012	0.0136	0.9864	76.76
46.5	5,619,420	76,059	0.0135	0.9865	75.72
47.5	5,114,195	95,845	0.0187	0.9813	74.69
48.5	4,501,263	93,798	0.0208	0.9792	73.29
49.5	3,783,071	86,963	0.0230	0.9770	71.76
50.5	3,291,457	82,784	0.0252	0.9748	70.11
51.5	3,105,098	91,938	0.0296	0.9704	68.35
52.5	2,580,377	72,983	0.0283	0.9717	66.33
53.5	2,193,320	65,014	0.0296	0.9704	64.45
54.5	1,938,976	67,264	0.0347	0.9653	62.54
55.5	1,722,450	63,585	0.0369	0.9631	60.37
56.5	1,607,476	69,352	0.0431	0.9569	58.14
57.5	1,510,301	65,697	0.0435	0.9565	55.63
58.5	1,362,858	61,564	0.0452	0.9548	53.21
59.5	1,214,097	88,740	0.0731	0.9269	50.81
60.5	1,059,075	55,231	0.0522	0.9478	47.10
61.5	901,767	41,824	0.0464	0.9536	44.64
62.5	760,265	29,615	0.0390	0.9610	42.57
63.5	658,228	23,048	0.0350	0.9650	40.91
64.5	554,029	26,667	0.0481	0.9519	39.48
65.5	436,018	41,969	0.0963	0.9037	37.58
66.5	317,549	25,320	0.0797	0.9203	33.96
67.5	230,452	21,550	0.0935	0.9065	31.25
68.5	171,917	14,618	0.0850	0.9150	28.33
69.5	140,265	10,120	0.0721	0.9279	25.92
70.5	115,467	8,730	0.0756	0.9244	24.05
71.5	99,711	3,379	0.0339	0.9661	22.23
72.5	91,651	3,831	0.0418	0.9582	21.48
73.5	85,589	2,052	0.0240	0.9760	20.58
74.5	82,161	3,737	0.0455	0.9545	20.09
75.5	75,836	2,189	0.0289	0.9711	19.18
76.5	66,781	3,243	0.0486	0.9514	18.62
77.5	59,879	5,844	0.0976	0.9024	17.72
78.5	50,553	7,583	0.1500	0.8500	15.99

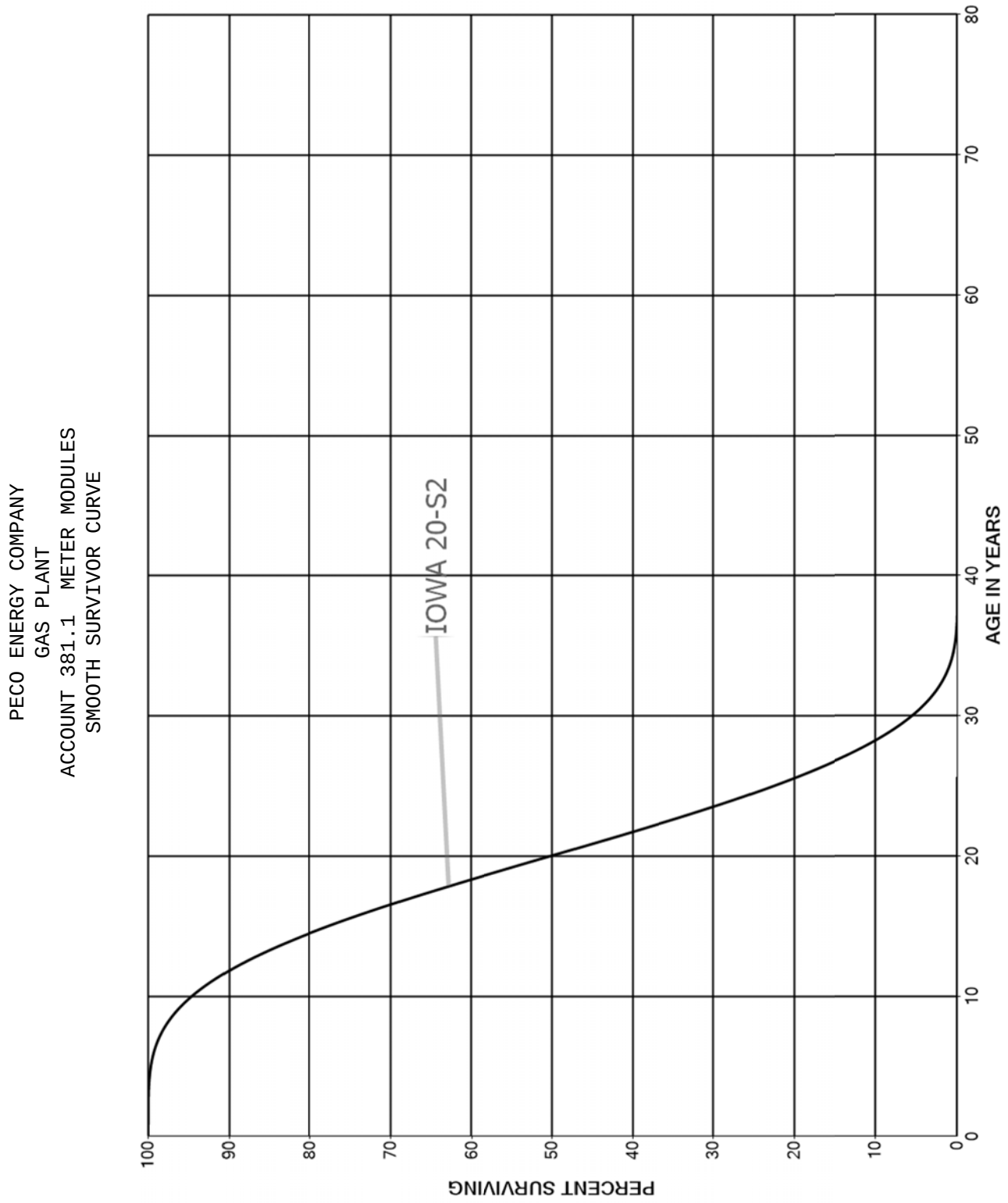
PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

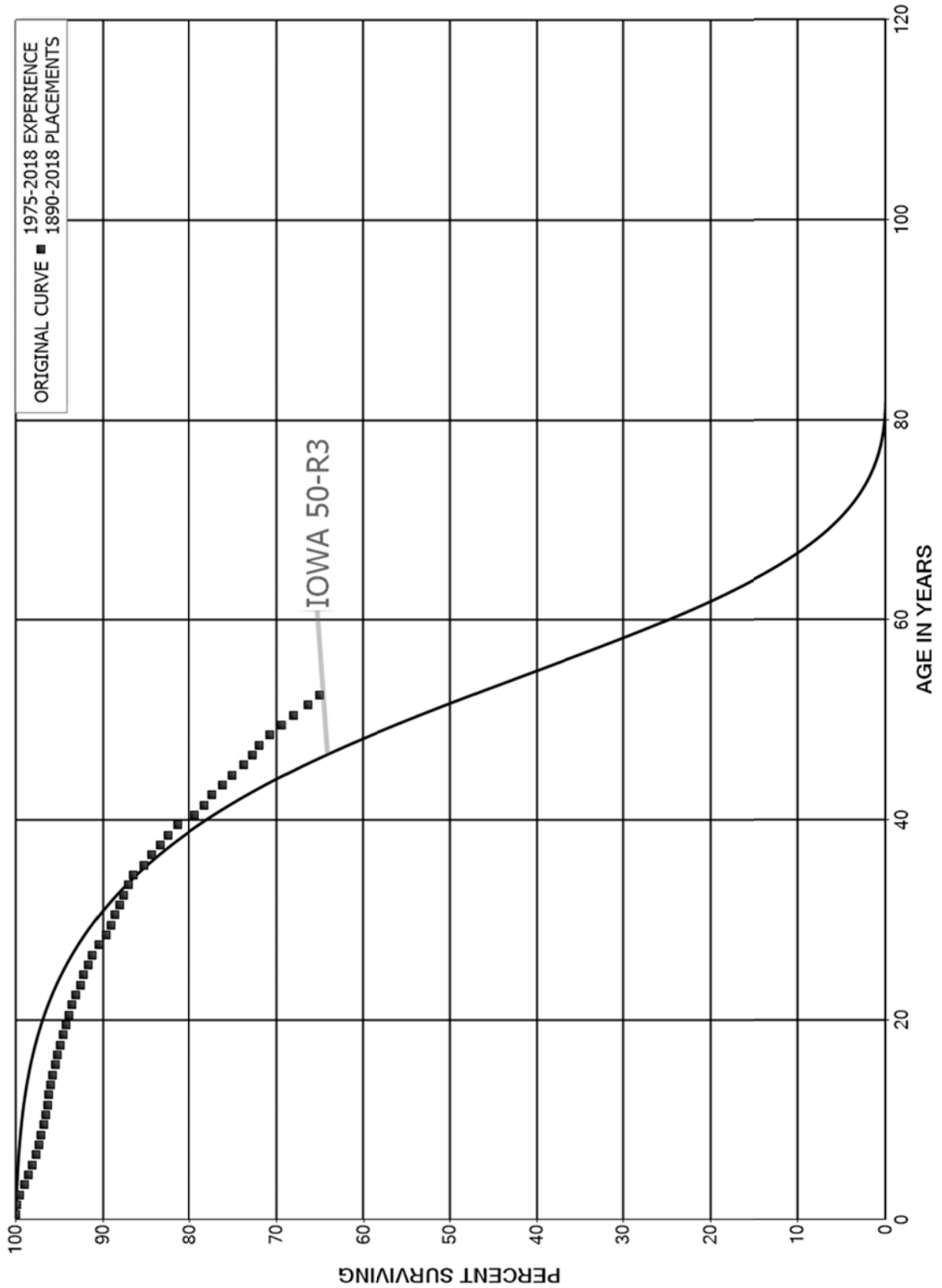
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	40,584	6,672	0.1644	0.8356	13.59
80.5	32,284	7,521	0.2330	0.7670	11.36
81.5	23,201	5,538	0.2387	0.7613	8.71
82.5	17,187	4,451	0.2590	0.7410	6.63
83.5	12,082	488	0.0404	0.9596	4.91
84.5	11,441	280	0.0245	0.9755	4.72
85.5	10,579	279	0.0264	0.9736	4.60
86.5	10,067	346	0.0344	0.9656	4.48
87.5	9,173	329	0.0358	0.9642	4.32
88.5	7,673	346	0.0451	0.9549	4.17
89.5	5,773	284	0.0492	0.9508	3.98
90.5	4,121	248	0.0602	0.9398	3.79
91.5	2,311	115	0.0496	0.9504	3.56
92.5	1,065	64	0.0596	0.9404	3.38
93.5	114	7	0.0594	0.9406	3.18
94.5	85	1	0.0081	0.9919	2.99
95.5	84	10	0.1227	0.8773	2.97
96.5	70	1	0.0120	0.9880	2.60
97.5	65	13	0.1988	0.8012	2.57
98.5	50	1	0.0159	0.9841	2.06
99.5	49	5	0.1017	0.8983	2.03
100.5	44	1	0.0137	0.9863	1.82
101.5	42	5	0.1252	0.8748	1.80
102.5	35	0	0.0092	0.9908	1.57
103.5	31	0	0.0156	0.9844	1.56
104.5	30	0	0.0064	0.9936	1.53
105.5	29	1	0.0221	0.9779	1.52
106.5	26	5	0.1751	0.8249	1.49
107.5	22	10	0.4669	0.5331	1.23
108.5	9	0	0.0485	0.9515	0.65
109.5	8	0	0.0376	0.9624	0.62
110.5	6	0	0.0173	0.9827	0.60
111.5	6	0	0.0176	0.9824	0.59
112.5	5		0.0000	1.0000	0.58
113.5	5		0.0000	1.0000	0.58
114.5	5	0	0.0304	0.9696	0.58
115.5	4	0	0.0761	0.9239	0.56
116.5	4	0	0.0484	0.9516	0.52
117.5	2	0	0.0327	0.9673	0.49
118.5					0.48


PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 381.1 METER MODULES
SMOOTH SURVIVOR CURVE
IOWA 20-S2
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
AGE IN YEARS
0
10
20
30
40
50
60
70
80

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 382 METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 382 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	179,475,912	13,792	0.0001	0.9999	100.00
0.5	168,332,118	294,987	0.0018	0.9982	99.99
1.5	161,439,753	502,561	0.0031	0.9969	99.82
2.5	154,531,692	791,332	0.0051	0.9949	99.51
3.5	148,181,745	706,640	0.0048	0.9952	99.00
4.5	143,842,322	626,643	0.0044	0.9956	98.52
5.5	138,749,012	606,748	0.0044	0.9956	98.10
6.5	134,410,186	497,976	0.0037	0.9963	97.67
7.5	127,535,185	244,466	0.0019	0.9981	97.30
8.5	124,338,080	442,576	0.0036	0.9964	97.12
9.5	88,369,448	214,925	0.0024	0.9976	96.77
10.5	99,322,281	217,369	0.0022	0.9978	96.54
11.5	106,030,308	216,657	0.0020	0.9980	96.33
12.5	107,327,270	197,450	0.0018	0.9982	96.13
13.5	108,947,822	312,667	0.0029	0.9971	95.95
14.5	106,802,341	323,231	0.0030	0.9970	95.68
15.5	104,464,575	291,108	0.0028	0.9972	95.39
16.5	100,729,736	341,303	0.0034	0.9966	95.12
17.5	95,175,562	296,150	0.0031	0.9969	94.80
18.5	94,302,169	301,600	0.0032	0.9968	94.50
19.5	90,933,761	327,898	0.0036	0.9964	94.20
20.5	77,372,388	338,464	0.0044	0.9956	93.86
21.5	67,757,107	299,448	0.0044	0.9956	93.45
22.5	63,513,533	334,502	0.0053	0.9947	93.04
23.5	57,996,928	268,077	0.0046	0.9954	92.55
24.5	53,723,131	276,517	0.0051	0.9949	92.12
25.5	49,599,123	266,945	0.0054	0.9946	91.65
26.5	45,751,266	355,052	0.0078	0.9922	91.15
27.5	40,267,557	361,556	0.0090	0.9910	90.45
28.5	36,658,177	224,937	0.0061	0.9939	89.63
29.5	33,892,289	178,836	0.0053	0.9947	89.08
30.5	31,179,895	183,348	0.0059	0.9941	88.61
31.5	27,948,550	159,577	0.0057	0.9943	88.09
32.5	25,037,457	155,137	0.0062	0.9938	87.59
33.5	21,847,006	147,466	0.0067	0.9933	87.05
34.5	19,889,111	269,771	0.0136	0.9864	86.46
35.5	17,649,719	188,867	0.0107	0.9893	85.29
36.5	15,673,955	174,070	0.0111	0.9889	84.37
37.5	12,963,575	145,407	0.0112	0.9888	83.44
38.5	9,761,295	137,076	0.0140	0.9860	82.50

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 382 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,487,780	203,131	0.0239	0.9761	81.34
40.5	7,745,418	104,260	0.0135	0.9865	79.40
41.5	7,283,526	88,032	0.0121	0.9879	78.33
42.5	6,891,829	104,153	0.0151	0.9849	77.38
43.5	6,431,579	98,649	0.0153	0.9847	76.21
44.5	5,919,554	103,258	0.0174	0.9826	75.04
45.5	5,152,592	68,070	0.0132	0.9868	73.73
46.5	4,459,397	52,148	0.0117	0.9883	72.76
47.5	3,758,998	64,353	0.0171	0.9829	71.91
48.5	3,255,407	57,256	0.0176	0.9824	70.68
49.5	2,750,175	52,383	0.0190	0.9810	69.43
50.5	2,329,459	57,390	0.0246	0.9754	68.11
51.5	1,973,943	41,948	0.0213	0.9787	66.43
52.5	1,718,898	45,730	0.0266	0.9734	65.02
53.5	1,419,052	45,535	0.0321	0.9679	63.29
54.5	1,199,077	39,794	0.0332	0.9668	61.26
55.5	1,033,724	26,255	0.0254	0.9746	59.23
56.5	883,770	17,159	0.0194	0.9806	57.72
57.5	822,462	28,837	0.0351	0.9649	56.60
58.5	703,377	16,223	0.0231	0.9769	54.62
59.5	639,861	15,270	0.0239	0.9761	53.36
60.5	572,065	16,564	0.0290	0.9710	52.09
61.5	507,158	11,672	0.0230	0.9770	50.58
62.5	453,522	10,620	0.0234	0.9766	49.41
63.5	391,324	11,531	0.0295	0.9705	48.26
64.5	324,800	11,761	0.0362	0.9638	46.83
65.5	276,020	10,816	0.0392	0.9608	45.14
66.5	227,571	7,592	0.0334	0.9666	43.37
67.5	200,633	7,465	0.0372	0.9628	41.92
68.5	161,279	9,585	0.0594	0.9406	40.36
69.5	125,415	9,705	0.0774	0.9226	37.96
70.5	108,314	6,271	0.0579	0.9421	35.03
71.5	92,832	6,279	0.0676	0.9324	33.00
72.5	87,234	7,230	0.0829	0.9171	30.77
73.5	80,499	5,943	0.0738	0.9262	28.22
74.5	72,853	5,246	0.0720	0.9280	26.13
75.5	62,541	3,724	0.0595	0.9405	24.25
76.5	56,879	4,000	0.0703	0.9297	22.81
77.5	51,737	4,711	0.0911	0.9089	21.20
78.5	44,071	3,355	0.0761	0.9239	19.27

PECO ENERGY COMPANY
GAS PLANT

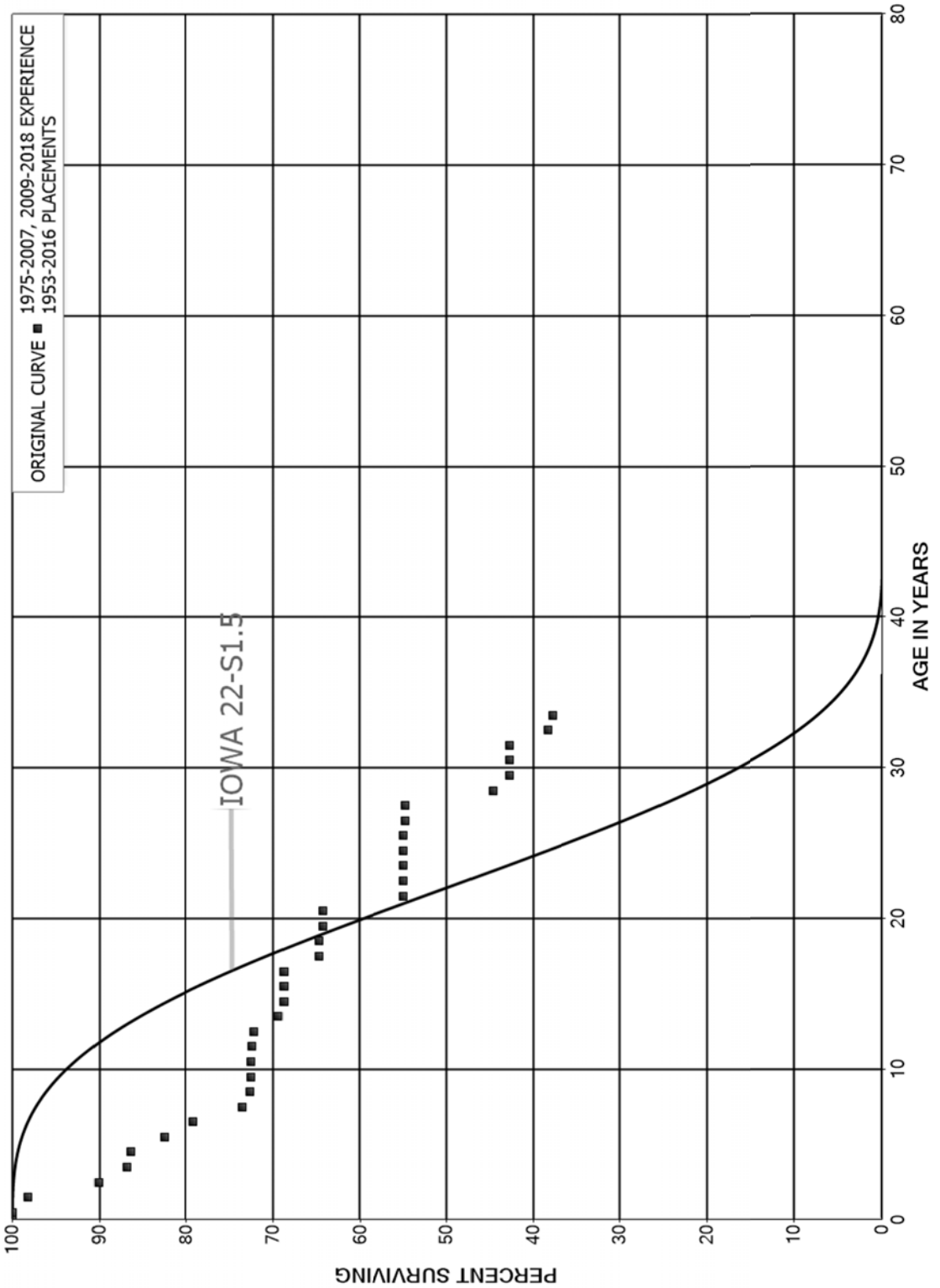
ACCOUNT 382 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	37,049	3,650	0.0985	0.9015	17.81
80.5	28,597	4,389	0.1535	0.8465	16.05
81.5	23,387	5,725	0.2448	0.7552	13.59
82.5	17,326	2,398	0.1384	0.8616	10.26
83.5	14,743	2,102	0.1426	0.8574	8.84
84.5	13,157	526	0.0400	0.9600	7.58
85.5	12,581	825	0.0656	0.9344	7.28
86.5	11,741	1,716	0.1462	0.8538	6.80
87.5	10,001	690	0.0690	0.9310	5.81
88.5	9,297	790	0.0850	0.9150	5.41
89.5	8,487	1,734	0.2044	0.7956	4.95
90.5	6,734	687	0.1020	0.8980	3.94
91.5	6,042	464	0.0768	0.9232	3.53
92.5	5,577	510	0.0914	0.9086	3.26
93.5	5,067	650	0.1282	0.8718	2.96
94.5	4,417	211	0.0477	0.9523	2.58
95.5	4,207	740	0.1759	0.8241	2.46
96.5	3,467	487	0.1404	0.8596	2.03
97.5	2,980	478	0.1603	0.8397	1.74
98.5	2,502	318	0.1272	0.8728	1.46
99.5	2,184	247	0.1132	0.8868	1.28
100.5	1,937	23	0.0118	0.9882	1.13
101.5	1,914	93	0.0485	0.9515	1.12
102.5	1,821	58	0.0318	0.9682	1.07
103.5	1,763	58	0.0328	0.9672	1.03
104.5	1,705	192	0.1127	0.8873	1.00
105.5	1,513	100	0.0663	0.9337	0.89
106.5	1,413	974	0.6892	0.3108	0.83
107.5	439	184	0.4200	0.5800	0.26
108.5	255	56	0.2207	0.7793	0.15
109.5	198	21	0.1035	0.8965	0.12
110.5	178		0.0000	1.0000	0.10
111.5	178		0.0000	1.0000	0.10
112.5	178		0.0000	1.0000	0.10
113.5	178	93	0.5225	0.4775	0.10
114.5	85		0.0000	1.0000	0.05
115.5	85	85	1.0000		0.05
116.5					

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 387 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1953-2016 EXPERIENCE BAND 1975-2007, 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,383,524	120	0.0000	1.0000	100.00
0.5	5,433,951	99,879	0.0184	0.9816	100.00
1.5	4,517,804	373,271	0.0826	0.9174	98.16
2.5	4,194,711	147,526	0.0352	0.9648	90.05
3.5	3,946,531	24,079	0.0061	0.9939	86.88
4.5	3,730,948	164,855	0.0442	0.9558	86.35
5.5	2,343,690	94,326	0.0402	0.9598	82.54
6.5	2,380,236	172,739	0.0726	0.9274	79.21
7.5	2,213,908	25,672	0.0116	0.9884	73.47
8.5	2,343,758	3,849	0.0016	0.9984	72.61
9.5	2,306,935		0.0000	1.0000	72.49
10.5	1,952,695	1,919	0.0010	0.9990	72.49
11.5	1,913,362	7,732	0.0040	0.9960	72.42
12.5	1,902,590	71,151	0.0374	0.9626	72.13
13.5	1,841,517	18,787	0.0102	0.9898	69.43
14.5	1,814,730		0.0000	1.0000	68.73
15.5	1,814,344		0.0000	1.0000	68.73
16.5	729,124	42,475	0.0583	0.9417	68.73
17.5	1,684,804		0.0000	1.0000	64.72
18.5	1,773,864	10,487	0.0059	0.9941	64.72
19.5	1,684,897		0.0000	1.0000	64.34
20.5	1,761,603	255,431	0.1450	0.8550	64.34
21.5	1,509,268	536	0.0004	0.9996	55.01
22.5	1,421,657		0.0000	1.0000	54.99
23.5	1,508,731		0.0000	1.0000	54.99
24.5	1,508,731		0.0000	1.0000	54.99
25.5	1,500,315	6,661	0.0044	0.9956	54.99
26.5	1,502,070		0.0000	1.0000	54.75
27.5	416,379	77,234	0.1855	0.8145	54.75
28.5	251,178	10,770	0.0429	0.9571	44.59
29.5	240,408		0.0000	1.0000	42.68
30.5	161,929		0.0000	1.0000	42.68
31.5	159,147	16,574	0.1041	0.8959	42.68
32.5	142,573	1,872	0.0131	0.9869	38.23
33.5	53,626		0.0000	1.0000	37.73
34.5	53,626		0.0000	1.0000	37.73
35.5	53,626	20	0.0004	0.9996	37.73
36.5	45,190	24	0.0005	0.9995	37.72
37.5	45,166		0.0000	1.0000	37.70
38.5	41,275		0.0000	1.0000	37.70

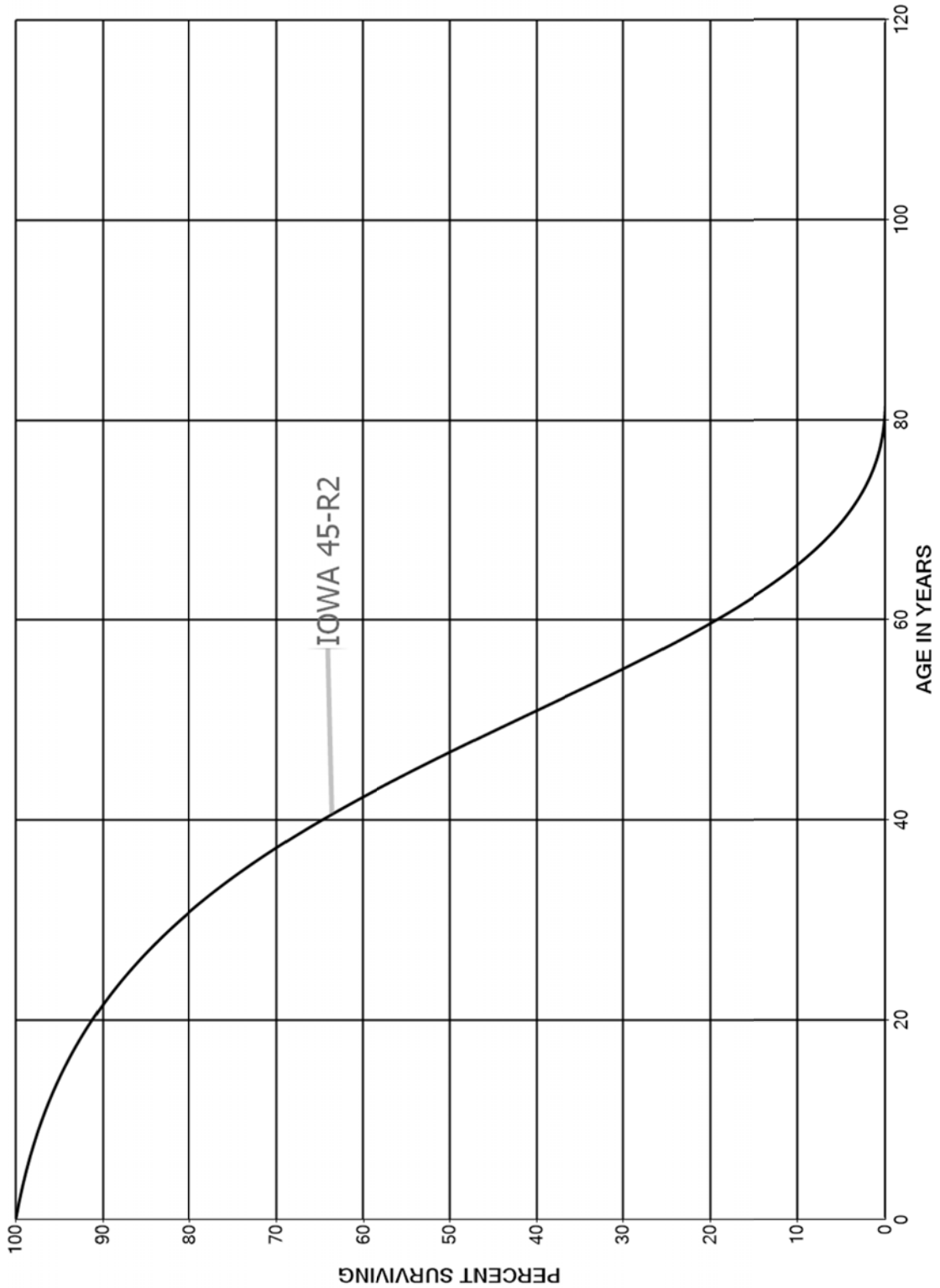
PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 387 OTHER EQUIPMENT

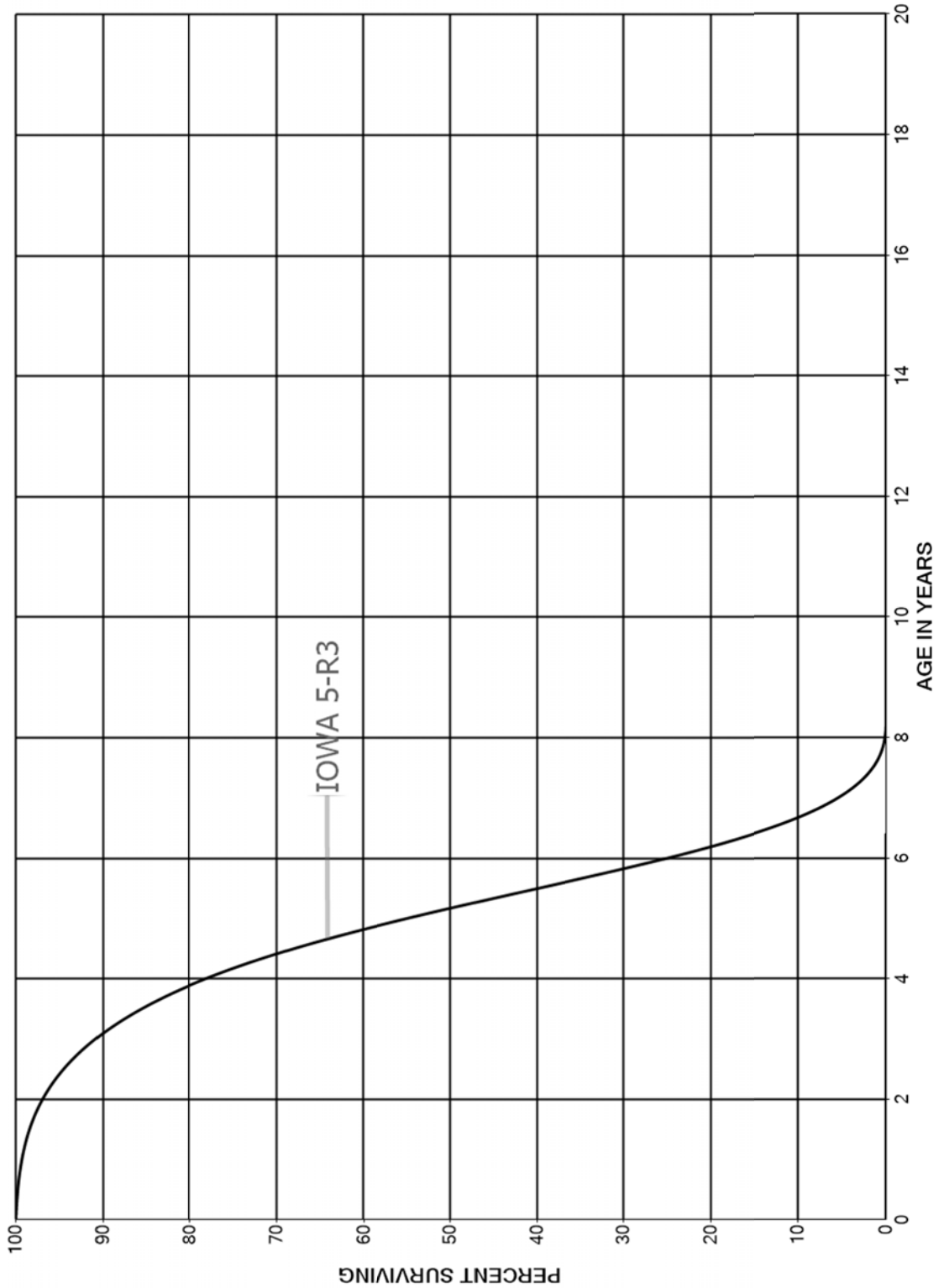
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1953-2016			EXPERIENCE BAND 1975-2007, 2009-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	40,764		0.0000	1.0000	37.70
40.5	45,166	2,732	0.0605	0.9395	37.70
41.5	35,296		0.0000	1.0000	35.42
42.5	29,854	94	0.0031	0.9969	35.42
43.5	41,587		0.0000	1.0000	35.31
44.5	42,340	919	0.0217	0.9783	35.31
45.5	31,609	430	0.0136	0.9864	34.54
46.5	40,990	1,093	0.0267	0.9733	34.07
47.5	39,897		0.0000	1.0000	33.16
48.5	39,897	44	0.0011	0.9989	33.16
49.5	35,962	313	0.0087	0.9913	33.12
50.5	31,247	28	0.0009	0.9991	32.84
51.5	31,219		0.0000	1.0000	32.81
52.5	24,082		0.0000	1.0000	32.81
53.5	10,564		0.0000	1.0000	32.81
54.5	10,749		0.0000	1.0000	32.81
55.5	10,749		0.0000	1.0000	32.81
56.5	938		0.0000	1.0000	32.81
57.5	938		0.0000	1.0000	32.81
58.5	938		0.0000	1.0000	32.81
59.5	938		0.0000	1.0000	32.81
60.5	938		0.0000	1.0000	32.81
61.5	938		0.0000	1.0000	32.81
62.5	938		0.0000	1.0000	32.81
63.5	938		0.0000	1.0000	32.81
64.5					32.81

PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 390 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
GAS PLANT
ACCOUNT 397 COMMUNICATION EQUIPMENT - SCADA HW & SW
SMOOTH SURVIVOR CURVE



PART VIII. DETAILED DEPRECIATION CALCULATIONS

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 305 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-S0						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. 0						
1984	747,606.59	493,316	600,590	147,017	14.66	10,028
1993	124,790.01	74,465	90,658	34,132	15.01	2,274
2016	294,361.21	39,312	47,860	246,501	15.96	15,445
2017	155,403.19	13,231	16,109	139,295	16.01	8,700
	1,322,161.00	620,324	755,217	566,944		36,447

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.6 2.76

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 311 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 40-S3						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. 0						
1984	5,303,580.67	4,033,585	5,096,409	207,172	9.43	21,969
1987	17,117.63	12,491	15,782	1,336	10.50	127
1989	9,322.14	6,596	8,334	988	11.22	88
1991	3,754.14	2,566	3,242	512	11.94	43
1993	6,217,273.94	4,091,588	5,169,695	1,047,579	12.64	82,878
1994	1,283,548.26	827,478	1,045,514	238,034	12.98	18,339
1995	9,642.15	6,082	7,685	1,957	13.31	147
1996	37,266.63	22,970	29,022	8,245	13.63	605
2003	3,176.74	1,589	2,008	1,169	15.42	76
2010	556,722.42	191,123	241,482	315,240	16.26	19,387
2011	606,249.70	190,884	241,181	365,069	16.32	22,369
2012	254,192.92	72,247	91,283	162,910	16.37	9,952
2016	31,990.70	4,216	5,327	26,663	16.47	1,619
	14,333,838.04	9,463,415	11,956,964	2,376,874		177,599

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.4 1.24

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 110-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1919	19,425.84	15,243	19,426			
1920	25,268.38	19,789	25,268			
1923	8,953.00	6,969	8,953			
1924	511.93	398	512			
1925	2,797.56	2,168	2,798			
1926	16,084.93	12,439	16,085			
1927	39,836.86	30,742	39,837			
1928	47,397.64	36,496	47,398			
1929	59,402.98	45,631	59,403			
1930	46,086.20	35,320	46,086			
1931	38,848.01	29,702	38,848			
1932	9,613.68	7,333	9,614			
1933	3,181.34	2,420	3,181			
1934	8,981.21	6,816	8,981			
1935	171.36	130	171			
1937	2,440.38	1,837	2,440			
1938	760.27	571	760			
1939	485.64	364	486			
1940	2,237.19	1,670	2,237			
1941	1,677.90	1,249	1,678			
1942	469.01	348	469			
1943	516.27	382	516			
1944	43.01	32	43			
1945	10,007.72	7,357	10,008			
1947	18,774.72	13,708	18,775			
1948	84,644.89	61,587	84,645			
1949	8,616.29	6,247	8,616			
1950	58,712.43	42,413	58,712			
1951	315,186.25	226,830	315,186			
1952	101,367.63	72,671	101,368			
1953	25,708.75	18,358	25,709			
1954	2,517.60	1,791	2,518			
1955	9,240.28	6,545	9,240			
1956	9,541.18	6,729	9,541			
1957	261,437.20	183,560	261,437			
1958	558.57	390	559			
1959	375.46	261	375			
1960	160,404.14	111,073	160,404			
1961	8,006.93	5,517	8,007			
1962	319.64	219	320			

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 110-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1963	2,302.93	1,571	2,294	9	22.01	
1966	775.64	520	759	17	22.08	1
1967	347.22	231	337	10	22.10	
1968	8,394.36	5,563	8,122	272	22.12	12
1969	22,491.19	14,810	21,623	868	22.14	39
1970	1,600.99	1,047	1,529	72	22.16	3
1971	5,071.51	3,295	4,811	261	22.18	12
1972	535,033.52	345,204	504,019	31,015	22.20	1,397
1973	2,907.79	1,862	2,719	189	22.22	9
1975	48,120.14	30,347	44,308	3,812	22.26	171
1977	470.76	292	426	45	22.29	2
1984	50,450.84	29,172	42,593	7,858	22.40	351
1985	108,675.03	62,109	90,683	17,992	22.41	803
1986	45,654.93	25,763	37,616	8,039	22.43	358
1987	3,634.89	2,024	2,955	680	22.44	30
1990	33,395.47	17,804	25,995	7,400	22.48	329
1991	39,877.30	20,920	30,544	9,333	22.49	415
1992	50,105.43	25,834	37,719	12,386	22.51	550
1993	910,009.58	460,792	672,784	237,226	22.52	10,534
1994	17,113.12	8,501	12,412	4,701	22.53	209
1995	19,444.33	9,463	13,817	5,627	22.54	250
1996	135,571.21	64,558	94,259	41,312	22.55	1,832
1997	849,356.12	395,188	576,998	272,358	22.56	12,073
2002	1,137,954.48	457,344	667,749	470,205	22.62	20,787
2003	385,362.28	149,220	217,870	167,492	22.63	7,401
2008	52,602.87	15,849	23,140	29,463	22.68	1,299
2010	367,717.44	95,169	138,953	228,764	22.71	10,073
2011	36,991.09	8,722	12,735	24,256	22.72	1,068
2012	22,054.71	4,660	6,804	15,251	22.73	671
2013	10,288.08	1,903	2,778	7,510	22.74	330
2014	84,393.24	13,231	19,318	65,075	22.75	2,860
2016	7,423,447.24	694,463	1,013,958	6,409,490	22.77	281,488
	13,822,226.00	3,990,736	5,743,237	8,078,989		355,357

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.7 2.57

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 362 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1972	6,231,437.89	4,139,482	6,231,438			
1973	729.80	481	730			
1993	22,862.34	11,898	19,557	3,305	23.50	141
1996	75,191.57	36,778	60,453	14,739	23.50	627
1997	384,842.22	183,870	302,232	82,610	23.50	3,515
2001	78,986.68	33,714	55,416	23,571	23.50	1,003
2005	13,492.23	4,923	8,092	5,400	23.50	230
2006	275,997.26	95,832	157,522	118,476	23.50	5,042
	7,083,539.99	4,506,978	6,835,440	248,100		10,558

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.5 0.15

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363 PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-L3						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1972	167,384.73	122,646	167,385			
1974	1,487.29	1,082	1,487			
1978	534.98	380	535			
1988	31,917.34	20,119	29,117	2,800	16.63	168
1989	59,437.92	36,797	53,254	6,184	17.00	364
1999	12,787.13	6,154	8,906	3,881	20.60	188
2001	151,099.45	67,838	98,178	52,921	21.16	2,501
2006	142,562.51	51,153	74,031	68,532	22.23	3,083
2008	371,903.24	118,072	170,880	201,023	22.53	8,922
2013	390,764.08	75,253	108,910	281,854	23.06	12,223
	1,329,878.67	499,494	712,683	617,196		27,449

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.5 2.06

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.1 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 40-L3						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1972	63,840.83	47,264	63,841			
1974	392.86	288	393			
1975	257,281.94	187,849	257,282			
1978	20,990.19	15,152	20,990			
1980	4,705.18	3,369	4,705			
1981	367.99	262	368			
1983	3,058.68	2,158	3,059			
1991	9,685.24	6,238	9,219	466	13.55	34
1995	18,441.73	10,866	16,058	2,384	15.26	156
1996	88,893.53	50,955	75,303	13,591	15.74	863
1998	1,759,425.62	948,137	1,401,186	358,240	16.72	21,426
1999	293,626.33	152,862	225,904	67,722	17.22	3,933
2001	560,278.80	270,262	399,402	160,877	18.20	8,839
2003	3,479,366.23	1,537,706	2,272,469	1,206,897	19.13	63,089
2005	1,181,948.17	472,354	698,059	483,889	19.98	24,219
2010	521,714.43	146,638	216,706	305,008	21.69	14,062
2012	322,478.91	72,974	107,843	214,636	22.19	9,673
2013	432,585.86	85,276	126,024	306,562	22.40	13,686
2015	427,070.36	56,963	84,182	342,888	22.74	15,079
2016	512,036.12	50,456	74,565	437,471	22.87	19,129
	9,958,189.00	4,118,029	6,057,558	3,900,631		194,188

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.1 1.95

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.2 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-L2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1972	127,380.15	90,048	127,380			
1973	276.59	195	277			
1974	437.64	307	438			
1978	1,014.80	701	1,015			
1982	1,740.45	1,173	1,740			
1983	633.00	423	633			
1994	24,293.42	13,788	21,984	2,309	17.03	136
1997	745,717.46	392,404	625,661	120,056	18.08	6,640
2001	202,227.31	93,546	149,153	53,074	19.46	2,727
2005	140,272.55	54,509	86,911	53,362	20.69	2,579
2006	203,549.71	74,965	119,527	84,023	20.96	4,009
2008	1,162,010.60	377,956	602,625	559,386	21.45	26,079
2009	76,444.49	23,093	36,820	39,624	21.67	1,829
2010	1,850,435.49	513,773	819,176	1,031,259	21.88	47,132
2017	1,696,334.30	104,291	166,285	1,530,049	22.90	66,814
2018	9,437,820.14	200,837	320,221	9,117,599	23.00	396,417
	15,670,588.10	1,942,009	3,079,846	12,590,742		554,362

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.7 3.54

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.3 COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 30-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1998	69,359.93	40,225	51,327	18,033	12.53	1,439
1999	439.65	245	313	127	13.16	10
2001	113,909.55	58,399	74,517	39,393	14.41	2,734
2002	1,200,922.10	587,815	750,056	450,866	15.03	29,998
2006	60,078.74	23,640	30,165	29,914	17.34	1,725
2010	96,072.32	27,854	35,542	60,530	19.25	3,144
2011	220,795.87	57,729	73,662	147,134	19.66	7,484
2012	40,117.36	9,330	11,905	28,212	20.03	1,408
2016	1,685,442.53	169,825	216,698	1,468,745	21.24	69,150
2017	495,743.22	30,944	39,485	456,258	21.48	21,241
2018	1,841,260.73	39,845	50,842	1,790,419	21.70	82,508
	5,824,142.00	1,045,851	1,334,512	4,489,630		220,841

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.3 3.79

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.4 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-L2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1997	1,092,188.58	574,721	902,425	189,764	18.08	10,496
2001	27,595.47	12,765	20,044	7,551	19.46	388
2013	14,594.17	2,869	4,505	10,089	22.40	450
2016	290,082.29	28,663	45,006	245,076	22.80	10,749
2018	123,212.65	2,622	4,117	119,096	23.00	5,178
	1,547,673.16	621,640	976,097	571,576		27,261

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.0 1.76

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.5 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-L2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1926	343.55	297	344			
1928	6,191.16	5,319	6,191			
1929	693.40	594	693			
1930	80.95	69	81			
1931	7,328.18	6,227	7,328			
1935	248.78	208	249			
1938	47.14	39	47			
1939	75.65	62	76			
1940	1,035.40	849	1,035			
1941	1,512.24	1,234	1,512			
1942	20.05	16	20			
1943	593.49	480	593			
1945	560.69	449	561			
1946	445.00	355	445			
1947	1,693.25	1,343	1,693			
1948	13,743.16	10,851	13,743			
1949	48,765.99	38,308	48,766			
1950	5,085.96	3,975	5,086			
1951	58,244.55	45,281	58,245			
1952	31,657.11	24,490	31,657			
1953	27,520.78	21,178	27,521			
1954	8,359.78	6,399	8,360			
1955	15,182.54	11,563	15,183			
1956	2,455.17	1,860	2,455			
1957	39,990.70	30,136	39,991			
1958	9,711.72	7,283	9,712			
1959	12,016.31	8,963	12,016			
1960	1,519.13	1,127	1,519			
1961	3,287.88	2,429	3,288			
1962	2,734.73	2,010	2,735			
1963	1,662.14	1,216	1,662			
1964	300.83	219	301			
1965	27,798.54	20,161	27,799			
1966	13,783.17	9,955	13,783			
1967	116.69	84	117			
1968	971.44	696	971			
1972	3,047,781.89	2,154,538	3,047,782			
1973	6,506.48	4,583	6,506			
1974	11,357.50	7,975	11,358			
1975	91,573.10	64,057	91,573			

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 363.5 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-L2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1976	7,015.46	4,889	7,015			
1977	679.12	471	677	2	13.31	
1978	3,966.69	2,740	3,940	27	13.40	2
1979	4,155.61	2,856	4,106	50	13.50	4
1980	8,383.73	5,729	8,237	147	13.62	11
1981	60,226.95	40,901	58,808	1,419	13.75	103
1982	4,845.28	3,267	4,697	148	13.90	11
1983	59,874.83	40,053	57,589	2,286	14.06	163
1984	20,822.38	13,806	19,850	972	14.24	68
1985	38,560.75	25,307	36,387	2,174	14.45	150
1986	1,989.80	1,292	1,858	132	14.67	9
1987	86,724.30	55,632	79,988	6,736	14.90	452
1988	10,558.65	6,683	9,609	950	15.16	63
1989	7,980.31	4,977	7,156	824	15.44	53
1990	9,408.27	5,775	8,303	1,105	15.73	70
1991	83,421.76	50,318	72,348	11,074	16.04	690
1992	70,677.67	41,843	60,162	10,516	16.36	643
1993	273,145.94	158,460	227,836	45,310	16.69	2,715
1994	54,181.68	30,751	44,214	9,968	17.03	585
1996	70,658.89	38,195	54,917	15,742	17.73	888
1999	2,656.56	1,317	1,894	763	18.78	41
2002	29,732.02	13,232	19,025	10,707	19.79	541
2004	1,311,198.22	534,825	768,978	542,220	20.41	26,566
2005	373,515.91	145,145	208,691	164,825	20.69	7,966
2006	214,574.26	79,026	113,625	100,949	20.96	4,816
2010	8,363.84	2,322	3,339	5,025	21.88	230
2012	247,054.87	55,610	79,957	167,098	22.24	7,513
2014	594,884.52	98,781	142,028	452,857	22.55	20,082
2015	173,534.73	23,143	33,275	140,260	22.68	6,184
2016	298,071.28	29,452	42,346	255,725	22.80	11,216
2017	69,069.50	4,246	6,105	62,964	22.90	2,750
	7,702,930.00	4,017,922	5,689,957	2,012,973		94,585

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.3 1.23

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. 0						
1910	1,046.66	1,047	1,047			
1915	1,143.09	1,143	1,143			
1931	821.26	821	821			
1932	37.51	38	38			
1943	447.14	445	393	54	0.27	54
1954	4,600.69	4,358	3,851	750	2.64	284
1955	343.25	323	285	58	2.90	20
1962	142,557.58	128,701	113,739	28,819	4.86	5,930
1963	8,670.53	7,772	6,868	1,803	5.18	348
1964	40,780.17	36,286	32,068	8,712	5.51	1,581
1965	192,553.59	169,948	150,191	42,363	5.87	7,217
1966	33,520.90	29,331	25,921	7,600	6.25	1,216
1971	223,034.69	184,762	163,283	59,752	8.58	6,964
1972	1,571.01	1,284	1,135	436	9.14	48
1973	4,245.03	3,418	3,021	1,224	9.74	126
1975	1,994.22	1,555	1,374	620	11.00	56
1978	732.74	542	479	254	13.04	19
1979	13,095.44	9,497	8,393	4,702	13.74	342
1980	377,828.96	268,561	237,340	140,489	14.46	9,716
1981	6,330.35	4,406	3,894	2,436	15.20	160
1982	210,672.48	143,468	126,789	83,883	15.95	5,259
1983	57,390.13	38,210	33,768	23,622	16.71	1,414
1984	233,206.14	151,631	134,003	99,203	17.49	5,672
1985	261,461.84	165,819	146,542	114,920	18.29	6,283
1986	8,008.81	4,949	4,374	3,635	19.10	190
1987	1,129.98	680	601	529	19.92	27
1988	313,781.34	183,499	162,166	151,615	20.76	7,303
1989	627,443.11	356,262	314,845	312,598	21.61	14,465
1990	50,101.91	27,576	24,370	25,732	22.48	1,145
1991	23,320.58	12,425	10,981	12,340	23.36	528
1992	27,196.22	14,006	12,378	14,818	24.25	611
1994	3,302,580.25	1,581,275	1,397,445	1,905,135	26.06	73,106
1995	411,605.08	189,503	167,472	244,133	26.98	9,049
1996	580,187.29	256,327	226,528	353,659	27.91	12,671
1997	1,388,434.92	587,308	519,031	869,404	28.85	30,135
1998	1,574,602.31	636,454	562,464	1,012,138	29.79	33,976
1999	8,943.15	3,443	3,043	5,900	30.75	192
2001	194,581.67	67,442	59,602	134,980	32.67	4,132
2002	50,149.65	16,409	14,501	35,649	33.64	1,060
2003	925,633.96	284,725	251,624	674,010	34.62	19,469
2004	129,057.30	37,169	32,848	96,209	35.60	2,702

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. 0						
2007	49,885.92	11,424	10,096	39,790	38.55	1,032
2012	364,549.18	47,318	41,817	322,732	43.51	7,417
2013	464,798.22	51,035	45,102	419,696	44.51	9,429
2014	85,767.42	7,702	6,807	78,960	45.51	1,735
2015	290,805.73	20,356	17,989	272,817	46.50	5,867
2016	168,305.12	8,415	7,437	160,868	47.50	3,387
2017	36,404.01	1,092	965	35,439	48.50	731
2018	757,146.89	7,571	6,691	750,456	49.50	15,161
	13,652,505.42	5,767,731	5,097,563	8,554,942		308,229
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.8	2.26

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.1 MAINS - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1880	0.99	1	1			
1890	0.92	1	1			
1891	0.71	1	1			
1899	0.97	1	1			
1900	0.98	1	1			
1901	0.97	1	1			
1902	5.74	6	6			
1903	1.80	2	2			
1904	0.98	1	1			
1905	2.23	2	2			
1906	42.34	42	42			
1907	18.19	18	18			
1908	58.75	57	59			
1909	94.31	91	94			
1910	120.25	116	120			
1911	1,994.51	1,921	1,995			
1912	623.78	599	624			
1913	403.82	386	404			
1914	261.60	249	262			
1915	2,068.01	1,962	2,068			
1916	6,074.19	5,740	6,074			
1917	3,144.42	2,960	3,144			
1918	523.96	491	524			
1919	1,654.01	1,545	1,654			
1920	13,036.41	12,129	13,036			
1921	12,915.14	11,969	12,876	39	5.13	8
1922	4,758.70	4,392	4,725	34	5.39	6
1923	27,318.62	25,114	27,016	303	5.65	54
1924	24,130.71	22,093	23,766	365	5.91	62
1925	28,973.21	26,424	28,425	548	6.16	89
1926	86,189.76	78,272	84,200	1,990	6.43	309
1927	86,624.89	78,346	84,280	2,345	6.69	351
1928	109,001.45	98,179	105,615	3,386	6.95	487
1929	108,288.07	97,119	104,475	3,813	7.22	528
1930	363,130.70	324,276	348,837	14,294	7.49	1,908
1931	101,356.59	90,106	96,931	4,426	7.77	570
1932	12,768.45	11,300	12,156	612	8.05	76
1933	12,275.58	10,813	11,632	644	8.34	77
1934	11,849.08	10,387	11,174	675	8.64	78
1935	7,748.49	6,759	7,271	477	8.94	53
1936	2,054.07	1,782	1,917	137	9.26	15

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.1 MAINS - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1937	11,451.56	9,884	10,633	819	9.58	85
1938	31,341.37	26,904	28,942	2,399	9.91	242
1939	22,712.85	19,387	20,855	1,858	10.25	181
1940	15,007.93	12,733	13,697	1,311	10.61	124
1941	18,447.89	15,557	16,735	1,713	10.97	156
1942	35,650.54	29,870	32,132	3,519	11.35	310
1943	18,619.22	15,497	16,671	1,948	11.74	166
1944	115,274.13	95,266	102,481	12,793	12.15	1,053
1945	105,627.86	86,675	93,240	12,388	12.56	986
1946	513,615.66	418,304	449,987	63,629	12.99	4,898
1947	533,180.25	430,884	463,519	69,661	13.43	5,187
1948	229,690.81	184,113	198,058	31,633	13.89	2,277
1949	425,957.75	338,577	364,221	61,737	14.36	4,299
1950	452,045.70	356,212	383,192	68,854	14.84	4,640
1951	1,260,641.56	984,385	1,058,943	201,699	15.34	13,149
1952	1,149,258.53	889,032	956,368	192,891	15.85	12,170
1953	1,459,250.69	1,117,990	1,202,667	256,584	16.37	15,674
1954	1,920,829.79	1,456,815	1,567,155	353,675	16.91	20,915
1955	1,657,670.79	1,244,198	1,338,434	319,237	17.46	18,284
1956	1,686,575.15	1,252,164	1,347,003	339,572	18.03	18,834
1957	4,472,841.90	3,284,363	3,533,122	939,720	18.60	50,523
1958	2,026,745.65	1,471,134	1,582,558	444,188	19.19	23,147
1959	2,145,312.20	1,538,811	1,655,361	489,951	19.79	24,758
1960	2,708,760.42	1,918,967	2,064,310	644,450	20.41	31,575
1961	2,084,224.13	1,458,061	1,568,495	515,729	21.03	24,523
1962	4,402,392.81	3,039,544	3,269,760	1,132,633	21.67	52,267
1963	3,309,302.30	2,254,098	2,424,824	884,478	22.32	39,627
1964	4,597,200.39	3,087,985	3,321,870	1,275,330	22.98	55,497
1965	3,655,836.35	2,420,675	2,604,018	1,051,818	23.65	44,474
1966	5,070,389.05	3,308,074	3,558,629	1,511,760	24.33	62,136
1967	4,883,217.42	3,137,809	3,375,468	1,507,749	25.02	60,262
1968	4,852,049.21	3,069,261	3,301,728	1,550,321	25.72	60,277
1969	6,329,694.41	3,939,792	4,238,194	2,091,500	26.43	79,134
1970	5,350,713.56	3,276,188	3,524,328	1,826,386	27.14	67,295
1971	4,932,908.35	2,968,920	3,193,787	1,739,121	27.87	62,401
1972	4,558,181.31	2,695,207	2,899,343	1,658,838	28.61	57,981
1973	4,282,344.87	2,486,800	2,675,151	1,607,194	29.35	54,760
1974	3,159,437.68	1,800,437	1,936,803	1,222,635	30.11	40,606
1975	2,121,489.62	1,185,913	1,275,735	845,755	30.87	27,397
1976	1,461,918.15	801,131	861,809	600,109	31.64	18,967
1977	1,057,207.11	567,572	610,560	446,647	32.42	13,777

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.1 MAINS - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1978	1,376,433.43	723,605	778,411	598,022	33.20	18,013
1979	3,035,431.41	1,561,517	1,679,787	1,355,644	33.99	39,884
1980	9,449,779.34	4,753,239	5,113,251	4,336,528	34.79	124,649
1981	10,821,655.49	5,318,086	5,720,880	5,100,775	35.60	143,280
1982	4,293,457.17	2,059,614	2,215,610	2,077,847	36.42	57,052
1983	4,327,969.15	2,025,490	2,178,901	2,149,068	37.24	57,709
1984	3,995,671.77	1,822,586	1,960,629	2,035,043	38.07	53,455
1985	6,833,746.73	3,035,140	3,265,023	3,568,724	38.91	91,717
1986	6,622,478.56	2,861,838	3,078,595	3,543,884	39.75	89,154
1987	8,164,512.05	3,429,095	3,688,816	4,475,696	40.60	110,239
1988	10,757,006.33	4,385,739	4,717,917	6,039,089	41.46	145,661
1989	13,252,748.08	5,240,534	5,637,454	7,615,294	42.32	179,946
1990	12,969,210.27	4,967,208	5,343,427	7,625,783	43.19	176,564
1991	13,012,031.86	4,820,047	5,185,119	7,826,913	44.07	177,602
1992	15,493,809.06	5,544,615	5,964,567	9,529,242	44.95	211,996
1993	11,686,483.13	4,033,473	4,338,970	7,347,513	45.84	160,286
1994	8,043,587.40	2,673,930	2,876,455	5,167,132	46.73	110,574
1995	28,352,224.34	9,060,520	9,746,768	18,605,456	47.63	390,625
1996	27,888,792.87	8,549,867	9,197,437	18,691,356	48.54	385,071
1997	33,773,068.62	9,914,760	10,665,708	23,107,361	49.45	467,287
1998	20,825,011.67	5,842,874	6,285,416	14,539,596	50.36	288,713
1999	15,980,520.65	4,271,433	4,594,953	11,385,568	51.29	221,984
2000	86,981.78	22,106	23,780	63,202	52.21	1,211
2001	10,372,226.89	2,498,255	2,687,474	7,684,753	53.14	144,613
2002	4,870,691.26	1,107,741	1,191,642	3,679,049	54.08	68,030
2003	3,727,203.04	797,621	858,033	2,869,170	55.02	52,148
2004	7,003,598.25	1,404,712	1,511,106	5,492,492	55.96	98,150
2005	8,216,736.66	1,536,530	1,652,907	6,563,830	56.91	115,337
2006	10,101,748.10	1,751,946	1,884,639	8,217,109	57.86	142,017
2007	6,661,378.08	1,064,888	1,145,543	5,515,835	58.81	93,791
2008	10,264,304.50	1,500,025	1,613,638	8,650,666	59.77	144,733
2009	7,481,892.43	990,827	1,065,873	6,416,019	60.73	105,648
2010	7,325,104.72	868,538	934,321	6,390,784	61.70	103,578
2011	8,531,040.57	893,285	960,943	7,570,098	62.67	120,793
2012	5,378,227.50	488,666	525,678	4,852,550	63.64	76,250
2013	4,547,044.12	350,122	376,640	4,170,404	64.61	64,547
2014	12,409,951.66	781,827	841,043	11,568,909	65.59	176,382
2015	14,136,975.16	694,691	747,307	13,389,668	66.56	201,167

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.1 MAINS - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
2016	12,724,833.21	447,151	481,018	12,243,815	67.54	181,282
2017	13,877,414.29	293,369	315,589	13,561,825	68.52	197,925
2018	23,276,646.57	162,937	175,278	23,101,368	69.51	332,346
	532,104,163.44	174,171,290	187,362,763	344,741,400		7,201,094
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.9	1.35

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 12-2035						
NET SALVAGE PERCENT.. 0						
1868	1.68	2	2			
1870	0.51	1	1			
1880	25.69	26	26			
1890	1,239.80	1,240	1,240			
1891	1,052.73	1,053	1,053			
1892	671.42	671	671			
1893	691.59	692	692			
1895	2,306.43	2,306	2,306			
1896	5,394.78	5,395	5,395			
1897	6,020.84	6,021	6,021			
1898	8,945.36	8,945	8,945			
1899	15,461.55	15,462	15,462			
1900	4,775.66	4,776	4,776			
1901	24,732.25	24,732	24,732			
1902	27,100.18	27,100	27,100			
1903	19,568.04	19,568	19,568			
1904	1,263.18	1,263	1,263			
1905	19,217.64	19,218	19,218			
1906	27,717.16	27,717	27,717			
1907	7,150.54	7,145	2,561	4,590	0.05	4,590
1908	3,090.90	3,076	1,102	1,989	0.29	1,989
1909	10,378.07	10,293	3,689	6,689	0.49	6,689
1910	17,888.78	17,662	6,330	11,559	0.76	11,559
1911	49,937.46	49,097	17,595	32,342	1.01	32,022
1912	45,938.56	44,966	16,115	29,824	1.27	23,483
1913	16,489.60	16,069	5,759	10,731	1.53	7,014
1914	58,566.14	56,809	20,359	38,207	1.80	21,226
1915	23,797.98	22,981	8,236	15,562	2.06	7,554
1916	24,946.31	23,973	8,591	16,355	2.34	6,989
1917	26,773.18	25,609	9,178	17,595	2.61	6,741
1918	30,463.50	28,996	10,391	20,072	2.89	6,945
1919	8,660.11	8,203	2,940	5,720	3.17	1,804
1920	9,327.46	8,791	3,150	6,177	3.45	1,790
1921	14,091.73	13,213	4,735	9,357	3.74	2,502
1922	80,088.04	74,722	26,778	53,310	4.02	13,261
1923	82,878.82	76,926	27,568	55,311	4.31	12,833
1924	145,809.51	134,630	48,247	97,563	4.60	21,209
1925	214,220.90	196,762	70,514	143,707	4.89	29,388
1926	206,719.18	188,873	67,687	139,032	5.18	26,840
1927	145,935.62	132,655	47,540	98,396	5.46	18,021

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 12-2035						
NET SALVAGE PERCENT.. 0						
1928	189,048.69	170,932	61,257	127,792	5.75	22,225
1929	186,039.62	167,343	59,971	126,069	6.03	20,907
1930	79,021.81	70,725	25,346	53,676	6.30	8,520
1931	59,638.82	53,107	19,032	40,607	6.57	6,181
1932	37,812.82	33,508	12,008	25,805	6.83	3,778
1933	12,365.27	10,906	3,908	8,457	7.08	1,194
1934	7,989.02	7,013	2,513	5,476	7.33	747
1935	18,640.67	16,287	5,837	12,804	7.57	1,691
1936	20,727.75	18,031	6,462	14,266	7.80	1,829
1937	26,016.79	22,531	8,074	17,943	8.03	2,234
1938	64,591.61	55,697	19,960	44,632	8.25	5,410
1939	68,673.55	58,961	21,130	47,544	8.47	5,613
1940	62,971.06	53,838	19,294	43,677	8.68	5,032
1941	57,598.92	49,029	17,571	40,028	8.90	4,498
1942	51,096.81	43,317	15,524	35,573	9.10	3,909
1943	97,843.06	82,590	29,598	68,245	9.31	7,330
1944	41,846.95	35,177	12,606	29,241	9.51	3,075
1945	72,874.66	61,002	21,861	51,014	9.71	5,254
1946	39,430.21	32,866	11,778	27,652	9.91	2,790
1947	216,693.44	179,843	64,450	152,243	10.11	15,059
1948	119,698.46	98,925	35,452	84,246	10.30	8,179
1949	435,185.12	358,062	128,319	306,866	10.50	29,225
1950	693,678.20	568,289	203,658	490,020	10.69	45,839
1951	679,717.85	554,391	198,678	481,040	10.88	44,213
1952	334,880.26	271,919	97,448	237,432	11.07	21,448
1953	552,334.74	446,535	160,025	392,310	11.25	34,872
1954	484,198.80	389,606	139,623	344,576	11.44	30,120
1955	722,782.70	578,920	207,468	515,315	11.62	44,347
1956	627,025.13	499,877	179,141	447,884	11.80	37,956
1957	633,490.15	502,598	180,116	453,374	11.98	37,844
1958	474,202.33	374,454	134,193	340,009	12.15	27,984
1959	596,543.96	468,770	167,994	428,550	12.32	34,785
1960	513,757.00	401,712	143,962	369,795	12.49	29,607
1961	740,979.62	576,504	206,602	534,378	12.65	42,243
1962	771,639.71	597,303	214,056	557,584	12.81	43,527
1963	390,123.80	300,411	107,659	282,465	12.97	21,778
1964	418,482.38	320,562	114,880	303,602	13.12	23,140
1965	359,614.88	273,987	98,189	261,426	13.27	19,701
1966	724,038.53	548,553	196,585	527,454	13.42	39,304
1967	614,064.64	462,642	165,797	448,268	13.56	33,058

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 12-2035						
NET SALVAGE PERCENT.. 0						
1968	810,460.96	607,214	217,608	592,853	13.69	43,306
1969	466,295.85	347,246	124,443	341,853	13.83	24,718
1970	155,904.27	115,435	41,368	114,536	13.95	8,210
1971	30,913.91	22,746	8,152	22,762	14.08	1,617
2009	112.58	40	14	99	16.49	6
2011	0.03					
2018	77,788.07	2,220	796	76,992	16.68	4,616
	15,228,174.34	12,219,263	4,485,659	10,742,516		1,123,368

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 7.38

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1951	48.66	40	40	9	11.99	1
1967	10,931.20	7,442	7,484	3,447	20.75	166
1969	316,299.93	208,856	210,028	106,272	22.08	4,813
1970	684,632.32	444,908	447,406	237,226	22.76	10,423
1971	817,792.08	522,757	525,692	292,100	23.45	12,456
1972	2,427,177.13	1,525,020	1,533,581	893,596	24.16	36,987
1973	640,270.41	395,290	397,509	242,761	24.87	9,761
1974	676,603.74	410,232	412,535	264,069	25.59	10,319
1976	320,110.11	186,797	187,846	132,264	27.07	4,886
1977	723,277.02	413,714	416,037	307,240	27.82	11,044
1978	1,938,694.43	1,086,270	1,092,368	846,326	28.58	29,613
1979	2,140,274.58	1,173,855	1,180,445	959,830	29.35	32,703
1980	5,725,059.73	3,071,266	3,088,508	2,636,552	30.13	87,506
1981	8,769,229.45	4,599,110	4,624,929	4,144,300	30.91	134,076
1982	3,619,511.61	1,853,733	1,864,140	1,755,372	31.71	55,357
1983	3,785,620.18	1,892,242	1,902,865	1,882,755	32.51	57,913
1984	3,039,962.62	1,481,617	1,489,935	1,550,028	33.32	46,519
1985	4,303,285.47	2,043,071	2,054,540	2,248,745	34.14	65,868
1986	5,583,526.48	2,580,427	2,594,913	2,988,613	34.96	85,487
1987	7,632,142.43	3,428,587	3,447,834	4,184,308	35.80	116,880
1988	6,396,207.53	2,790,729	2,806,396	3,589,812	36.64	97,975
1989	8,215,616.87	3,477,096	3,496,616	4,719,001	37.49	125,874
1990	10,484,753.38	4,300,322	4,324,463	6,160,290	38.34	160,675
1991	12,194,349.22	4,838,352	4,865,514	7,328,835	39.21	186,912
1992	16,251,786.33	6,230,610	6,265,587	9,986,199	40.08	249,157
1993	9,331,469.87	3,452,644	3,472,026	5,859,444	40.95	143,088
1994	13,907,041.32	4,957,304	4,985,133	8,921,908	41.83	213,290
1995	11,037,637.43	3,783,371	3,804,610	7,233,027	42.72	169,312
1996	9,208,193.44	3,028,759	3,045,762	6,162,431	43.62	141,275
1997	12,945,990.27	4,079,023	4,101,922	8,844,068	44.52	198,654
1998	8,021,353.31	2,415,069	2,428,627	5,592,726	45.43	123,106
1999	5,443,147.16	1,562,619	1,571,391	3,871,756	46.34	83,551
2000	3,877,213.23	1,058,169	1,064,109	2,813,104	47.26	59,524
2001	36,801,483.27	9,523,120	9,576,581	27,224,902	48.18	565,066
2002	19,061,475.47	4,659,768	4,685,927	14,375,548	49.11	292,721
2003	14,097,514.75	3,242,428	3,260,630	10,836,885	50.05	216,521
2004	23,502,308.40	5,065,688	5,094,126	18,408,182	50.99	361,016
2005	17,055,644.84	3,429,549	3,448,802	13,606,843	51.93	262,023
2006	16,069,167.51	2,996,257	3,013,077	13,056,091	52.88	246,900
2007	14,337,470.12	2,463,894	2,477,726	11,859,744	53.83	220,318
2008	21,788,626.85	3,425,826	3,445,058	18,343,569	54.78	334,859

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
2009	21,143,531.85	3,012,108	3,029,018	18,114,514	55.74	324,982
2010	23,794,255.72	3,034,719	3,051,755	20,742,501	56.71	365,764
2011	30,061,629.48	3,390,050	3,409,081	26,652,548	57.67	462,156
2012	37,990,463.27	3,717,367	3,738,236	34,252,227	58.64	584,110
2013	37,552,916.23	3,113,888	3,131,369	34,421,547	59.61	577,446
2014	30,116,509.31	2,043,405	2,054,876	28,061,633	60.59	463,140
2015	55,662,116.50	2,945,639	2,962,175	52,699,942	61.56	856,074
2016	62,235,333.01	2,355,607	2,368,831	59,866,502	62.54	957,251
2017	75,668,612.75	1,722,974	1,732,647	73,935,966	63.52	1,163,979
2018	67,524,078.69	509,132	511,990	67,012,088	64.51	1,038,786
	784,932,346.96	133,950,720	134,702,696	650,229,651		12,058,283
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					53.9	1.54

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2						
NET SALVAGE PERCENT.. 0						
1910	79.83	80	80			
1913	57.08	57	57			
1916	168.14	168	168			
1917	78.47	78	78			
1919	405.63	406	406			
1925	350.06	350	350			
1926	395.12	393	395			
1927	631.15	626	631			
1928	1,034.55	1,022	1,035			
1929	655.31	644	655			
1930	3,186.76	3,115	3,187			
1931	312.99	304	313			
1932	1,970.66	1,905	1,971			
1933	1,472.06	1,415	1,472			
1934	161.73	155	162			
1935	192.04	183	192			
1936	432.85	409	433			
1939	2,875.24	2,667	2,875			
1940	4,140.73	3,817	4,141			
1941	7,713.66	7,067	7,714			
1942	4,530.72	4,125	4,531			
1943	2,490.76	2,253	2,491			
1944	2,307.79	2,074	2,308			
1945	11,149.29	9,954	11,149			
1946	7,610.62	6,751	7,611			
1947	15,379.39	13,552	15,379			
1948	22,669.76	19,841	22,670			
1949	21,288.41	18,504	21,288			
1950	20,502.91	17,698	20,503			
1951	33,270.98	28,513	33,062	209	7.15	29
1952	17,478.24	14,870	17,242	236	7.46	32
1953	36,431.54	30,763	35,671	761	7.78	98
1954	39,244.19	32,887	38,134	1,110	8.10	137
1955	66,415.06	55,217	64,026	2,389	8.43	283
1956	41,714.48	34,398	39,886	1,828	8.77	208
1957	73,301.86	59,946	69,510	3,792	9.11	416
1958	100,248.87	81,262	94,226	6,023	9.47	636
1959	28,720.21	23,074	26,755	1,965	9.83	200
1960	58,984.50	46,940	54,429	4,556	10.21	446
1961	68,645.61	54,106	62,738	5,908	10.59	558
1962	62,063.82	48,422	56,147	5,917	10.99	538

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2						
NET SALVAGE PERCENT.. 0						
1963	74,491.54	57,522	66,699	7,793	11.39	684
1964	65,988.87	50,402	58,443	7,546	11.81	639
1965	19,466.67	14,701	17,046	2,421	12.24	198
1966	46,979.53	35,066	40,660	6,320	12.68	498
1967	53,053.66	39,122	45,364	7,690	13.13	586
1968	74,237.93	54,045	62,667	11,571	13.60	851
1969	45,321.53	32,568	37,764	7,558	14.07	537
1970	100,789.93	71,440	82,838	17,952	14.56	1,233
1971	85,653.47	59,855	69,404	16,249	15.06	1,079
1972	233,140.61	160,541	186,154	46,987	15.57	3,018
1973	122,793.61	83,279	96,565	26,229	16.09	1,630
1974	48,246.73	32,200	37,337	10,910	16.63	656
1975	288,917.34	189,703	219,968	68,949	17.17	4,016
1976	199,902.22	129,017	149,600	50,302	17.73	2,837
1977	153,429.69	97,274	112,793	40,637	18.30	2,221
1978	211,404.05	131,578	152,570	58,834	18.88	3,116
1979	59,387.30	36,250	42,033	17,354	19.48	891
1980	319,476.95	191,175	221,675	97,802	20.08	4,871
1981	519,057.01	304,167	352,694	166,363	20.70	8,037
1982	629,293.59	360,963	418,551	210,743	21.32	9,885
1983	466,547.24	261,640	303,382	163,165	21.96	7,430
1984	297,699.67	163,139	189,166	108,534	22.60	4,802
1985	419,949.68	224,589	260,420	159,530	23.26	6,859
1986	526,593.85	274,566	318,370	208,224	23.93	8,701
1987	562,037.23	285,515	331,066	230,971	24.60	9,389
1988	502,317.07	248,245	287,850	214,467	25.29	8,480
1989	319,984.12	153,720	178,244	141,740	25.98	5,456
1990	420,201.19	195,898	227,152	193,049	26.69	7,233
1991	260,550.91	117,769	136,558	123,993	27.40	4,525
1992	962,075.70	420,812	487,948	474,128	28.13	16,855
1993	434,525.95	183,718	213,028	221,498	28.86	7,675
1994	51,185.92	20,884	24,216	26,970	29.60	911
1999	81,615.48	27,064	31,382	50,233	33.42	1,503
2000	250,107.82	78,984	91,585	158,523	34.21	4,634
2001	821,338.24	246,237	285,522	535,816	35.01	15,305
2002	144,553.91	41,024	47,569	96,985	35.81	2,708
2003	223,840.93	59,900	69,456	154,385	36.62	4,216
2004	276,991.38	69,580	80,681	196,310	37.44	5,243
2005	239,186.47	56,161	65,121	174,065	38.26	4,550
2006	157,350.44	34,334	39,812	117,538	39.09	3,007
2007	555,509.42	111,880	129,729	425,780	39.93	10,663

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2						
NET SALVAGE PERCENT.. 0						
2008	365,362.09	67,446	78,206	287,156	40.77	7,043
2009	151,698.10	25,394	29,445	122,253	41.63	2,937
2010	148,531.41	22,339	25,903	122,628	42.48	2,887
2011	1,072,934.31	142,700	165,466	907,468	43.35	20,934
2012	379,635.42	43,886	50,888	328,747	44.22	7,434
2013	523,629.23	51,420	59,624	464,005	45.09	10,291
2014	136,939.79	11,037	12,798	124,142	45.97	2,701
2015	585,509.36	36,770	42,636	542,873	46.86	11,585
2016	524,696.27	23,611	27,378	497,318	47.75	10,415
2017	449,315.05	12,132	14,067	435,248	48.65	8,947
2018	1,730,920.05	15,578	18,063	1,712,857	49.55	34,568
	18,155,129.00	6,488,851	7,519,627	10,635,502		310,951

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.2 1.71

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1923	222.34	222	222			
1928	2,865.67	2,866	2,866			
1940	16.14	16	16			
1941	145.80	141	146			
1942	70.66	68	71			
1947	1,478.40	1,384	1,478			
1948	108.78	101	109			
1949	8,472.09	7,843	8,472			
1950	10,899.33	10,036	10,899			
1951	327,667.29	300,012	327,667			
1952	41,909.50	38,154	41,910			
1953	21,595.85	19,549	21,596			
1954	57,430.89	51,688	57,431			
1957	161,462.11	142,636	161,462			
1958	7,161.94	6,284	7,162			
1959	13,299.44	11,589	13,299			
1960	5,610.02	4,853	5,610			
1961	28,161.47	24,174	28,161			
1962	137,405.52	117,015	137,406			
1963	50,579.24	42,699	50,579			
1964	68,166.20	57,041	68,166			
1965	169,285.38	140,304	169,285			
1966	118,767.24	97,460	118,767			
1967	4,811.95	3,907	4,812			
1968	1,005.81	808	1,006			
1969	51,911.78	41,197	51,912			
1971	373,915.78	289,261	373,916			
1972	12,081.53	9,218	12,082			
1974	3,053.02	2,262	3,053			
1977	1,535.98	1,083	1,536			
1978	80,993.97	56,064	79,712	1,282	15.39	83
1979	25,537.05	17,350	24,668	869	16.03	54
1980	539,840.82	359,534	511,185	28,656	16.70	1,716
1981	793.85	518	736	58	17.38	3
1982	318,662.52	203,498	289,333	29,330	18.07	1,623
1983	9,218.07	5,758	8,187	1,031	18.77	55
1985	1,628,554.82	969,967	1,379,099	249,456	20.22	12,337
1986	16,591.68	9,633	13,696	2,896	20.97	138
1987	1,379.40	780	1,109	270	21.72	12
1988	324,440.05	178,507	253,801	70,639	22.49	3,141
1989	405,890.17	217,070	308,630	97,260	23.26	4,181

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1991	1,379,105.05	693,690	986,288	392,817	24.85	15,808
1992	903,491.71	439,820	625,336	278,156	25.66	10,840
1994	6,516,394.01	2,957,140	4,204,461	2,311,933	27.31	84,655
1995	7,446.48	3,254	4,627	2,819	28.15	100
1996	1,754,578.01	736,923	1,047,757	706,821	29.00	24,373
1997	519,242.44	209,151	297,371	221,871	29.86	7,430
1998	229,853.97	88,586	125,952	103,902	30.73	3,381
1999	53,766.59	19,786	28,132	25,635	31.60	811
2001	6,767,163.93	2,249,405	3,198,203	3,568,961	33.38	106,919
2002	2,196,354.45	690,534	981,801	1,214,553	34.28	35,430
2003	1,182,863.99	350,364	498,147	684,717	35.19	19,458
2004	4,638,715.16	1,288,635	1,832,180	2,806,535	36.11	77,722
2005	998,204.80	258,934	368,152	630,053	37.03	17,015
2006	1,757,865.79	423,294	601,839	1,156,027	37.96	30,454
2007	1,287,214.15	286,019	406,662	880,552	38.89	22,642
2008	990,091.64	201,187	286,048	704,044	39.84	17,672
2009	1,421,084.78	262,048	372,579	1,048,506	40.78	25,711
2010	602,746.66	99,574	141,574	461,173	41.74	11,049
2011	264,156.87	38,620	54,910	209,247	42.69	4,902
2012	295,658.45	37,489	53,302	242,356	43.66	5,551
2013	529,994.86	57,027	81,081	448,914	44.62	10,061
2014	297,609.24	26,249	37,321	260,288	45.59	5,709
2015	519,445.76	35,634	50,664	468,782	46.57	10,066
2016	73,310.04	3,607	5,128	68,182	47.54	1,434
2018	12,638,825.62	123,860	176,105	12,462,721	49.51	251,721
	52,858,184.00	15,023,380	21,016,873	31,841,311		824,257

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.6 1.56

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.1 SERVICES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-S0						
NET SALVAGE PERCENT.. 0						
1944	2.29	2	2			
1947	1,347.58	1,314	265	1,083	0.92	1,083
1948	3,840.01	3,707	747	3,093	1.28	2,416
1949	5,161.96	4,932	993	4,169	1.65	2,527
1950	11,539.03	10,909	2,197	9,342	2.02	4,625
1951	13,496.37	12,625	2,543	10,953	2.39	4,583
1952	17,775.68	16,445	3,312	14,464	2.77	5,222
1953	38,929.41	35,626	7,175	31,754	3.14	10,113
1954	34,294.65	31,032	6,249	28,046	3.52	7,968
1955	72,075.43	64,478	12,985	59,090	3.90	15,151
1956	66,042.67	58,403	11,762	54,281	4.28	12,682
1957	139,641.80	122,054	24,580	115,062	4.66	24,691
1958	95,794.64	82,745	16,664	79,131	5.04	15,701
1959	146,789.70	125,247	25,223	121,567	5.43	22,388
1960	127,351.31	107,353	21,620	105,731	5.81	18,198
1961	299,692.42	249,473	50,241	249,451	6.20	40,234
1962	355,785.16	292,416	58,889	296,896	6.59	45,053
1963	417,285.50	338,565	68,183	349,102	6.98	50,015
1964	501,801.03	401,712	80,900	420,901	7.38	57,033
1965	760,621.32	600,685	120,970	639,651	7.78	82,217
1966	761,866.13	593,433	119,510	642,356	8.18	78,528
1967	707,513.17	543,448	109,444	598,069	8.58	69,705
1968	692,138.55	524,157	105,559	586,580	8.98	65,321
1969	407,615.76	304,171	61,256	346,360	9.39	36,886
1970	82,848.81	60,905	12,265	70,584	9.80	7,202
1971	142,054.39	102,854	20,713	121,341	10.21	11,885
1972	190,173.14	135,588	27,306	162,867	10.62	15,336
1982	124,380.46	74,192	14,941	109,439	14.93	7,330
1983	556,785.52	325,191	65,489	491,297	15.39	31,923
1984	584,803.39	334,443	67,353	517,450	15.84	32,667
1985	703,684.64	393,683	79,283	624,402	16.30	38,307
1986	637,639.57	348,636	70,211	567,429	16.77	33,836
1987	751,283.49	401,223	80,801	670,482	17.24	38,891
1988	833,007.36	434,288	87,460	745,547	17.71	42,098
1989	787,267.86	400,231	80,601	706,667	18.19	38,849
1990	819,048.67	405,765	81,716	737,333	18.67	39,493
1991	1,013,387.33	488,615	98,401	914,986	19.16	47,755
1992	778,149.47	364,680	73,442	704,707	19.66	35,845
1993	777,797.30	354,007	71,293	706,504	20.16	35,045
1994	334,021.16	147,420	29,689	304,332	20.67	14,723
1995	844,394.66	360,810	72,663	771,732	21.19	36,420

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.1 SERVICES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-S0						
NET SALVAGE PERCENT.. 0						
1996	901,878.50	372,692	75,055	826,824	21.71	38,085
1997	1,673,277.34	667,504	134,427	1,538,850	22.24	69,193
1998	2,561,393.31	984,395	198,245	2,363,148	22.78	103,738
1999	1,633,591.27	603,547	121,547	1,512,044	23.33	64,811
2000	2,572,421.72	911,460	183,556	2,388,866	23.89	99,994
2001	7,967,564.14	2,702,518	544,253	7,423,311	24.45	303,612
2002	5,577,068.51	1,804,237	363,350	5,213,719	25.03	208,299
2003	6,515,473.88	2,003,964	403,573	6,111,901	25.62	238,560
2004	2,919,012.22	850,454	171,271	2,747,741	26.22	104,796
2005	4,771,834.03	1,311,586	264,137	4,507,697	26.83	168,010
2006	4,500,186.09	1,161,543	233,920	4,266,266	27.45	155,420
2007	4,072,734.39	980,755	197,512	3,875,222	28.09	137,957
2008	4,921,328.03	1,097,309	220,984	4,700,344	28.75	163,490
2009	3,017,732.15	618,213	124,500	2,893,232	29.42	98,342
2010	3,396,225.20	633,362	127,551	3,268,674	30.10	108,594
2011	3,364,100.91	562,814	113,343	3,250,758	30.81	105,510
2012	3,637,651.31	536,808	108,106	3,529,545	31.54	111,907
2013	3,583,915.81	456,232	91,879	3,492,037	32.29	108,146
2014	3,169,105.49	336,622	67,792	3,101,313	33.07	93,780
2015	2,265,949.97	191,677	38,601	2,227,349	33.87	65,762
2016	3,196,587.37	197,837	39,842	3,156,745	34.71	90,946
2017	3,330,308.32	126,918	25,560	3,304,748	35.59	92,856
2018	3,120,474.18	41,315	8,320	3,112,154	36.51	85,241
	98,308,942.93	28,811,225	5,802,220	92,506,723		3,996,994

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.1 4.07

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.2 SERVICES - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 56-R3						
NET SALVAGE PERCENT.. 0						
1951	614.53	538	615			
1966	144,840.08	111,087	131,459	13,381	13.05	1,025
1967	375,533.81	284,467	336,636	38,898	13.58	2,864
1968	564,385.89	421,878	499,247	65,139	14.14	4,607
1969	1,578,376.78	1,163,769	1,377,195	201,182	14.71	13,677
1970	2,853,428.67	2,074,329	2,454,744	398,685	15.29	26,075
1971	3,854,123.89	2,759,822	3,265,951	588,173	15.90	36,992
1972	5,528,588.51	3,898,650	4,613,631	914,958	16.51	55,418
1973	1,214,868.03	843,033	997,639	217,229	17.14	12,674
1974	1,202,689.74	820,619	971,114	231,576	17.79	13,017
1975	1,551,292.13	1,040,203	1,230,968	320,324	18.45	17,362
1976	2,761,776.28	1,818,823	2,152,381	609,395	19.12	31,872
1977	2,623,834.71	1,696,125	2,007,181	616,654	19.80	31,144
1978	4,021,386.18	2,549,277	3,016,794	1,004,592	20.50	49,004
1979	9,658,644.23	6,000,433	7,100,865	2,557,779	21.21	120,593
1980	12,363,399.60	7,521,769	8,901,202	3,462,198	21.93	157,875
1981	12,736,752.06	7,582,953	8,973,606	3,763,146	22.66	166,070
1982	10,204,781.03	5,938,774	7,027,898	3,176,883	23.41	135,706
1983	9,445,475.23	5,370,414	6,355,305	3,090,170	24.16	127,904
1984	8,499,775.57	4,717,375	5,582,504	2,917,272	24.92	117,065
1985	12,195,295.36	6,598,508	7,808,622	4,386,673	25.70	170,688
1986	11,897,650.25	6,271,727	7,421,912	4,475,738	26.48	169,023
1987	15,904,386.76	8,159,587	9,655,990	6,248,397	27.27	229,131
1988	14,446,835.55	7,202,759	8,523,688	5,923,148	28.08	210,938
1989	15,493,207.12	7,500,416	8,875,933	6,617,274	28.89	229,051
1990	17,544,491.54	8,236,437	9,746,934	7,797,558	29.71	262,456
1991	23,923,478.61	10,876,570	12,871,246	11,052,233	30.54	361,894
1992	23,205,566.52	10,202,095	12,073,078	11,132,489	31.38	354,764
1993	16,701,277.94	7,089,024	8,389,095	8,312,183	32.23	257,902
1994	11,237,062.29	4,599,217	5,442,677	5,794,385	33.08	175,163
1995	5,122,034.99	2,017,723	2,387,757	2,734,278	33.94	80,562
1996	5,341,152.93	2,020,077	2,390,543	2,950,610	34.82	84,739
1997	10,699,457.18	3,878,553	4,589,849	6,109,608	35.70	171,137
1998	9,245,883.32	3,206,380	3,794,405	5,451,478	36.58	149,029
1999	9,633,005.14	3,185,731	3,769,969	5,863,036	37.48	156,431
2000	6,255,251.35	1,968,152	2,329,095	3,926,156	38.38	102,297
2001	22,541,100.44	6,726,039	7,959,541	14,581,559	39.29	371,126
2002	13,748,247.38	3,878,931	4,590,296	9,157,951	40.20	227,810
2003	10,873,296.74	2,889,144	3,418,990	7,454,307	41.12	181,282
2004	11,015,221.55	2,744,002	3,247,230	7,767,992	42.05	184,732
2005	13,324,887.96	3,098,036	3,666,191	9,658,697	42.98	224,725

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 380.2 SERVICES - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 56-R3						
NET SALVAGE PERCENT.. 0						
2006	11,361,519.28	2,450,793	2,900,249	8,461,270	43.92	192,652
2007	12,372,951.67	2,461,351	2,912,743	9,460,209	44.86	210,883
2008	12,880,936.68	2,343,815	2,773,652	10,107,285	45.81	220,635
2009	14,989,863.05	2,473,327	2,926,915	12,062,948	46.76	257,976
2010	18,148,478.72	2,683,434	3,175,554	14,972,925	47.72	313,766
2011	19,779,580.33	2,585,389	3,059,529	16,720,051	48.68	343,469
2012	23,688,233.09	2,686,009	3,178,602	20,509,631	49.65	413,084
2013	24,928,996.03	2,394,929	2,834,140	22,094,856	50.62	436,485
2014	20,188,401.90	1,589,837	1,881,400	18,307,002	51.59	354,856
2015	34,840,371.56	2,133,973	2,525,327	32,315,045	52.57	614,705
2016	41,971,684.36	1,843,816	2,181,957	39,789,727	53.54	743,178
2017	47,335,007.60	1,251,064	1,480,499	45,854,509	54.52	841,058
2018	71,965,748.85	629,700	745,182	71,220,567	55.51	1,283,022
	725,985,130.99	196,490,883	232,525,725	493,459,406		11,701,593

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.2 1.61

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
1900	2.37	2	2			
1901	1.48	1	1			
1906	1.52	2	2			
1908	1.58	2	2			
1910	2.92	3	3			
1912	2.43	2	2			
1914	1.35	1	1			
1915	3.11	3	3			
1916	1.53	2	2			
1917	1.68	2	2			
1920	2.19	2	2			
1921	4.22	4	4			
1922	3.97	4	4			
1924	22.36	22	22			
1925	888.01	888	888			
1926	1,131.38	1,131	1,131			
1927	1,561.85	1,562	1,562			
1928	1,367.02	1,367	1,367			
1929	1,553.66	1,554	1,554			
1930	1,171.32	1,171	1,171			
1931	548.29	548	548			
1932	232.79	233	233			
1933	581.97	582	582			
1934	152.80	153	153			
1935	654.43	654	654			
1936	476.12	476	476			
1937	1,561.49	1,561	1,561			
1938	1,628.10	1,628	1,628			
1939	2,386.38	2,386	2,386			
1940	3,482.03	3,482	3,482			
1941	3,658.91	3,659	3,659			
1942	6,865.83	6,866	6,866			
1943	2,587.45	2,587	2,587			
1944	1,389.65	1,390	1,390			
1945	2,237.63	2,238	2,238			
1946	4,681.34	4,681	4,681			
1947	7,026.72	7,027	7,027			
1948	14,677.69	14,678	14,678			
1949	17,033.36	17,033	17,033			
1950	36,991.68	36,992	36,992			
1951	61,777.09	61,700	61,777			

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
1952	76,520.82	75,947	76,521			
1953	91,344.16	90,180	91,344			
1954	81,194.06	79,692	81,194			
1955	72,522.28	70,764	72,522			
1956	99,738.47	96,721	99,738			
1957	102,096.25	98,370	102,096			
1958	66,301.14	63,467	66,301			
1959	87,245.44	82,970	87,245			
1960	81,753.88	77,217	81,754			
1961	27,831.47	26,113	27,831			
1962	51,441.27	47,930	51,441			
1963	149,302.45	138,142	149,302			
1964	189,573.24	174,170	189,573			
1965	314,137.31	286,650	314,137			
1966	432,838.50	392,152	432,838			
1967	103,683.25	93,237	103,683			
1968	405,032.24	361,491	405,032			
1969	647,156.50	573,057	647,156			
1970	542,914.64	476,815	542,915			
1971	465,409.17	405,139	465,409			
1972	728,733.40	628,533	728,733			
1973	329,830.71	281,758	329,831			
1974	169,698.38	143,438	169,698			
1975	132,793.28	110,982	132,793			
1976	207,255.73	171,141	207,256			
1977	137,086.44	111,760	137,086			
1978	145,409.15	116,909	144,593	816	7.84	104
1979	1,417,918.13	1,123,346	1,389,357	28,561	8.31	3,437
1980	1,583,179.42	1,234,880	1,527,302	55,877	8.80	6,350
1981	1,019,422.23	781,897	967,052	52,370	9.32	5,619
1982	502,560.22	378,679	468,351	34,209	9.86	3,469
1983	399,989.21	295,792	365,836	34,153	10.42	3,278
1984	430,246.60	311,821	385,661	44,586	11.01	4,050
1985	1,012,180.80	718,142	888,199	123,982	11.62	10,670
1986	799,435.80	554,609	685,942	113,494	12.25	9,265
1987	983,147.82	666,328	824,116	159,032	12.89	12,338
1988	983,408.27	650,033	803,962	179,446	13.56	13,233
1989	1,018,385.68	655,586	810,830	207,556	14.25	14,565
1990	1,217,029.97	762,165	942,647	274,383	14.95	18,353
1991	1,347,030.15	819,331	1,013,350	333,680	15.67	21,294
1992	1,325,529.43	782,062	967,256	358,273	16.40	21,846

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
1993	1,448,898.79	827,683	1,023,680	425,219	17.15	24,794
1994	1,319,896.76	728,913	901,521	418,376	17.91	23,360
1995	1,016,227.08	541,395	669,598	346,629	18.69	18,546
1996	1,496,008.01	767,452	949,186	546,822	19.48	28,071
1997	2,114,713.82	1,042,025	1,288,779	825,935	20.29	40,707
1998	991,033.97	468,264	579,150	411,884	21.10	19,521
1999	1,361,876.43	615,228	760,915	600,961	21.93	27,404
2000	4,394.00	1,892	2,340	2,054	22.78	90
2001	19,924,881.40	8,154,258	10,085,203	9,839,678	23.63	416,406
2002	2,286,526.23	886,601	1,096,550	1,189,976	24.49	48,590
2003	1,119,636.41	409,507	506,479	613,157	25.37	24,169
2004	507,825.76	174,438	215,745	292,081	26.26	11,123
2005	1,591,773.77	511,357	632,447	959,327	27.15	35,334
2006	733,709.82	219,012	270,875	462,835	28.06	16,494
2007	946,030.68	260,631	322,349	623,682	28.98	21,521
2008	2,107,316.08	532,097	658,099	1,449,217	29.90	48,469
2009	1,206,438.85	276,576	342,070	864,369	30.83	28,037
2010	1,316,894.06	270,951	335,113	981,781	31.77	30,903
2011	1,299,141.93	236,444	292,434	1,006,708	32.72	30,767
2012	1,336,227.28	211,124	261,119	1,075,108	33.68	31,921
2013	2,095,023.70	280,733	347,211	1,747,813	34.64	50,456
2014	2,004,901.45	220,539	272,763	1,732,138	35.60	48,656
2015	3,991,551.59	342,276	423,327	3,568,225	36.57	97,572
2016	3,267,417.64	200,129	247,520	3,019,898	37.55	80,423
2017	2,012,498.95	73,959	91,473	1,921,026	38.53	49,858
2018	1,396,769.07	17,110	21,161	1,375,608	39.51	34,817
	79,054,278.59	33,458,289	40,753,346	38,300,932		1,435,880

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.7 1.82

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 381.1 METER MODULES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S2						
NET SALVAGE PERCENT.. 0						
2013	2,270,274.80	615,244	643,120	1,627,155	14.58	111,602
2014	32,663,594.09	7,300,313	7,631,083	25,032,511	15.53	1,611,881
2015	23,792,671.15	4,151,821	4,339,936	19,452,735	16.51	1,178,240
2016	6,551,872.83	818,984	856,091	5,695,782	17.50	325,473
2017	1,135,241.91	85,143	89,001	1,046,241	18.50	56,554
2018	741,601.20	18,540	19,380	722,221	19.50	37,037
	67,155,255.98	12,990,045	13,578,611	53,576,645		3,320,787

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1 4.94

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1926	2.00	2	2			
1927	4.84	5	5			
1928	18.74	19	19			
1929	19.94	20	20			
1930	13.74	14	14			
1931	24.07	24	24			
1932	14.83	15	15			
1933	50.07	50	50			
1934	43.12	43	43			
1935	184.63	183	185			
1936	429.66	425	430			
1937	821.28	809	821			
1938	4,801.19	4,709	4,801			
1939	3,685.20	3,597	3,685			
1940	2,977.65	2,892	2,978			
1941	1,299.43	1,256	1,299			
1942	2,378.12	2,287	2,378			
1943	6,844.65	6,548	6,845			
1944	2,924.41	2,783	2,924			
1945	40.92	39	41			
1947	9,809.05	9,183	9,809			
1948	8,061.19	7,505	8,061			
1949	26,512.89	24,546	26,513			
1950	32,804.92	30,207	32,805			
1951	20,005.24	18,317	20,005			
1952	38,731.10	35,261	38,731			
1953	37,488.15	33,934	37,488			
1954	59,238.09	53,314	59,238			
1955	53,287.95	47,671	53,288			
1956	43,597.97	38,759	43,598			
1957	50,168.57	44,319	49,933	236	5.83	40
1958	53,547.98	46,983	52,934	614	6.13	100
1959	48,461.08	42,229	47,578	883	6.43	137
1960	91,827.30	79,431	89,493	2,334	6.75	346
1961	45,841.68	39,350	44,335	1,507	7.08	213
1962	127,228.81	108,348	122,073	5,156	7.42	695
1963	127,605.29	107,724	121,370	6,235	7.79	800
1964	176,107.85	147,367	166,034	10,074	8.16	1,235
1965	255,884.95	212,077	238,941	16,944	8.56	1,979
1966	217,282.82	178,302	200,888	16,395	8.97	1,828
1967	302,520.78	245,647	276,763	25,758	9.40	2,740

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1968	376,439.42	302,281	340,571	35,868	9.85	3,641
1969	460,905.49	365,775	412,108	48,797	10.32	4,728
1970	450,568.37	353,155	397,890	52,678	10.81	4,873
1971	660,003.94	510,579	575,255	84,749	11.32	7,487
1972	637,811.59	486,650	548,295	89,517	11.85	7,554
1973	673,357.15	506,499	570,658	102,699	12.39	8,289
1974	422,891.59	313,278	352,961	69,931	12.96	5,396
1975	361,928.36	263,918	297,349	64,579	13.54	4,769
1976	306,764.03	220,011	247,880	58,884	14.14	4,164
1977	359,338.33	253,334	285,424	73,914	14.75	5,011
1978	543,005.91	375,869	423,481	119,525	15.39	7,766
1979	1,141,144.19	775,293	873,500	267,644	16.03	16,696
1980	3,062,092.10	2,039,353	2,297,680	764,412	16.70	45,773
1981	2,542,892.36	1,658,983	1,869,128	673,764	17.38	38,767
1982	1,815,131.91	1,159,143	1,305,973	509,159	18.07	28,177
1983	1,991,219.38	1,243,716	1,401,259	589,960	18.77	31,431
1984	1,828,077.64	1,115,493	1,256,794	571,284	19.49	29,312
1985	3,049,156.84	1,816,078	2,046,123	1,003,034	20.22	49,606
1986	2,770,703.87	1,608,671	1,812,443	958,261	20.97	45,697
1987	3,069,353.65	1,736,026	1,955,931	1,113,423	21.72	51,263
1988	2,549,323.62	1,402,638	1,580,312	969,012	22.49	43,086
1989	2,546,943.62	1,362,105	1,534,645	1,012,299	23.26	43,521
1990	3,255,500.49	1,689,605	1,903,629	1,351,871	24.05	56,211
1991	5,172,527.18	2,601,781	2,931,352	2,241,175	24.85	90,188
1992	3,621,283.72	1,762,841	1,986,142	1,635,142	25.66	63,723
1993	3,931,801.49	1,849,519	2,083,800	1,848,001	26.48	69,789
1994	4,123,914.43	1,871,432	2,108,489	2,015,425	27.31	73,798
1995	5,305,131.44	2,318,342	2,612,009	2,693,122	28.15	95,670
1996	4,071,906.77	1,710,201	1,926,834	2,145,073	29.00	73,968
1997	9,439,177.08	3,802,101	4,283,718	5,155,459	29.86	172,654
1998	13,417,674.37	5,171,172	5,826,211	7,591,463	30.73	247,038
1999	3,301,792.84	1,215,060	1,368,973	1,932,820	31.60	61,165
2000	771,885.41	270,314	304,555	467,330	32.49	14,384
2001	5,382,437.37	1,789,122	2,015,752	3,366,685	33.38	100,859
2002	3,615,183.90	1,136,614	1,280,590	2,334,594	34.28	68,104
2003	2,229,334.64	660,329	743,974	1,485,361	35.19	42,210
2004	2,098,326.75	582,915	656,754	1,441,573	36.11	39,922
2005	3,598,123.75	933,353	1,051,582	2,546,542	37.03	68,770
2006	2,941,561.18	708,328	798,053	2,143,508	37.96	56,468
2007	2,937,969.44	652,817	735,510	2,202,459	38.89	56,633
2008	2,727,511.86	554,230	624,435	2,103,077	39.84	52,788

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
2009	3,484,593.95	642,559	723,953	2,760,641	40.78	67,696
2010	3,433,610.85	567,233	639,085	2,794,526	41.74	66,951
2011	6,868,659.58	1,004,198	1,131,401	5,737,259	42.69	134,394
2012	4,352,895.30	551,947	621,863	3,731,032	43.66	85,457
2013	5,200,282.83	559,550	630,429	4,569,854	44.62	102,417
2014	4,290,673.83	378,437	426,374	3,864,300	45.59	84,762
2015	6,458,206.92	443,033	499,152	5,959,055	46.57	127,959
2016	7,293,891.72	358,859	404,316	6,889,576	47.54	144,922
2017	7,500,633.14	222,019	250,143	7,250,490	48.52	149,433
2018	11,728,445.58	114,939	129,498	11,598,948	49.51	234,275
	176,026,583.32	57,567,892	64,850,693	111,175,890		3,199,728
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					34.7	1.82

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-S1.5						
NET SALVAGE PERCENT.. 0						
1954	937.85	938	938			
1962	9,811.52	9,812	9,812			
1964	752.97	753	753			
1965	12,579.66	12,580	12,580			
1966	7,136.95	7,137	7,137			
1968	4,402.06	4,402	4,402			
1969	3,890.94	3,891	3,891			
1982	8,416.09	7,678	5,170	3,246	1.93	1,682
1985	87,074.72	76,388	51,436	35,639	2.70	13,200
1987	2,782.50	2,374	1,599	1,184	3.23	367
1988	78,479.19	65,958	44,413	34,066	3.51	9,705
1990	87,966.45	71,613	48,221	39,745	4.09	9,718
1991	1,085,691.19	869,042	585,176	500,515	4.39	114,013
1998	0.43					
2002	448.74	268	180	269	8.85	30
2003	386.07	221	149	237	9.39	25
2004	7,999.43	4,374	2,945	5,054	9.97	507
2005	2,280.86	1,184	797	1,484	10.58	140
2006	32,245.56	15,800	10,639	21,607	11.22	1,926
2007	37,413.81	17,194	11,578	25,836	11.89	2,173
2008	354,999.25	151,521	102,028	252,971	12.61	20,061
2009	74,455.23	29,241	19,690	54,765	13.36	4,099
2014	199,116.02	39,642	26,693	172,423	17.62	9,786
2016	19,055.77	2,148	1,446	17,609	19.52	902
	2,118,323.26	1,394,159	951,673	1,166,650		188,334

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.2 8.89

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1919	492.98	493	493			
1920	885.33	885	885			
1923	80.20	80	80			
1924	33.74	34	34			
1925	69.47	69	69			
1926	175.73	176	176			
1927	2,625.90	2,626	2,626			
1928	17,692.59	17,693	17,693			
1929	20,441.26	20,441	20,441			
1930	63,129.70	63,130	63,130			
1931	12,389.42	12,389	12,389			
1932	887.18	887	887			
1933	379.04	379	379			
1934	592.01	592	592			
1937	145.04	143	145			
1939	82.12	80	82			
1940	547.84	532	545	3	1.31	2
1941	101.53	98	100	2	1.58	1
1942	330.51	317	325	6	1.86	3
1943	34.03	32	33	1	2.13	
1944	2,504.83	2,371	2,428	77	2.41	32
1945	555.06	522	535	20	2.69	7
1947	167,797.08	155,603	159,349	8,448	3.27	2,583
1948	141,323.54	130,143	133,276	8,048	3.56	2,261
1949	63,061.68	57,666	59,054	4,008	3.85	1,041
1950	8,174.22	7,422	7,601	573	4.14	138
1951	131,398.32	118,463	121,315	10,083	4.43	2,276
1952	148,181.49	132,639	135,832	12,349	4.72	2,616
1953	1,746.80	1,552	1,589	158	5.01	32
1955	531.02	465	476	55	5.60	10
1956	628.92	546	559	70	5.90	12
1957	4,681.57	4,037	4,134	548	6.20	88
1958	36.82	31	32	5	6.51	1
1960	10,573.24	8,896	9,110	1,463	7.14	205
1961	527.79	440	451	77	7.47	10
1962	30,452.14	25,167	25,773	4,679	7.81	599
1963	4,977.86	4,076	4,174	804	8.15	99
1964	221.12	179	183	38	8.50	4
1965	4,980.19	3,999	4,095	885	8.87	100
1966	451.55	359	368	84	9.24	9
1968	868.44	675	691	177	10.03	18

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1969	1,482.53	1,139	1,166	317	10.44	30
1970	105.53	80	82	24	10.86	2
1971	3,414.51	2,557	2,619	796	11.30	70
1972	42,168.48	31,158	31,908	10,260	11.75	873
1973	4,866.88	3,546	3,631	1,236	12.21	101
1974	1,032.19	741	759	273	12.69	22
1975	90,069.62	63,689	65,222	24,848	13.18	1,885
1976	26,857.40	18,693	19,143	7,714	13.68	564
1977	16,455.30	11,266	11,537	4,918	14.19	347
1978	1,448.28	975	998	450	14.72	31
1979	26,600.10	17,580	18,003	8,597	15.26	563
1981	3,490.23	2,219	2,272	1,218	16.39	74
1982	22,815.31	14,211	14,553	8,262	16.97	487
1983	5,111.74	3,117	3,192	1,920	17.56	109
1984	4,312.39	2,572	2,634	1,678	18.16	92
1985	3,688.27	2,149	2,201	1,487	18.78	79
1986	120,002.64	68,242	69,885	50,118	19.41	2,582
1987	30,078.97	16,677	17,078	13,001	20.05	648
1989	115,814.54	60,815	62,279	53,536	21.37	2,505
1991	2,699.55	1,336	1,368	1,332	22.73	59
1992	1,774,500.25	850,979	871,465	903,035	23.42	38,558
1994	17,548.67	7,862	8,051	9,498	24.84	382
1995	216,345.73	93,414	95,663	120,683	25.57	4,720
2003	30,649.72	9,052	9,270	21,380	31.71	674
2004	10,125.00	2,810	2,878	7,247	32.51	223
2005	919,501.62	238,666	244,411	675,091	33.32	20,261
2006	883,357.10	212,986	218,113	665,244	34.15	19,480
2014	38,316.39	3,423	3,505	34,811	40.98	849
2015	694,511.94	48,463	49,630	644,882	41.86	15,406
2016	18,202.55	910	932	17,271	42.75	404
2017	492,410.38	14,772	15,128	477,282	43.65	10,934
2018	1,714,737.57	17,147	17,560	1,697,178	44.55	38,096
	8,177,510.68	2,599,573	2,659,265	5,518,246		173,257

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.9 2.12

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	3,002.17	2,902	2,978	24	0.50	24
2012	1,193.88	517	531	663	8.50	78
2013	62,557.53	22,938	23,540	39,018	9.50	4,107
2017	261,866.30	26,187	26,873	234,993	13.50	17,407
	328,619.88	52,544	53,922	274,698		21,616

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7 6.58

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	34,807.57	24,365	34,808			
2017	837,194.90	251,158	482,247	354,948	3.50	101,414
2018	2,307,989.53	230,799	443,156	1,864,834	4.50	414,408
	3,179,992.00	506,322	960,211	2,219,781		515,822
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					4.3	16.22

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1999	505,151.19	492,522	485,648	19,503	0.50	19,503
2000	8,426.29	7,794	7,685	741	1.50	494
2001	377,404.46	330,229	325,620	51,784	2.50	20,714
2002	259,886.34	214,406	211,414	48,472	3.50	13,849
2003	196,795.42	152,516	150,387	46,408	4.50	10,313
2004	100,164.19	72,619	71,605	28,559	5.50	5,193
2005	324,274.22	218,885	215,830	108,444	6.50	16,684
2006	520,392.52	325,245	320,706	199,687	7.50	26,625
2007	460,766.21	264,941	261,243	199,523	8.50	23,473
2008	738,136.57	387,522	382,114	356,023	9.50	37,476
2009	907,863.63	431,235	425,216	482,648	10.50	45,966
2010	896,247.89	380,905	375,589	520,659	11.50	45,275
2011	476,038.52	178,514	176,023	300,016	12.50	24,001
2012	352,323.30	114,505	112,907	239,416	13.50	17,735
2013	492,497.32	135,437	133,547	358,950	14.50	24,755
2014	429,896.26	96,727	95,377	334,519	15.50	21,582
2015	626,101.96	109,568	108,039	518,063	16.50	31,398
2016	789,570.93	98,696	97,318	692,253	17.50	39,557
2017	1,465,375.69	109,903	108,369	1,357,007	18.50	73,352
2018	1,486,590.09	37,165	36,646	1,449,944	19.50	74,356
	11,413,903.00	4,159,334	4,101,283	7,312,620		572,301

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.8 5.01

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 5-R3						
NET SALVAGE PERCENT.. 0						
2012	2,427,195.92	2,189,331	2,427,196			
2013	88,065.36	73,975	88,065			
2014	50,131.40	37,398	49,686	445	1.27	350
2015	13,204.24	8,160	10,841	2,363	1.91	1,237
2016	271,314.51	125,347	166,533	104,782	2.69	38,952
2017	1,764,259.57	508,107	675,057	1,089,203	3.56	305,956
	4,614,171.00	2,942,318	3,417,378	1,196,793		346,495

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 7.51

PECO ENERGY COMPANY
GAS PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	37,164.00	35,925	37,164			
2005	4,370.13	3,933	4,370			
2015	30,200.00	7,047	7,840	22,360	11.50	1,944
2017	97,063.87	9,706	10,799	86,264	13.50	6,390
	168,798.00	56,611	60,173	108,625		8,334

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0 4.94

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Caroline Fulginiti, hereby state that I am the Vice President and Assistant Controller for Exelon Corporation; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statement and exhibits listed below 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.

- PECO Statement No. 4
- PECO Exhibit CF-1
- PECO Exhibit CF-2
- PECO Exhibit CF-3
- PECO Exhibit CF-4

Dated: August 5, 2024

Caroline Fulginiti

PECO Statement No. 5:

Direct Testimony of Paul R. Moul

PECO ENERGY COMPANY
STATEMENT NO. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: PAUL R. MOUL

SUBJECT: OVERALL RATE OF RETURN, INCLUDING CAPITAL STRUCTURE RATIOS, EMBEDDED COST OF DEBT AND THE COST OF EQUITY, FOR PECO ENERGY COMPANY – GAS DIVISION

DATED: MARCH 28, 2024

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APPENDIX A - Educational Background, Business Experience and Qualifications

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings Approach
Commission	Pennsylvania Public Utility Commission
Company	PECO Energy Company
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Company
Lev	Leverage modification
LT	Long Term
M&M	Modigliani & Miller
OCI	Other Comprehensive Income
PECO Energy	PECO Energy Company
PUHCA	Public Utility Holding Company Act
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY

OF

PAUL R. MOUL

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

1. Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

2. Q. What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("Commission") should recognize in determining the revenues that the Natural Gas Division of PECO Energy Company ("PECO" or the "Company") will be authorized to realize at the conclusion of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in PECO Exhibit PRM-1, which is a multi-page document divided into fourteen (14) schedules. My testimony is based upon my first-hand knowledge of PECO, consisting of information obtained from meetings with the Company's management and Company-specific data that is widely disseminated within the financial community.

3. Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.15% for its Gas Division. The 11.15% rate of return on common equity is composed of an 11.00% cost of equity determined from the results of my proxy group analysis and 0.15% in recognition of the exemplary performance of the Company's management. The cost of equity is derived from a blended rate plus a risk adjustment applicable to the Gas Division. This rate reflects the risk reducing benefits that arise from PECO being a combination utility that has a diversified portfolio of utility investments, as well as the additional risk of the Gas Division.

My analysis of the Company and its superior performance is based upon the direct testimony of Ms. Amy E. Hamilton, the Company's Vice President of Gas Operations and the direct testimony of other Company witnesses. As shown on page 1 of Schedule 1, I have calculated an 8.08% overall cost of capital for the Company's fully projected future test year ("FPFTY") estimated at December 31, 2025. This return, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

4. Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of Exelon Corporation ("Exelon"). The common stock of Exelon is traded on the Nasdaq Global Select Market. Exelon is a component of the S&P 500 Composite Index. PECO provides natural gas distribution service to over half a million retail customers located in the suburban counties surrounding the City of Philadelphia. Electric delivery service is also provided to approximately 1.7 million electric customers in both the City of Philadelphia and the surrounding counties. Throughput to the Company's natural gas customers in 2023 was composed of approximately 45% to residential customers, approximately 28% to small commercial and industrial customers, and approximately 27% to large commercial and industrial customers. Approximately 29% of throughput goes to transportation customers. With about 636 large commercial and industrial customers, the energy needs of a few customers can have a significant impact on the Company's operations. PECO obtains its natural gas supplies from producers and marketers with transportation arrangements through interconnections with three interstate pipelines. The Company has storage arrangements with pipeline service providers and owns liquefied natural gas and propane facilities to supplement flowing gas. Since the restructuring of the gas utility industry in Pennsylvania, PECO has been the supplier of last resort for customers that do not obtain their own supply.

5. Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital-market and financial data that investors rely upon to assess the relative risk, and hence the cost of equity for a gas utility. In this regard, I employed four well-recognized measures of the cost of equity: (1) the Discounted Cash Flow ("DCF") model; (2) the Risk Premium ("RP") analysis; (3) the Capital Asset Pricing Model ("CAPM"); and (4) the Comparable Earnings ("CE") approach.

6. Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark *Bluefield* and *Hope* cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

[1] *Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia*, 262 U.S. 679 (1923) ("Bluefield") and *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

7. Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of eight (8) gas companies. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the natural gas utilities contained in The Value Line Investment Survey, which consists of nine companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. The companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report (Docket No. M-2023-3044811) approved by the Commission on January 18, 2024.

8. Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, I have helped to reduce the effect of extraneous influences on the market data for an individual company.

9. Q. What noteworthy factors have influenced your cost of equity analysis?

A. My cost of equity analysis reflects the impact of high levels of inflation, which have not been seen for four decades. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and by February 2024 it had fallen to 3.2%. High levels of inflation, i.e., those above the Federal Open Market Committee ("FOMC") policy goal of 2%, have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt, and the need for more cautious financial practices, such as a prudent level of borrowing. While short-term interest rates were at historically low levels during much of the Pandemic, longer-term interest rates began to rise in February 2021 and have continued at high levels throughout 2022 and 2023. Following the Pandemic, the accommodative policy by the FOMC has ended, and higher interest rates have occurred. The FOMC uses its open market operations to control the Fed Funds rate as a means of implementing its dual mandate of healthy employment and price stability. This was revealed by the Fed Funds rate, which increased 525 basis points since the beginning of 2022 through 11 increases in 21 months. The FOMC paused its rate increases and held rates steady at its meeting on June 14, 2023. Thereafter, another rate increase occurred on July 26, 2023. The FOMC paused again at its meetings on September 20, November 1, and December 13, 2023, and January 31, 2024. It appears that we are at the end of the current interest rate tightening cycle. Modest reductions in the future would not reduce the Fed Funds rate to Pandemic or pre-Pandemic levels, which were very low after the financial crisis of 2007-08.

10. Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	12.05%
Risk Premium	11.50%
CAPM	12.84%
Comparable Earnings	13.10%

To arrive at my recommended equity return, I have incorporated the risk reducing benefits of the combination characteristics of both the Company's gas and electric operations.

11. Q. How have you used this data to set the rate of return on common equity for the Gas Division of PECO?

A. I have used this data along with the data for the Electric Group assembled for the Electric Division rate case being filed by PECO. In this regard, I selected as the low end of the range the DCF result for the Gas Group and the Electric Group

computed without regard to the leverage adjustment, i.e., 10.74%, and the DCF stated on the same basis in the Company's Electric Division rate case. By doing so I have reduced the equity return in recognition of the combined Gas and Electric utility operations of the Company. That is not to say that diversification in any way changes the fact that the market value leverage and the book value leverage is altered through diversification, but rather it is a convenient way to reduce the return for a combined utility, rather than a stand-alone utility.

As revealed in the Electric Division rate case, the cost of equity was 10.80% by considering both the DCF and Risk Premium methods. That return was prior to recognition of the 15 basis points for superior management performance. I will refer to the 10.80% equity return as the baseline cost of equity that reflects the risk reducing benefits of the diversified electric and gas operations of PECO.

12. Q. With the baseline cost of equity for PECO, have you made an adjustment to recognize the risk of the Gas Division in this case?

A. Yes. To the 10.80% baseline cost of equity for PECO, I have increased that return by 20 basis points (i.e., 0.20%) to recognize the higher risk of the Company's Gas Division that increases the equity return to 11.00% prior to the recognition of management performance. It is well recognized, including by the Commission, that natural gas utilities require a higher cost of equity than other types of utilities. To identify the difference in return, I have analyzed the earnings/price ("E/P") ratio for my Gas Group and the E/P ratio for the Electric Group used in the Company's companion rate case for the Electric Division. The E/P ratio is merely the reciprocal of the price-earnings multiple that I will discuss

below. E/P ratios are familiar to the Commission because they were a major input to the rate of return on common equity when the Commission used a fair value rate base for setting rates under the old public utility law. Here, I use it for comparative purposes to measure the differences in risk between electric and natural gas operations. That is to say, a higher E/P signifies more risk and a higher required return.

13. Q. What have you found?

A. Using the 5-year average price-earnings multiple of the Gas Group and the Electric Group, the respective E/Ps are 4.55% (1 ÷ 22) for the Gas Group and 4.35% (1 ÷ 23) for the Electric Group. The difference in the ratios is 0.20% (4.55% - 4.35%) for the two groups, with the Gas Group being higher. As such, the 10.80% baseline cost of equity increases to 11.00% for the Gas Division. To that rate, management performance adds 0.15%, which results in a final 11.15% cost of equity for the Gas Division.

14. Q. Is an 11.15% cost of equity reasonable for the Gas Division?

A. Yes, it is. The 11.15% cost of equity after adjusting for the higher risk of the Gas Division rests within the overall range that I determined in the case of 10.57% to 11.50% that is established in the Electric Division rate case. There, the lower bound was the average DCF return, excluding the leverage adjustment for the Electric Group and the Gas Group. The upper bound was the Risk Premium result.

II. NATURAL GAS RISK FACTORS

15. Q. What factors currently affect the business risk of natural gas utilities?

A. Gas utilities face risks arising from competition from other energy sources, the purveyors of those sources and natural gas, economic regulation, the business cycle, and customer usage patterns. Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues.

16. Q. Is PECO proposing to adjust its rates to deal with variations in weather?

A. Yes. Most of the Company's residential customers use natural gas for space heating purposes. Indeed, 81% of residential throughput is to customers with natural gas space heating. This indicates that the energy requirements of a large proportion of the Company's residential customers are significantly influenced by temperature conditions over which the Company has absolutely no control. If weather patterns in the future do not align with rate case test period data, a weather normalization adjustment ("WNA") feature, as proposed by PECO, would enable the Company to adjust its revenue collections to account for those variations with additional benefits to customers from that stability. My cost of equity analysis takes into account the Company's proposed WNA mechanism proposal.

17. Q. Please explain.

A. My analysis reflects the impact of the WNA on investor expectations through the use of market-determined models. All of the companies in my Gas Group have

some form of WNA mechanism that is intended to accomplish the same result as the Company's proposal in this case. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by a WNA. Therefore, my analysis reflects the impacts of decoupling on investor expectations through the use of market-determined models.

As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of these mechanisms in the LDC business. Because the Gas Group that I use to measure the cost of equity has the risk attributes related to the revenue decoupling mechanism "baked in" to their stock prices, the absence of the benefit of the WNA would increase the cost of equity as determined by the models that are applied with the Gas Group data.

18. Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. PECO's ten largest volume customers, which account for 10.9 million cubic feet of throughput, are engaged in the manufacturing, pharmaceuticals, food processing, health care, and electric generation (including cogeneration) businesses. Changes in the business environment can negatively affect these companies, and, in that way, cause material reductions in throughput on PECO's distribution system. This risk is especially apparent in this time of economic

uncertainty attributed to inflation, supply-side issues, and global geopolitical situations. Additionally, large volume users, which predominantly use transportation service, may be located close enough to interstate pipelines to take gas directly from those sources and bypass the local distribution company ("LDC") entirely. The Company has identified customers with combined annual throughput of approximately 7.6 million cubic feet ("MCF") of gas that have the potential to bypass the Company's distribution system. Because a large part of PECO's distribution revenue recovers fixed costs, which the Company continues to bear even if a customer leaves the system, the loss of 7.6 million MCF of throughput would impose a significant amount of uncompensated fixed costs that PECO would not have the opportunity to recover until it could complete another base rate case.

19. Q. Can the Company's construction program affect its risk profile?

A. Yes. The Company must undertake substantial investments to maintain and upgrade existing facilities in its service territory to ensure safe and reliable service to its customers. In particular, the rehabilitation of the Company's infrastructure requires it to invest capital without adding any new customers and without increasing sales to existing customers. In short, infrastructure rehabilitation increases fixed costs without an attendant increase in revenues. Moreover, the Company is confronting significant levels of infrastructure investment. For example, at year-end 2023, 671 miles (or approximately 9%) of the Company's distribution system consisted of cast iron and ductile iron pipe and steel pipe that is not cathodically protected and is, therefore, susceptible to corrosion. These are

all considered vulnerable materials that will need to be replaced. The Company projects that its construction expenditures will approximate $9,260 million during the period 2024-2028, which represents approximately 71% ($9,260 million ÷ $13,128 million) of its net utility plant as of December 31, 2023. Of these amounts, construction expenditures for the gas division are expected to be $1,907 million during the period 2024-2028.

Year	Construction
2024	$1,691,000
2025	$1,829,000
2026	$1,930,000
2027	$1,905,000
2028	$1,905,000
Total	$9,260,000

20. Q. How should the Commission respond to the issues facing natural gas utilities in general and PECO in particular?

A. The Commission should recognize and take into account the high-risk profile of PECO's Gas Division and its future capital requirements in determining the cost of equity for the Company. A fair rate of return is key to PECO maintaining a financial profile that will provide it with the ability to raise the capital necessary to meet its capital needs on reasonable terms.

21. Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where additional capital is required, as shown by the projected construction expenditures indicated above, the regulatory process must establish a

return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is essential to the Company's ability to raise capital in all market conditions and to satisfy investor requirements in an evolving industry.

III. FUNDAMENTAL RISK ANALYSIS

22. Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for the determination of the cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared PECO to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Gas Group.

23. Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

24. Q. What companies comprise your Gas Group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., Southwest Gas Holdings, and Spire, Inc.

25. Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is an important determinant in analyzing a company's cost of equity because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is directly shown by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus a premium to recognize the higher risk of an equity investment compared to debt.

26. Q. How do the bond ratings compare for PECO, the Gas Group, and the S&P Public Utilities?

A. Presently, the issuer credit rating for PECO is BBB+ (A on First Mortgage Bonds) from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is A2 (Aa3 on First Mortgage Bonds) from Moody's Investors Services ("Moody's"). The issuer credit rating designation by S&P and LT issuer rating by Moody's focus upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The Company's credit quality is similar to that of the Gas Group, which has an average A3 and A- credit rating

from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite credit rating is A3 by Moody's and BBB+ by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process.

27. Q. How do the financial data compare for PECO, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2018-2022. I will highlight the important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, PECO is larger than the average size of the Gas Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company, because a given change in revenue and expense has a proportionately greater impact on a small firm.

Market Ratios. Historical market-based financial ratios, such as price-earnings multiples and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies which exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

[2] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

Since PECO's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was equivalent for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The following common equity ratios are computed from balance sheet values that represent book value. The five-year average common equity ratios, based on permanent capital book value, were 53.8% for PECO, 49.0% for the Gas Group, and 40.5% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating somewhat lower financial risk. Significantly, for this case, the Company's common equity ratio is within the range of other gas distribution utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.114

(1.3% ÷ 11.4%) for PECO, 0.113 (1.1% ÷ 9.7%) for the Gas Group, and 0.040 (0.4% ÷ 10.0%) for the S&P Public Utilities. The variability of the Company's rates of return was similar to the Gas Group and higher than the S&P Public Utilities. As a further observation, the direct testimony of Ms. Marissa Humphrey has calculated that the equity return in the FPFTY will be 6.87% for the Gas Division. Such return is below the rates of return generally afforded to public utilities and completely inadequate based upon the Company's historical performance, my cost of equity analysis, and maintenance of its current credit quality ratings.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 79.8% for the Company, 82.7% for the Gas Group, and 81.0% for the S&P Public Utilities. The Company's operating ratios were fairly similar to the Gas Group, thereby indicating similar risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.35 times for PECO, 4.33 times for the Gas Group, and 2.94 times for the

[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

S&P Public Utilities. The interest coverages were similar for the Company and the Gas Group, thereby indicating similar risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 49.9% for PECO, 56.3% for the Gas Group, and 62.3% for the S&P Public Utilities. The Company's average IGF to construction percentage has been weaker than the Gas Group and S&P Public Utilities indicating more risk for the Company. The Company's IGF to construction expenditures will be under pressure in future years as its construction expenditures continue to increase.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common

equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas of .87 as the average for the Gas Group provided on page 2 of Schedule 3 and .90 as the average for the S&P Public Utilities provided on page 3 of Schedule 4. The systematic risk was similar for the Gas Group and the S&P Public Utilities.

28. Q. Please summarize your risk evaluation of PECO and the Gas Group.

A. The investment risk of PECO parallels that of the Gas Group in several respects. In certain regards, principally related to its weaker IGF to construction, PECO has higher risk traits. PECO has lower risk as shown by its higher common equity. Earnings variability, operating ratios, interest coverages and quality earnings indicate comparable risk for PECO compared to the Gas Group. On balance, the cost of equity for the Gas Group would fairly represent the Company's cost of equity for this case.

IV. RECOMMENDED CAPITAL STRUCTURE RATIOS

29. Q. Please explain the selection of capital structure ratios for PECO.

A. The capital structure ratios of PECO should be employed for rate of return purposes. If the operating public utility raises its own debt directly in the capital

[4] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

markets, as PECO does, the operating public utility's own capital structure ratios should be used to determine its overall rate of return. Additionally, if the Company's actual capital structure ratios are used, as they should be, then consistency requires that the embedded cost rates associated with the senior securities reflected in those capital structure ratios should also be employed.

30. Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

A. Yes. The capitalization and capital structure ratios at December 31, 2023, 2024, and 2025 correspond with the end of the historic test year ("HTY"), future test year ("FTY"), and fully projected future test year ("FPFTY") in this case. The capitalization and capital structure ratios for the FTY and FPFTY reflect the Company's plan to issue $575 million of new long-term debt in 2024, and $975 million in 2025. There is a $350 million debt maturity in FPFTY. Future equity financings include $580 million in the FTY and $472 million in the FPFTY. The build-up of retained earnings is also reflected. In presenting the Company's capital structure on Schedule 5, I have removed the call premiums on the early redemption of high-cost long-term debt and preferred stock.

31. Q. Please describe the adjustment for the call premiums paid to redeem high-cost debt and preferred stock

A. I have adjusted the principal amounts of long-term debt to exclude the amounts used to finance premiums paid for the early redemption of long-term debt and preferred stock previously redeemed. To do otherwise would deny PECO the opportunity to recover the costs (i.e., a return on and of the money used to fund

the call premiums) it incurred solely to redeem high-cost capital. The additional debt PECO issued to finance the call premiums does not increase the Company's rate base. That is to say, no additional rate base was created as a consequence of issuing additional debt and preferred stock to finance the redemptions. Therefore, an adjustment to the capitalization is required to provide the return necessary to service the additional capital PECO issued to fund the call premiums. Thus, while rate base does not change, the return component of the overall cost of capital reflects an adjustment that, when applied to the rate base, furnishes the return necessary to pay the cost of the incremental capitalization that supported the call premiums paid by PECO.

The adjustment for call premiums is appropriate because customers receive all of the cost savings, in the form of a lower overall rate of return, produced by refinancing higher-cost debt and preferred stock, while PECO is simply made whole by recovering the actual costs it incurred to provide these benefits to its customers. In order to produce the savings that resulted from redeeming higher-cost debt and preferred stock, the Company paid to the holders of that debt and preferred stock a premium to surrender their securities prior to maturity. Those premiums represented an investment made by PECO to reduce its overall cost of capital. Because the reduced interest costs and preferred stock dividends are reflected in the lower cost of capital to customers, it is proper that the Company recover the costs incurred to produce these savings, which consist of a return of and a return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides for the appropriate cost recovery by

providing a return on the funds used to pay the premiums, which is reflected as an increment included in the embedded cost rates of PECO's total capital.

32. Q. Should short-term debt be included in the capital structure for rate of return purposes?

A. No. There is no need to consider short-term debt in the capital structure because the amount of short-term debt is well below the construction work in progress ("CWIP") at the end of the FTY and the FPFTY. Exclusion of short-term debt is required because it finances CWIP and hence the cost of short-term debt is reflected in the AFUDC rate. To avoid double-counting, short-term debt must be excluded from the capital structure ratios when setting base rates.

33. Q. What capital structure ratios do you recommend for determining PECO's overall cost of capital in this proceeding?

A. Because rate-setting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the test year. As a result, I will adopt the Company's FPFTY capital structure ratios of 46.60% long-term debt and 53.40% common equity. These ratios are consistent with the Company's current investment grade credit ratings of A2/BBB+.

V. COSTS OF SENIOR CAPITAL

34. Q. What cost rate have you assigned to the debt portion of PECO's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is because the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on Schedule 6, pages 1, 2 and 3, I have computed the weighted average embedded cost rates of long-term debt as of the end of the HTY, FTY and FPFTY, respectively. For the planned new issues of debt, the Company has budgeted 5.46% as the coupon rate for the two debt issues in each of the years 2024 and 2025. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on Schedule 6, page 4. The cost rate, or yield to maturity ("ytm"), is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond. In my calculation of the embedded cost of long-term debt, I have recognized the costs associated with the Company's early redemption of high cost debt. As previously explained, it is necessary to compensate PECO for the costs incurred to lower the embedded debt cost rate, which reduces the cost of capital charged to customers.

35. Q. What cost rate have you determined for the Company's long-term debt?

A. I will adopt the 4.58% embedded cost of long-term debt at December 31, 2025, as shown on Schedule 6, page 3. This rate is related to the amount of long-term debt shown in the last three columns of Schedule 5, which provides the basis for the 46.60% long-term debt ratio.

VI. COST OF EQUITY – GENERAL APPROACH

36. Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among PECO, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage and bond ratings, must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.15% for PECO including an increment for management performance.

VII. DISCOUNTED CASH FLOW

37. Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of

return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 12.05% with the leverage adjustment and 10.74% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance.

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF. Hence, the DCF should always be used along with other methods that are more responsive to changes in interest rates.

While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[6]

Similarly, in the later Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon

[6] *Pennsylvania Public Utility Commission v. PPL Electric Utilities*, R-2012-2290597, meeting held December 5, 2012, at 80.

> the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[7]

Again, the Commission recognized the need for additional methods in its decision for Columbia Water.

> In *Aqua 2022,* the Commission determined the ROE by using informed judgement based on I&E's DCF and CAPM methodologies. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. We historically have primarily relied upon the DCF methodology in arriving at ROE determinations and utilized the results of the CAPM, as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our ROE determination.[8]

The Commission has acknowledged the usefulness of other methods as a means of establishing a range of reasonable returns. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone.

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[7] *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, R-2021-3027385, order entered May 16, 2022, at 154-55.

[8] *Pennsylvania Public Utility Commission v. Columbia Water Company*, R-2023-3040258, order entered January 18, 2024, at 108.

38. Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the 12 months ended December 2023, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the 12 months ended December 2023, the average dividend yield was 3.61% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.85% and 4.00%, respectively. In applying the DCF model, I have used the six-month average dividend yield of 3.85% for the Gas Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three

adjusted values as calculated in the lower panel of data presented on Schedule 7.[9] This adjustment adds 14 basis points to the six-month average historical yield, thus producing the 3.99% adjusted dividend yield for the Gas Group.

39. Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus on prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b *x* r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s *x* v, where "s" is the number of new common shares that the firm

[9] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0) results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle but rather to rely upon analysts' growth forecasts used by investors when pricing common stocks.

40. Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

41. Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedule 8 and Schedule 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While

historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

42. Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the P-E multiple. As such, my company-specific growth analysis, which focuses principally on five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because

market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points to make informed decisions to purchase and sell stocks.

43. Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule 9.

44. Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.87%), Zacks (5.69%) and Value Line (7.31%).

45. Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While various factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[10] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks and Value Line, provide the best indication of investor expectations.

[10] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

46. Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.69% to 7.31%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

47. Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 37.01% long-term debt, 1.37% preferred stock, and 61.62% common equity, as shown on Schedule 10. These ratios are calculated from market values based on the fair value of debt and preferred stock, if any, and the price of each company's common stock. Hence, all values here related to the investors' valuation of debt and equity in the capital markets. If book values are used to compute the capital structure ratios, then a leverage adjustment is required in the case where the capital structure ratios vary from market values.

48. Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

49. Q. Why is a leverage adjustment appropriate?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate-setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated

with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[11] provide a return of 9.09% when applicable to a capital structure with 100% common equity.

50. Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e.,

[11] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed, the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

51. Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the

simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 9.09%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.85% to compensate investors for the risk of 51.40% debt ratio and 0.11% for a 1.59% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 12.05% (9.09% + 2.85% + 0.11%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.99% dividend yield, the 6.75% growth rate, and 1.31% for the leverage adjustment to arrive at the same 12.05% return computed directly with the M&M formula. I know of no means to mathematically solve for the 1.31% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.31% adjustment is merely a convenient way to compare the 12.05% return computed using the M&M formulas to the 10.74% return generated by the DCF

model (i.e., D1/P0 + g, or the traditional form of the DCF shown on Schedule 7) based on a market-value capital structure. A 10.74% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

52. Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D1/P0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 12.05%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	k
Gas Group	3.99%	+	6.75%	+	1.31%	=	12.05%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of

return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

VIII. RISK PREMIUM ANALYSIS

53. Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.50%.

54. Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 5.00% yield represents a reasonable estimate of the prospective yield on long-term, public utility bonds. The 5.00% public utility bond yield I used in the Risk Premium method is very conservative given current interest rates.

55. Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the 12 months ended December

2023 the average monthly yield on Moody's index A-rated public utility bonds was 5.54%. For the six- and three-month periods ended December 2023, the yields were 5.78% and 5.91%, respectively. During the 12 months ended December 2023, the range of the yields on A-rated public utility bonds were 5.13% to 6.34%. Page 2 of Schedule11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.45% on a twelve-month average basis, 1.37% on a six-month average basis, and 1.32% on a three-month average basis. With these data, 1.25% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

56. Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above. Blue Chip is a reliable authority and contains consensus forecasts of various interest rates compiled from a panel of banking, brokerage and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on December 28, 2023, and a yield spread of 1.25%, derived from recent historical data.

57. Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I have also shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2024	First	5.1%	6.1%	4.3%	1.25%	5.55%
2024	Second	5.0%	6.0%	4.3%	1.25%	5.55%
2024	Third	4.9%	6.0%	4.2%	1.25%	5.45%
2024	Fourth	4.8%	5.9%	4.1%	1.25%	5.35%
2025	First	4.8%	5.8%	4.0%	1.25%	5.25%
2025	Second	4.7%	5.8%	4.0%	1.25%	5.25%

58. Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2023 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2025-2029	4.9%	6.0%	4.1%
2030-2034	5.0%	6.0%	4.2%

The longer-term forecasts by Blue Chip suggest that interest rates will continue to be above pre-Pandemic levels. A 5.00% yield on A-rated public utility bonds represents a reasonably conservative benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are based on forecasts available to investors, who regularly rely upon such data to make investment decisions. In this case, I have taken a conservative approach in selecting a 5.00% yield on A-rated public utility bonds, because current rates and forecasts would support a higher rate. My rate will accommodate reductions that may occur later in 2024.

59. Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule 12, page 1.

Common Equity Risk Premiums

Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

Based on my analysis of the historical data, the equity risk premium was 7.13% when the marginal cost of long-term government bonds was low (i.e.,

2.83%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 4.76%. Over the entire spectrum of interest rates, the equity risk premium was 5.96% when the average government bond yield was 4.91%. From these data, I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% is between the premiums associated with low interest rates (i.e., 7.13%) and average for the entire historical period interest rates (i.e., 5.96%).

60. Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	RP	=	k
Gas Group	5.00%	+	6.50%	=	11.50%

IX. CAPITAL ASSET PRICING MODEL

61. Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 12.84% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 10.94% (12.84% - (0.23 x 8.26%)) through use of the Value Line beta

excluding the leverage adjustment (i.e., 1.10 - 0.87 = 0.23). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β") and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

62. Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.87 for the Gas Group.

63. Q. Did you use the <u>Value Line</u> betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage-adjusted betas that I used in the CAPM. The Value Line betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line

(market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula, [12] as follows:

$$\beta l = \beta u \, [1 + (1 - t) \, D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.58 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.10 for the book value capital structure of the Gas Group.

64. Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the 12 months ended December 2023, the average yield on 30-year Treasury bonds was 4.09%. For the six- and three-months ended December 2023, the yields on 30-year Treasury bonds were 4.41% and 4.58%,

[12] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

respectively. During the 12 months ended December 2023, the range of the yields on 30-year Treasury bonds was 3.66% to 4.95%.

Due to high inflation rates above the policy goal of the FOMC, the accommodative policy was ended by the FOMC in the first quarter of 2022. A tighter monetary policy was put in place and resulted in higher interest rates. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it is in the process of running off its $9 trillion asset portfolio, which will keep interest rates at elevated levels.

High interest rates clearly point to high capital costs as indicated by recent bond yields. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, for the first time since late 2018. By December 2023, the yield on 30-year Treasury bonds moved to 4.14%, or an increase of 2.47% (or 148%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on December 28, 2023, indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.0% to 4.3% during the next six quarters. This means that elevated interest rates will continue near current levels. The longer-term forecasts show that the yields on 30-year Treasury bonds will average 4.1% from 2025 through 2029 and 4.2% from 2030 to 2034. Hence, I have used a conservative 3.75% risk-free rate of return for CAPM purposes, which considers the possibility of some moderation of rates prospectively.

65. Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.21% (12.40% + 12.02% = 24.42% ÷ 2) as the midpoint of the "low" and "average" interest rate environments. During those periods, the yield on long-term government bonds was 3.87% (2.83% + 4.91% = 7.74% ÷ 2). The resulting market premium is 8.34% (12.21% - 3.87%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 11.93% total market return based on the Value Line forecasts. With these data, I calculated a market premium of 8.18% (11.93% - 3.75%) using the forecast data by Value Line. The resulting market premium applicable to the CAPM derived from these sources equals 8.26% (8.18% + 8.34% = 16.52% ÷ 2).

66. Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.10 for the Gas Group, and the 8.26% market premium, the following result is indicated.

	Rf	+	β	x	(	$Rm-Rf$	)	=	k
Gas Group	3.75%	+	1.10	x	(	8.26%	)	=	12.84%

X. COMPARABLE EARNINGS APPROACH

67. Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it

> employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[13]

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

68. Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures

[13] *Bluefield*, at 668.

shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities

69. Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the *Bluefield* case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the

point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.6% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return, as published by Value Line, is 13.6% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data, my Comparable Earnings result is 13.10%, as shown on page 2 of Schedule 1.

XI. CONCLUSION ON COST OF EQUITY

70. Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.15% for the Gas Division of PECO, which includes my quantification of the additional risk of the Gas Division using an analysis of E/P ratios and fifteen basis points or 0.15% for recognition of the Company's strong management performance (which is well within the 5 to 25 basis point range of management performance provisions that the Commission has recognized previously). My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the Gas Group companies. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize an 11.15% rate of return on common equity so that it can compete in the capital markets, attain reasonable

credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

71. Q. Does this complete your direct testimony?

A. Yes, it does.

Educational Background, Business Experience

and Qualifications

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct

testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987

(Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

PECO Exhibit PRM-1:

Cost of Capital and Fair Rate of Return

PECO Exhibit PRM-1

PECO ENERGY COMPANY

Schedules to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

and

Fair Rate of Return

PECO ENERGY COMPANY
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PECO Energy Company
Proposed Rate of Return
Estimated at December 31, 2025

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.60%	4.58%	2.13%
Common Equity	53.40%	11.15%	5.95%
Total	100.00%		8.08%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a 27.3121% composite federal and state income tax rate
(10.32% ÷ 2.13%) 4.85 x

Post-tax coverage of interest expense
(8.08% ÷ 2.13%) 3.79 x

PECO - Gas
Cost of Equity
as of December 31, 2023

Market Models (DCF, RP & CAPM)

Discounted Cash Flow (DCF)	D_1/P_0 (1)	+	*g* (2)	+	*lev.* (3)	=	*k*
Gas Group	3.99%	+	6.75%	+	1.31%	=	12.05%
Risk Premium (RP)			*I* (4)	+	*RP* (5)	=	*k*
Gas Group			5.00%	+	6.50%	=	11.50%
Capital Asset Pricing Model (CAPM)	*Rf* (6)	+	*ß* (7)	*x (*	*Rm-Rf* (8)	*) =*	*k*
Gas Group	3.75%	+	1.10	x (	8.26%	) =	12.84%

Book Value Method

Comparable Earnings (CE) (10)	***Historical***	***Forecast***	**Average**
Comparable Earnings Group	12.6%	13.6%	13.10%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return and a yield spread of 1.25% (Schedule 11 page 3)
(5) Schedule 07
(6) Schedule 09
(7) Schedule 10
(8) Schedule 07
(9) Schedule 09
(10) Schedule 10

PECO Energy Company
Capitalization and Financial Statistics
2018-2022, Inclusive

	2022	2021	2020	2019	2018	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$10,359.0	$ 9,493.0	$ 8,470.0	$ 7,767.0	$ 7,088.0	
Short-Term Debt	$ 239.0	$ -	$ 40.0	$ -	$ -	
Total Capital	$10,598.0	$ 9,493.0	$ 8,510.0	$ 7,767.0	$ 7,088.0	
Capital Structure Ratios						Average
Based on Permanent Capital:						
Long-Term Debt	46.3%	46.1%	46.5%	46.2%	46.1%	46.2%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity [1]	53.7%	53.9%	53.5%	53.8%	53.9%	53.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	47.5%	46.1%	46.7%	46.2%	46.1%	46.5%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity [1]	52.5%	53.9%	53.3%	53.8%	53.9%	53.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	10.8%	10.5%	10.3%	13.2%	12.4%	11.4%
Operating Ratio [2]	79.5%	79.6%	82.1%	77.0%	80.6%	79.8%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	4.70 x	4.20 x	3.84 x	5.36 x	4.48 x	4.52 x
Post-tax: All Interest Charges	4.25 x	4.13 x	4.04 x	4.88 x	4.43 x	4.35 x
Overall Coverage: All Int. & Pfd. Div.	4.25 x	4.13 x	4.04 x	4.88 x	4.43 x	4.35 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	4.46 x	3.99 x	3.68 x	5.24 x	4.39 x	4.35 x
Post-tax: All Interest Charges	4.02 x	3.92 x	3.88 x	4.76 x	4.34 x	4.18 x
Overall Coverage: All Int. & Pfd. Div.	4.02 x	3.92 x	3.88 x	4.76 x	4.34 x	4.18 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.3%	6.7%	5.1%	3.2%	2.6%	5.0%
Effective Income Tax Rate	12.1%	2.3%	-7.2%	11.0%	1.3%	3.9%
Internal Cash Generation/Construction [4]	48.9%	42.3%	39.7%	59.6%	59.0%	49.9%
Gross Cash Flow/ Avg. Total Debt [5]	22.5%	20.7%	21.0%	26.8%	25.4%	23.3%
Gross Cash Flow Interest Coverage [6]	6.92 x	6.30 x	6.39 x	7.70 x	6.96 x	6.85 x
Common Dividend Coverage [7]	2.65 x	2.55 x	2.34 x	2.56 x	2.64 x	2.55 x

See Page 2 for Notes.

PECO Energy Company
Capitalization and Financial Statistics
2018-2022, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is a percentage calculated as gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by total debt.
(6) Gross Cash Flow plus interest charges divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: SEC Form 10-K
Utility COMPUSTAT

Gas Group
Capitalization and Financial Statistics [1]
2018-2022, Inclusive

	2022	2021	2020	2019	2018	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 7,730.2	$ 7,293.8	$ 6,052.7	$ 5,316.3	$ 4,769.0	
Short-Term Debt	$ 745.4	$ 577.9	$ 285.2	$ 516.3	$ 527.8	
Total Capital	$ 8,475.6	$ 7,871.7	$ 6,337.9	$ 5,832.6	$ 5,296.8	
Market-Based Financial Ratios						
Price-Earnings Multiple	19 x	21 x	24 x	25 x	20 x	22 x
Market/Book Ratio	193.5%	185.7%	188.6%	225.0%	218.5%	202.3%
Dividend Yield	3.1%	3.2%	3.1%	2.5%	2.7%	2.9%
Dividend Payout Ratio	57.1%	65.6%	74.7%	63.9%	52.4%	62.7%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	52.1%	53.5%	48.6%	46.4%	45.4%	49.2%
Preferred Stock	2.1%	2.3%	1.8%	1.7%	1.1%	1.8%
Common Equity [2]	45.7%	44.2%	49.6%	52.0%	53.6%	49.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	57.0%	58.2%	52.3%	51.4%	51.3%	54.0%
Preferred Stock	1.9%	2.1%	1.7%	1.5%	1.0%	1.6%
Common Equity [2]	41.2%	39.7%	46.1%	47.2%	47.7%	44.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.6%	9.0%	8.7%	9.0%	11.2%	9.7%
Operating Ratio [3]	81.9%	81.3%	82.7%	83.1%	84.3%	82.7%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	5.01 x	4.88 x	4.18 x	4.02 x	4.02 x	4.42 x
Post-tax: All Interest Charges	4.28 x	4.09 x	3.61 x	3.57 x	3.80 x	3.87 x
Overall Coverage: All Int. & Pfd. Div.	4.18 x	3.99 x	3.57 x	3.52 x	3.80 x	3.81 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.90 x	4.76 x	4.07 x	3.96 x	3.96 x	4.33 x
Post-tax: All Interest Charges	4.16 x	3.97 x	3.50 x	3.50 x	3.75 x	3.78 x
Overall Coverage: All Int. & Pfd. Div.	4.06 x	3.87 x	3.46 x	3.45 x	3.74 x	3.72 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	2.4%	4.3%	3.1%	2.5%	1.6%	2.8%
Effective Income Tax Rate	20.7%	20.3%	16.5%	14.3%	8.5%	16.1%
Internal Cash Generation/Construction [5]	61.0%	62.8%	54.8%	52.1%	50.6%	56.3%
Gross Cash Flow/ Avg. Total Debt [6]	15.2%	17.4%	19.1%	19.8%	20.1%	18.3%
Gross Cash Flow Interest Coverage [7]	7.02 x	8.34 x	7.35 x	6.67 x	6.67 x	7.21 x
Common Dividend Coverage [8]	3.85 x	4.22 x	3.96 x	4.10 x	3.93 x	4.01 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2018-2022, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group "Natural Gas Utility," they are not currently the target of a publicly-announced merger or acquisition (i.e., South Jersey Industries), and after eliminating UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
ATO	Atmos Energy Corp.	A1	A-	NYSE	0.85
CPK	Chesapeake Utilities Corp.	NAIC "2b"		NYSE	0.80
NJR	New Jersey Resources Corp.	A1	-	NYSE	0.95
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.90
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.85
OGS	ONE Gas, Inc.	A3	A-	NYSE	0.85
SWX	Southwest Gas Holdings, Inc.	Baa1	BBB	NYSE	0.90
SR	Spire, Inc.	A1	A-	NYSE	0.85
	Average	A3	A-		0.87

Note: Ratings are those of utility subsidiaries

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2018-2022, Inclusive

	2022	2021	2020	2019	2018	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 42,136.6	$ 40,154.3	$ 38,732.9	$ 36,461.6	$ 32,871.6	
Short-Term Debt	$ 1,713.7	$ 1,397.4	$ 1,154.1	$ 1,221.9	$ 1,420.3	
Total Capital	$ 43,850.3	$ 41,551.7	$ 39,887.0	$ 37,683.5	$ 34,291.9	
Market-Based Financial Ratios						
Price-Earnings Multiple	23 x	22 x	23 x	20 x	21 x	22 x
Market/Book Ratio	219.2%	220.7%	218.2%	220.9%	204.4%	216.7%
Dividend Yield	3.3%	3.5%	3.6%	3.2%	3.5%	3.4%
Dividend Payout Ratio	72.5%	72.9%	78.0%	62.7%	68.7%	71.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	58.3%	57.4%	58.1%	56.7%	55.0%	57.1%
Preferred Stock	2.2%	2.3%	2.6%	2.4%	2.5%	2.4%
Common Equity [2]	39.6%	40.4%	39.4%	41.0%	42.5%	40.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	60.0%	58.9%	59.4%	58.1%	57.0%	58.7%
Preferred Stock	2.1%	2.2%	2.5%	2.3%	2.4%	2.3%
Common Equity [2]	37.9%	38.9%	38.1%	39.6%	40.7%	39.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.9%	9.4%	10.2%	10.3%	10.3%	10.0%
Operating Ratio [3]	83.1%	83.1%	79.8%	79.3%	79.8%	81.0%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.28 x	3.16 x	2.80 x	3.05 x	2.94 x	3.05 x
Post-tax: All Interest Charges	2.94 x	2.87 x	2.60 x	3.10 x	2.59 x	2.82 x
Overall Coverage: All Int. & Pfd. Div.	2.89 x	2.81 x	2.55 x	3.04 x	2.55 x	2.77 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.17 x	3.06 x	2.70 x	2.95 x	2.84 x	2.94 x
Post-tax: All Interest Charges	2.84 x	2.78 x	2.50 x	3.00 x	2.48 x	2.72 x
Overall Coverage: All Int. & Pfd. Div.	2.79 x	2.72 x	2.46 x	2.94 x	2.44 x	2.67 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	7.4%	6.8%	6.0%	7.3%	6.9%
Effective Income Tax Rate	12.9%	10.6%	9.9%	12.2%	42.0%	17.5%
Internal Cash Generation/Construction [5]	60.2%	60.5%	58.6%	65.9%	66.2%	62.3%
Gross Cash Flow/ Avg. Total Debt [6]	15.1%	15.0%	15.9%	17.5%	17.4%	16.2%
Gross Cash Flow Interest Coverage [7]	5.70 x	5.17 x	4.90 x	4.97 x	4.98 x	5.14 x
Common Dividend Coverage [8]	3.49 x	3.47 x	3.52 x	5.56 x	4.80 x	4.17 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2018-2022, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating [1] Moody's	Credit Rating [1] S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.90
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.10
CMS Energy	CMS	Baa1	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.85
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A2	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa1	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	BBB+	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	0.90
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NDQ	NMF
FirstEnergy Corp.	FE	A3	BBB	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.95
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB	NYSE	1.10
Pinnacle West Capital	PNW	A3	BBB+	NYSE	0.90
PPL Corp.	PPL	A3	A	NYSE	1.05
Public Serv. Enterprise Inc.	PEG	A3	A-	NYSE	0.90
Sempra Energy	SRE	A3	BBB+	NYSE	0.95
Southern Co.	SO	Baa1	BBB+	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.90

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service, Inc.
S&P Global Inc.
The Value Line Investment Survey

PECO Energy Company
Capitalization and Related Capital Structure Ratios
Actual at December 31, 2023 and Estimated at December 31, 2024 and December 31, 2025

	Actual at December 31, 2023			Estimated at December 31, 2024			Estimated at December 31, 2025		
		Capital Structure Ratios			Capital Structure Ratios			Capital Structure Ratios	
	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt
	($000)			($000)			($000)		
Long-Term Debt [1]	$ 5,383,555	46.34%	47.01%	$ 5,958,830 [2]	46.17%	46.60%	$ 6,583,898 [2]	46.10%	46.60%
Common Equity									
Common Stock	1,423,004			1,423,004			1,423,004		
Other Paid-In Capital	2,627,349			3,207,349 [4]			3,679,349 [5]		
Retained Earnings [3]	2,019,166			2,197,166 [5]			2,442,166 [4]		
Total Common Equity	6,069,519	52.24%	52.99%	6,827,519	52.90%	53.40%	7,544,519	52.83%	53.40%
Total Permanent Capital	11,453,074	98.58%	100.00%	12,786,349	99.07%	100.00%	14,128,417	98.93%	100.00%
Short-Term Debt	164,783	1.42%		120,179	0.93%		153,029	1.07%	
Total Capital Employed	$ 11,617,857	100.00%		$ 12,906,528	100.00%		$ 14,281,446	100.00%	

Notes:
[1] Includes current portion of long-term debt.
[2] Reflects change in long-term debt consisting of:

New issue(s)	$ 575,000	$ 975,000
Maturity		$ (350,000)
Change in Adjustment for Tenders and Calls	$ 278	$ 68

[3] Excludes Accumulated Other Comprehensive Income
[4] Equity Infusions $ 580,000 472,000
[5] Reflects change in retained earnings consisting of:

Net income	$ 570,000	$ 763,000
Common Dividends	$ (400,000)	$ (534,000)
Tax Sharing Benefit	$ 8,000	$ 16,000

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2023

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
3.15%	10/15/25	$ 350,000,000	6.50%	3.29%	0.21%
5.90%	05/01/34	75,000,000	1.39%	6.00%	0.08%
5.95%	10/01/36	300,000,000	5.57%	6.04%	0.34%
5.70%	03/15/37	175,000,000	3.25%	5.81%	0.19%
4.80%	10/15/43	250,000,000	4.64%	4.89%	0.23%
4.15%	10/01/44	300,000,000	5.57%	4.21%	0.23%
3.70%	09/15/47	325,000,000	6.04%	3.77%	0.23%
3.90%	03/01/48	650,000,000	12.07%	4.08%	0.49%
3.00%	09/15/49	325,000,000	6.04%	3.10%	0.19%
2.80%	06/15/50	350,000,000	6.50%	2.86%	0.19%
3.05%	03/01/51	375,000,000	6.97%	3.11%	0.22%
2.85%	09/15/51	375,000,000	6.97%	2.90%	0.20%
4.60%	05/15/52	350,000,000	6.50%	4.71%	0.31%
4.38%	08/15/52	425,000,000	7.89%	4.46%	0.35%
4.90%	06/15/33	575,000,000	10.68%	5.03%	0.54%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.50%	7.46%	0.11%
6.75%	04/06/28	805,206	0.02%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.92%	5.88%	0.11%
		5,384,418,609	100.00%		4.22%
Adjustment for Tenders and Calls		(864,000)			
Long-Term Debt		$ 5,383,554,609			
Annualized Cost		$ 227,222,465			
Adjustment for Tenders and Calls on Reacquired Debt		341,000			
Total Cost		$ 227,563,465			4.23%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at December 31, 2024

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
3.15%	10/15/25	$ 350,000,000	5.87%	3.29%	0.19%
5.90%	05/01/34	75,000,000	1.26%	6.00%	0.08%
5.95%	10/01/36	300,000,000	5.03%	6.04%	0.30%
5.70%	03/15/37	175,000,000	2.94%	5.81%	0.17%
4.80%	10/15/43	250,000,000	4.20%	4.89%	0.21%
4.15%	10/01/44	300,000,000	5.03%	4.21%	0.21%
3.70%	09/15/47	325,000,000	5.45%	3.77%	0.21%
3.90%	03/01/48	650,000,000	10.91%	4.08%	0.45%
3.00%	09/15/49	325,000,000	5.45%	3.10%	0.17%
2.80%	06/15/50	350,000,000	5.87%	2.86%	0.17%
3.05%	03/01/51	375,000,000	6.29%	3.11%	0.20%
2.85%	09/15/51	375,000,000	6.29%	2.90%	0.18%
4.60%	05/15/52	350,000,000	5.87%	4.71%	0.28%
4.38%	08/15/52	425,000,000	7.13%	4.46%	0.32%
4.90%	06/15/33	575,000,000	9.65%	5.03%	0.49%
5.46%	09/01/54	575,000,000	9.65%	5.53%	0.53%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.35%	7.46%	0.10%
6.75%	04/06/28	805,206	0.01%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.73%	5.88%	0.10%
		5,959,418,609	100.00%		4.36%
Adjustment for Tenders and Calls		(589,000)			
Long-Term Debt		$ 5,958,829,609			
Annualized Cost		$ 259,830,651			
Adjustment for Tenders and Calls on Reacquired Debt		68,000			
Total Cost		$ 259,898,651			4.36%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at December 31, 2025

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
5.90%	05/01/34	$ 75,000,000	1.14%	6.00%	0.07%
5.95%	10/01/36	300,000,000	4.56%	6.04%	0.28%
5.70%	03/15/37	175,000,000	2.66%	5.81%	0.15%
4.80%	10/15/43	250,000,000	3.80%	4.89%	0.19%
4.15%	10/01/44	300,000,000	4.56%	4.21%	0.19%
3.70%	09/15/47	325,000,000	4.94%	3.77%	0.19%
3.90%	03/01/48	650,000,000	9.87%	4.08%	0.40%
3.00%	09/15/49	325,000,000	4.94%	3.10%	0.15%
2.80%	06/15/50	350,000,000	5.32%	2.86%	0.15%
3.05%	03/01/51	375,000,000	5.70%	3.11%	0.18%
2.85%	09/15/51	375,000,000	5.70%	2.90%	0.17%
4.60%	05/15/52	350,000,000	5.32%	4.71%	0.25%
4.38%	08/15/52	425,000,000	6.46%	4.46%	0.29%
4.90%	06/15/33	575,000,000	8.73%	5.03%	0.44%
5.46%	09/01/54	575,000,000	8.73%	5.53%	0.48%
5.46%	09/01/55	975,000,000	14.81%	5.53%	0.82%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.22%	7.46%	0.09%
6.75%	04/06/28	805,206	0.01%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.57%	5.88%	0.09%
		6,584,418,609	100.00%		4.58%
Adjustment for Tenders and Calls		(521,000)			
Long-Term Debt		$ 6,583,897,609			
Annualized Cost		$ 301,566,372			
Adjustment for Tenders and Calls on Reacquired Debt		68,000			
Total Cost		$ 301,634,372			4.58%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company

Calculation of the Effective Cost of Long-Term Debt by Series

Series	Date of Issue	Date of Maturity	Average Term in Years [1]	Principal Amount Issued	Premium/ Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [2]
First and Refunding Mortgage Bonds								
3.15%	10/05/15	10/15/25	10	$ 350,000,000	$ 4,156,454	$ 345,843,546	98.81%	3.29%
5.90%	04/23/04	05/01/34	30	75,000,000	1,024,692	73,975,308	98.63%	6.00%
5.95%	09/25/06	10/01/36	30	300,000,000	3,862,236	296,137,764	98.71%	6.04%
5.70%	03/19/07	03/15/37	30	175,000,000	2,672,126	172,327,874	98.47%	5.81%
4.80%	09/23/13	10/15/43	30	250,000,000	3,475,050	246,524,950	98.61%	4.89%
4.15%	09/15/14	10/01/44	30	300,000,000	3,167,148	296,832,852	98.94%	4.21%
3.70%	09/18/17	09/15/47	30	325,000,000	4,197,845	320,802,155	98.71%	3.77%
3.90%	02/23/18	03/01/48	30	650,000,000	20,205,761	629,794,239	96.89%	4.08%
3.00%	09/10/19	09/15/49	30	325,000,000	6,226,403	318,773,597	98.08%	3.10%
2.80%	06/01/20	06/15/50	30	350,000,000	4,016,000	345,984,000	98.85%	2.86%
3.05%	03/01/21	03/01/51	30	375,000,000	4,623,750	370,376,250	98.77%	3.11%
2.85%	09/14/21	09/15/51	30	375,000,000	3,952,315	371,047,685	98.95%	2.90%
4.60%	05/24/22	05/15/52	30	350,000,000	6,229,966	343,770,034	98.22%	4.71%
4.38%	08/23/22	08/15/52	30	425,000,000	6,205,230	418,794,770	98.54%	4.46%
4.90%	06/23/23	06/15/33	10	575,000,000	6,027,683	568,972,317	98.95%	5.03%
5.46% [3]	09/01/24	09/01/54	30	575,000,000	6,037,500	568,962,500	98.95%	5.53%
5.46% [3]	09/01/25	09/01/55	30	975,000,000	10,237,500	964,762,500	98.95%	5.53%
Trust Preferred Capital Securities								
7.38%	04/06/98	04/06/28	30	80,520,619	760,181	79,760,438	99.06%	7.46%
6.75% [4]	04/06/98	04/06/28	30	805,206	-	805,206	100.00%	6.75%
5.75%	06/24/03	06/15/33	30	103,092,784	1,934,015	101,158,769	98.12%	5.88%

Notes: [1] Determined by taking into account the effect of the annual sinking fund requirements which are met by the retirement of bonds which reduce the term of each issue.

[2] The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

[3] Estimated.

[4] Variable rate at Prime Rate of 4.75% plus two-percentage points.

Source of Information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending December 2023

Company	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	2.53%	2.63%	2.64%	2.61%	2.57%	2.55%	2.44%	2.56%	2.80%	3.01%	2.83%	2.79%			
Chesapeake Utilities Corp (CPK)	1.70%	1.68%	1.67%	1.92%	1.86%	1.98%	2.00%	2.15%	2.42%	2.67%	2.48%	2.24%			
New Jersey Resources Corporation (NJR)	3.14%	3.08%	2.94%	3.03%	3.24%	3.31%	3.51%	3.73%	3.84%	4.16%	4.01%	3.78%			
NiSource Inc (NI)	3.64%	3.65%	3.60%	3.51%	3.73%	3.68%	3.59%	3.75%	4.08%	3.98%	3.91%	3.79%			
Northwest Natural Holding Company (NWN)	3.87%	4.03%	4.11%	4.13%	4.56%	4.54%	4.52%	4.96%	5.13%	5.31%	5.35%	5.05%			
ONE Gas Inc (OGS)	3.18%	3.24%	3.29%	3.40%	3.22%	3.40%	3.31%	3.59%	3.83%	4.34%	4.52%	4.10%			
Southwest Gas Holdings Inc (SWX)	3.73%	3.94%	3.99%	4.47%	4.25%	3.92%	3.79%	4.01%	4.13%	4.27%	4.20%	3.93%			
Spire Inc. (SR)	4.01%	4.13%	4.12%	4.28%	4.51%	4.55%	4.56%	4.99%	5.11%	5.47%	5.01%	4.86%			
Average	**3.23%**	**3.30%**	**3.30%**	**3.42%**	**3.49%**	**3.49%**	**3.47%**	**3.72%**	**3.92%**	**4.15%**	**4.04%**	**3.82%**	**3.61%**	**3.85%**	**4.00%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: https://finance.yahoo.com/quote
https://www.nasdaq.com/market-activity/stocks

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	
	3.85%	1.033750	3.98%	
Discrete	D_0/P_0	Adj.	D_1/P_0	
	3.85%	1.041843	4.01%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	
	0.9625%	1.016464	3.97%	
Average			3.99%	
Growth rate			6.75%	
K			10.74%	

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Atmos Energy Corp (ATO)	9.00%	9.00%	8.50%	6.50%	12.00%	9.00%	7.00%	6.50%
Chesapeake Utilities Corp (CPK)	11.00%	9.50%	9.50%	7.50%	10.00%	10.00%	9.50%	8.00%
New Jersey Resources Corporation (NJR)	2.50%	5.00%	6.50%	6.50%	7.00%	7.50%	4.50%	7.00%
NiSource Inc (NI)	15.00%	1.50%	3.50%	-0.50%	0.50%	-3.00%	6.50%	0.50%
Northwest Natural Holding Company (NWN)	2.50%	-1.00%	0.50%	1.50%	0.50%	1.00%	2.50%	1.00%
ONE Gas Inc (OGS)	8.00%	-	10.00%	-	4.00%	-	7.50%	-
Southwest Gas Holdings Inc (SWX)	4.50%	5.50%	7.00%	8.50%	7.00%	6.50%	1.50%	4.00%
Spire Inc. (SR)	1.00%	2.50%	6.00%	5.00%	4.00%	6.50%	4.00%	5.50%
Average	6.69%	4.57%	6.44%	5.00%	5.63%	5.36%	5.38%	4.64%

Source of Information: Value Line Investment Survey, November 24, 2023

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	I/B/E/S First Call	Zacks	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
Atmos Energy Corp (ATO)	7.50%	7.30%	7.00%	7.50%	5.00%	6.50%	5.00%
Chesapeake Utilities Corp (CPK)	7.00%	NA	6.00%	8.50%	6.50%	6.00%	5.50%
New Jersey Resources Corporatior	6.00%	6.00%	5.00%	5.00%	4.50%	5.00%	5.50%
NiSource Inc (NI)	8.30%	7.20%	9.50%	4.50%	5.00%	5.50%	4.50%
Northwest Natural Holding Compar	2.80%	3.70%	6.50%	0.50%	4.00%	5.00%	3.50%
ONE Gas Inc (OGS)	5.00%	5.00%	6.50%	5.50%	6.50%	8.00%	4.00%
Southwest Gas Holdings Inc (SWX	4.00%	5.00%	10.00%	5.50%	7.50%	8.50%	3.00%
Spire Inc. (SR)	6.36%	5.60%	8.00%	5.00%	6.50%	6.50%	2.50%
Average	5.87%	5.69%	7.31%	5.25%	5.69%	6.38%	4.19%

Source of Information :
Yahoo Finance, January 17, 2024
Zacks, January 17, 2024
Value Line Investment Survey, November 24, 2023

Gas Group
Financial Risk Adjustment

	ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year	09/30/23	12/31/22	09/30/23	12/31/22	12/31/22	12/31/22	12/31/22	09/30/23	
Capitalization at Fair Values									
Debt(D)	5,402,591	505,000	2,106,536	8,479,400	1,148,395	2,500,000	3,945,072	3,270,200	3,419,649
Preferred(P)	0	0	0	1,546,500	0	0	0	242,000	223,563
Equity(E)	15,729,841	2,096,681	3,964,327	11,300,961	1,690,635	4,191,099	4,153,333	3,008,371	5,766,906
Total	21,132,432	2,601,681	6,070,863	21,326,861	2,839,030	6,691,099	8,098,405	6,520,571	9,410,118
Capital Structure Ratios									
Debt(D)	25.57%	19.41%	34.70%	39.76%	40.45%	37.36%	48.71%	50.15%	37.01%
Preferred(P)	0.00%	0.00%	0.00%	7.25%	0.00%	0.00%	0.00%	3.71%	1.37%
Equity(E)	74.43%	80.59%	65.30%	52.99%	59.55%	62.64%	51.29%	46.14%	61.62%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock									
Issued	148,492.783	17,741.418	97,584.455	416,106.000	35,525.000	55,349.954	67,119.143	53,170.224	
Treasury	0.000	0.000	13.041	3,963.000	0.000	0.000	0.000	0.000	
Outstanding	148,492.783	17,741.418	97,571.414	412,143.000	35,525.000	55,349.954	67,119.143	53,170.224	
Market Price	$ 105.93	$ 118.18	$ 40.63	$ 27.42	$ 47.59	$ 75.72	$ 61.88	$ 56.58	
Capitalization at Carrying Amounts									
Debt(D)	6,560,000	600,800	2,587,845	9,553,600	1,336,864	2,682,471	4,447,856	3,710,600	3,935,005
Preferred(P)	0	0	0	1,546,500	0	0	0	242,000	223,563
Equity(E)	10,870,064	832,801	1,990,735	6,028,900	1,175,441	2,584,426	3,058,759	2,675,300	3,652,053
Total	17,430,064	1,433,601	4,578,580	17,129,000	2,512,305	5,266,897	7,506,615	6,627,900	7,810,620
Capital Structure Ratios									
Debt(D)	37.64%	41.91%	56.52%	55.77%	53.21%	50.93%	59.25%	55.98%	51.40%
Preferred(P)	0.00%	0.00%	0.00%	9.03%	0.00%	0.00%	0.00%	3.65%	1.59%
Equity(E)	62.36%	58.09%	43.48%	35.20%	46.79%	49.07%	40.75%	40.36%	47.01%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%
Betas Value Line	0.85	0.80	0.95	0.90	0.85	0.85	0.90	0.85	0.87

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]										
	0.87	=	Bu	[1+	(1-0.21)	0.6006	+	0.0222	]										
	0.87	=	Bu	[1+	0.79	0.6006	+	0.0222	]										
	0.87	=	Bu	1.4967															
	0.58	=	Bu																
Hamada	Bl	=	0.58	[1+	(1 - t)	D/E	+	P/E	]										
	Bl	=	0.58	[1+	0.79	1.0934	+	0.0337	]										
	Bl	=	0.58	1.8975															
	Bl	=	1.10																

M&M	ku	=	ke	-	(((	ku	-	i	)		1-t	)		D	/	E	-	(ku	-	d	)	P	/	E	
	9.09%	=	10.74%	-	(((	9.09%	-	5.78%	)		0.79	)		37.01%	/	61.62%	-	9.09%	-	5.68%	)	1.37%	/	61.62%	
	9.09%	=	10.74%	-	(((	3.31%			)		0.79	)		0.6006			-	3.41%			)	0.0222			
	9.09%	=	10.74%	-	((	2.61%						)		0.6006			-	3.41%			)	0.0222			
	9.09%	=	10.74%	-		1.57%											-	0.08%							

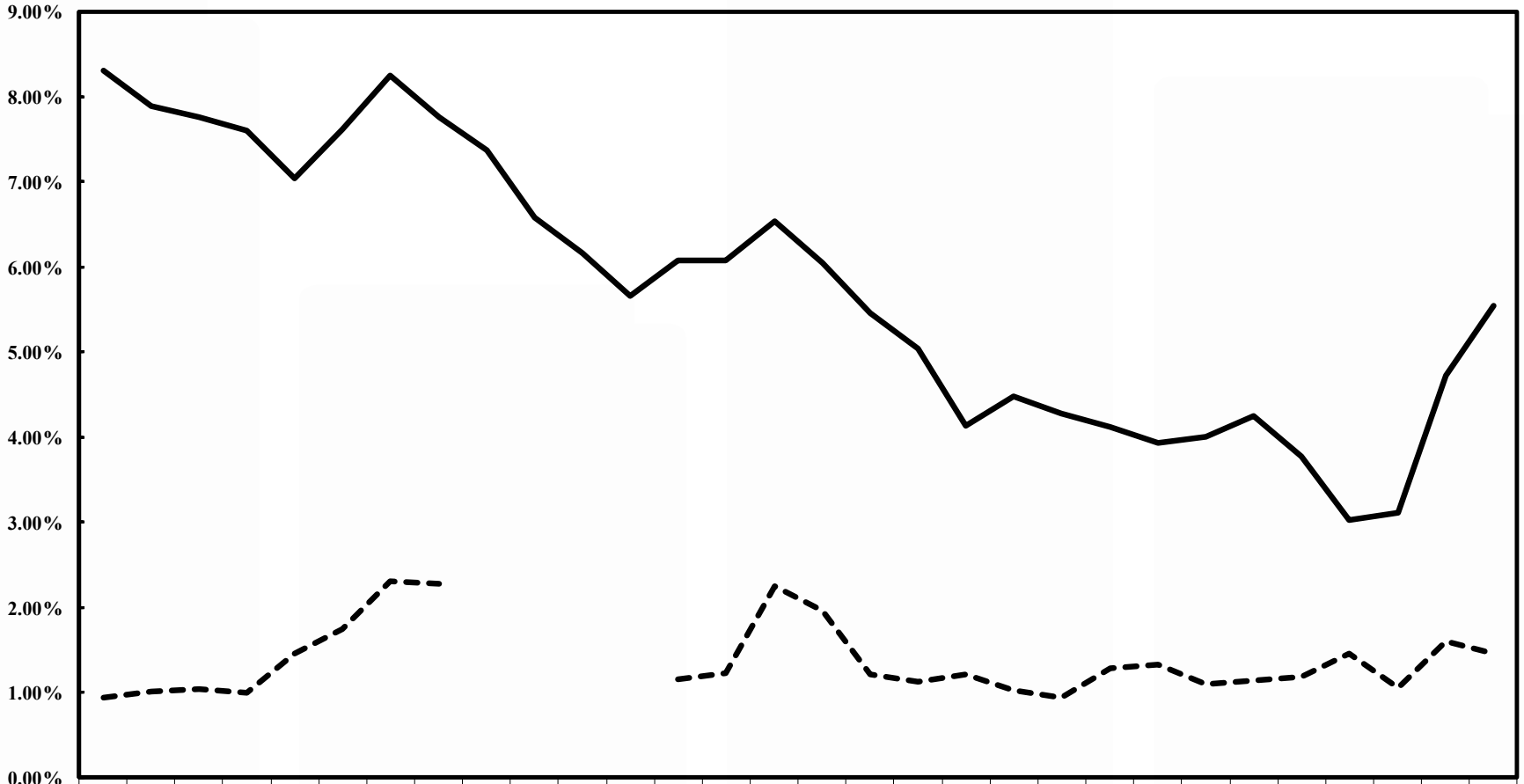
M&M	ke	=	ku	+	(((	ku	-	i	)		1-t	)		D	/	E	+	(ku	-	d	)	P	/	E	
	12.05%	=	9.09%	+	(((	9.09%	-	5.78%	)		0.79	)		51.40%	/	47.01%	+	9.09%	-	5.68%	)	1.59%	/	47.01%	
	12.05%	=	9.09%	+	(((	3.31%			)		0.79	)		1.0934			+	3.41%			)	0.0337			
	12.05%	=	9.09%	+	((	2.61%						)		1.0934			+	3.41%			)	0.0337			
	12.05%	=	9.09%	+		2.85%											+	0.11%							

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2017-2022
and the Twelve Months Ended December 2023

Years	Aa Rated	A Rated	Baa Rated	Average
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
2021	2.97%	3.11%	3.36%	3.15%
2022	4.53%	4.72%	5.03%	4.77%
Five-Year Average	3.60%	3.77%	4.13%	3.84%
Months				
Jan-23	4.98%	5.20%	5.49%	5.23%
Feb-23	5.12%	5.29%	5.54%	5.32%
Mar-23	5.24%	5.39%	5.68%	5.44%
Apr-23	5.00%	5.13%	5.47%	5.20%
May-23	5.24%	5.36%	5.71%	5.44%
Jun-23	5.26%	5.38%	5.73%	5.46%
Jul-23	5.30%	5.41%	5.73%	5.48%
Aug-23	5.58%	5.71%	6.08%	5.77%
Sep-23	5.72%	5.86%	6.15%	5.91%
Oct-23	6.19%	6.34%	6.61%	6.38%
Nov-23	5.82%	5.96%	6.20%	5.99%
Dec-23	5.27%	5.42%	5.68%	5.46%
Twelve-Month Average	5.39%	5.54%	5.84%	5.59%
Six-Month Average	5.65%	5.78%	6.08%	5.83%
Three-Month Average	5.76%	5.91%	6.16%	5.94%

Source: Mergent Bond Record

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.77	3.02	3.11	4.72	5.54
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.33	1.10	1.14	1.19	1.46	1.06	1.60	1.45

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Oct-21	3.09%	2.06%	1.03%
Nov-21	3.02%	1.94%	1.08%
Dec-21	3.13%	1.85%	1.28%
Jan-22	3.33%	2.10%	1.23%
Feb-22	3.68%	2.25%	1.43%
Mar-22	3.98%	2.41%	1.57%
Apr-22	4.32%	2.81%	1.51%
May-22	4.75%	3.07%	1.68%
Jun-22	4.86%	3.25%	1.61%
Jul-22	4.78%	3.10%	1.68%
Aug-22	4.76%	3.13%	1.63%
Sep-22	5.28%	3.56%	1.72%
Oct-22	5.88%	4.04%	1.84%
Nov-22	5.75%	4.00%	1.75%
Dec-22	5.28%	3.66%	1.62%
Jan-23	5.20%	3.66%	1.54%
Feb-23	5.29%	3.80%	1.49%
Mar-23	5.39%	3.77%	1.62%
Apr-23	5.13%	3.68%	1.45%
May-23	5.36%	3.86%	1.50%
Jun-23	5.38%	3.87%	1.51%
Jul-23	5.41%	3.96%	1.45%
Aug-23	5.71%	4.28%	1.43%
Sep-23	5.86%	4.47%	1.39%
Oct-23	6.34%	4.95%	1.39%
Nov-23	5.96%	4.66%	1.30%
Dec-23	5.42%	4.14%	1.28%

Recent Average:	12-months	1.45%
	6-months	1.37%
	3-months	1.32%

Common Equity Risk Premiums
Years 1926-2022

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.40%	5.27%	7.13%	2.83%
Average Across All Interest Rates	12.02%	6.06%	5.96%	4.91%
High Interest Rates	11.63%	6.87%	4.76%	7.03%

Source of Information: 2023 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
2020	18.40%	15.40%	1.37%
2021	28.71%	-2.66%	1.88%
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
2022	-18.11%	-26.18%	4.24%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2018-2022
and the Twelve Months Ended December 2023

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
2021	0.10%	0.27%	0.46%	0.86%	1.19%	1.44%	1.98%	2.05%
2022	2.79%	2.98%	3.05%	3.00%	3.01%	2.95%	3.30%	3.12%
Five-Year Average	1.53%	1.63%	1.70%	1.82%	1.97%	2.07%	2.41%	2.48%
Months								
Jan-23	4.69%	4.21%	3.91%	3.64%	3.59%	3.53%	3.81%	3.66%
Feb-23	4.93%	4.53%	4.23%	3.94%	3.86%	3.75%	3.95%	3.80%
Mar-23	4.68%	4.30%	4.09%	3.82%	3.77%	3.66%	3.94%	3.77%
Apr-23	4.68%	4.02%	3.76%	3.54%	3.50%	3.46%	3.80%	3.68%
May-23	4.91%	4.13%	3.82%	3.59%	3.58%	3.57%	3.96%	3.86%
Jun-23	5.24%	4.64%	4.27%	3.95%	3.85%	3.75%	4.04%	3.87%
Jul-23	5.37%	4.83%	4.47%	4.14%	4.03%	3.90%	4.15%	3.96%
Aug-23	5.37%	4.90%	4.59%	4.31%	4.26%	4.17%	4.46%	4.28%
Sep-23	5.44%	5.02%	4.74%	4.49%	4.46%	4.38%	4.65%	4.47%
Oct-23	5.42%	5.07%	4.89%	4.77%	4.82%	4.80%	5.13%	4.95%
Nov-23	5.28%	4.88%	4.64%	4.49%	4.53%	4.50%	4.84%	4.66%
Dec-23	4.96%	4.46%	4.19%	4.00%	4.04%	4.02%	4.32%	4.14%
Twelve-Month Average	5.08%	4.58%	4.30%	4.06%	4.02%	3.96%	4.25%	4.09%
Six-Month Average	5.31%	4.86%	4.59%	4.37%	4.36%	4.30%	4.59%	4.41%
Three-Month Average	5.22%	4.80%	4.57%	4.42%	4.46%	4.44%	4.76%	4.58%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated December 1, 2023 and December 28, 2023

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2024	First	5.0%	4.5%	4.2%	4.2%	4.3%	5.1%	6.1%
2024	Second	4.7%	4.2%	4.0%	4.1%	4.3%	5.0%	6.0%
2024	Third	4.4%	4.0%	3.9%	3.9%	4.2%	4.9%	6.0%
2024	Fourth	4.2%	3.8%	3.8%	3.9%	4.1%	4.8%	5.9%
2025	First	3.9%	3.7%	3.6%	3.8%	4.0%	4.8%	5.8%
2025	Second	3.7%	3.6%	3.6%	3.7%	4.0%	4.7%	5.8%
Long-range CONSENSUS								
2025		3.7%	3.7%	3.7%	3.9%	4.1%	5.0%	6.0%
2026		3.4%	3.5%	3.7%	3.9%	4.1%	4.9%	6.0%
2027		3.3%	3.4%	3.7%	3.9%	4.1%	4.9%	6.0%
2028		3.3%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%
2029		3.2%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%
Averages:								
	2025-2029	3.4%	3.5%	3.7%	3.9%	4.1%	4.9%	6.0%
	2030-2034	3.2%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%

Measures of the Market Premium

Historical Market Premium

Avg. to Low Interest Rates	(Rm)	(Rf)	
1926-2022 Arith. mean	12.21%	3.87%	8.34%

Forecast Market Premium

Value Line	Dividend Yield		Median Appreciation Potential		Median Total Return
As of: 29-Dec-23	2.2%	+	9.73%	=	11.93%
Risk-free Rate of Return (Rf)					3.75%
					8.18%
Average - Historical/Forecast					8.26%

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 1, 2, 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 80 to 95; Betas of .80 to .95; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AAON Inc	Machinery	3	3	B+	80	0.85	3
Abbott Laboratories	Med Supp Non-Invasive	3	1	A+	95	0.90	4
AbbVie Inc	Drug	3	2	A	95	0.85	4
Agilent Technologies	Precision Instrument	3	2	A	90	0.95	3
Archer Daniels Midland Company	Food Processing	3	1	A+	95	0.95	3
Arthur J Gallagher and Company	Financial Svcs. (Div.)	4	1	A	95	0.95	4
AutoZone Inc	Retail Automotive	2	3	B+	85	0.95	3
Booz Allen Hamilton Holding Corporation	Industrial Services	3	2	B++	85	0.85	3
Brady Corp	Diversified Co.	3	2	B++	90	0.95	4
Brown and Brown Inc	Financial Svcs. (Div.)	3	1	A	95	0.95	3
BWX Technologies	Power	4	2	B++	90	0.80	3
CACI International Inc	IT Services	3	3	B+	90	0.90	3
Caseys General Stores Inc	Retail/Wholesale Food	2	2	B++	90	0.90	4
Cboe Global Markets	Brokers & Exchanges	3	2	A	95	0.80	3
Cencora	Med Supp Non-Invasive	2	2	A	95	0.80	4
Comcast Corporation	Cable TV	2	1	A+	95	0.85	3
Commerce Bancshares Inc	Bank (Midwest)	3	3	B++	90	0.90	4
Corteva Inc.	Chemical (Basic)	4	3	B++	80	0.95	3
CSW Industrials	Petroleum (Producing)	3	2	B++	85	0.90	3
CVS Caremark Corporation	Retail Store	1	2	A+	85	0.90	4
Expeditors International of Washington Inc	Industrial Services	3	1	A+	95	0.95	3
Exponent Inc.	Information Services	4	3	B+	80	0.95	4
FirstCash Holdings	Financial Svcs. (Div.)	2	3	B++	80	0.90	3
GATX Corp	Railroad	4	3	B+	85	0.95	3
Harris Corp.	Aerospace/Defense	3	2	A+	85	0.90	3
Huntington Ingalls Industries Inc	Aerospace/Defense	2	3	A	80	0.95	3
Ingredion Incorporated	Food Processing	2	2	B++	95	0.90	3
Intercontinental Exch.	Brokers & Exchanges	4	1	A	95	0.95	3
Knight-Swift Trans.	Trucking	4	3	B++	85	0.85	3
McCormick and Co	Food Processing	4	1	A+	90	0.80	3
Motorola Solutions Inc	Telecom. Equipment	4	2	B++	95	0.95	3
O Reilly Automotive Inc	Retail Automotive	3	2	B++	90	0.90	3
Packaging Corp	Packaging & Container	3	2	A	90	0.95	4
RLI Corp	Insurance (Prop/Cas.)	3	2	A	95	0.80	4
Schneider National	Trucking	4	3	B++	85	0.80	4
Selective Insurance Group Inc	Insurance (Prop/Cas.)	2	3	B++	95	0.85	4
Sensient Technologies Corp	Food Processing	4	3	B++	95	0.90	3
Service Corp International Inc	Industrial Services	3	3	B+	85	0.90	3
Stepan Company	Chemical (Specialty)	4	2	B++	90	0.80	3
The Travelers Companies Inc	Insurance (Prop/Cas.)	3	1	A+	95	0.95	4
Thermo Fisher Scientific Inc	Precision Instrument	3	1	A	95	0.85	4
Trimas Corporation	Diversified Co.	3	3	B+	80	0.90	3
Tyler Technologies	IT Services	4	2	A+	80	0.85	3
UniFirst Corp	Industrial Services	3	2	A	90	0.90	3
United Parcel Service	Air Transport	4	2	A+	85	0.80	4
Waters Corp	Precision Instrument	2	2	A	85	0.95	3
Western Union Company	Financial Svcs. (Div.)	2	3	B+	85	0.85	4
Average		3	2	A	89	0.89	3
Gas Group	Average	3	2	A	88	0.87	3

Source of Information: Value Line Investment Survey for Windows, January 2024

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2018-2022 and
Projected 2026-28

Company	2018	2019	2020	2021	2022	Average	Projected 2026-28
AAON Inc	17.2%	18.5%	21.3%	12.6%	17.9%	17.5%	18.0%
Abbott Laboratories	16.8%	18.7%	20.0%	26.2%	25.8%	21.5%	24.0%
AbbVie Inc	-	-	NMF	NMF	NMF	-	NMF
Agilent Technologies	19.9%	20.8%	21.0%	24.7%	29.5%	23.2%	33.0%
Archer Daniels Midland Company	9.5%	7.2%	8.9%	12.1%	17.9%	11.1%	14.5%
Arthur J Gallagher and Company	13.9%	12.8%	13.2%	10.7%	8.9%	11.9%	18.0%
AutoZone Inc	-	-	-	-	-	-	NMF
Booz Allen Hamilton Holding Corporation	58.8%	56.4%	50.8%	54.5%	61.3%	56.4%	33.5%
Brady Corp	14.9%	15.4%	13.0%	13.5%	16.5%	14.7%	18.0%
Brown and Brown Inc	11.5%	11.9%	12.8%	14.0%	14.6%	13.0%	16.5%
BWX Technologies	96.3%	60.4%	45.1%	48.0%	31.8%	56.3%	32.5%
CACI International Inc	9.4%	11.2%	12.1%	17.2%	12.0%	12.4%	10.0%
Caseys General Stores Inc	14.5%	16.1%	16.2%	15.2%	16.8%	15.8%	15.5%
Cboe Global Markets	13.1%	11.1%	13.9%	14.6%	6.8%	11.9%	12.5%
Cencora	48.8%	52.2%	-	NMF	NMF	50.5%	NMF
Comcast Corporation	16.5%	17.4%	13.3%	15.7%	19.9%	16.6%	19.0%
Commerce Bancshares Inc	14.8%	13.4%	10.4%	15.4%	19.8%	14.8%	14.5%
Corteva Inc.	-	4.4%	4.5%	6.3%	7.6%	5.7%	10.0%
CSW Industrials	17.5%	16.6%	9.8%	14.2%	18.3%	14.5%	14.0%
CVS Caremark Corporation	12.7%	14.5%	14.2%	14.9%	16.2%	33.7%	12.5%
Expeditors International of Washington Inc	31.1%	26.9%	26.2%	40.5%	43.6%	33.7%	27.5%
Exponent Inc.	23.0%	23.5%	22.8%	24.3%	31.9%	25.1%	28.0%
FirstCash Holdings	11.6%	12.2%	8.3%	6.9%	13.5%	10.5%	12.0%
GATX Corp	11.2%	10.9%	6.5%	9.0%	10.7%	9.7%	9.5%
Harris Corp.	-	3.6%	5.4%	9.6%	5.7%	6.1%	17.0%
Huntington Ingalls Industries Inc	55.1%	36.5%	36.6%	19.4%	16.6%	32.8%	17.0%
Ingredion Incorporated	20.8%	16.4%	13.6%	14.4%	15.6%	16.2%	20.5%
Intercontinental Exch.	12.1%	12.7%	12.8%	12.8%	13.1%	12.7%	11.5%
Knight-Swift Trans.	8.4%	6.6%	8.0%	12.1%	11.8%	9.4%	7.5%
McCormick and Co	20.9%	20.8%	19.4%	18.7%	14.6%	18.9%	16.0%
Motorola Solutions Inc	-	-	-	-	-	-	NMF
O Reilly Automotive Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Packaging Corp	27.6%	22.7%	16.9%	24.8%	28.4%	24.1%	25.0%
RLI Corp	11.4%	11.8%	10.4%	14.5%	19.1%	13.4%	14.0%
Schneider National	12.6%	6.6%	10.3%	16.7%	16.1%	12.5%	12.0%
Selective Insurance Group Inc	12.2%	12.0%	9.1%	13.5%	13.0%	12.0%	21.0%
Sensient Technologies Corp	18.3%	14.2%	11.7%	14.1%	13.9%	14.4%	12.5%
Service Corp International Inc	20.4%	19.4%	29.8%	40.7%	36.3%	29.3%	29.0%
Stepan Company	14.4%	11.6%	12.9%	12.8%	12.6%	12.9%	8.5%
The Travelers Companies Inc	10.7%	9.8%	9.2%	12.2%	13.9%	11.2%	11.5%
Thermo Fisher Scientific Inc	10.7%	11.5%	18.5%	18.9%	15.8%	15.1%	15.5%
Trimas Corporation	13.1%	9.5%	11.8%	9.1%	10.2%	10.7%	11.5%
Tyler Technologies	14.6%	13.1%	11.5%	12.8%	12.1%	12.8%	15.5%
UniFirst Corp	10.2%	10.0%	7.8%	8.1%	5.4%	8.3%	8.5%
United Parcel Service	NMF	NMF	NMF	NMF	57.0%	57.0%	43.0%
Waters Corp	39.9%	-	NMF	NMF	NMF	39.9%	47.0%
Western Union Company	-	-	NMF	NMF	NMF	-	NMF
Average						20.2%	18.5%
Median						14.6%	15.5%
Average (excluding companies with values >20%)						12.6%	13.6%

Comparable Earnings Approach
Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

PECO ENERGY COMPANY
STATEMENT NO. 5-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: PAUL R. MOUL

SUBJECT: OVERALL RATE OF RETURN, INCLUDING CAPITAL STRUCTURE RATIOS, EMBEDDED COST OF DEBT AND THE COST OF EQUITY, FOR PECO ENERGY COMPANY – GAS DIVISION

DATED: July 16, 2024

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I. INTRODUCTION AND SUMMARY

1. Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

2. Q. Did you previously submit testimony in this proceeding on behalf of PECO Energy Company - Gas Division (" PECO Energy" or the "Company")?

A. Yes. I submitted my direct testimony, PECO Energy Statement No. 5, on March 28, 2024.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by David J. Garrett, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), and Anthony Spadaccio, a witness appearing on behalf of the Bureau of Investigation and Enforcement ("I&E"). If I fail to address each and every issue in the testimony of Messrs. Garrett and Spadaccio, it does not imply agreement with those issues. I also comment on certain aspects of the testimony of Walmart witness Lisa Perry and OCA witnesses John Defever, Clarence Johnson and Roger Colton.

4. Q. What are the key aspects of the rate of return issue that the Pennsylvania Public Utility Commission ("Commission") should consider when deciding this issue in this case?

A. The issues involve the Company's cost of equity and the capital structure. Mr. Spadaccio has accepted the Company's proposed capital structure ratios. Mr. Garrett has opposed the actual capital structure and instead proposed a hypothetical capital structure. All the witnesses have accepted the embedded cost of debt for PECO Energy.

The equity returns proposed by these witnesses are entirely too low to reflect the risks of PECO Energy and the prospective cost of equity. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration a rate of return that will reflect and be supportive of the Company's financial and risk profile. As I explain below, the opposing parties' recommendations fail to adequately consider this point and thereby understate the required cost of common equity in this proceeding.

5. Q. Please summarize the key points of your rebuttal testimony.

A. My key points are:

- Capital Structure Ratios – Mr. Garrett's use of a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY, is improper and contrary to standard practice in Pennsylvania.

- Comparable Companies – Mr. Spadaccio has made an erroneous deletion from my gas company barometer group by eliminating Southwest Gas. Mr. Garrett accepts my group.
- Discounted Cash Flow ("DCF") – A variety of DCF results are clearly too low to provide a reliable measure of the cost of equity. This can be traced to the formulaic approach taken by Mr. Spadaccio in applying this model (I&E Statement No. 2, pp. 27-28). In addition, Mr. Garrett fails to adequately reflect investor expectations of growth that are specific to the natural gas companies included in his proxy group. He errs when using analysts' growth rate forecasts by failing to consider earnings per share growth that is used by Mr. Spadaccio, me, and the Commission.
- DCF Leverage Adjustment – Mr. Spadaccio has not refuted the accuracy of the Company's leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM"). Mr. Garrett claims that my leverage adjustment is "incorrect" (OCA Statement No. 2, pp. 28-30). But he has not shown that the capital structure ratios and calculations of the leverage adjustment are in any way incorrect.
- CAPM – A reasonable application of the CAPM mandates using 30-year Treasury bond yields and leverage adjusted betas and indicates an equity cost rate that is near 11% in this case. Indeed, Mr. Spadaccio has proposed a 10.86% CAPM result in this case, even without these

considerations. This demonstrates that Mr. Garrett's CAPM results are inadequate.

- Additional methods should also be considered when establishing the cost of equity for PECO Energy. This is especially important because the Federal Reserve's Open Market Committee ("FOMC") policy and inflation in the last few months indicate a higher cost of equity, which both witnesses have chosen not to even mention in their testimony.

6. Q. How should the rate of return set by the Commission support the Company's financial profile?

A. The Commission should set the Company's return on equity at a level that will attract investment in the Company to ensure the Company's financial ability to render safe and reliable service. Applying this principle, the Commission should reject the proposals by Messrs. Spadaccio and Garrett to cut the Company's return on common equity to 9.93% and 9.00%, respectively. Equity returns of this magnitude would be viewed by investors as unsupportive of the Company's financial condition. In particular, Mr. Garrett's proposed return is completely unreasonable because it is much too low to allow PECO Energy to achieve the level of returns that meet investors' expectations.

7. Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt either of the positions of the I&E or OCA. If it

were to do so, investors would see Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment. If the Commission were to follow the proposals of I&E or the OCA, the regulatory ranking of Pennsylvania would certainly be jeopardized. The return on equity used by the Commission to set rates embodies in a single numerical value a clear signal of regulatory support for the financial strength of the utilities that it regulates. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the opportunity to achieve a reasonable return on equity represents a direct signal to the investment community of regulatory support (or lack thereof) for the utility's financial strength. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

8. Q. How does the cost of equity proposal by Mr. Garrett and Mr. Spadaccio compare to the utility returns recently authorized by the Commission?

A. Technical disputes about methodology and data aside, the proposed costs of equity proposed by Mr. Garrett and Mr. Spadaccio are simply not representative of the return investors can earn on other investments of comparable risk, including investments in other electric utilities, such as PECO. Indeed, the Commission established a 9.85% equity return for the UGI Utilities Electric Division rate case at Docket No. R-2017-2640058. With rising capital cost rates, a higher, not lower, equity return is required in this case. The Commission also granted equity returns of 9.54% for Citizens' Electric Company at Docket No. R-2019-3008212, 9.31% for Wellsboro Electric Company at Docket No. R-2019-3008208, 9.73% for Valley Energy at Docket No. R-2019-3008209, 9.86% for Columbia Gas of Pennsylvania at Docket No. R-2020-3018835, 10.8% for Pennsylvania-American Water Company at Docket Nos. R-2020-3019369, R-2020-3019371,[1] and later, a 10.24% equity return was provided to PECO Energy Company – Gas Division at Docket No. R-2020-3018929. Subsequently, the Commission granted Aqua Pennsylvania a 10.00% return on equity at Docket No. R-2021-3027385 and 9.75% to Columbia Water Company at Docket No. R-2023-3040258. Moreover, for purposes of setting the Distribution System Improvement Charge ("DSIC"), the Commission has set a 10.15% equity return for gas utilities. In the DSIC proceedings, DSIC recoveries are

[1] The Commission's Opinion and Order in this case held that: "We agree with the ALJ's rationale and recommendation on this issue, approving, as contained within the Joint Settlement, the Company's application of traditional ROE models and its analysis of current market conditions." *Pa. PUC, et al. v. Pennsylvania-American Water Company*, Docket Nos. R-2020-3019369 (Water), R-2020-3019371 (Wastewater), p. 62 (Opinion and Order entered Feb. 25, 2021).

reconciled and therefore the 10.15% is guaranteed. In contrast, the equity return set in a base rate case is an opportunity to earn an allowed equity return and should be higher than the DSIC equity allowance.

The rates of return on common equity of 9.00% proposed by Mr. Garrett and 9.93% proposed by Mr. Spadaccio are seriously deficient and will not provide PECO with the opportunity to earn its investor required cost of capital for the fully projected future test year ending December 31, 2025 ("FPFTY"). As explained below, this is not the time for the Commission to be reducing the Company's authorized return when there is a compelling need for capital investment to rehabilitate aging infrastructures.

9. Q. Should the Commission consider the future trend in capital costs when deciding the return on equity in this case?

A. Yes. The Commission should recognize that accommodative policy by the FOMC has ended and higher interest rates have occurred and will prevail in the future. High inflation also has been a driving factor. As noted previously, the rate of inflation spiked upward to 9.1% in June 2022, and as of May 2024, it stood at 3.3%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a prudent level of borrowing. Today's inflation continues to be higher than the target rate of 2%, which is the FOMC policy goal.

One reason that explains the higher long-term interest rates can be traced to investor expectations of high inflation noted above. Higher interest rates

clearly point to higher capital costs prospectively. The yield on 30-year Treasury bonds moved above the 2% level beginning in February 2021. In comparison, those yields closed out 2020 at 1.67% for December. By May 2024, the yield on 30-year Treasury bonds had moved to 4.62%, or an increase of 2.95% (or 177%). Likewise, the yield on A-rated public utility bonds has increased to 5.74% in May 2024 up from 2.77% in December 2020 – a 297 basis point (or 107%) increase. I will describe the Blue Chip forecast of interest rates and the continuation of this trend below. Indeed, the reality of high interest rates demands higher, not lower capital costs.

10. Q. Is there additional evidence that suggests that the cost of capital will continue at high levels?

A. Yes. To gain a consensus view of future interest rates, I tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well-recognized and investor-influencing sources. I chose the 10-year Treasury note because it is available on a consistent basis for each source. The comparisons are:

	2025	2026	207	2028	2029	2030
Blue Chip	4.0%	4.0%	4.0%	4.0%	4.2%	4.2%
CBO	4.1%	3.7%	3.6%	3.7%	3.8%	3.9%

The Blue Chip (June 1, 2024) and CBO (June 2024) reflect the general consensus that interest rates will remain at elevated levels in the future. The high levels of interest rates represent one key factor that adds to the risk of common equity. And for comparison purposes, the yield on public utility

bonds always exceeds Treasury yields. As noted in my direct testimony (PECO Statement No. 5, p. 43), the spread in those yields is at least 1.25%, and historically higher than that through most of the year 2023. Page 2 of Schedule 11 shows a spread of 1.45% on average for 2023. The Commission should take into account the forecast of interest rates when it sets the cost of equity for PECO.

11. Q. At page 24 of I&E Statement No. 2, Mr. Spadaccio indicated that he believes that the FOMC intends to cut rates in the near future. Should the Commission take this possibility into account when setting a cost of equity in this proceeding?

A. Not at this time. There is always the possibility that the Fed Funds rate could be cut by the FOMC. But there also is the possibility that the rate could be increased at some point in the future. To add perspective, there was considerable discussion early in 2024 that the FOMC might cut the Fed Funds rate six times in 2024. We are now halfway through 2024 and the Fed Funds rate remains unchanged. A variety of factors influence the FOMC, such as the condition of the economy, the health of the labor markets, and other factors. With no definitive plan in place, it would be speculative to infer what might occur in the future regarding the Fed Funds rate.

12. Q. What do you say about Mr. Garrett's idea (OCA Statement 2, pp. 4-5) that there is no need to develop a "blended rate" for PECO?

A. Ignoring my blended approach denies customers the benefit of the risk reduction associated with a combination utility, such as PECO Energy. He

says that using separate electric and gas proxy groups are enough to distinguish the risks for each of PECO Energy's divisions. But that provides a superficial analysis. So while the spot betas for the Electric Group (i.e., 0.95) was higher than the Gas Group (i.e., 0.88) when Mr. Garrett prepared his testimony, they were roughly similar (Gas at 0.88 and Electric at 0.87) when my testimony was prepared. The DCF, however, shows a higher return for the Gas Group (i.e., 12.05%) vs. the Electric Group (i.e., 11.78%). The Commission has had a history of setting the DSIC return for the gas utilities at a higher rate than for the electric utilities. At present, the DSIC return for the gas utilities is 10.15%, while the DSIC return for electric utilities is 9.80%. While this difference has varied, the returns for the gas utilities has typically been higher.

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

A. I will cover the issues of (i) capital structure, (ii) the updated cost of long-term debt, (iii) the composition of the proxy (i.e., barometer) group, (iv) the weight to be given to the DCF method, (v) the DCF growth rate, (vi) the leverage adjustment to the DCF and CAPM methods, (vii) the CAPM method, (viii) the Risk Premium analysis, (ix) Comparable Earnings, and (x) management performance as part of the return on equity consideration.

II. CAPITAL STRUCTURE RATIOS

14. Q. Is there a difference in the proposed capital structure ratios utilized by the rate of return witnesses in this case?

A. Yes. Mr. Garrett is alone in advocating an erroneous capital structure for

PECO. Mr. Spadaccio has accepted the Company's proposed capital structure, as it falls within the range of capital structures of the proxy group. Mr. Garrett's position is clearly contrary to long-standing Commission policy concerning capital structure ratios, most recently confirmed in Columbia Water Company at Docket No. R-2023-3040258, and previously in Aqua Pennsylvania, Inc. at Docket No. R-2021-3027385, and in the PECO Energy Company – Gas Division rate case at Docket No. R-2020-3018929.

15. Q. What capital structure ratios do Mr. Garrett propose?

A. Mr. Garrett has proposed a hypothetical capital structure for PECO without ever demonstrating that the Company's proposed capital structure is unreasonable. Rather, his proposed capital structure is simply designed to lower the Company's revenue requirement. In reaching his conclusion on capital structure ratios, Mr. Garrett performed three analyses. These are (i) a calculation of the cost of capital at various debt ratios, (ii) the debt ratios of the companies in his proxy group, and (iii) the debt ratios of thousands of other companies. He seems to favor option (ii), but does not propose a debt ratio as high as he reports for his proxy group. This approach essentially advocates the use of a hypothetical capital structure that violates Commission precedent on the use of the actual capital structure. If he had referred to other rate cases decided by the Commission as guides for the selection of capital structure ratios, then he should have relied upon PECO's actual capital structure ratios.

16. Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. First, Mr. Spadaccio explained (I&E Statement No. 2, pp. 10-14) that the Company's actual capital structure ratios (including the 53.41% common equity ratio) fall within the range of the proxy group. This is sufficient to meet the Commission's standard that makes the actual PECO Energy capital structure appropriate in this case.

Second, Mr. Garrett might also have been led to a different conclusion if he had considered the common equity ratios utilized by this Commission in recent rate case decisions. Indeed, in its Order Entered on October 25, 2018, in Docket No. R-2017-2640058, the Commission adopted a 54.02% common equity ratio for the Electric Division of UGI Utilities. Furthermore, the Commission accepted a 54.19% common equity ratio in the Columbia Gas of Pennsylvania rate case at Docket No. R-2020-3018835 (Order Entered February 19, 2021) and 53.38% common equity ratio for PECO Energy Company – Gas Division at Docket No. R-2020-3018929 (Order Entered June 22, 2021). And in the Aqua Pennsylvania case, the Commission accepted a 53.95% common equity ratio, and for Columbia Water Company a 63.34% common equity ratio was accepted. Indeed, the Company's proposed common equity ratio of 53.40% is entirely reasonable based on prior Commission action. Hence, the Company's actual common equity ratio conforms to Commission policy that the actual, not hypothetical, common equity ratio should be employed.

17. Q. Does Mr. Garrett provide clear justification for rejecting the Company's actual capital structure and substituting a different capital structure?

A. No. In addition to his proxy group comparisons, Mr. Garrett also performs a "quantitative analysis" that he says supports a 50.0% debt ratio with an 8.2% cost of equity calculation (see Exhibit DJG-15). There are a variety of deficiencies with his analysis. First, an 8.9% cost of equity is clearly outside the range of reasonable returns for reasons I explained previously. Second, Mr. Garrett never established that his analysis is applicable for PECO Energy in the FPFTY. I have verified the reasonableness of the Company's common equity ratio by considering the historical capital structure ratios as Mr. Spadaccio has done and analysts' forecasts, which influence investor expectations. I have also compared the Company's proposed common equity ratio to that of the Gas Group based upon forecast data widely available to investors from Value Line. Those ratios are:

Company	2027-2029
Atmos Energy Corp.	60.0%
Chesapeake Utilities Corp.	52.0%
New Jersey Resources Corp.	45.0%
NiSource Inc.	37.5%
Northwest Natural Holding Company	50.0%
ONE Gas, Inc.	49.0%
Southwest Gas Holdings, Inc.	43.0%
Spire, Inc.	45.0%
Range:	
High	60.0%
Low	37.5%

Source: The Value Line Investment Survey, May 24, 2024

These ratios are computed based on permanent capital, excluding short-term debt. The Value Line data shows that PECO Energy has a common equity ratio for the FPFTY that is within the range for the barometer group and that its actual capital structure has adequate support.

18. Q. Mr. Garrett also provides capital structure ratios for other industries. Is this information useful?

A. No. There is nothing useful that can be obtained from the tabulation of debt ratios shown on Figure 8 of OCA Statement No. 2. Mr. Garrett has never established a nexus between the debt ratios he provides and the cost of equity. It is not appropriate to compare the debt ratios for thousands of diverse companies to PECO, without first establishing some level of comparability of these companies.

19. Q. Is there another issue that should be considered regarding Mr. Garrett's hypothetical capital structure?

A. Yes. Another problem with Mr. Garrett's approach is that when proposing a hypothetical debt ratio, he creates a mismatch between the cost of long-term debt that he accepts and the hypothetical debt ratio that he advocates. This mismatch arises because the hypothetical long-term debt ratio contains more debt than the amount of long-term debt that is actually outstanding for PECO, which carries a 4.58% cost rate. That is to say, with more debt in the hypothetical capital structure, a higher cost of debt would be related to the higher hypothetical debt ratio. Mr. Garrett never addresses this inconsistency in his proposal, and hence, it should be rejected.

III. PROXY GROUP

20. Q. Are there differences in the proxy groups utilized by the rate of return witnesses in this case?

A. Yes. Mr. Spadaccio includes only seven companies from my Gas Group in his barometer group. He drops Southwest Gas Holdings. Mr. Garrett accepts all of the companies in my Gas Group.

21. Q. Mr. Spadaccio used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble his barometer group. Is this a correct criterion?

A. No. For utilities, the percentage of regulated revenues cannot be used as the criteria to select members of the barometer group. This is because the margins on other business segments within barometer group companies are generally dissimilar to the utility business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the large revenues and small margins associated with that business, when contained in potential barometer group companies. That is to say, energy trading generates large amounts of revenue, but little profit, because the margins on such trades are very small.

22. Q. How do the percentages of utility income and assets compare to the companies contained in your Gas Group?

A. Those results are shown below:

		Percent Regulated Operations		
		Revenues	Income	Assets
ATO	Atmos Energy Corp	96%	67%	97%
CPK	Chesapeake Utilities Corp.	62%	81%	77%
NJR	New Jersey Resources Corp.	39%	58%	64%
NI	NiSource, Inc.	100%	101%	93%
NWN	Northwest Natural Gas	95%	92%	93%
OGS	One Gas, Inc.	100%	100%	100%
SWX	Southwest Gas Corp.	39%	99%	67%
SR	Spire, Inc.	88%	83%	80%
	Average	77%	85%	84%

As shown above, the percentage of utility assets is above 64% for all members of my Gas Group. As such, these data show that no elimination to my Gas Group is appropriate in this case.

23. Q. Has the Commission used your Gas Group?

A. Yes. The Commission has recently used my Gas Group in its Quarterly Earnings Report (Docket Number U-2023-3044811) for the year ended September 30, 2023, which was adopted at the Public Meeting on January 18, 2024.

24. Q. Is there any basis to deviate from the proxy group that you proposed in this case for the Companies?

A. No. My group of companies provides the best group that is comparable to the Companies.

IV. COST OF COMMON EQUITY - DISCOUNTED CASH FLOW (DCF)

25. Q. The DCF model has been used by Mr. Spadaccio, Mr. Garrett and you as one method to measure the cost of equity. What is your position

concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, and/or level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[2]

Similarly, in the Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods

[2] *Pennsylvania Public Utility Commission v. PPL Electric Utilities*, Docket No. R-2012-2290597, meeting held Dec. 5, 2012, at 80.

> suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[3]

Again, the Commission recognized the need for additional methods in its decision for Columbia Water.

> In *Aqua 2022*, the Commission determined the ROE by using informed judgement based on I&E's DCF and CAPM methodologies. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. We historically have primarily relied upon the DCF methodology in arriving at ROE determinations and utilized the results of the CAPM, as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our ROE determination.[4]

The Commission has acknowledged the usefulness of other methods, such as CAPM, as a means of establishing a range of reasonable returns. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. Therefore, the use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for PECO Energy than does sole reliance on the DCF. Indeed, Mr. Garrett agrees with my position

[3] *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Docket No. R-2021-3027385, order entered May 16, 2022, at 154-55.

[4] *Pennsylvania Public Utility Commission v. Columbia Water Company*, Docket No. R-2023-3040258 (Order entered Jan. 18, 2024), p. 108 ("*Columbia*").

when he states: “It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model” (see page 9 of OCA Statement No. 2).

Indeed, the influence of other methods must have an impact on the Commission’s attitude toward the DCF model because the Commission’s selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. For example, in the Quarterly Earnings Report at Docket No. M-2024-3048688, the Commission set the DSIC return at 10.15% for Pennsylvania gas distribution companies, while the DCF returns were 9.79% using current stock prices and 9.53% using 52-week average stock prices. It is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return.

26. Q. What has Mr. Spadaccio done with the results of models other than DCF?

A. Nothing. In this case, Mr. Spadaccio essentially ignores the results of the CAPM, calling his CAPM results a basis for comparison purposes only (I&E Statement No. 2, pp. page 18, 19, 20, 25, 28, 33 and 37). Unlike Mr. Spadaccio, Mr. Garrett acknowledges (OCA Statement No. 3, p. 9) that he used several methods, along with DCF, to measure the cost of equity. The use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return. In his testimony, Mr. Spadaccio shows

that the average DCF result is too low by reference to his CAPM results. In this situation, due to this understatement, the Commission should consider moving to within the top half of the range of DCF returns submitted in this case. This process would preserve use of DCF, but also accommodate the tendency of the DCF model to understate the required return in this market. Mr. Spadaccio's DCF return range is from 8.69% for ONE Gas to 11.82% for NiSource. Since Mr. Spadaccio's CAPM result is 10.86%, then it stands to reason that the top half of the range of DCF results should be emphasized in this case, because the average DCF by itself is too low. Hence if DCF is to be used exclusively, as argued by Mr. Spadaccio, then the proper DCF return should be 10.84%, which is within the top half of the range, i.e., 9.86% + 11.82% = 21.68% ÷ 2, and is without regard to management performance.

Indeed, the CAPM and RP methods reflect directly the changes in interest rates and are an important indicator of higher equity cost rates. Although Mr. Spadaccio claims (I&E Statement No. 2, p. 19) that DCF sufficiently considers economic factors, including inflation, there is no input in the DCF that Mr. Spadaccio can point to that substantiates his position. Indeed, when viewing the components of the DCF model, i.e., D = dividend payments, P = stock price, and g = growth, dividend payments are a function of a company's earnings ability and internal cash flow needs, the stock price is influenced by a host of factors, such as investor sentiment, computer-generated program trading and others, and the growth rate is based on consensus estimates of analysts that do not define the myriads of factors that underline those growth

rates. We know that CAPM and RP reflect directly changes in interest rates, and that those models are more responsive to inflation in this regard than DCF.

27. Q. Has the National Association of Regulatory Utility Commissioners ("NARUC") taken a position on the use of multiple methods to measure the cost of equity?

A. Yes. NARUC has published a paper titled "Cost of Capital and Capital Markets Primer for Utility Regulators." In it, NARUC said:

> The goal of all cost of equity models is to capture the realities of the capital marketplace and each model does so from a different perspective. Because these financial models are simplifications of the real world, the ROE results are estimates rather than exact discernments of ultimate truth. Ideally, the model results will corroborate each other but may not in practice. Different estimates resulting from different models can usefully frame, bracket, or define a range or zone of estimates.

Investors, investment bankers, and corporate financial professionals use multiple models when evaluating the cost of equity. Likewise, it is desirable for regulators to also use multiple models when evaluating the cost of equity.

V. DCF APPLICATION BY I&E

28. Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Spadaccio, Mr. Garrett, and me.

29. Q. Are there limitations to the application of the DCF that indicates that it should not be used alone to establish the equity return, which Mr. Spadaccio seems to support?

A. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity. There are many assumptions associated with the specification of the DCF. These are:

- The form of the model. A choice must be made whether to employ the continuous or discrete form of the model.
- Whether a finite or infinite form of the model realistically represents investor's horizon.
- Whether compounding of the quarterly dividend should be employed.
- The timing of the dividend payments regarding the interval from the ex-dividend date and the stock measurement date needs to be addressed.
- A choice is necessary relative to a representative price that would reasonably represent the rate effective period, e.g., 12-month average, 6-month average, 13-week average, spot, etc.
- Assumptions concerning the structure of returns, which under the DCF assume that the price-earnings multiple, dividend payout ratio, and earned return will be constant.
- Whether single or multiple growth rates better reflect investor expectations.
- Choices concerning the use of historical or forecast growth rates.
- From a historical perspective, whether 10 years, 5 years, or some other historical period is representative of investor expectations.
- Choice among variables to measure growth, e.g., earnings per share, dividends per share, book value per share, cash flow per share, retention growth, price growth, etc.
- Choice of investor influencing growth rates that are available from I/B/E/S First Call, Zacks, Morningstar and Value Line.
- Whether the growth rate if measured by the formula "b x r" should be modified for external growth, i.e., "sv."

- The potential misspecification of the rate of return applicable to book value when taken directly from DCF if the market price diverges from book value.

Many of the assumptions, especially the constant price-earnings multiple, constant payout rate, and constant earned return, are particularly unrealistic. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity.

30. Q. Mr. Spadaccio presents a revenue requirements calculation showing the difference associated with using the DCF and CAPM results (I&E Statement No. 2, p. 35) What does this comparison reveal?

A. This comparison is not relevant to this case. The Commission has used the DCF and CAPM models to establish a range, and the authorized return would fall within that range. If any comparison can be made with these inputs, it would be between the midpoint of the range, i.e., 10.40% (10.86% + 9.93% = 20.79% ÷ 2) and the lower end of the range, i.e., 9.93%. This would then provide a point of reference between an approach that gives equal weight to both the DCF and CAPM and to using DCF alone. That produces a $12.102 million difference in revenue requirements, not the $24.204 million Mr. Spadaccio reports.

31. Q. Do the DCF results proposed by Mr. Spadaccio provide a reasonable representation of the cost of equity?

A. Not in my opinion. I&E Witness Spadaccio concludes that the DCF cost of equity is 9.93% and the CAPM cost rate is 10.86% (I&E Statement No. 2,

pages 28 and 27). The Commission has stated that it would consider other methods when other methods showed that the DCF method understated the cost of equity. (Columbia Order, page 131.) It should be noted that I&E's DCF result in this case is also too low for several reasons. First, there have been significant increases in interest rates and inflation since the midst of the Pandemic, indicating a higher cost of equity today. Second, I&E's own CAPM result of 10.86% illustrates that its DCF result is too low, in contrast to the lower CAPM return in the Columbia case.

Focusing on the DCF approach, the principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and thereby smooth out any abnormalities. That said, when some of the DCF results for companies in the barometer group are unreasonable on their face, the reliability of the method being used, or the witness's application of that method, must be questioned. As indicated below, two of the DCF results for Mr. Spadaccio's group fall into that category:

Company	52 wk & Spot Yield	+	Growth	=	Total
Chesapeake Utilities	2.46%	+	6.30%	=	8.76%
ONE Gas	4.03%	+	4.67%	=	8.70%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. Yet, each of the companies

listed above have DCF returns calculated by Mr. Spadaccio that fail to provide a sufficient spread over the yield of 5.74% on A-rated public utility bonds for May 2024. As I have demonstrated in my direct testimony (PECO Energy Statement No. 5 at pages 45-46), the spread between the cost of debt and cost of equity should be 6.50% in this market environment. As such, neither of the returns listed above can come close to meeting this standard.

32. Q. As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A. The theory of the DCF holds that (i) the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share with a constant P-E ratio, and (ii) dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' earnings growth rate forecasts significantly influence investor growth expectations. It is for this reason that GDP growth rates submitted by Mr. Garrett are an inappropriate representation of investor growth rate expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of

the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model are forecasts of earnings per share growth.[5]

33. Q. Please summarize the DCF growth rate analysis performed by Mr. Spadaccio.

A. As shown on page 29 of I&E Statement No. 2, Mr. Spadaccio proposes a growth rate based on his review of analysts' projected earnings growth rates. His growth rate (i.e., 5.95%) is below the 6.75% growth rate that I determined. Referring to Mr. Spadaccio's growth rates, the 4.65% growth rate for Northwest Natural and 4.67% for ONE Gas appear to be outliers. The range of growth rates for other companies is 5.29% (i.e., Spire) to 7.60% (i.e., NiSource).

34. Q. What DCF return is indicated from the data presented by Mr. Spadaccio after removing the unduly low results for Chesapeake and ONE Gas?

A. Those results are revealed below:

[5] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG) … we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Atmos Energy Corp.	3.02%	+	7.17%	=	10.19%
NiSource Inc.	4.22%	+	7.60%	=	11.82%
New Jersey Resources Corp.	3.91%	+	5.50%	=	9.41%
Northwest Natural Gas Co.	5.02%	+	4.65%	=	9.67%
Spire Inc.	5.18%	+	5.29%	=	10.47%
Average					**10.31%**

The DCF returns shown above are calculated without regard to the leverage adjustment that is necessary to align the market-determined cost of equity with the book value capital structure used for ratesetting.

VI. DCF APPLICATION BY OCA

35. Q. In his testimony, Mr. Garrett proposes to use a "sustainable" growth rate that is not specific to his proxy group of gas companies. Does this follow the traditional approach for applying the DCF model?

A. No. His testimony does not follow the normal, or typical, processes of applying the DCF model long used by the Commission and others for determining the return on equity. His approach to looking at GDP growth is certainly alien to all DCF analyses that are familiar to the Commission. On this basis alone, the DCF analysis submitted by Mr. Garrett in this case should be dismissed. I say this because, as I previously explained, Myron Gordon established that analysts' forecast of earnings growth are the correct input for the DCF for each member of the proxy group.

36. Q. What DCF growth rate did Mr. Garrett actually use in his DCF?

A. On Exhibit DJG-6, Mr. Garrett provides two very different expressions of DCF. One DCF calculation uses Mr. Garrett's unique view of sustainable growth and the second DCF results reflects analysts' growth rates. The most obvious problem with Mr. Garrett's testimony concerns his development of the sustainable growth rate form of the DCF model for determining the ROE. In this regard, he advances the proposition that the growth rate for a utility can never exceed the long-term gross domestic product ("GDP") of the country. As I have explained in my direct testimony, companies, including utilities, can cycle through the growth phases. While Mr. Garrett lists other lower criteria for determining the long-term growth rate, his long-term estimate of GDP growth of 3.8%, Exhibit DJG-5. This growth rate is well below analysts' projections of earnings growth used by Mr. Spadaccio and me, and it produces a nonsensical DCF cost rate of 7.6%.

37. Q. Do the DCF growth rates proposed by Mr. Garrett provide a reasonable input in the cost of equity analysis using the DCF model?

A. No. Mr. Garrett indicates that his method for analyzing sustainable growth rate rests on (i) nominal GDP, (ii) real GDP, (iii) inflation, and (iv) the risk-free rate. There are many problems with his approach. First, the combination of the real GDP growth and inflation equals nominal GDP, i.e., (1.017) * (1.020) = (1.0373 -1) = 3.7%. Hence, two of his input variables are double counted when he separately considers nominal GDP growth. Second, the risk-free rate provides no guide to the growth that a company can realize in its earnings. Earnings growth occurs through revenue growth, net of

O&M, depreciation, taxes, and interest. None of these factors are addressed with the risk-free rate of return. Third, Mr. Garrett is essentially developing a generic growth rate that would apply to any, or all, companies, whether they are regulated or non-regulated companies. However, each company has a unique company-specific growth rate. His approach is simply incompatible with the basic concept of the DCF, where future cash flows for each company are systematically related to one another by a constant growth rate that represents a basic tenant of the single-stage DCF. It is also incompatible with the use of the growth rates of a comparable barometer group of companies to meet the requirement that a utility is to be permitted to earn a return equal to comparable companies. The DCF equation is P = D / (k-g). Mr. Garrett's growth rate does not fit within this equation.

38. Q. Does Mr. Garrett's alternative DCF calculation provide an improvement on his preferred sustainable DCF calculation?

A. It is a step in the right direction, but it too is deficient. Using analysts' forecasts, which have been demonstrated to be a superior growth rate measure in the DCF,[6] still falls short. This is because Mr. Garrett erroneously used the Value Line forecast growth rate of dividends per share rather than earnings per share. Had he used this growth rate, he would have

[6] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG) … we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

then produced a DCF return of 10.37% (3.8% + 6.57%) with the quarterly form of the DCF proposed by Mr. Garrett. This shows that his DCF return is completely inadequate for the reasons explained above.

VII. LEVERAGE ADJUSTMENT

39. Q. At pages 49-56 of I&E Statement No. 2, Mr. Spadaccio responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. No. Mr. Spadaccio states that he opposes the leverage adjustment. In his discussion of my leverage adjustment, Mr. Spadaccio mentions market-to-book ratios ("M/B") (I&E Statement No. 2, p. 50). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio.

40. Q. Please respond to Mr. Spadaccio's criticism of your leverage adjustment.

A. Mr. Spadaccio offers three reasons for not making a leverage adjustment. First, Mr. Spadaccio notes that the credit rating agencies assess financial risk in terms of a company's booked debt obligations in their analysis of the creditworthiness of a company (I&E Statement No. 2, pp. 51-52). I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr.

Spadaccio's observation is correct, it has no relevance to my leverage adjustment.

41. Q. Second, Mr. Spadaccio also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Mr. Spadaccio points to several decisions where the Commission declined to make a leverage adjustment (I&E Statement No. 2, pp. 52-54). The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Mr. Spadaccio does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Just as an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI Utilities – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity

return. And for Columbia, the Company accepted the I&E's recommendation of the allowed return, which was 9.86%, in a case litigated at the height of the COVID-19 Pandemic. Thus, Columbia chose not to argue the leverage adjustment in Exceptions to the Commission. However, based upon the current inputs to the DCF that indicated a low result, the Commission should now consider using the leverage adjustment, just as it did previously when the DCF was suggesting unusual results. In the PECO Energy – Gas Division rate case, the Commission arrived at a 10.24% return without the leverage adjustment, because that return was already deemed to be on the higher side and no additional adjustment was warranted. Finally, the Commission set the equity return at 10.00% for Aqua Pennsylvania recently without a leverage adjustment, but with an adjustment for management performance.

42. Q. Third, Mr. Spadaccio argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Mr. Spadaccio contends that information presented to investors (I&E Statement No. 2, pp. 55-56), such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the gas utility stocks that Mr. Spadaccio relies upon for his analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their

decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determine the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization. I clearly demonstrate this point on Schedule 10 of PECO Energy Exhibit PRM-1. Hence, the observation of Mr. Spadaccio is misplaced because I have clearly shown the difference in financial risk and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

43. Q. Mr. Garrett criticized the leverage adjustment that you propose to account for the divergence of market capitalization and book value capitalization. Please comment.

A. At pages 28-29 of OCA Statement 2, Mr. Garrett never really refutes my leverage adjustment. Indeed, he says that I misapplied the Hamada formula leverage adjustment approach. First, in the DCF approach, I did not use the Hamada formula, but rather, I used the Modigliani & Miller approach. Second, at page 63 of OCA Statement 2, Mr. Garrett claims that the Hamada formula generates an unlevered beta of 0.48. But what I have shown is that the correct unlevered beta is 0.58 (see Schedule 10 of PECO Energy Exhibit PRM-1). The reason for the difference is that I correctly use the market

capitalization for my calculation, including the market value of debt, and Mr. Garrett did not because he used the book value capital structure ratios of the proxy group. Indeed, if Mr. Garrett had used the market capital structure ratios of the proxy group, he would have calculated a different unlevered beta.

VIII. COST OF COMMON EQUITY - CAPITAL ASSET PRICING MODEL

44. Q. Do you have concerns regarding Mr. Spadaccio's and Mr. Garrett's applications of the CAPM?

A. Yes. Mr. Spadaccio's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the yield on 10-year Treasury notes, and (ii) his failure to use leveraged adjusted betas. The results of Mr. Garrett's CAPM approach are simply much too low.

45. Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The Blue Chip report shows this comparison. For the first quarter of 2024, the gap was 0.17% (4.33% - 4.16%) between the yields on 30-year and 10-year Treasury obligations. For the period from 2026 to 2030, that gap is projected to increase to 0.20% (4.3% - 4.1%) according to the June 1, 2024 Blue Chip. This shows a systematic understatement of Mr. Spadaccio's CAPM returns. Shorter-term rates, such as 10-year Treasury notes, respond more to the policy initiatives of monetary officials, while long-term rates, such as 30-year Treasury bonds, are more a reflection of investor sentiment of their required returns. While I am aware that the Commission has used the

yield on 10-year Treasury notes in past decisions, the yield on 30-year Treasury bonds is the better choice because it reflects the long-term nature of fixed assets that utilities employ to provide service. Just consider the average service life used in establishing the Company's depreciation accrual rates. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return.

46. Q. How has Mr. Spadaccio understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 8 of I&E Exhibit No. 2. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the third and fourth quarter of 2024 as he does for the entire five-year period from 2025 through 2029. This approach leads to a seriously understated risk-free rate of return. Even if 10-year Treasury rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Spadaccio. I have revised his forecast below, based upon Blue Chip. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

The resulting risk-free rate of return is 4.1% using the yield on 10-year Treasury Notes and 4.3% using the yield on 30-year Treasury bonds.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2025	4.00%	4.20%
2026	4.00%	4.20%
2027	4.00%	4.20%
2028	4.00%	4.30%
2029	4.20%	4.40%
2030	4.20%	4.40%
Average	4.07%	4.28%

47. Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present above. I have corrected Mr. Spadaccio's CAPM as indicated below using those inputs and the forecast yield on 10-year Treasury bond shown above:

	Rf	+	β	(	Rm	-	Rf	)	=	K
Gas Group	4.30%	+	0.86	(	12.00%	-	4.30%	)	=	10.92%

48. Q. Mr. Garrett has also performed a CAPM calculation in addition to his DCF analysis. Are the results of his CAPM useful in setting the Company's equity return in this case?

A. No. There are a variety of problems with Mr. Garrett's CAPM approach that makes it not useful in this case. He makes CAPM calculations that produce results of 9.3%. This is shown by the Commission's Quarterly Earnings Report that produces a CAPM return of 10.87% for the Gas Company barometer group that exceeded substantially the DCF return. First, Mr. Garrett uses a backward-looking 4.7% yield on 30-year Treasury bonds. A

30-day historical average period is not compatible with the Commission's use of forecast Treasury yields (see UGI - Electric Division at Docket No. R-2017-2640058, Order Entered October 25, 2018). Second, the 5.2% equity risk premium ("ERP") selected by Mr. Garrett is completely off the mark. The principal departure from the normal input is in his calculation of the ERP. He rejects the use of both historic ERPs and projected ERPs calculated based on projected market returns. Instead, he reviews "Expert Surveys" and his own calculations. He then uses the 2022 survey conducted by IESE Business School, indicating that it provides the highest ERP of 5.8%. There is no evidence that investors use this source of the ERP in their CAPM calculations. Both Mr. Spadaccio and I have considered both historical data and investor expected future returns when measuring the equity risk premium. Mr. Garrett used three approaches. He did not rely upon on a historical analysis, with good reason, because it erroneously employed geometric means. His other approach (i.e., "implied equity risk premium") is likewise deficient because his 9.8% market return is much too low, as shown by my data (i.e., 11.93% forecast market return) and Mr. Spadaccio's data (i.e., 12.0% forecast market return). His last method "ERP surveys" are not conclusive because Mr. Garrett has not shown that current investors consider or use this method. Furthermore, the implied total market return using Mr. Garrett's final inputs is just 9.9% (4.7% + 5.2%), which is clearly incompatible with actual stock market returns of 26.29% in 2023, a five-year annualized return of 17.36%, and 12.0% on average for the past 97 years

(1926–2023). It is also well off the market given Mr. Spadaccio's determination that the total market return is 12.0%.

IX. COST OF COMMON EQUITY - RISK PREMIUM ANALYSIS

49. Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straightforward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity, which must be higher than the cost of debt in recognition of the higher risk of equity (PECO Energy Statement No. 5, pp. 45-46). So, while Mr. Spadaccio and Mr. Garrett decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return, because it considers additional factors not reflected in the beta measure of systematic risk. It is particularly useful when investors expect changes in the cost of debt prospectively, which is currently the expectation of investors, as I have explained above. At this point, it is speculative to infer that the FOMC is at the threshold of cuts in the Fed Funds rate, as I explained above. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore should be given weight in determining the equity cost rate in this case.

50. Q. Please respond to Mr. Garrett's criticisms of your Risk Premium approach.

A. While Mr. Garrett declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. As I explained in my direct testimony, we are facing the prospect of increasing interest rates for the future and the market has increased yields on debt instruments. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.50% (5.00% interest rate on A-rated public utility bonds + 6.50% equity risk premium). The recent increase in interest rates would support a higher rate today.

51. Q. What does Mr. Spadaccio say about your Risk Premium analysis?

A. Mr. Spadaccio makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility rate-setting process (I&E Statement 2, p. 21). In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Spadaccio's assertion that the Risk

Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony and earlier in this rebuttal testimony, we are facing the prospect of increasing interest rates for the future. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.50%, although as noted above actual interest rates on A-rated public utility bonds have already exceeded the projection I used for my Risk Premium cost of equity. Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals and the credit quality of the Gas Group.

X. COST OF COMMON EQUITY - COMPARABLE EARNINGS APPROACH

52. Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the *Hope* case.[7] In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that equity returns from non-regulated companies provide better assessment of investor requirements than those available for regulated utilities.[8]

XI. MANAGEMENT PERFORMANCE

53. Q. Both Mr. Spadaccio and Mr. Garrett oppose any recognition for management performance in the determination of the return on equity. Mr. Spadaccio and Mr. Garrett assert that PECO Energy has only done what it is required to by law. How do you respond?

A. As I stated in my direct testimony, I believe PECO Energy has performed in an exemplary manner, as explained by PECO Energy Witness Ms. Hamilton, and that performance should be recognized in this case. Mr. Spadaccio simply disagrees, without addressing any of the items highlighted by Ms. Hamilton as examples of PECO Energy's excellent performance. Mr. Garrett's position regarding management performance is that the models of the cost of equity already incorporate management effectiveness. In each

[7] *F.P.C. v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*").

[8] "Natural Gas: The Case for ROE Reform," John E. Olson, First Vice President, Merrill Lynch & Co., Oct. 11, 1994.

case, neither Messrs. Spadaccio nor Garrett have shown that PECO Energy is not entitled to some form of management performance recognition by the Commission. Ms. Hamilton's direct and rebuttal testimony establish that the Company's management performance warrants recognition by the Commission. Ms. Perry also discusses the management adder, as do both Mr. Colton and OCA witness Nicholas DeMarco. My assessment of their testimony indicates that other PECO witnesses have addressed the performance issues which justify inclusion of a management performance increment in this case.

54. Q. OCA witness Garrett argues (see page 50 of OCA Statement 2) that additional basis points for management performance would charge individually the Electric Division ratepayers and the Gas Division ratepayers a higher equity return for services provided by the diversified PECO Energy. He seems to find fault with this proposition, as does OCA witness DeMarco (see pages 4-5 of OCA Statement 5), who contends that PECO should not be able to "double-dip." Please respond.

A. It is not entirely clear to me what Mr. Garrett or Mr. DeMarco find wrong with each division receiving recognition of management performance. Each division has its own cost of service, rate base, and a return on that rate base. The Company witnesses have substantiated its superior management for each division individually. By considering management performance individually for each division would not result in any double counting for it, if that is what bothers Mr. Garrett and Mr. DeMarco. Moreover, not all of PECO Energy

customers take both services from the Company. Some customers receive electric service and no gas service and some customers receive gas service and no electric service. Each division's rates are determined individually, and so should consideration of management performance.

XII. WALMART AND ADDITIONAL OCA PROPOSALS

55. Q. Walmart witness Ms. Lisa Perry argues that the cost of capital for PECO Energy is lower than proposed by the Company based generally on rate case decisions by other state regulatory commissions. Do you agree?

A. No. As I explained previously, decisions of the Pennsylvania Commission should provide a guide to the equity return in this case, rather than actions by other state commissions. If there is any merit to other authorized returns, then the 9.13% equity return in PECO Energy's transmission business should serve as a point of reference. The general theme of the witness for Walmart is that the trend in authorized returns has been lower in recent years and that other state commissions are granting lower returns. I agree that the trend has been lower, but some context is required for this information to be useful. It is obvious that as the authorized returns have declined, the "regulatory premium," here defined as the authorized return less the yield on A-rated public utility bonds, has expanded. This is revealed by the data shown below:

Years	Number of Years	Average Regulatory Risk Premium
1984-2024	41	4.07%
2005-2024	20	4.89%
2015-2024	10	5.59%
2020-2028	5	5.81%

Indeed, it is not the authorized returns viewed in isolation that are important, but how those returns are viewed by reference to changes in interest rates. What the table provided above shows is that the "regulatory premiums" have increased during periods of declining interest rates. This is entirely consistent with the relationship of the risk premiums and interest rates that I describe in my direct testimony (PECO Energy Statement No. 5, p. 45). We can see that the "regulatory risk premiums" have expanded in recent periods in the response to the decline in public utility bond yields. That fact has not been adequately reflected in the proposal by Ms. Perry.

56. Q. OCA witness Roger Colton argues that establishing a cost of equity is "fundamentally predicated on balancing consumer and investor interests" and must be determined with reference to whether a "sizeable portion" of customers can afford to pay the resulting utility rates (OCA Statement No. 1, p. 16). He also contends that the "greater adverse impacts that inflation has imposed on low-income customers when setting rates" and determining a cost of equity (p. 19). How do you respond?

A. OCA witness Roger Colton makes some very broad statements regarding the need to consider consumer's ability to pay in setting PECO Energy's return on equity. Mr. Colton's claims are entirely inconsistent with the fundamental principles of Hope. Indeed, during the Pandemic, witnesses from the OCA made similar arguments against rate increases at that time. The Commission roundly rejected those OCA arguments then and should do so now. The Commission has always weighted the balance of ratepayers and investors in setting rates. That balance has been a key to providing utilities with the ability to attract capital. Indeed, utilities such as PECO Energy, must provide service to their customers at all times, and to do so it must be in a capital attraction position at all times. Mr. Colton's proposal does not comply with the capital attraction standard of a fair return. No one has contested the need for PECO Energy to undertake new investment in this case. As a consequence, an adequate return is a prerequisite to attract necessary capital for infrastructure investment. In fact, the effects on low-income customers that Mr. Colton addresses are matters for the design of PECO's universal service programs.

57. Q. OCA witness Clarence Johnson argues that there is some linkage between the Company's rate of return and the rate design associated with method used to recover fixed costs. Please respond.

A. In my opinion, there is no practical means to quantify any purported, if any, linkage between the two issues. Mr. Johnson has not proposed any basis points adjustment to the rate of return associated with shifting revenue

requirements recovered in the Company's tariff from variable rates to the customer charge or vis-versa. He has not quantified his position on this matter because none is possible. From a cost of equity perspective, the risk associated with rate design issues are an unsystematic (i.e., company-specific) risk that receives no compensation (i.e., not addressed) in the CAPM formula. Other methods that may be employed to measure the cost of equity (e.g., DCF) contain no components (i.e., yield, growth, leverage) that could be quantified to account for rate design variations. The bottom line is that Mr. Johnson's proposal has no merit because there is no way to implement it.

XIII. SUMMARY

58. Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Spadaccio and Mr. Garrett seriously understate the cost of common equity for PECO Energy. This is particularly true for Mr. Garrett's proposal. In an environment of prospectively higher interest rates and Company-specific risk factors, an opportunity to earn a cost of equity of 11.15% is reasonable for PECO Energy.

59. Q. Does this conclude your rebuttal testimony at this time?

A. Yes, it does

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2024-3046932**
	:	
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Paul R. Moul, hereby state that I am the Managing Consultant of the firm P. Moul & Associates; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below 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.

- PECO Statement No. 5
- PECO Exhibit PRM-1

- PECO Statement No. 5-R

Dated: August 5, 2024

Paul R. Moul

PECO Statement No. 6:

Direct Testimony of Jiang Ding

PECO ENERGY COMPANY
STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: JIANG DING

SUBJECT: CLASS COST-OF-SERVICE STUDY

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
JIANG DING

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Jiang Ding. 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 Principal Regulatory & Rates Specialist.

3. Q. Please describe your educational background.

A. I received a Bachelor's Degree in Law from China University of Political Science and Law, and I received a Master of Science Degree in Finance from Texas A&M University.

4. Q. Please describe your work experience with the energy industry.

A. Upon graduation from Texas A&M University, I worked as an Accountant for Enron and as a Financial Analyst for Halliburton Energy Services. I was hired by Exelon Power as an Operational Area Analyst in 2002. I then worked for Exelon Generation and Exelon Corporation as a Senior Project Evaluation Analyst. I was appointed Principal Regulatory & Rates Specialist in PECO's Regulatory Strategy and Revenue Policy Division in 2013. My main responsibilities include revenue

requirement modeling and analyses for regulatory initiatives, cost-of-service studies, and base rate case filings.

5. Q. Please describe the purpose of your testimony.

A. I will explain the cost-of-service principles underlying the unbundled, fully allocated class cost-of-service study ("COSS") that I performed, the methods and procedures employed to perform such study, and the results produced by the COSS.

6. Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. PECO Exhibits JD-1 through JD-7 were prepared by me or under my supervision and are described in detail in my testimony.

7. Q. How is your testimony organized?

A. My testimony is divided into five parts. First, I introduce my testimony and explain its purpose. Second, I provide some background information, identify the exhibits that I am sponsoring, and summarize the results of the COSS. Third, I introduce and discuss the COSS methodology. Fourth, I explain the development of the revenue requirement for each rate class. Fifth, I present the results of the COSS in detail and discuss the contents of the exhibits.

8. Q. Please identify the exhibits that are included with your testimony.

A. The following exhibits are included with my testimony. They are discussed in detail in Section V of my testimony.

PECO Exhibit JD-1	Summary of Results
PECO Exhibit JD-2	Allocation by Rate Class
PECO Exhibit JD-3	Allocation by Functional Classification
PECO Exhibit JD-4	Unitized Functionally Classified Revenue Requirement
PECO Exhibit JD-5	Customer-Related Costs
PECO Exhibit JD-6	External Allocation Factors
PECO Exhibit JD-7	Calculation of Costs to Serve NGS Customers

II. BACKGROUND INFORMATION AND SUMMARY OF COST-OF-SERVICE STUDY RESULTS

9. Q. What is the total revenue requirement you used to prepare PECO's COSS?

A. I used the total distribution revenue requirement for the fully projected future test year ("FPFTY") developed in PECO Exhibit MJT-1, which is sponsored by Company witness Michael J. Trzaska in PECO Statement No. 3. The total distribution revenue requirement for the FPFTY is $592 million (PECO Exhibit JD-1, line 81) excluding costs recovered under PECO's Purchased Gas Cost adjustment ("PGC") and $854 million (PECO Exhibit JD-1, line 133), including costs recovered under the PGC. The total distribution revenues and distribution revenues by customer class for the FPFTY under existing rates that are used in the COSS were also obtained from PECO Exhibit MJT-1, and in the proof of revenues set forth in PECO Exhibit JAB-4.

10. Q. What is a class COSS?

A. A class COSS is a widely employed analytical tool used in supporting a utility's recommendation for a rate design. These studies are utilized to determine the

costs that different classes of customers impose on the utility system and to quantify the revenue requirements for the services provided by the utility to each customer class. The purpose and the guiding principles in performing a class cost-of-service study are described further in Section III.

11. Q. Please summarize the results of the COSS as they pertain to changes in rates proposed in PECO's filing.

A. The results of the COSS and my conclusions based on those results are as follows:

(1) The current tariff rates produce the net income by rate class shown on line 17 of PECO Exhibit JD-1, which yields the rates of return on rate base shown on line 26 of that exhibit.

(2) PECO's total distribution revenue requirement for the FPFTY has been allocated or assigned among the rate classes based on the results of the COSS. The results of the COSS are summarized on pages 1 to 3 of PECO Exhibit JD-1, which show the total distribution revenue requirement separately for distribution service including and excluding purchased gas costs and PGC revenues.

(3) The increases in revenue by rate class needed to produce rates of return by class equal to the Company's proposed overall rate of return are shown on line 140 of page 3 of PECO Exhibit JD-1. The increase in revenue shown on line 140 is shown separately in PECO Exhibit JD-1 for: (i) distribution base rates (line 59), (ii) forfeited discounts revenues (line 63); and (iii) the non-fuel gas procurement costs recovered outside distribution base rates

through the Gas Procurement Charge ("GPC") (line 126), a component of the PGC. While the rate increases shown on line 140 are those necessary to move each rate class to the system average rate of return, the Company is not proposing rates that will take all classes to their indicated cost-of-service at this time, as explained in the direct testimony of Mr. Joseph A. Bisti (PECO Statement No. 7).

III. PECO'S CLASS COST-OF-SERVICE STUDY

12. Q. Briefly describe the purpose of a class COSS.

A. The purpose of a COSS is to determine the cost to serve, expressed as revenue requirement, for each rate class served by a utility. The revenue requirement for a rate class is that portion of a utility's total cost of service attributed to that rate class in accordance with principles of cost causation. In a COSS, all of the utility's costs of providing service must be analyzed and assigned or allocated among the rate classes. A COSS is used, along with other factors, as discussed in more detail by Mr. Bisti, to design rates that fully recover the utility's costs.

13. Q. What are the guiding principles for performing a class COSS?

A. The central element in performing a COSS is the determination of allocation factors based on causal relationships between, on the one hand, customer demands, load profiles, and usage characteristics, and, on the other hand, the costs incurred by the Company to meet customers' service requirements imposed by those demands, load profiles, and usage characteristics. The primary goals in selecting allocation factors are: (1) the appropriate recognition of cost causality; (2) the stability of study methods and their consistent application over time, so

that trends in the direction of class revenues relative to cost of service can be discerned properly from case to case; and (3) completeness, such that the COSS captures all of the costs that each class imposes on the distribution system.

14. Q. Please summarize the approach you used in preparing PECO's COSS.

A. As I previously explained, the most critical task in performing any COSS is establishing relationships between customer demands, load profiles, and usage characteristics, and the costs incurred to meet those customer requirements. This requires an understanding of the design of the utility's distribution system how that design relates to the characteristics of the customers it is designed to serve.

PECO, like most gas utilities, designs its gas distribution system to meet three primary objectives:

(1) Extend distribution service to all customers;

(2) Meet the aggregate design peak day capacity requirements of all customers entitled to receive service on the design peak day; and

(3) Deliver volumes of natural gas to those customers either on a sales or transportation service basis.

The allocation methods used in a COSS must take into account the objectives that the distribution system is designed to achieve so that the allocation of plant investment and operating expenses properly aligns with cost-causation factors. Other factors, such as incentives to influence customer behavior (e.g., conservation or demand reduction) or to temper the impact on customers of rate changes, are more appropriately considered in the revenue allocation and rate design phase.

The PECO COSS performed uses the proprietary Gas Cost-of-Service Model ("Model") developed by Management Applications Consulting, Inc., which employs a Microsoft Excel platform. The Model facilitates the preparation of the COSS, accelerates computations, and develops appropriate documentation. The Model uses a three-step process to allocate or assign costs to rate classes, in accordance with general cost of service principles. These three steps consist of: (1) functionalizing rate base, purchased gas supply costs, and expenses to determine the particular rate schedules that should share responsibility for each of those assets and costs; (2) classifying functionalized costs into demand-related, commodity-related, and customer-related cost categories to facilitate allocating such costs to rate schedules in accordance with identifiable characteristics; and (3) allocating the functionalized, classified costs among rate classes. The Model provides functionalized, classified cost information by rate class, develops unbundled revenue requirements by functional classification and in total for each rate class, and calculates unit costs.

15. Q. Please identify the rate classes that are included in the COSS.

A. The following nine rate classes are included: (1) GR - General Service - Residential; (2) GC - General Service - Commercial and Industrial; (3) L - Large High Load Factor Service; (4) MV-F - Motor Vehicle Service-Firm; (5) MV-I - Motor Vehicle Service-Interruptible; (6) IS - Interruptible Service; (7) TCS - Temperature Controlled Service; (8) TS-F - Gas Transportation Service-Firm; and (9) TS-I - Gas Transportation Service-Interruptible. In the COSS, the rate class in PECO's current tariff titled OL - Outdoor Lighting is combined with rate class

GC because the usage of rate class OL is very small. In addition, customers participating in PECO's Customer Assistance Program ("CAP") are combined with rate class GR because their usage characteristics are the same as other rate class GR customers and because CAP rates are designed to reference rate class GR rates.

16. Q. Are these the same rate classes that were used by the Company in the COSS presented in PECO's most recent gas base rate proceeding (Docket No. R-2022-3031113)?

A. Yes.

17. Q. Please describe the functions included in the COSS.

A. The COSS includes the following functions:

Production: This function includes operation and management costs related to gas production, including production of liquid propane gas ("LPG").

Storage: This function reflects costs incurred to ensure that firm customers' demand can be met on the design day. It includes the costs of operation and management of liquefied natural gas ("LNG") facilities.

Commodity: This function includes PGC, balancing service cost, and gas storage inventory.

Service: This function includes the investment in, and operating and maintenance expenses related to, the service lines from the Company's main to customer locations.

Meter: This function includes the investment in meters and devices, including the installation of meters.

Customer Installation: This function includes the expenses incurred in working on customers' premises.

Customer Service: This function includes customer assistance and demonstrating and selling expenses.

Customer Accounts: This function includes the costs of customer billing and records, call center, collection of customer accounts, and uncollectable accounts.

Distribution: This function includes all other investments and costs, including investments in distribution plant, operating and maintenance expenses, and costs that are part of PECO's regulated utility function.

18. Q. Please describe the classification step of a COSS.

A. In the classification step, the previously functionalized assets and costs are separated according to the system design or operating characteristics that cause those costs to be incurred in the first instance. In this step, each cost is determined to be incurred to serve customers, to supply the natural gas commodity, or to meet various capacity demands related to the customers' peak usage.

19. Q. Please describe the class allocation step of the COSS.

A. In the class allocation step, costs that have been functionalized and classified are allocated among the rate classes based on appropriate causal relationships. The

allocation phase takes into account the design of the utility system and how it is operated; cost data derived from the utility's accounting records; and usage and load data both for the system overall and for specific customer classes. Based on analyses of the relationship between costs and the factors driving the need to incur such costs, each component of the revenue requirement is either directly assigned to a rate class or an allocator is selected to apportion that component among rate classes.

20. Q. Please explain the term "direct assignment."

A. The term "direct assignment" means identifying specific plant investments or specific expenses incurred exclusively to serve a specific customer or group of customers. Direct assignments reflect a direct causal connection between costs to serve and the customers being served. Therefore, if data are available to make a direct assignment, it is generally the preferred approach.

21. Q. Can significant portions of a utility's assets and expenses generally be directly assigned in a COSS?

A. No, most costs must be allocated. Utility service is generally provided to customers by facilities that are used, and expenses that are incurred in common by all, or many, classes of customers. In addition, even in instances where it might be possible to associate specific physical facilities with particular customers, the detailed cost information needed to make a direct assignment may not be reasonably available.

22. Q. Please explain how allocation factors are determined.

A. External and internal allocation factors are typically used to perform a COSS and, consequently, were employed in the Model.

An external allocation factor is a factor that is developed from an external source, outside the cost-of-service model. Examples of external allocators are number of customers (CUST) and estimated design day send-out (DPKDAYS). PECO Exhibit JD-6 shows the development of the external allocators.

An internal allocation factor is one that is developed within the cost-of-service model using other allocated line items. Internal allocators are based on some combination of external allocators, directly assigned costs and other internal allocators. For example, the allocator for property insurance costs is based on plant investment amounts assigned to components of the rate base. It is necessary to compute the rate base before property insurance costs can be assigned.

Other examples of internal allocation factors include total operation and maintenance salaries and wages expense (SALWGES) and total gross gas distribution plant (DISTPLT). PECO Exhibit JD-2, pages 18 to 22, shows the internally developed allocation factors.

23. Q. Has PECO changed any of the allocation methods used in PECO's 2022 gas base rate proceeding?

A. No, PECO is using the same basic allocation methods that the Company employed in the 2022 proceeding.

24. Q. Turning to the components of PECO's revenue requirement that are assigned or allocated in the COSS, please explain what rate base consists of and how it affects the COSS.

A. The rate base is the cost, net of accumulated depreciation, of PECO's investment in plant and other assets used to serve customers.

25. Q. What is the source of the total rate base amount being allocated or assigned to customer classes in the PECO COSS?

A. The total rate base amount employed in the COSS is $3.52 billion (PECO Exhibit JD-1, line 46) and is derived from PECO Exhibit MJT-1, page 1.

26. Q. What are the major components of PECO's rate base?

A. For purposes of discussing how I functionalized, classified, and allocated the rate base in the COSS and treated major rate base categories, I will refer to the following groupings of rate base items: production plant, storage plant, distribution plant, general plant, depreciation reserve, other rate base items and cash working capital.

Production plant represents the investment in LPG production assets which are used to meet design peak day and short-term needs of firm sales customers. These assets have been functionalized to Production, classified to demand, and allocated among rate classes based on design peak day send-out.

Storage plant represents the investment in LNG facilities which are used to meet design peak day and short-term needs of firm sales customers. These assets have

been functionalized to Storage, classified to demand, and allocated among rate classes based on design peak day send-out.

Distribution plant comprises mains, services, meters and meter installation, and other distribution plant. A description of each of those components is as follows:

- **Mains** were functionalized to Distribution and classified as capacity. A portion of mains costs was directly assigned. The balance of mains costs (approximately 99% of the total) was classified and allocated using the Average and Excess Demand method. In that method, the portion of mains costs equal to the system average load factor is allocated among the rate classes based on their average daily deliveries (annual deliveries divided by 365 days). The balance of mains costs is allocated based on excess demand, which is the excess of design peak demand over average demand. The excess demand is allocated among rate classes in proportion to each class's peak demand over its average demand (PECO Exhibit JD-6, page 5). This method was used by PECO in its 2022 gas base rate case (Docket R-2022-3031113), was recently approved by the Commission in PECO's 2020 gas base rate case (Docket R-2020-3018929), and has been recognized as an acceptable method by the American Gas Association's Gas Rate Fundamentals, 1987 Edition.

- **Services** are functionalized to their own category, classified as customer-related costs, and allocated among rate classes based on cost per unit

("CPU") calculations and related ratios by class, as shown in PECO Exhibit JD-6 at page 8.

- **Meters and meter installation** includes assets that have been functionalized to their own category and classified as customer-related costs. A portion of meter and meter installation costs was directly assigned. The balance of meter and meter installation costs (approximately 99% of the total) was allocated among rate classes based on the average cost of meters of each type for each rate class, as determined from the Company's records (PECO Exhibit JD-6, pages 7 and 9).

- **Other distribution plant** comprises primarily: (1) measuring and regulating station equipment ("M&R"), a portion of which was directly assigned, and the balance of which was functionalized to Distribution, classified as demand-related, and allocated among the rate classes based on the mains allocation; and (2) land and land rights and structures and improvements, which were functionalized to Distribution, classified as demand-related, and allocated among rate classes based on distribution plant (mains and measuring and regulating station equipment).

General plant includes primarily structures and improvements, tools and shop and garage equipment. These assets were functionalized, classified, and allocated among rate classes based on direct labor content of operating expenses, reflecting the nature of the assets and common cost-of-service practice.

Depreciation reserve was based on each asset account. Each component of the depreciation reserve items was functionalized, classified, and allocated among rate classes in the same ratio as the related assets.

Other rate base items include primarily gas storage inventory, accumulated deferred income taxes ("ADIT"), common plant, customer deposits, customer advances, cash working capital and pension, which are discussed below.

- **Gas storage inventories** are used to support the planned winter heating requirements of the Company's sales customers and the daily balancing requirements of all its customers. Gas storage inventories were functionalized and classified to commodity. The Company has identified 1.78%[1] of its storage activity that relates to the daily balancing of its transportation service customers (PECO Exhibit JD-6, page 6). Therefore, 1.78% of PECO's gas storage inventory costs were allocated among its transportation rate classes based on their annual volumes. The remainder of the Company's storage activity was allocated among the firm sales rate classes based on the average excess of their winter (November-March) gas volumes over their average annual volumes.

- **ADIT** refers to tax liabilities that are deferred as a result of accelerated depreciation and includes "excess" ADIT that has been removed from the ADIT account and recorded as a regulatory liability. Those ADIT

[1] This value was approved by the Commission as part of the Company's most recent PGC proceeding at Docket No. R-2023-3040285.

liabilities were functionalized, classified, and allocated among rate classes in proportion to plant in service.

- **Common plant** contains assets similar to those customarily found in general plant, and therefore, was functionalized, classified, and allocated among rate classes based on direct labor content of operating expenses.

- **Customer deposits and customer advances** were directly assigned to rate classes based on information from the Company's records (PECO Exhibit JD-6, page 14).

- **Cash working capital** represents PECO's need for cash to keep the business running until revenues are collected to pay the costs of providing services. Cash working capital was calculated based on the results of the lead-lag study prepared by Mr. Trzaska and described in PECO Statement No. 3. Payroll and pension-related cash working capital were allocated based on labor; commodity-related cash working capital was directly assigned to commodity.

27. Q. What are the major categories of PECO's expenses?

A. The major expense categories in PECO's cost of service are:

- Production costs;
- Storage costs;
- Distribution costs;
- Customer accounts and customer service expenses;
- Administrative and general expenses;

- Depreciation and amortization expense;
- Taxes other than income taxes; and
- Income taxes.

28. Q. In determining how to treat these expenses in the COSS, was there another important grouping of expenses that had to be considered?

A. Yes, there was. Labor costs affect some cost categories. Consequently, certain cost categories are allocated based on the direct labor costs. For example, Account 920 – Administrative and General Salaries is allocated among rate classes based on the composite allocation of direct labor costs included in all operating expense accounts. Likewise, employee benefits are allocated using a labor allocator. In order to develop such allocators, the direct labor costs included in each expense account were obtained from data assembled by Mr. Trzaska.

29. Q. What costs are included in PECO's production costs and how were these costs functionalized, classified, and allocated among the rate classes?

A. Production costs include costs related to operating and maintaining LPG production assets and natural gas operating costs. Costs related to LPG production have been functionalized to Production, classified to demand, and allocated among rate classes based on design peak day send-out.

30. Q. What costs are included in PECO's storage costs and how were these costs functionalized, classified, and allocated among the rate classes?

A. Storage costs are the costs of operating PECO's LNG facilities, which PECO maintains to meet the design peak day and short-term needs. Therefore, these

costs were functionalized to Storage, classified as demand, and allocated among rate classes based on design peak day send-out.

31. Q. What costs are included in PECO's distribution costs and how were these costs functionalized, classified, and allocated among the rate classes?

A. Most of PECO's distribution costs are the costs of operating and maintaining PECO's mains, services, and meters, i.e., the gas delivery system. Some of these costs are functionalized to distribution and some to their own categories. To the extent possible, costs were directly assigned. The balance of the costs of operating and maintaining PECO's gas delivery system was analyzed to determine which assets they were incurred to operate or maintain, and was functionalized, classified, and allocated among rate classes in the same manner as the assets they were incurred to operate or maintain. In addition to the costs of operating and maintaining PECO's gas delivery system, distribution costs include the following:

- **Customer installation expenses:** These expenses include field investigations for odors, high bill complaints, and potential and actual energy theft, and were allocated based on number of customers; and

- **Other Operating and Maintenance expenses**: These expenses were allocated in proportion to total distribution plant.

32. Q. What do PECO's customer accounts and customer service expenses include and how were those expenses functionalized, classified, and allocated among the rate classes?

A. PECO's customer accounts and customer service costs include meter reading expenses, customer records and collection expenses, uncollectible accounts expense, miscellaneous customer accounts expense, customer assistance expense, and demonstrating and selling expense.

- **Meter reading expenses** were functionalized to Customer Accounts, classified to the customer category, and allocated among rate classes based on the number of customers.

- **Customer records and collection expenses** include activities for billing, call center, payments processing, recoveries, and support for CAP customers. These costs were functionalized to Customer Accounts and classified to the customer category. The account was analyzed in detail to identify the activities included and each activity was allocated among the rate classes using an appropriate basis. For example, the costs of bill activities were allocated based on customer counts, and call center costs were allocated based on a study of calls over a twelve-month period (PECO Exhibit JD-6, page 10). A single customer allocation could not be used because some costs are specific to residential customers while others are specific to commercial and industrial customers. Therefore, a weighted allocator, based upon the analysis discussed above, was used for this account.

- **Uncollectible accounts expense**, or bad debt expense, was classified to the customer category. The expense was allocated among rate classes based on the Company's write-off experience over a historical five-year period (2019-2023) (PECO Exhibit JD-6, page 13).

- **Miscellaneous customer accounts expenses** were functionalized to Customer Accounts and classified to the customer category. These expenses include primarily IT support costs and communication and marketing costs. Those costs were allocated among rate classes based on number of customers.

- **Customer assistance expense** comprises expenses incurred for the Low Income Usage Reduction Program ("LIURP"). The associated costs were directly assigned to residential customers (PECO Exhibit JD-6, page 11).

- **Demonstrating and selling expense** includes expenses incurred in demonstrating activities. The expense was functionalized to Customer Accounts, classified to the customer category, and directly assigned to different customer classes based on the Company's records (PECO Exhibit JD-6, page 11).

33. Q. How were administrative and general expenses functionalized, classified, and allocated among rate classes?

A. Administrative and general ("A&G") costs include administrative and general salaries, office supplies and expenses, outside services, injuries and damages, employee benefits, property insurance costs, regulatory commission expenses, miscellaneous general expenses, and maintenance of general plant.

Except for items discussed immediately below, A&G costs are related to labor costs and therefore were functionalized, classified, and allocated among rate classes in the same ratio as direct labor content.

- **Property insurance costs** were functionalized, classified, and allocated among rate classes in the same ratio as plant in service.

- **Regulatory commission expenses** were functionalized, classified, and allocated among rate classes in proportion to claimed revenue.

- **Maintenance of general plant expenses** were functionalized, classified, and allocated among rate classes in the same ratio as general plant in service.

34. Q. How was depreciation expense functionalized, classified, and allocated among the rate classes?

A. Depreciation and amortization expenses were derived from PECO Exhibit CF-3, sponsored by Company witness. Caroline Fulginiti, and PECO Exhibit No. MJT-1, sponsored by Mr. Trzaska, which show depreciation expense by plant account. Each component of depreciation and amortization expense was functionalized, classified, and allocated among rate classes in the same ratio as the related assets.

35. Q. How was Manufactured Gas Plant remediation expense functionalized, classified, and allocated among the rate classes?

A. Manufactured Gas Plant ("MGP") expense is the normalized level of expense for remediating former MGP sites in the Company's service territory. This cost was allocated among rate classes based on annual gas throughput volumes.

36. Q. How were taxes other than income taxes functionalized, classified, and allocated among the rate classes?

A. Taxes other than income tax include payroll-related taxes, Public Utility Realty Tax Act ("PURTA") taxes, local use taxes, and real estate taxes. Payroll-related taxes were functionalized, classified, and allocated among rate classes based on direct labor expenses. PURTA taxes and real estate taxes were allocated based on total plant in service, and local use taxes based on claimed revenue.

37. Q. How was income tax expense functionalized, classified, and allocated among rate classes?

A. Income tax expense was calculated based on revenue at present rates using the same methodology employed by Mr. Trzaska in PECO Exhibit MJT-1, Schedule D-18. Income tax expense was functionalized, classified, and allocated among rate classes based on plant other than Regulatory Asset Programs M-1, which was functionalized, classified and allocated among rate classes based on salaries and wages expense.

38. Q. How were PECO's revenues at present rates computed and assigned among rate classes?

A. The revenues were computed and assigned as follows:

- **Distribution revenue** at present rates is shown in PECO Exhibit MJT-1, Schedule D-5, and in the proof of revenues set forth in PECO Exhibit JAB-4. The total was assigned to the rate classes based on the same revenue requirement exhibit and the proof of revenues. Distribution revenue at present rates for each rate class is shown on line 5 of PECO Exhibit JD-1.

- **Purchased gas revenue** consists of revenues collected under the applicable PGC tariff provisions for commodity and balancing service. Commodity revenue and balancing service revenue are determined and assigned based upon PECO's budget. For each rate class, and in total, purchased gas revenue equals the sum of the commodity cost, the balancing service cost, and the revenue requirement for cash working capital.

- **Forfeited discount revenue** is determined from PECO's budget and was allocated among the rate classes based on an analysis of forfeited discount over a historical three-year period (2021-2023) (PECO Exhibit JD-6, page 14).

- **Other gas revenue** consists of reimbursement revenues from contracting companies for their employees to conduct necessary operator qualification testing to work on PECO's system and was allocated among the rate classes based on salaries and wages expense.

39. Q. Apart from the COSS being presented in this case, did the Company prepare any additional cost of service calculations?

A. Yes. In the Commission-approved Settlement of PECO's 2022 gas base rate proceeding (Docket No. R-2022-3031113), the Company agreed to provide, in its next gas base rate case filing, a good-faith calculation of the costs (both directly assigned and allocated) to serve Negotiated Gas Service ("NGS") customers. The Company's calculations specific to NGS customers are presented in PECO Exhibit JD-7. PECO applied the same cost of service methodology to develop the

NGS calculations as was utilized in the COSS proposed by the Company in this case.

IV. DEVELOPMENT OF RATE CLASS REVENUE REQUIREMENT

40. Q. How did you develop the revenue requirement for each class?

A. The revenue requirement for each rate class was calculated using the same method employed by Mr. Trzaska to compute the overall revenue requirement for the FPFTY. Thus, the revenue requirement for each rate class is the sum of that class's forecasted revenue at present rates and change in revenue. The change in revenue for each rate class was computed by multiplying the change in operating income by a gross revenue conversion factor. The change in operating income for each rate class was computed by multiplying the rate class' rate base by the difference between the proposed system average rate of return, which is the same for all rate classes, and the present rate of return. PECO Exhibit JD-1, line 133, shows the total revenue requirement by rate class reflecting the fully allocated distribution cost-of-service at the proposed system average rate of return. PECO Exhibit JD-1, line 81, shows the portion of the total revenue requirement PECO proposes to collect in distribution rates.

41. Q. How did you determine the increase or decrease in revenue needed for each class to produce the system average rate of return?

A. The increase or decrease needed for each rate class was calculated by comparing the revenue requirements for each rate class to the forecasted revenue at present rates for that class for the FPFTY. This is the same method used by Mr. Trzaska

in PECO Exhibit MJT-1, Schedule A-1, with respect to the overall revenue requirement and revenue deficiency. The increases or (decreases) in rate class revenue needed to produce a rate of return equal to the Company's proposed overall rate of return are shown in PECO Exhibit JD-1 at line 141, which total $111.17 million. In addition, forfeited discounts (i.e., late payment charges) are expected to increase by $0.18 million as a result of the increase in distribution revenue (PECO Exhibit JD-1 at line 63). The increases in class distribution revenue are shown on line 83, which total $110.28 million. The increase in purchased gas revenue of $1.07 million under the PGC is shown on line 126.

V. RESULTS OF THE COST-OF-SERVICE STUDY

42. Q. Please describe what is shown on PECO Exhibit JD-1.

A. PECO Exhibit JD-1, which sets forth the substance of the COSS, compares the revenue at current rates by rate class to the revenue requirement allocated on a cost-of-service basis to each rate class. Net income at present rates, shown on line 17, is computed by subtracting operating expenses, depreciation and amortization, taxes other than income taxes, and income taxes (lines 10 to 14) from revenue at present rates (line 7). The return on rate base at present rates for each rate class is shown on line 26, and the relative rates of return are shown on line 27.

Line 133 shows each rate class's revenue requirement (including revenue from distribution charges and purchased gas) at the proposed overall rate of return. Line 68 shows operating expenses, and line 69 shows depreciation and amortization expense. Lines 79 and 122 show operating income assuming each rate class pays its full cost-of-service. Line 140 shows the increase in revenue

needed for each rate class to produce revenues equal to its revenue requirement at full cost-of-service and produce the system average rate of return. Line 83 shows the increase (decrease) in distribution revenue for each rate class to produce revenue from distribution charges equal to its distribution revenue requirement at full cost-of-service.

43. Q. What information is shown on PECO Exhibit JD-2?

A. PECO Exhibit JD-2 is the rate class cost-of-service and shows the allocation of each element of measures of value also known as rate base (RB schedules), operating expenses (E schedules), depreciation expense (D schedules), and taxes (TO and TI schedules) among the rate classes. This information is contained on the first 14 pages of the exhibit.

Also included in this exhibit are the external and internal allocators used for the rate case allocations, which are shown on pages 14 to 30 of the exhibit.

44. Q. Please describe the information contained in PECO Exhibit JD-3.

A. PECO Exhibit JD-3 contains the COSS by functional category and classification. The summary appears on pages 1 to 6 and the account-by-account allocation to functional category and classification is provided on pages 7 to 33. Pages 33 to 66 of this exhibit provide the external and internal allocators used for the exhibit.

45. Q. Please describe what is shown in PECO Exhibit JD-4.

A. PECO Exhibit JD-4 presents the unitized revenue requirement for each rate class. The unitized revenue requirements are the functionalized and classified revenue requirements allocated to each class of service divided by the appropriate units.

For example, capacity and commodity related cost are divided by Mcf and customer-related cost is divided by number of customers. The unit cost is provided by classification and functional area.

46. Q. Which costs were considered in developing the proposed customer charges?

A. The proposed customer charges are based on the specific customer-classified costs in the COSS that are approved by the Commission for recovery in customer charges. Customer related costs include all costs incurred to attach a customer to the distribution system, for meter usage, and to maintain the customer's account. They include: (1) capital costs associated with services and meters, and general plant supporting the functions identified above; (2) operating and maintenance expenses related to those assets described in (1); and (3) associated administrative and general expense, metering and billing expenses, customer service and account expenses, appropriate pensions and benefits, payroll taxes that are part of the applicable labor expenses, and working capital. Total customer costs by rate class for the FPFTY are shown in PECO Exhibit JD-4, in the unit cost analysis. PECO Exhibit JD-5 provides a summary and each element of measures of value of customer charges.

47. Q. Please describe the information shown on PECO Exhibit JD-6.

A. PECO Exhibit JD-6 presents the development of the main external allocators that are described below and used in the COSS. Except where noted, all data are for the FPFTY.

Index (page 1) – Table of External Allocators.

Summary of External Allocator Values by Rate Class (page 2)

Gas Deliveries (page 3) – Annual and monthly gas deliveries in Mcf, for each rate class.

Customer Numbers (page 4) – Monthly and average annual number of customers for each rate class.

Demand (page 5) – Average and Excess Demand allocator, which is used to allocate a portion of main, measuring and regulating station equipment costs.

Storage (page 6) – Storage allocator based on usage of storage assets for balancing needs of firm sales customers and transportation customers.

Mains, M&R and Meter Direct (page 7) – Data for customers with directly assigned mains, measuring and regulating station equipment, meter and meter installation. Data include cost, accumulated depreciation, depreciation expense, and annual usage as of December 31, 2023.

Service Costs (page 8) – Computes investment in services for each rate class at average cost for the period 2019 to 2023. PECO does not account for services separately and, therefore, has used estimated cost to allocate the account to the classes of service.

Meter Costs (page 9) – Computes investment in meters for each rate class at current costs for each meter type as of October 2023.

Account 903 Allocator (page 10) – Allocates costs associated with each activity recorded in Account 903 (2022, Customer Records and Collection), by using an appropriate external allocator. Each activity, the cost of the activity, and the allocator assigned to each is shown in a separate row. Row 19 summarizes the costs by rate class. The weighted allocators are shown on row 20. The separate allocations are necessary because some costs are only applicable to specific rate classes.

Account 908-916 Allocator (page 11) – Allocates the costs of each activity recorded in Account 908-916 (2022, including Customer Assistance and Sales Expenses), by using an appropriate external allocator. Rows 1-5 list each activity, the cost of the activity and the allocator assigned to it. Row 11 summarizes the costs by rate class. The weighted allocators are on row 12.

Accounts Receivable Over 60-Day (page 12) – Computes the A/R Over 60-Day allocators. The column "Over 60-Day Allocator" shows the percentage of PECO's total gas accounts receivable outstanding for more than two months for each rate class at each month-end in 2023.

Write-Offs (page 13) – Computes the write-off allocators by using net charge-offs for 2019 to 2023.

Directs (page 14) – Direct assignments for deposits, interest on deposits (2021 to 2023), advances (as of 2023), and forfeited discounts (2021 to 2023), Gas Energy Efficiency Program, Gas Procurement Charge, and Merchant Function Charge/Purchase of Receivables.

Purchased Gas Cost (page 15) – Annual costs for each rate class.

Balancing Service Cost (page 16) – Annual costs for each rate class.

Purchase of Receivables (page 17) – Annual costs for each rate class.

Design Day Demand (page 18) – Computes design day peak demand for rate classes GR, GC, L, MV-F and TS-F.

Base Customer Charge (page 19) – Annual revenues at current rates for each rate class.

VI. CONCLUSION

48. Q. Please summarize your conclusion with respect to the COSS.

A. The Company's COSS was prepared using an appropriate and well-accepted cost of service method. The results of the Company's COSS provide a reasonable allocation of PECO's cost of service among its rate classes and are an appropriate guide for use in designing PECO's proposed rates.

49. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit JD-1:

Gas Class Cost of Service Study for FPFTY Ended December 31, 2025 - Summary of Results

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
S	1	**SUMMARY AT PRESENT RATES**											
S	2												
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**											
S	4	**OPERATING REVENUE**											
S	5	Sales of Gas Revenue - Base	SCH RBC, LN 54	481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
S	6	Other Operating Revenue	SCH RBC, LN 64	3,549	2,404	919	1	4	0	0	3	146	72
S	7	TOTAL OPERATING REVENUE		485,530	330,170	123,595	185	615	4	75	700	19,266	10,920
S	8												
S	9	**OPERATING EXPENSES**											
S	10	Operation and Maintenance Expense Excl Pur Gas	SCH E, LN 99	167,687	123,018	35,534	38	166	1	7	47	6,100	2,776
S	11	Depreciation and Amortization Expense	SCH D, LN 45	118,763	80,999	30,846	19	144	0	3	35	4,521	2,194
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 10	9,067	6,373	2,184	2	11	0	0	3	341	153
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 18	0	0	0	0	0	0	0	0	0	0
S	14	Income Taxes	SCH TI, LN 61	14,297	11,849	2,509	(21)	(0)	(0)	(14)	(134)	441	(331)
S	15	TOTAL OPERATING EXPENSES		281,220	198,541	66,056	80	321	1	25	220	10,521	5,453
S	16												
S	17	**OPERATING INCOME (RETURN)**		204,311	131,629	57,539	104	294	2	50	480	8,745	5,467
S	18												
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**											
S	20	Gas Plant in Service	SCH RBP, LN 65	4,630,050	3,126,806	1,225,457	726	5,495	17	127	1,352	186,019	84,052
S	21	Less: Accumulated Depreciation	SCH RBD, LN 37	1,022,690	699,138	266,349	150	1,142	4	25	316	35,239	20,325
S	22	Plus: Rate Base Additions Excl Purchased Gas	SCH RBO, LN 13	253,066	181,674	59,722	44	239	1	8	61	7,594	3,725
S	23	Less: Rate Base Deductions	SCH RBO, LN 26	346,452	229,908	97,612	59	409	1	10	104	12,483	5,866
S	24	TOTAL RATE BASE EXCL PURCHASED GAS	SCH RBO, LN 29	3,513,974	2,379,433	921,218	561	4,182	12	99	993	145,891	61,585
S	25												
S	26	RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		5.81%	5.53%	6.25%	18.59%	7.03%	17.52%	50.89%	48.30%	5.99%	8.88%
S	27	INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		1.00	0.95	1.07	3.20	1.21	3.01	8.75	8.31	1.03	1.53
S	28												
S	29												
S	30	**DEVELOPMENT OF PURCHASED GAS RETURN**											
S	31	Purchased Gas Revenues (PGC)	SCH RBC, LN 55	234,407	176,887	55,442	99	1,289	8	77	606	0	0
S	32	Other Sales of Gas Revenue (BSC)	SCH RBC, LN 56	26,508	17,003	9,245	8	194	1	6	50	0	0
S	33	Purchased Gas O&M Expense	SCH E, LN 98	260,932	193,902	64,692	107	1,483	9	84	656	0	0
S	34	Purchased Gas Income Taxes (Fed & State PP)		57	43	14	0	0	0	0	0	0	0
S	35	**PURCHASED GAS OPERATING INCOME (RETURN)**		40	31	9	0	0	0	0	0	(0)	(0)
S	36	RATE BASE - PURCHASED GAS CASH WORKING CAPITAL		10,032	7,570	2,373	4	55	0	3	26	0	0
S	37	PURCHASED GAS RATE OF RETURN (PRESENT)		0.40%	0.41%	0.37%	0.53%	0.52%	0.53%	0.53%	0.53%	0.00%	0.00%
S	38												
S	39												
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**											
S	41	Total Distribution Sales Revenue at Current Rates		742,897	521,656	187,363	291	2,094	12	158	1,353	19,121	10,848
S	42	Total Distribution Operating Revenues		746,445	524,060	188,282	292	2,098	12	159	1,356	19,266	10,920
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes		556,449	404,292	133,257	166	1,804	10	94	742	10,962	5,123
S	44	Plus: Total Federal & State Taxes		14,354	11,892	2,523	(21)	(0)	(0)	(14)	(134)	441	(331)
S	45	Total Operating Income (Return)		204,351	131,660	57,548	104	294	2	50	480	8,745	5,467
S	46	Total Rate Base		3,524,006	2,387,003	923,590	566	4,237	13	102	1,019	145,891	61,585
S	47												
S	48	COMPOSITE RATE OF RETURN (PRESENT)		5.80%	5.52%	6.23%	18.46%	6.94%	17.09%	49.26%	47.08%	5.99%	8.88%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)		1.00	0.95	1.07	3.18	1.20	2.95	8.49	8.12	1.03	1.53
S	50												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**											
S	52												
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)**											
S	54												
S	55	Rate Base Excluding Purchased Gas	SCH S, LN 24	3,513,974	2,379,433	921,218	561	4,182	12	99	993	145,891	61,585
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		79,618	60,629	16,895	(59)	44	(1)	(42)	(399)	3,043	(491)
S	57			8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	58	**OPERATING REVENUES**											
S	59	**Change in Revenue (Change in Return * 1.383)**		110,103	83,843	23,364	(82)	61	(2)	(59)	(552)	4,208	(678)
S	60	Distribution Base Rate Revenue (Present Rates)	SCH S, LN 5	481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	592,085	411,609	146,041	102	672	2	16	145	23,328	10,170
S	62												
S	63	Forfeited Discounts Revenues	CALCULATED	179	137	38	(0)	0	(0)	(0)	(1)	7	(1)
S	64	Other Operating Revenue (Present Rates)	SCH S, LN 6	3,549	2,404	919	1	4	0	0	3	146	72
S	65	**TOTAL OPERATING REVENUES**		595,813	414,150	146,997	103	676	2	16	147	23,481	10,241
S	66												
S	67	**OPERATING EXPENSES**											
S	68	Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 10	167,687	123,018	35,534	38	166	1	7	47	6,100	2,776
S	69	Depreciation and Amortization Expense	SCH S, LN 11	118,763	80,999	30,846	19	144	0	3	35	4,521	2,194
S	70	Additional Bad Debt Expense	CALCULATED	406	310	86	(0)	0	(0)	(0)	(2)	16	(3)
S	71	Additional PUC / OTS & SBA Fee Expense	CALCULATED	340	259	72	(0)	0	(0)	(0)	(2)	13	(2)
S	72	Taxes Other Than Income Taxes-General	SCH S, LN 12	9,067	6,373	2,184	2	11	0	0	3	341	153
S	73	Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 13	0	0	0	0	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**		296,263	210,959	68,723	58	321	1	10	82	10,991	5,118
S	75	State and Federal Income Taxes @ Effective Tax Rate	CALCULATED	(14,297)	(11,849)	(2,509)	21	0	0	14	134	(441)	331
S	76	State and Federal Income Taxes @ Statutory Rates	CALCULATED	29,917	22,781	6,348	(22)	17	(0)	(16)	(150)	1,143	(184)
S	77	**TOTAL OPERATING EXPENSES**		311,883	221,891	72,563	58	338	1	8	66	11,693	5,265
S	78												
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**		283,930	192,259	74,435	45	338	1	8	80	11,788	4,976
S	80												
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**		592,085	411,609	146,041	102	672	2	16	145	23,328	10,170
S	82												
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**		110,283	83,980	23,402	(82)	61	(2)	(59)	(553)	4,214	(679)
S	84	REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVENUES (%)		22.88%	25.62%	19.08%	-44.43%	9.97%	-45.26%	-78.66%	-79.36%	22.04%	-6.26%
S	85												
S	86												
S	87												
S	88												
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S	98												
S	99												
S	100												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**											
S	102												
S	103	**DEVELOPMENT OF PURCHASED GAS RETURN (EQUALIZED RATE)**											
S	104												
S	105	Rate Base for Purchased Gas	SCH S, LN 36	10,032	7,570	2,373	4	55	0	3	26	0	0
S	106	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		770	581	183	0	4	0	0	2	0	0
S	107			8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%		
S	108	**OPERATING REVENUES**											
S	109	**Change in Revenue (Change in Return * 1.383)**		1,065	803	253	0	6	0	0	3	0	0
S	110	Distribution Base Rate Revenue (Present Rates)	CALCULATED	260,915	193,890	64,687	107	1,483	9	84	656	0	0
S	111	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	261,980	194,693	64,940	107	1,489	9	84	659	0	0
S	112												
S	113	**OPERATING EXPENSES**											
S	114	Purchased Gas O&M Expense	SCH S, LN 33	260,932	193,902	64,692	107	1,483	9	84	656	0	0
S	115	Additional Bad Debt Expense	CALCULATED	4	3	1	0	0	0	0	0	0	0
S	116	Additional PUC / OTS & SBA Fee Expense	CALCULATED	3	2	1	0	0	0	0	0	0	0
S	117	**TOTAL OPERATING EXPENSES BEFORE TAXES**		260,939	193,907	64,694	107	1,483	9	84	656	0	0
S	118	State and Federal Inc Taxes @ Effective Tax Rate	CALCULATED	(57)	(43)	(14)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
S	119	State and Federal Income Taxes @ Statutory Rates	CALCULATED	289	218	69	0	2	0	0	1	0	0
S	120	**TOTAL OPERATING EXPENSES**		261,171	194,082	64,748	107	1,484	9	84	656	0	0
S	121												
S	122	**NET OPERATING INCOME FOR PURCHASED GAS**		809	611	191	0	4	0	0	2	(0)	(0)
S	123												
S	124	**EQUALS TOTAL PURCHASED GAS COST OF SERVICE @ ROR**		261,980	194,693	64,940	107	1,489	9	84	659	0	0
S	125												
S	126	**TOTAL SALES PURCH GAS INCREASE/DECREASE**		1,065	803	253	0	6	0	0	3	0	0
S	127	SALES REVENUE INCREASE TO RURCHASED GAS REVENUES (%)		0.45%	0.45%	0.46%	0.45%	0.45%	0.45%	0.45%	0.45%	0.00%	0.00%
S	128												
S	129												
S	130												
S	131												
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**											
S	133	**Total Composite Base Rate Sales Revenue Requirement**		854,065	606,302	210,980	210	2,160	11	100	803	23,328	10,170
S	134	**Other Operating Revenue**		3,728	2,541	957	1	4	0	0	2	153	71
S	135	**Total Revenue**		857,793	608,843	211,937	211	2,165	11	100	805	23,481	10,241
S	136	**Total Operating Expense before Income Taxes**		557,202	404,866	133,417	166	1,804	10	94	738	10,991	5,118
S	137	**OIBIT**		300,591	203,977	78,521	45	360	1	7	67	12,490	5,122
S	138	**Total Income Taxes**		15,851	11,107	3,894	(1)	18	(0)	(2)	(15)	702	146
S	139	**Net Operating Income**		284,739	192,870	74,626	46	342	1	8	82	11,788	4,976
S	140	**Total Increase (Decrease) Base Sales Required w/ Addt'l Forfeited Discount**		111,348	84,783	23,655	(81)	67	(2)	(58)	(551)	4,214	(679)
S	141	**TOTAL INCREASE (DECREASE) BASE SALES REQUIRED W/O ADDT'L FORFEITED DISCO**		111,168	84,646	23,617	(81)	67	(2)	(58)	(550)	4,208	(678)
S	142	**RATE OF RETURN (PROPOSED)**		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	143												
S	144												
S	145												
S	146												
S	147												
S	148												
S	149												
S	150												

PECO Exhibit JD-2:

Gas Class Cost of Service Study for FPFTY Ended December 31, 2025 - Allocation By Rate Class

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBP	1	**DEVELOPMENT OF RATE BASE**											
RBP	2												
RBP	3	**GAS PLANT IN SERVICE**											
RBP	4	INTANGIBLE PLANT											
RBP	5	301-Organization	TOTPLT	16,406	11,079	4,342	3	19	0	0	5	659	298
RBP	6	303-Miscellaneous Intangible Plant	TOTPLT	0	0	0	0	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT		16,406	11,079	4,342	3	19	0	0	5	659	298
RBP	8												
RBP	9	PRODUCTION PLANT (LPG)											
RBP	10	305-Land and Land Rights	DPKDAYP	1,225	826	397	0	2	0	0	0	0	0
RBP	11	311- Liquefied Petroleum Gas Equipment	DPKDAYP	14,334	9,663	4,639	4	28	0	0	0	0	0
RBP	12	320-Other Equipment (SNG Plant)	DPKDAYP	0	0	0	0	0	0	0	0	0	0
RBP	13	TOTAL PRODUCTION PLANT		15,559	10,489	5,035	4	31	0	0	0	0	0
RBP	14												
RBP	15	STORAGE PLANT (LNG)											
RBP	16	360-Land and Land Rights	DPKDAYS	16	11	5	0	0	0	0	0	0	0
RBP	17	361-Structures and Improvements	DPKDAYS	14,932	10,067	4,832	4	30	0	0	0	0	0
RBP	18	362-Gas Holders.	DPKDAYS	7,084	4,775	2,292	2	14	0	0	0	0	0
RBP	19	363-Purification Equipment	DPKDAYS	0	0	0	0	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYS	171,597	115,683	55,530	44	340	0	0	0	0	0
RBP	21	TOTAL STORAGE PLANT		193,629	130,536	62,659	49	384	0	0	0	0	0
RBP	22												
RBP	23	TRANSMISSION PLANT											
RBP	24	371- Transmission Related Plant	DTRAN	0	0	0	0	0	0	0	0	0	0
RBP	25	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0	0
RBP	26												
RBP	27	DISTRIBUTION PLANT											
RBP	28	374-Land & Land Rights	DDISTPLT	3,915	2,378	1,143	1	7	0	0	1	270	114
RBP	29	375-Structures & Improvements	DDISTPLT	16,785	10,198	4,899	4	31	0	1	6	1,158	488
RBP	30	376-Mains											
RBP	31	General - Excess	DEXCESS	1,784,138	1,156,478	537,221	411	1,004	0	0	0	89,024	0
RBP	32	General - Average	DAVGDD	570,169	290,102	157,741	139	3,324	7	109	855	[redacted]	
RBP	33	Direct Assignment	DAMAINS	15,529	0	0	0	0	0	0	0		
RBP	34	Total Account 376		2,369,836	1,446,581	694,963	549	4,328	7	109	855	158,172	64,273
RBP	35	378-Measuring & Regulating Station Equip-General	PLT_376	26,029	15,889	7,633	6	48	0	1	9	1,737	706
RBP	36	379-Measuring & Regulating Station Equip-City Gate											
RBP	37	City Gate	PLT_376	50,069	30,563	14,683	12	91	0	2	18	[redacted]	
RBP	38	Direct Assignment	DAMR	11,399	0	0	0	0	0	0	0		
RBP	39	Total Account 379		61,468	30,563	14,683	12	91	0	2	18	9,651	6,448
RBP	40	380-Services	CSERVICE	1,417,248	1,103,049	309,725	54	102	7	7	134	2,711	1,459
RBP	41	381-Meters	CMETERS	178,422	129,144	42,689	14	157	1	2	120	[redacted]	
RBP	42	Direct Assignment	CMETERSDA	583	0	0	0	0	0	0	0		
RBP	43	Total Account 381		179,005	129,144	42,689	14	157	1	2	120	3,865	3,014
RBP	44	382-Meter Installations	CMETERS	288,504	208,822	69,028	22	255	2	3	193	[redacted]	
RBP	45	Direct Assignment	CMETINSTDA	2,764	0	0	0	0	0	0	0		
RBP	46	Total Account 382		291,268	208,822	69,028	22	255	2	3	193	6,340	6,603
RBP	47	387-Other Equipment	DISTPLT	2,084	1,407	547	0	2	0	0	1	88	40
RBP	48	388-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	884	597	232	0	1	0	0	0	37	17

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBP	49	TOTAL DISTRIBUTION PLANT		4,368,523	2,948,627	1,145,541	662	5,022	17	125	1,338	184,030	83,161
RBP	50												
RBP	51	**GAS PLANT IN SERVICE CONTINUED**											
RBP	52												
RBP	53	GENERAL PLANT											
RBP	54	389-Land and Land Rights	SALWAGES	0	0	0	0	0	0	0	0	0	0
RBP	55	390-Structures and Improvements	SALWAGES	11,508	8,350	2,523	3	12	0	0	3	426	190
RBP	56	391-Office Furniture & Equipment	SALWAGES	1,783	1,294	391	0	2	0	0	0	66	29
RBP	57	393-Store Equipment	SALWAGES	0	0	0	0	0	0	0	0	0	0
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	16,536	11,998	3,626	4	18	0	1	4	612	273
RBP	59	395-Laboratory Equipment	SALWAGES	69	50	15	0	0	0	0	0	3	1
RBP	60	397-Communication Equipment	SALWAGES	5,786	4,199	1,269	1	6	0	0	1	214	95
RBP	61	398-Miscellaneous Equipment	SALWAGES	252	183	55	0	0	0	0	0	9	4
RBP	62	TOTAL GENERAL PLANT		35,933	26,074	7,879	8	39	0	1	9	1,330	593
RBP	63												
RBP	64												
RBP	65	**TOTAL GAS PLANT IN SERVICE**		4,630,050	3,126,806	1,225,457	726	5,495	17	127	1,352	186,019	84,052
RBP	66												
RBP	67												
RBP	68												
RBP	69												
RBP	70												
RBP	71												
RBP	72												
RBP	73												
RBP	74												
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RBP	95												
RBP	96												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBP	97												
RBP	98												
RBP	99												
RBP	100												
RBD	1	**LESS: ACCUMULATED DEPRECIATION**											
RBD	2												
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT	8,018	5,415	2,122	1	10	0	0	2	322	146
RBD	4												
RBD	5	PRODUCTION PLANT ACCUMULATED DEPRECIATION	PRODPLT	13,939	9,397	4,511	4	28	0	0	0	0	0
RBD	6												
RBD	7	STORAGE PLANT ACCUMULATED DEPRECIATION	STORPLT	36,086	24,328	11,678	9	71	0	0	0	0	0
RBD	8												
RBD	9	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT	0	0	0	0	0	0	0	0	0	0
RBD	10												
RBD	11	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION											
RBD	12	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0	0	0
RBD	13	375-Structures & Improvements	PLT_375	6,841	4,157	1,997	2	12	0	0	2	472	199
RBD	14	376-Mains											
RBD	15	General - Excess	PLT_376GE	319,532	207,121	96,214	74	180	0	0	0	15,944	0
RBD	16	General - Average	PLT_376GA	102,115	51,956	28,251	25	595	1	19	153	10,924	10,190
RBD	17	Direct Assignment	DAMAINSAD	2,855	0	0	0	0	0	0	0	402	2,452
RBD	18	Total Account 376		424,502	259,077	124,465	98	775	1	19	153	27,271	12,642
RBD	19	378-Measuring & Regulating Station Equip-General	PLT_378	5,942	3,627	1,743	1	11	0	0	2	397	161
RBD	20	379-Measuring & Regulating Station Equip-City Gate											
RBD	21	City Gate	PLT_379CG	24,325	14,849	7,134	6	44	0	1	9	1,624	660
RBD	22	Direct Assignment	DAMRAD	3,423	0	0	0	0	0	0	0	436	2,987
RBD	23	Total Account 379		27,748	14,849	7,134	6	44	0	1	9	2,060	3,647
RBD	24	380-Services	PLT_380	312,616	243,310	68,319	12	22	1	1	30	598	322
RBD	25	381-Meters	CMETERS	88,212	63,848	21,106	7	78	1	1	59	1,757	1,356
RBD	26	Direct Assignment	CMETERSDAA	63	0	0	0	0	0	0	0	28	35
RBD	27	Total Account 381		88,274	63,848	21,106	7	78	1	1	59	1,785	1,390
RBD	28	382-Meter Installations	CMETERS	80,125	57,996	19,171	6	71	1	1	54	1,596	1,231
RBD	29	Direct Assignment	CMETINSTDAA	332	0	0	0	0	0	0	0	52	280
RBD	30	Total Account 382		80,458	57,996	19,171	6	71	1	1	54	1,648	1,512
RBD	31	387-Other Equipment	PLT_387	1,716	1,158	450	0	2	0	0	1	72	33
RBD	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	608	411	160	0	1	0	0	0	26	12
RBD	33	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		948,707	648,433	244,543	132	1,017	4	25	310	34,327	19,917
RBD	34												
RBD	35	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	15,939	11,565	3,495	4	17	0	1	4	590	263
RBD	36												
RBD	37	**TOTAL ACCUMULATED DEPRECIATION**		1,022,690	699,138	266,349	150	1,142	4	25	316	35,239	20,325
RBD	38												
RBD	39												
RBD	40												
RBD	41	**NET GAS PLANT IN SERVICE**		3,607,360	2,427,667	959,108	577	4,352	13	102	1,036	150,780	63,726
RBD	42												
RBD	43												
RBD	44												

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBD	45												
RBD	46												
RBD	47												
RBD	48												
RBD	49												
RBD	50												
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**											
RBO	2												
RBO	3	**PLUS: ADDITIONS TO RATE BASE**											
RBO	4												
RBO	5	COMMON PLANT	SALWAGES	190,266	138,060	41,721	42	205	1	7	48	7,045	3,138
RBO	6												
RBO	7	**WORKING CAPITAL**											
RBO	8	Cash Working Capital - Purchased Gas	SCH RBC, LN 37	10,032	7,570	2,373	4	55	0	3	26	0	0
RBO	9	Cash Working Capital	SCH RBC, LN 22	3,705	2,603	1,077	2	12	0	1	12	(14)	12
RBO	10	Gas Storage Inventory	ESTORAGE	56,972	39,577	16,361	0	20	0	0	0	478	536
RBO	11	Materials and Supplies	TOTPLT	2,123	1,434	562	0	3	0	0	1	85	39
RBO	12	TOTAL WORKING CAPITAL		72,832	51,184	20,373	6	89	0	4	39	549	587
RBO	13	TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS		253,066	181,674	59,722	44	239	1	8	61	7,594	3,725
RBO	14	TOTAL ADDITIONS TO RATE BASE		263,098	189,244	62,095	49	294	1	11	87	7,594	3,725
RBO	15												
RBO	16	**LESS: DEDUCTIONS TO RATE BASE**											
RBO	17	Customer Deposits	CUSTDEP	13,354	4,067	8,928	4	3	0	1	4	224	122
RBO	18	Customer Advances for Construction	CUSTADV	1,323	882	191	0	0	0	0	0	190	59
RBO	19	Deferred Income Taxes and Credits											
RBO	20	Plant	TOTPLT	377,436	254,893	99,898	59	448	1	10	110	15,164	6,852
RBO	21	Common Plant	SALWAGES	15,921	11,552	3,491	4	17	0	1	4	589	263
RBO	22	Pension Assets / (Liability)	SALWAGES	0	0	0	0	0	0	0	0	0	0
RBO	23	Corporate Alternative Minimum Tax	TOTPLT	(49,890)	(33,692)	(13,205)	(8)	(59)	(0)	(1)	(15)	(2,004)	(906)
RBO	24	Contributions in Aid of Construction (CIAC)	CUSTADV	(11,690)	(7,794)	(1,692)	0	0	0	0	0	(1,680)	(524)
RBO	25	Total Deferred Income Taxes and Credits		331,776	224,959	88,492	55	406	1	10	100	12,069	5,684
RBO	26	TOTAL DEDUCTIONS TO RATE BASE		346,452	229,908	97,612	59	409	1	10	104	12,483	5,866
RBO	27												
RBO	28	TOTAL PURCHASED GAS RATE BASE		10,032	7,570	2,373	4	55	0	3	26	0	0
RBO	29	TOTAL RATE BASE EXCLUDING PURCHASED GAS		3,513,974	2,379,433	921,218	561	4,182	12	99	993	145,891	61,585
RBO	30												
RBO	31	**TOTAL RATE BASE**		3,524,006	2,387,003	923,590	566	4,237	13	102	1,019	145,891	61,585
RBO	32												
RBO	33												
RBO	34												
RBO	35												
RBO	36												
RBO	37												
RBO	38												
RBO	39												
RBO	40												
RBO	41												
RBO	42												

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBO	43												
RBO	44												
RBO	45												
RBO	46												
RBO	47												
RBO	48												
RBO	49												
RBO	50												
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**											
RBC	2												
RBC	3	**TOTAL EXCLUDING PURCHASED GAS**											
RBC	4	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	5	Payroll (Distribution Only)	SALWAGES	52,481	38,081	11,508	12	56	0	2	13	1,943	866
RBC	6	Pension	SALWAGES	973	706	213	0	1	0	0	0	36	16
RBC	7	Other Expenses											
RBC	8	Other Expenses	OMXPPPP	111,873	82,154	23,543	26	106	0	4	32	4,113	1,894
RBC	9	BSC	EBSC	26,508	17,003	9,245	8	194	1	6	50	0	0
RBC	10	Purchase of Recievables (POR)	POR	82,479	48,229	33,888	0	169	1	0	193	0	0
RBC	11	TOTAL EXPENSES		274,313	186,172	78,397	46	526	3	13	288	6,093	2,776
RBC	12												
RBC	13	TOTAL EXPENSES PER DAY		752	510	215	0	1	0	0	1	17	8
RBC	14												
RBC	15	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		7,812	5,302	2,233	1	15	0	0	8	173	79
RBC	16												
RBC	17	AVERAGE PREPAYMENTS		2,733	1,990	615	1	4	0	0	2	83	38
RBC	18	DISTRIBUTION ACCRUED TAXES		1,896	1,211	541	1	3	0	1	5	81	54
RBC	19	INTEREST PAYMENTS	TOTPLT	(8,736)	(5,900)	(2,312)	(1)	(10)	(0)	(0)	(3)	(351)	(159)
RBC	20												
RBC	21												
RBC	22	NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT		3,705	2,603	1,077	2	12	0	1	12	(14)	12
RBC	23												
RBC	24												
RBC	25	**PURCHASED GAS**											
RBC	26	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	27	Commodity Purchased - Contract Purchases	EGAS	234,407	176,887	55,442	99	1,289	8	77	606	0	0
RBC	28	Commodity Purchased - Spot Market Purchases	ETHRUPUTF	0	0	0	0	0	0	0	0	0	0
RBC	29	TOTAL EXPENSES		234,407	176,887	55,442	99	1,289	8	77	606	0	0
RBC	30												
RBC	31	TOTAL EXPENSES PER DAY		642	485	152	0	4	0	0	2	0	0
RBC	32												
RBC	33	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		10,032	7,570	2,373	4	55	0	3	26	0	0
RBC	34												
RBC	35	PURCHASED GAS ACCRUED TAXES	ETHRUPUTF	0	0	0	0	0	0	0	0	0	0
RBC	36												
RBC	37	NET PURCHASED GAS CASH WORKING CAPITAL REQUIREMENT		10,032	7,570	2,373	4	55	0	3	26	0	0
RBC	38												
RBC	39												
RBC	40	**TOTAL NET CASH WORKING CAPITAL**		13,737	10,173	3,450	6	67	0	4	38	(14)	12

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	41												
RBC	42												
RBC	43												
RBC	44												
RBC	45												
RBC	46												
RBC	47												
RBC	48												
RBC	49												
RBC	50												
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**											
RBC	2												
RBC	3	**LAG/LEAD DAYS**		NET DAYS									
RBC	4	REVENUE LAG DAYS	48.86										
RBC	5	EXPENSE LEAD DAYS	38.46	10									
RBC	6												
RBC	7	PURCHASED GAS EXP LEAD DAYS	33.24	16									
RBC	8												
RBC	9												
RBC	10												
RBC	11												
RBC	12												
RBC	13												
RBC	14												
RBC	15												
RBC	16	DISTRIBUTION ACCRUED TAXES											
RBC	17	Federal Income Tax	EBT	304,366	182,524	93,620	301	540	6	166	1,569	13,762	11,878
RBC	18	State Income Tax	EBT	32,373	19,413	9,958	32	57	1	18	167	1,464	1,263
RBC	19	PURTA Taxes	TOTPLT	228,094	154,038	60,371	36	271	1	6	67	9,164	4,141
RBC	20	PA Capital Stock Tax	TOTPLT	0	0	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	TOTPLT	0	0	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	127,229	85,922	33,674	20	151	0	3	37	5,112	2,310
RBC	23	TOTAL ACCRUED TAXES		692,062	441,897	197,622	389	1,019	8	193	1,840	29,501	19,592
RBC	24	TOTAL ACCRUED TAXES PER DAY		1,896	1,211	541	1	3	0	1	5	81	54
RBC	25												
RBC	26	DISTRIBUTION AVERAGE PREPAYMENTS											
RBC	27	AGA Membership Dues	SALESREV	161	110	41	0	0	0	0	0	6	4
RBC	28	EAPA Membership Dues	CLAIMREV	38	27	9	0	0	0	0	0	1	0
RBC	29	PUC Assess - Gas	CLAIMREV	1,029	730	254	0	3	0	0	1	28	12
RBC	30	Cellent Gas Meter Reading	PLT_381	0	0	0	0	0	0	0	0	0	0
RBC	31	Gas Software Maintenance	DISTPLT	27	18	7	0	0	0	0	0	1	1
RBC	32	Customer and Research	CUSTBILLS	67	61	5	0	0	0	0	0	0	0
RBC	33	VEBA Adjustment	SALWAGES	774	562	170	0	1	0	0	0	29	13
RBC	34	Facility Contracts	DISTPLT	13	9	3	0	0	0	0	0	1	0
RBC	35	IT License & Maintenance	TOTPLT	283	191	75	0	0	0	0	0	11	5
RBC	36	Fleet Activities	GENLPLT	100	72	22	0	0	0	0	0	4	2
RBC	37	Prepaid Rent	DISTPLT	47	32	12	0	0	0	0	0	2	1
RBC	38	Postage	CUSTBILLS	194	178	16	0	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	39	TOTAL AVERAGE PREPAYMENTS		2,733	1,990	615	1	4	0	0	2	83	38
RBC	40												
RBC	41												
RBC	42												
RBC	43												
RBC	44												
RBC	45												
RBC	46												
RBC	47												
RBC	48												
RBC	49												
RBC	50												
RBC	51	**OPERATING REVENUES**											
RBC	52												
RBC	53	**SALES REVENUES**											
RBC	54	Sales of Gas Revenues - Base		481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
RBC	55	Sales Revenues - Purchased Gas-PGC	EGAS	234,407	176,887	55,442	99	1,289	8	77	606	0	0
RBC	56	Sales Revenues - Balancing Service Charge-BSC	EBSC	26,508	17,003	9,245	8	194	1	6	50	0	0
RBC	57	TOTAL SALES OF GAS		742,897	521,656	187,363	291	2,094	12	158	1,353	19,121	10,848
RBC	58												
RBC	59	**OTHER OPERATING REVENUES**											
RBC	60	487-Forfeited Discounts	REV_487	1,329	879	359	1	2	0	0	2	55	31
RBC	61	489-Revenues from Transportation of Gas of Others	PLT_376	0	0	0	0	0	0	0	0	0	0
RBC	62	493-Rent from Gas Property	DISTPLT	1,703	1,149	447	0	2	0	0	1	72	32
RBC	63	495-Other Gas Revenues	SALWAGES	517	375	113	0	1	0	0	0	19	9
RBC	64	TOTAL OTHER OPERATING REV		3,549	2,404	919	1	4	0	0	3	146	72
RBC	65												
RBC	66	**TOTAL OPERATING REVENUES**		746,445	524,060	188,282	292	2,098	12	159	1,356	19,266	10,920
RBC	67												
RBC	68												
RBC	69												
RBC	70												
RBC	71												
RBC	72												
RBC	73												
RBC	74												
RBC	75												
RBC	76												
RBC	77												
RBC	78												
RBC	79												
RBC	80												
RBC	81												
RBC	82												
RBC	83												
RBC	84												
RBC	85												
RBC	86												

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	87												
RBC	88												
RBC	89												
RBC	90												
RBC	91												
RBC	92												
RBC	93												
RBC	94												
RBC	95												
RBC	96												
RBC	97												
RBC	98												
RBC	99												
RBC	100												
E	1	**OPERATION & MAINTENANCE EXPENSE**											
E	2	PRODUCTION EXPENSE											
E	3	Manufactured Gas Production Expense											
E	4	Operation											
E	5	710-Operations Labor	DPKDAYP	7	5	2	0	0	0	0	0	0	0
E	6	717-Liquefied Petroleum Gas Expenses	DPKDAYP	129	87	42	0	0	0	0	0	0	0
E	7	Total Operation		137	92	44	0	0	0	0	0	0	0
E	8	Maintenance											
E	9	741-Maintenance of Structures and Improvements.	DPKDAYP	86	58	28	0	0	0	0	0	0	0
E	10	742-Maintenance of Production Equipment	DPKDAYP	215	145	70	0	0	0	0	0	0	0
E	11	Total Maintenance		302	203	98	0	1	0	0	0	0	0
E	12	Total Manufactured Gas Production Expense		439	296	142	0	1	0	0	0	0	0
E	13	Other Gas Supply Expense											
E	14	Operation											
E	15	804-Natural Gas Purchases-PGC	EGAS	234,407	176,887	55,442	99	1,289	8	77	606	0	0
E	16	804-Natural Gas Purchases-BSC	EBSC	26,508	17,003	9,245	8	194	1	6	50	0	0
E	17	805-Other Natural Gas Purchases	ETHRUPUT	0	0	0	0	0	0	0	0	0	0
E	18	807-Purchased Gas Expenses	ESTORAGE	17	12	5	0	0	0	0	0	0	0
E	19	808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	0	0	0	0	0	0	0	0	0	0
E	20	808.1 Gas withdrawn from storage—Direct	ETHRUPUTT	0	0	0	0	0	0	0	0	0	0
E	21	Total Other Gas Supply Expense		260,932	193,902	64,692	107	1,483	9	84	656	0	0
E	22	TOTAL PRODUCTION EXPENSE		261,371	194,197	64,834	107	1,484	9	84	656	0	0
E	23												
E	24	NATURAL GAS STORAGE EXPENSE											
E	25	Operation											
E	26	840-Operation Supervision and Engineering	DPKDAYS	363	245	117	0	1	0	0	0	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYS	929	626	301	0	2	0	0	0	0	0
E	28	Total Operation		1,292	871	418	0	3	0	0	0	0	0
E	29	Maintenance											
E	30	843-Maintenance Expense	DPKDAYS	5,043	3,400	1,632	1	10	0	0	0	0	0
E	31	Total Maintenance		5,043	3,400	1,632	1	10	0	0	0	0	0
E	32	Total Natural Gas Storage Expense		6,335	4,271	2,050	2	13	0	0	0	0	0
E	33												
E	34	TRANSMISSION EXPENSES											

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
E	35	Operation Expense	TRANPLT	0	0	0	0	0	0	0	0	0	0
E	36	Maintenance Expense	TRANPLT	0	0	0	0	0	0	0	0	0	0
E	37	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0	0	0
E	38												
E	39	DISTRIBUTION EXPENSES											
E	40	Operation											
E	41	870-Operation Supervision and Engineering	SALWAGDO	538	401	113	0	0	0	0	0	16	7
E	42	874-Mains and Services Expenses	PLT_376380	19,001	12,793	5,041	3	22	0	1	5	807	330
E	43	875-Measuring & Reg. Station Exp.-General	PLT_378	1,901	1,161	558	0	3	0	0	1	127	52
E	44	877-Measuring & Reg. Station Exp.-City Gate Sta.	PLT_379	0	0	0	0	0	0	0	0	0	0
E	45	878-Meter & House Regulator Expenses	PLT_3815	7,627	5,481	1,812	1	7	0	0	5	166	156
E	46	879-Customer Installations Expenses	CUSTINSTALL	8,140	7,467	664	0	0	0	0	0	6	3
E	47	880-Other Expenses	DISTPLT	19,955	13,469	5,233	3	23	0	1	6	841	380
E	48	880-Other Expenses - GPC	E880DA	(1,742)	(1,119)	(609)	(1)	(13)	0	0	0	0	0
E	49	Total Distribution Operation		55,422	39,652	12,811	6	43	0	1	17	1,962	928
E	50												
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**											
E	52	DISTRIBUTION EXPENSES CONTINUED											
E	53	Maintenance											
E	54	887-Maintenance of Mains	PLT_376	26,734	16,319	7,840	6	49	0	1	10	1,784	725
E	55	889-Maint. of Measuring & Reg. Station Equip.-Gen	PLT_378	1,537	938	451	0	3	0	0	1	103	42
E	56	892-Maintenance of Services	PLT_380	2,864	2,229	626	0	0	0	0	0	5	3
E	57	893-Maint. of Meters & House Regulators	PLT_3815	243	175	58	0	0	0	0	0	5	5
E	58	894-Maintenance of Other Equipment	DISTPLT	680	459	178	0	1	0	0	0	29	13
E	59	Total Distribution Maintenance		32,058	20,120	9,153	7	53	0	1	11	1,926	788
E	60	TOTAL DISTRIBUTION PLANT O&M EXPENSES		87,480	59,772	21,964	13	96	0	3	28	3,888	1,715
E	61	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		355,186	258,241	88,848	122	1,592	9	86	684	3,889	1,716
E	62												
E	63	CUSTOMER ACCOUNTS EXPENSES											
E	64	902-Meter Reading	CMETRDG	163	149	13	0	0	0	0	0	0	0
E	65	903-Customer Records and Collection Expense	CUSTREC	20,632	17,887	1,841	11	6	0	2	4	569	313
E	66	904-Uncollectible Accounts	EXP_904	3,047	2,684	349	1	2	0	0	2	6	3
E	67	904-Uncollectible Accounts - MFC/POR	E904DA	(1,200)	(1,057)	(143)	0	0	0	0	0	0	0
E	68	904-Uncollectible Accounts - PPA	EXP_904PPA	530	530	0	0	0	0	0	0	0	0
E	69	905-Miscellaneous CA	CUSTCAM	1,001	918	82	0	0	0	0	0	1	0
E	70	TOTAL CUSTOMER ACCTS EXPENSE		24,173	21,112	2,142	11	7	0	2	6	576	317
E	71												
E	72	CUSTOMER SERVICE & SALES EXPENSES											
E	73	908-Customer Assistance	CUSTASST	7,183	6,836	137	3	0	0	0	0	134	73
E	74	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0	0	0	0	0	0	0	0	0	0
E	75	909-Advertisement	CUSTADVT	345	329	7	0	0	0	0	0	6	4
E	76	910-Miscellaneous CS	CUSTCSM	54	52	1	0	0	0	0	0	1	1
E	77	912-Demonstrating and Selling Expenses	CUSTSALES	774	736	15	0	0	0	0	0	14	8
E	78	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0	0	0	0	0
E	79	TOTAL CUSTOMER SERVICE & SALES EXP		8,357	7,952	159	3	0	0	0	0	156	85
E	80	TOTAL OPER & MAINT EXCL A&G		387,716	287,305	91,149	136	1,600	9	89	690	4,621	2,118
E	81												
E	82	ADMINISTRATIVE & GENERAL EXPENSE											

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
E	83	920-Administrative Salaries	SALWAGES	7,180	5,210	1,574	2	8	0	0	2	266	118
E	84	921-Office Supplies & Expense	SALWAGES	1,197	869	263	0	1	0	0	0	44	20
E	85	923-Outside Service Employed	SALWAGES	17,810	12,923	3,905	4	19	0	1	5	659	294
E	86	924-Property Insurance	PSTDGPLT	148	100	39	0	0	0	0	0	6	3
E	87	925-Injuries and Damages	SALWAGES	410	297	90	0	0	0	0	0	15	7
E	88	926-Employee Pensions & Benefits	SALWAGES	8,683	6,301	1,904	2	9	0	0	2	322	143
E	89	928-Regulatory Commission	CLAIMREV	3,637	2,582	899	1	9	0	0	3	99	43
E	90	929-Duplicate Charges-Credit	CLAIMREV	(7)	(5)	(2)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
E	91	930.1-General Advertising	CLAIMREV	0	0	0	0	0	0	0	0	0	0
E	92	930.2-Miscellaneous General	SALWAGES	828	601	182	0	1	0	0	0	31	14
E	93	932-Maintenance of General Plant	GENLPLT	1,015	737	223	0	1	0	0	0	38	17
E	94	TOTAL A&G EXPENSE		40,903	29,615	9,077	9	49	0	2	13	1,480	658
E	95												
E	96	**TOTAL OPERATION & MAINTENANCE EXPENSES**		428,619	316,920	100,226	145	1,649	9	90	703	6,100	2,776
E	97												
E	98	**TOTAL PURCHASED GAS O&M EXPENSES**		260,932	193,902	64,692	107	1,483	9	84	656	0	0
E	99	**TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS**		167,687	123,018	35,534	38	166	1	7	47	6,100	2,776
E	100												
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**											
D	2												
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	15,857	10,709	4,197	2	19	0	0	5	637	288
D	4												
D	5	PRODUCTION PLANT EXPENSE	PRODPLT	170	115	55	0	0	0	0	0	0	0
D	6												
D	7	LOCAL STORAGE PLANT EXPENSE	STORPLT	6,983	4,707	2,260	2	14	0	0	0	0	0
D	8												
D	9	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0	0	0	0	0
D	10												
D	11	DISTRIBUTION PLANT EXPENSE											
D	12	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0	0	0
D	13	375-Structures & Improvements	PLT_375	361	219	105	0	1	0	0	0	25	10
D	14	376-Mains											
D	15	General - Excess	PLT_376GE	31,515	20,428	9,490	7	18	0	0	0	1,573	0
D	16	General - Average	PLT_376GA	10,072	5,124	2,786	2	59	0	2	15	1,077	1,005
D	17	Direct Assignment	DAMAINSDE	222	0	0	0	0	0	0	0	116	105
D	18	Total Account 376		41,809	25,553	12,276	10	76	0	2	15	2,766	1,110
D	19	378-Measuring & Regulating Station Equip-General	PLT_378	584	356	171	0	1	0	0	0	39	16
D	20	379-Measuring & Regulating Station Equip-City Gate											
D	21	City Gate	PLT_379CG	822	502	241	0	2	0	0	0	55	22
D	22	Direct Assignment	DAMRDE	228	0	0	0	0	0	0	0	126	102
D	23	Total Account 379		1,050	502	241	0	2	0	0	0	181	124
D	24	380-Services	PLT_380	28,325	22,045	6,190	1	2	0	0	3	54	29
D	25	381-Meters	CMETERS	5,749	4,161	1,375	0	5	0	0	4	114	88
D	26	Direct Assignment	CMETERSDAE	15	0	0	0	0	0	0	0	8	7
D	27	Total Account 381		5,763	4,161	1,375	0	5	0	0	4	122	95
D	28	382-Meter Installations	CMETERS	5,922	4,287	1,417	0	5	0	0	4	118	91
D	29	Direct Assignment	CMETINSTDAE	69	0	0	0	0	0	0	0	15	54
D	30	Total Account 382		5,992	4,287	1,417	0	5	0	0	4	133	145

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
D	31	387-Other Equipment	PLT_378387	93	50	24	0	0	0	0	0	12	7
D	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	0	0	0	0	0	0	0	0	0	0
D	33	TOTAL DISTRIBUTION PLANT EXPENSE		83,975	57,172	21,800	12	92	0	2	26	3,332	1,538
D	34												
D	35	GENERAL PLANT EXPENSE	GENLPLT	1,927	1,398	423	0	2	0	0	0	71	32
D	36												
D	37	COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	8,070	5,856	1,770	2	9	0	0	2	299	133
D	38												
D	39	NET MANUFACTURED GAS PLANT EXP	ETHRUPUT	1,431	671	365	0	8	0	0	2	182	204
D	40	NET AMORTIZATION OF CUSTOMER PROGRAMS	TOTPLT	0	0	0	0	0	0	0	0	0	0
D	41	Direct Assignment - EE	CSEHPDA	321	350	(29)	0	0	0	0	0	0	0
D	42	Direct Assignment - Gas Unbundling	OX_880904DA	28	21	7	0	0	0	0	0	0	0
D	43	TOTAL NET AMORTIZATION OF CUSTOMER PROGRAMS		349	371	(22)	0	0	0	0	0	0	0
D	44												
D	45	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		118,763	80,999	30,846	19	144	0	3	35	4,521	2,194
D	46												
D	47												
D	48												
D	49												
D	50												
TO	1	**OTHER OPERATING EXPENSES**											
TO	2												
TO	3	**TAXES OTHER THAN INCOME TAXES**											
TO	4	**General Taxes**											
TO	5	PURTA Taxes	TOTPLT	2,076	1,402	550	0	2	0	0	1	83	38
TO	6	Capital Stock	TOTPLT	0	0	0	0	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	4,463	3,238	979	1	5	0	0	1	165	74
TO	8	Real Estate Tax	TOTPLT	1,796	1,213	475	0	2	0	0	1	72	33
TO	9	PA and Local Use Tax	CLAIMREV	732	520	181	0	2	0	0	1	20	9
TO	10	Total General Taxes		9,067	6,373	2,184	2	11	0	0	3	341	153
TO	11												
TO	12												
TO	13	**Franchise and Revenue Taxes**											
TO	14	Retail Revenue		0									
TO	15	Forfeited Discounts		0									
TO	16	Less: Bad Debt		0									
TO	17	Total Revenue	CALCULATED	0	0	0	0	0	0	0	0	0	0
TO	18	Total Distribution @ GRT Rate 0.00%	CALCULATED	0	0	0	0	0	0	0	0	0	0
TO	19	Total Franchise and Revenue Taxes		0	0	0	0	0	0	0	0	0	0
TO	20												
TO	21	**TOTAL TAXES OTHER THAN INCOME**		9,067	6,373	2,184	2	11	0	0	3	341	153
TO	22												
TO	23												
TO	24												
TO	25												
TO	26												
TO	27												
TO	28												

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TO	29												
TO	30												
TO	31												
TO	32												
TO	33												
TO	34												
TO	35												
TO	36												
TO	37												
TO	38												
TO	39												
TO	40												
TO	41												
TO	42												
TO	43												
TO	44												
TO	45												
TO	46												
TO	47												
TO	48												
TO	49												
TO	50												
TI	1	**DEVELOPMENT OF INCOME TAXES**											
TI	2												
TI	3	TOTAL OPERATING REVENUES EXCL PURCHASED GAS		485,530	330,170	123,595	185	615	4	75	700	19,266	10,920
TI	4	LESS:											
TI	5	OPER. & MAINT. EXP. EXCL PURCHASED GAS	SCH E, LN 99	167,687	123,018	35,534	38	166	1	7	47	6,100	2,776
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	SCH D, LN 45	118,763	80,999	30,846	19	144	0	3	35	4,521	2,194
TI	7	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 21	9,067	6,373	2,184	2	11	0	0	3	341	153
TI	8	NET OPERATING INCOME BEFORE TAXES		190,014	119,780	55,030	126	294	3	65	614	8,304	5,797
TI	9	LESS:											
TI	10	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		74,848	50,682	19,622	12	89	0	2	21	3,107	1,312
TI	11												
TI	12	**BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS**		115,166	69,098	35,408	114	205	2	63	593	5,197	4,486
TI	13												
TI	14	**FEDERAL & STATE TAX ADJUSTMENTS**											
TI	15	Regulatory Asset Programs M-1 (Pension & Post Ret)	SALWAGES	3,619	2,626	793	1	4	0	0	1	134	60
TI	16	Other Property Basis Adjustment (CIAC/ICM)	DISTPLT	21,960	14,822	5,758	3	25	0	1	7	925	418
TI	17	Removal Costs/Software	TOTPLT	2,426	1,638	642	0	3	0	0	1	97	44
TI	18	AFUDC Equity	TOTPLT	7,418	5,009	1,963	1	9	0	0	2	298	135
TI	19	Permanent Adjustments	TOTPLT	(805)	(544)	(213)	(0)	(1)	(0)	(0)	(0)	(32)	(15)
TI	20	Repair Deduction	TOTPLT	151,000	101,975	39,966	24	179	1	4	44	6,067	2,741
TI	21	TOTAL FEDERAL & STATE TAX ADJUSTMENTS		185,617	125,526	48,910	29	219	1	5	54	7,489	3,383
TI	22												
TI	23	**CALCULATION OF PA STATE INCOME TAXES**											
TI	24	BASE TAXABLE INCOME	SCH TI, LN 12	115,166	69,098	35,408	114	205	2	63	593	5,197	4,486
TI	25	LESS:											
TI	26	State Tax Depreciation (Over) Under Book	TOTPLT	3,125	2,110	827	0	4	0	0	1	126	57

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TI	27	Total Tax Adjustments	SCH TI, LN 21	185,617	125,526	48,910	29	219	1	5	54	7,489	3,383
TI	28	PA STATE TAXALBE DISTRIBUTION INCOME		(73,576)	(58,539)	(14,329)	84	(18)	2	57	538	(2,418)	1,046
TI	29	**PA STATE INCOME TAXES @ Tax Rate 7.99%**		(5,879)	(4,677)	(1,145)	7	(1)	0	5	43	(193)	84
TI	30	**PLUS: DEFERRED STATE INCOME TAXES**											
TI	31	Net Operating Loss Utilization	CALCULATED	2,351	1,871	458	(3)	1	(0)	(2)	(17)	77	(33)
TI	32	**TOTAL STATE INCOME TAX**		3,527	2,806	687	(4)	1	(0)	(3)	(26)	116	(50)
TI	33	Deferred Taxes on Timing Differences - State	TOTPLT	(2,044)	(1,380)	(541)	(0)	(2)	(0)	(0)	(1)	(82)	(37)
TI	34	Excess Deferred Amortization	TOTPLT	271	183	72	0	0	0	0	0	11	5
TI	35	Deferred Taxes on State NOL	TOTPLT	2,359	1,593	624	0	3	0	0	1	95	43
TI	36	**TOTAL STATE INCOME TAX EXPENSE**		4,113	3,202	842	(4)	2	(0)	(3)	(26)	139	(40)
TI	37												
TI	38	**CALCULATION OF FEDERAL INCOME TAXES**											
TI	39	BASE TAXABLE INCOME	SCH TI, LN 12	115,166	69,098	35,408	114	205	2	63	593	5,197	4,486
TI	40	LESS:											
TI	41	PA State Income Taxes	CALCULATED	(3,527)	(2,806)	(687)	4	(1)	0	3	26	(116)	50
TI	42	Federal Tax Depreciation (Over) Under Book	TOTPLT	(4,332)	(2,925)	(1,146)	(1)	(5)	(0)	(0)	(1)	(174)	(79)
TI	43	Total Tax Adjustments	SCH TI, LN 21	185,617	125,526	48,910	29	219	1	5	54	7,489	3,383
TI	44	FEDERAL TAXALBE DISTRIBUTION INCOME		(62,592)	(50,697)	(11,668)	81	(8)	2	55	514	(2,002)	1,131
TI	45	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		13,144	10,646	2,450	(17)	2	(0)	(12)	(108)	420	(238)
TI	46												
TI	47												
TI	48												
TI	49												
TI	50												
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**											
TI	52												
TI	53	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**	SCH TI, LN 45	13,144	10,646	2,450	(17)	2	(0)	(12)	(108)	420	(238)
TI	54	**PLUS: DEFERRED FEDERAL INCOME TAXES**											
TI	55	Deferred Taxes on Timing Differences - Federal	TOTPLT	(5,037)	(3,402)	(1,333)	(1)	(6)	(0)	(0)	(1)	(202)	(91)
TI	56	Excess Deferred Amortization	TOTPLT	3,023	2,042	800	0	4	0	0	1	121	55
TI	57	FIT Expense on Flow Through Adjustments	TOTPLT	(951)	(642)	(252)	(0)	(1)	(0)	(0)	(0)	(38)	(17)
TI	58	**LESS: OTHER FEDERAL TAX ADJUSTMENTS**											
TI	59	Amortization of ITC - Gas Plant	TOTPLT	(5)	(3)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
TI	60	**TOTAL FEDERAL INCOME TAX EXPENSE**		10,184	8,647	1,667	(18)	(2)	(0)	(12)	(109)	301	(291)
TI	61	**TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS**		14,297	11,849	2,509	(21)	(0)	(0)	(14)	(134)	441	(331)
TI	62												
TI	63	**DEVELOPMENT OF PURCHASED GAS TAXES**											
TI	64	PURCHASED GAS OPERATING REVENUES		260,915	193,890	64,687	107	1,483	9	84	656	0	0
TI	65	LESS:											
TI	66	OPERATION & MAINTAINENCE EXPENSE		260,932	193,902	64,692	107	1,483	9	84	656	0	0
TI	67	NET OPERATING INCOME BEFORE TAXES		(17)	(12)	(5)	0	(0)	0	0	0	(0)	(0)
TI	68	LESS:											
TI	69	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		214	161	51	0	1	0	0	1	0	0
TI	70	**BASE TAXABLE PURCHASED GAS INCOME**		(231)	(173)	(55)	(0)	(1)	(0)	(0)	(1)	(0)	(0)
TI	71	LESS:											
TI	72	**PA STATE PURCHASED GAS INCOME TAXES @ Tax Rate 7.99%**		(18)	(14)	(4)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
TI	73	Net Operating Loss Utilization	CALCULATED	7	6	2	0	0	0	0	0	0	0
TI	74	**TOTAL STATE INCOME TAX**		11	8	3	0	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TI	75	EQUALS:											
TI	76	**FEDERAL PURCHASED GAS INCOME TAXES @ Tax Rate 21.00%**		46	35	11	0	0	0	0	0	0	0
TI	77												
TI	78	**TOTAL PA INCOME TAX EXPENSE**		4,125	3,211	845	(4)	2	(0)	(3)	(26)	139	(39)
TI	79	**TOTAL FEDERAL INCOME TAX EXPENSE**		10,230	8,682	1,678	(18)	(2)	(0)	(12)	(109)	302	(291)
TI	80	**TOTAL INCOME TAX EXPENSE**		14,354	11,892	2,523	(21)	(0)	(0)	(14)	(134)	441	(331)
TI	81												
TI	82	**TOTAL OTHER TAX EXPENSE**		9,067	6,373	2,184	2	11	0	0	3	341	153
TI	83												
TI	84	**TOTAL TAX EXPENSE**		23,422	18,265	4,707	(20)	11	(0)	(14)	(131)	782	(178)
TI	85												
TI	86												
TI	87												
TI	88												
TI	89												
TI	90	**TAX RATES & FACTORS**											
TI	91	GROSS RECEIPTS TAX RATE	0.00%										
TI	92	STATE TAX RATE	7.99%										
TI	93	FEDERAL TAX RATE - CURRENT	21.00%										
TI	94												
TI	95	LPC REVENUE FACTOR	0.00161										
TI	96	GROSS REVENUE CONVERSION FACTOR	1.38289										
TI	97	UNCOLLECTIBLES EXPENSE FACTOR	0.00369										
TI	98	PUC / OTS & SBA FEE AS % OF REV FACTOR	0.00309										
TI	99	WEIGHTED COST OF DEBT	2.13%										
TI	100												
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**											
SW	2												
SW	3	**PRODUCTION SALARIES & WAGES EXPENSE**											
SW	4	Manufactured Gas Production Expense											
SW	5	Operation - Acct 717	OX_PRODM	80	54	26	0	0	0	0	0	0	0
SW	6	Maintenance - Accts 741-742	MX_PRODM	179	120	58	0	0	0	0	0	0	0
SW	7	Total Manufactured Gas Production Expense		259	174	84	0	1	0	0	0	0	0
SW	8												
SW	9	Other Gas Supply Expense											
SW	10	Operation - Accounts 804-808	OX_PRODO	0	0	0	0	0	0	0	0	0	0
SW	11	Total Other Gas Supply		0	0	0	0	0	0	0	0	0	0
SW	12	TOTAL PRODUCTION S&W EXP		259	174	84	0	1	0	0	0	0	0
SW	13												
SW	14	**STORAGE SALARIES & WAGES EXPENSE**											
SW	15	Operation - Accts 840-841	OX_STOR	678	457	219	0	1	0	0	0	0	0
SW	16	Maintenance - Acct 843	MX_STOR	2,108	1,421	682	1	4	0	0	0	0	0
SW	17	TOTALSTORAGE S&W EXP		2,786	1,878	902	1	6	0	0	0	0	0
SW	18												
SW	19	**TRANSMISSION SALARIES & WAGES EXPENSE**											
SW	20	Operation	OX_TRAN	0	0	0	0	0	0	0	0	0	0
SW	21	Maintenance	MX_TRAN	0	0	0	0	0	0	0	0	0	0
SW	22	TOTAL TRANSMISSION S&W EXP		0	0	0	0	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
SW	23												
SW	24	**DISTRIBUTION SALARIES & WAGES EXPENSE**											
SW	25	Operation											
SW	26	874-Mains and Services Expenses	OX_874	6,263	4,216	1,661	1	7	0	0	2	266	109
SW	27	875-Measuring & Reg. Station Exp.-General	OX_875	1,228	750	360	0	2	0	0	0	82	33
SW	28	878-Meter & House Regulator Expenses	OX_878	2,012	1,446	478	0	2	0	0	1	44	41
SW	29	879-Customer Installations Expenses	OX_879	5,612	5,148	458	0	0	0	0	0	4	2
SW	30	880-Other Expenses	OX_880	4,291	2,896	1,125	1	5	0	0	1	181	82
SW	31	880-Other Expenses - GPC	E880DA	0	0	0	0	0	0	0	0	0	0
SW	32	Total Operation		19,406	14,456	4,083	2	16	0	0	5	576	267
SW	33	Maintenance											
SW	34	887-Maintenance of Mains	MX_887	12,525	7,646	3,673	3	23	0	1	5	836	340
SW	35	889-Maint. of Measuring & Reg. Station Equip.-Gen	MX_889	770	470	226	0	1	0	0	0	51	21
SW	36	892-Maintenance of Services	MX_892	1,334	1,038	291	0	0	0	0	0	3	1
SW	37	893-Maint. of Meters & House Regulators	MX_893	154	111	37	0	0	0	0	0	3	3
SW	38	894-Maintenance of Other Equipment	MX_894	124	83	32	0	0	0	0	0	5	2
SW	39	Total Distribution Maintenance		14,907	9,348	4,259	3	25	0	1	5	898	367
SW	40	TOTAL DISTRIBUTION S&W EXP		34,313	23,804	8,342	5	41	0	1	10	1,475	635
SW	41	TOTAL OPER & MAINT S&W EXP (PROD, STOR, TRAN,& DIST)		37,358	25,857	9,327	6	47	0	1	10	1,475	635
SW	42												
SW	43												
SW	44												
SW	45												
SW	46												
SW	47												
SW	48												
SW	49												
SW	50												
SW	51	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR CONTINUED**											
SW	52												
SW	53	CUSTOMER ACCOUNTS EXPENSES											
SW	54	902-Meter Reading	CMETRDG	0	0	0	0	0	0	0	0	0	0
SW	55	903-Customer Records and Collection Expense	CUSTREC	7,338	6,362	655	4	2	0	1	2	202	111
SW	56	904-Uncollectible Accounts	EXP_904	0	0	0	0	0	0	0	0	0	0
SW	57	904-Uncollectible Accounts - PPA	EXP_904	0	0	0	0	0	0	0	0	0	0
SW	58	904-Uncollectible Accounts - MFC/POR	E904DA	0	0	0	0	0	0	0	0	0	0
SW	59	905-Miscellaneous CA	CUSTCAM	245	225	20	0	0	0	0	0	0	0
SW	60	TOTAL CUSTOMER ACCTS S&W EXPENSE		7,583	6,587	675	4	2	0	1	2	202	111
SW	61												
SW	62	CUSTOMER SERVICE & SALES EXPENSES											
SW	63	908-Customer Assistance	CUSTASST	397	378	8	0	0	0	0	0	7	4
SW	64	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0	0	0
SW	65	910-Miscellaneous CS	CUSTCSM	42	40	1	0	0	0	0	0	1	0
SW	66	912-Demonstrating and Selling Expenses	CUSTSALES	298	284	6	0	0	0	0	0	6	3
SW	67	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0	0	0	0	0
SW	68	TOTAL CUST SERVICE & SALES S&W EXP		737	701	14	0	0	0	0	0	14	8
SW	69												
SW	70	TOTAL OPER & MAINT S&W EXP EXCL A&G		45,678	33,145	10,016	10	49	0	2	12	1,691	753

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
SW	71												
SW	72	ADMINISTRATIVE & GENERAL EXPENSE											
SW	73	920-Administrative Salaries	SALWAGXAG	6,396	4,641	1,403	1	7	0	0	2	237	105
SW	74	921-Office Supplies & Expense	SALWAGXAG	0	0	0	0	0	0	0	0	0	0
SW	75	923-Outside Service Employed	SALWAGXAG	0	0	0	0	0	0	0	0	0	0
SW	76	924-Property Insurance	PSTDGPLT	0	0	0	0	0	0	0	0	0	0
SW	77	925-Injuries and Damages	SALWAGXAG	160	116	35	0	0	0	0	0	6	3
SW	78	926-Employee Pensions & Benefits	SALWAGXAG	0	0	0	0	0	0	0	0	0	0
SW	79	928-Regulatory Commission	CLAIMREV	0	0	0	0	0	0	0	0	0	0
SW	80	929-Duplicate Charges-Credit	CLAIMREV	0	0	0	0	0	0	0	0	0	0
SW	81	930.1-General Advertising	SALWAGXAG	0	0	0	0	0	0	0	0	0	0
SW	82	930.2-Miscellaneous General	SALWAGXAG	9	7	2	0	0	0	0	0	0	0
SW	83	932-Maintenance of General Plant	GENLPLT	228	166	50	0	0	0	0	0	8	4
SW	84	TOTAL A&G S&W EXPENSE		6,794	4,930	1,490	2	7	0	0	2	252	112
SW	85												
SW	86	**TOTAL OPER & MAINTENANCE SALARIES & WAGES EXP**		52,472	38,074	11,506	12	56	0	2	13	1,943	865
SW	87												
SW	88												
SW	89												
SW	90												
SW	91												
SW	92												
SW	93												
SW	94												
SW	95												
SW	96												
SW	97												
SW	98												
SW	99												
SW	100												
AF	1	**ALLOCATION FACTOR TABLE**											
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	3												
AF	4	**CAPACITY**											
AF	5	CAPACITY - PRODUCTION RELATED (LPG)											
AF	6	Capacity Production - Design Peak Day Sendout	DPKDAYP	912,000	614,831	295,129	233	1,807	0	0	0	0	0
AF	7												
AF	8												
AF	9	CAPACITY - STORAGE RELATED (LNG)											
AF	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS	912,000	614,831	295,129	233	1,807	0	0	0	0	0
AF	11												
AF	12												
AF	13												
AF	14	CAPACITY - TRANSMISSION RELATED											
AF	15	Capacity Transmission - Design Peak Day Sendout	DTRAN	912,000	614,831	295,129	233	1,807	0	0	0	0	0
AF	16												
AF	17												
AF	18												

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	19												
AF	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincident Peak Capacity)											
AF	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	739,136	479,108	222,561	170	416	0	0	0	36,881	0
AF	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	15,529	0	0	0	0	0	0	0	[redacted]	
AF	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	2,855	0	0	0	0	0	0	0	402	2,452
AF	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	222	0	0	0	0	0	0	0	116	105
AF	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY	912,000	614,831	295,129	233	1,807	0	0	0	0	0
AF	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR	11,399	0	0	0	0	0	0	0	[redacted]	
AF	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	3,423	0	0	0	0	0	0	0	436	2,987
AF	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	228	0	0	0	0	0	0	0	126	102
AF	29												
AF	30	Capacity Avg Daily Del excl Direct	DAVGDD	236,211	120,184	65,349	58	1,377	3	45	354	25,270	23,571
AF	31												
AF	32												
AF	33												
AF	34												
AF	35												
AF	36												
AF	37												
AF	38												
AF	39												
AF	40												
AF	41												
AF	42												
AF	43												
AF	44												
AF	45												
AF	46												
AF	47												
AF	48												
AF	49												
AF	50												
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	53												
AF	54	**COMMODITY**											
AF	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
AF	56	Annual Gas Deliveries - Firm	ETHRUPUTF	80,117,169	43,867,240	23,852,516	21,000	502,606	0	0	0	11,873,807	0
AF	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT	25,211,944	0	0	0	0	0	0	0	11,873,807	13,338,137
AF	58												
AF	59	Commodity Gas Storage	ESTORAGE	1.0000	0.6947	0.2872	0.0000	0.0003	0.0000	0.0000	0.0000	0.0084	0.0094
AF	60												
AF	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA	1,742	1,119	609	1	13	0	0	0	0	0
AF	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA	1,200	1,057	143	0	0	0	0	0	0	0
AF	63	Total Account 880DA and 904DA	OX_880904DA	2,942	2,176	752	1	13	0	0	0	0	0
AF	64												
AF	65												
AF	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA	-	0	0	0	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	67												
AF	68	Annual Gas Cost (PGC)	EGAS	234,407	176,887	55,442	99	1,289	8	77	606	0	0
AF	69	Commodity - Balancing Service Charge (BSC)	EBSC	26,508	17,003	9,245	8	194	1	6	50	0	0
AF	70												
AF	71	**CUSTOMER**											
AF	72	380-Services	CSERVICE	4,425,936	3,444,722	967,241	170	318	21	21	419	8,465	4,558
AF	73	381-Meters (Avg Cost per meter)	CMETERS	244,046	176,643	58,391	19	215	2	3	164	4,861	3,750
AF	74	381-Meters Direct Assignment	CMETERSDA	583	0	0	0	0	0	0	0	[redacted]	
AF	75	382-Meters Installations Direct Assignment	CMETINSTDA	2,764	0	0	0	0	0	0	0		
AF	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA	63	0	0	0	0	0	0	0	28	35
AF	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA	332	0	0	0	0	0	0	0	52	280
AF	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE	15	0	0	0	0	0	0	0	8	7
AF	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE	69	0	0	0	0	0	0	0	15	54
AF	80												
AF	81	Customer Deposits	CUSTDEP	10,867	3,310	7,265	4	2	0	0	3	182	100
AF	82	Customer Deposits Interest	CUSTDEPINT	650	265	371	0	0	0	0	0	9	5
AF	83												
AF	84	879-Customer Installation Expense	CUSTINSTALL	558,912	512,659	45,589	8	15	1	1	20	400	219
AF	85	902-Meter Reading Expense	CMETRDG	558,912	512,659	45,589	8	15	1	1	20	400	219
AF	86	903-Customer Records and Collections	CUSTREC	1.0000	0.8670	0.0892	0.0005	0.0003	0.0000	0.0001	0.0002	0.0276	0.0152
AF	87	905-Miscellaneous Customer Accounts	CUSTCAM	558,912	512,659	45,589	8	15	1	1	20	400	219
AF	88	908-Customer Assistance	CUSTASST	1.0000	0.9516	0.0191	0.0004	0.0000	0.0000	0.0000	0.0000	0.0187	0.0102
AF	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0	0	0	0	0	0	0	0	0	0
AF	90	909-Informational and Instructional Advertising	CUSTADVT	1.0000	0.9516	0.0191	0.0004	0.0000	0.0000	0.0000	0.0000	0.0187	0.0102
AF	91	910-Miscellaneous Customer Service	CUSTCSM	1.0000	0.9516	0.0191	0.0004	0.0000	0.0000	0.0000	0.0000	0.0187	0.0102
AF	92	916-Miscellaneous Sales Expense	CUSTSALES	1.0000	0.9516	0.0191	0.0004	0.0000	0.0000	0.0000	0.0000	0.0187	0.0102
AF	93												
AF	94	Number of Bills	CUSTBILLS	6,706,945	6,151,911	547,071	96	180	12	12	237	4,800	2,626
AF	95	Number of Customers (Average Annual)	CUST	558,912	512,659	45,589	8	15	1	1	20	400	219
AF	96												
AF	97	Gas Energy Efficiency Program	CSEHPDA	321	350	(29)	0	0	0	0	0	0	0
AF	98												
AF	99												
AF	100												
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	103	**Plant Related**											
AF	104	Intangible Plant	INTPLT	16,406	11,079	4,342	3	19	0	0	5	659	298
AF	105	Production Plant	PRODPLT	15,559	10,489	5,035	4	31	0	0	0	0	0
AF	106	Storage Plant	STORPLT	193,629	130,536	62,659	49	384	0	0	0	0	0
AF	107	Transmission Plant in Service	TRANPLT	0	0	0	0	0	0	0	0	0	0
AF	108	Distribution Plant in Service	DISTPLT	4,368,523	2,948,627	1,145,541	662	5,022	17	125	1,338	184,030	83,161
AF	109	General Plant in Service	GENLPLT	35,933	26,074	7,879	8	39	0	1	9	1,330	593
AF	110	Total Gas Plant In Service	TOTPLT	4,630,050	3,126,806	1,225,457	726	5,495	17	127	1,352	186,019	84,052
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	4,367,639	2,948,030	1,145,309	662	5,021	17	125	1,338	183,992	83,144
AF	112	Total Transmission and Distribution Plant	TDPLT	4,368,523	2,948,627	1,145,541	662	5,022	17	125	1,338	184,030	83,161
AF	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	4,613,644	3,115,726	1,221,114	724	5,475	17	127	1,347	185,360	83,754
AF	114	Total Distribution and General Plant	DGPLT	4,404,456	2,974,701	1,153,420	670	5,061	17	127	1,347	185,360	83,754

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	115	Rate Base	RATEBASE	3,524,006	2,387,003	923,590	566	4,237	13	102	1,019	145,891	61,585
AF	116	Distribution Plant in Service - Capacity Related	DDISTPLT	2,457,334	1,493,032	717,279	567	4,467	7	112	882	169,561	71,426
AF	117												
AF	118	Account 374	PLT_374	3,915	2,378	1,143	1	7	0	0	1	270	114
AF	119	Account 375	PLT_375	16,785	10,198	4,899	4	31	0	1	6	1,158	488
AF	120	Account 376-General Excess	PLT_376GE	1,784,138	1,156,478	537,221	411	1,004	0	0	0	89,024	0
AF	121	Account 376-General Average	PLT_376GA	570,169	290,102	157,741	139	3,324	7	109	855	[redacted]	
AF	122	Account 376-DA	PLT_376DA	15,529	0	0	0	0	0	0	0		
AF	123	Account 376	PLT_376	2,369,836	1,446,581	694,963	549	4,328	7	109	855	158,172	64,273
AF	124	Account 378	PLT_378	26,029	15,889	7,633	6	48	0	1	9	1,737	706
AF	125	Account 379-City Gate	PLT_379CG	50,069	30,563	14,683	12	91	0	2	18	[redacted]	
AF	126	Account 379-DA	PLT_379DA	11,399	0	0	0	0	0	0	0		
AF	127	Account 379	PLT_379	61,468	30,563	14,683	12	91	0	2	18	9,651	6,448
AF	128	Account 380	PLT_380	1,417,248	1,103,049	309,725	54	102	7	7	134	2,711	1,459
AF	129	Account 381	PLT_381	179,005	129,144	42,689	14	157	1	2	120	3,865	3,014
AF	130	Account 382	PLT_382	291,268	208,822	69,028	22	255	2	3	193	6,340	6,603
AF	131	Account 387	PLT_387	2,084	1,407	547	0	2	0	0	1	88	40
AF	132	Account 388-Asset Retirement Costs for Distribution	PLT_388	884	597	232	0	1	0	0	0	37	17
AF	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	2,457,334	1,493,032	717,279	567	4,467	7	112	882	169,561	71,426
AF	134	Accounts 376 & 380 - Mains & Services	PLT_376380	3,787,085	2,549,630	1,004,687	604	4,430	14	116	989	160,883	65,732
AF	135	Accounts 380 & 381 - Services & Meters	PLT_380381	1,596,253	1,232,193	352,414	68	259	8	9	254	6,575	4,473
AF	136	Accounts 374 & 375 - Land & Structures	PLT_374375	20,699	12,577	6,042	5	38	0	1	7	1,428	602
AF	137	Accounts 381 through 385	PLT_3815	470,273	337,965	111,717	36	412	3	5	313	10,205	9,617
AF	138	Accounts 378, 379, & 387	PLT_378387	89,582	47,858	22,863	18	141	0	4	28	11,476	7,194
AF	139												
AF	140	Residential	DPLTRES	2,596,082	2,596,082	0	0	0	0	0	0	0	0
AF	141	Small Commercial and Industrilal	DPLTCI	1,027,003	0	1,027,003	0	0	0	0	0	0	0
AF	142	Large High Load Factor	DPLTLHLF	621	0	0	621	0	0	0	0	0	0
AF	143	Motor Vehicle - Firm	DPLTMVF	4,569	0	0	0	4,569	0	0	0	0	0
AF	144	Motor Vehicle - Interruptible	DPLTMVI	14	0	0	0	0	14	0	0	0	0
AF	145	Interruptible Service	DPLTIS	119	0	0	0	0	0	119	0	0	0
AF	146	Temperature Control	DPLTTC	1,016	0	0	0	0	0	0	1,016	0	0
AF	147	Transportation Service - Firm	DPLTTSF	172,271	0	0	0	0	0	0	0	172,271	0
AF	148	Transportation Service - Interruptible	DPLTTSI	72,886	0	0	0	0	0	0	0	0	72,886
AF	149												
AF	150												
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	153												
AF	154	**Production Expense Related**											
AF	155	Account 717	OX_717	129	87	42	0	0	0	0	0	0	0
AF	156	Account 741	MX_741	86	58	28	0	0	0	0	0	0	0
AF	157	Account 742	MX_742	215	145	70	0	0	0	0	0	0	0
AF	158	Manufactured Gas Production Operation Expense	OX_PRODM	137	92	44	0	0	0	0	0	0	0
AF	159	Manufactured Gas Production Maintenance Expense	MX_PRODM	302	203	98	0	1	0	0	0	0	0
AF	160	Other Production Operation Expense	OX_PRODO	260,932	193,902	64,692	107	1,483	9	84	656	0	0
AF	161												
AF	162												

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	163	**Storage Expense Related**											
AF	164	Storage Operation Expense	OX_STOR	1,292	871	418	0	3	0	0	0	0	0
AF	165	Storage Maintenance Expense	MX_STOR	5,043	3,400	1,632	1	10	0	0	0	0	0
AF	166												
AF	167												
AF	168	**Transmission Expense Related**											
AF	169	Transmission Operation Expense	OX_TRAN	0	0	0	0	0	0	0	0	0	0
AF	170	Transmission Maintenance Expense	MX_TRAN	0	0	0	0	0	0	0	0	0	0
AF	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0	0	0	0	0	0	0	0	0	0
AF	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0	0	0	0	0	0	0	0	0	0
AF	173												
AF	174												
AF	175	**Distribution Expense Related**											
AF	176	Account 874	OX_874	19,001	12,793	5,041	3	22	0	1	5	807	330
AF	177	Account 875	OX_875	1,901	1,161	558	0	3	0	0	1	127	52
AF	178	Account 878	OX_878	7,627	5,481	1,812	1	7	0	0	5	166	156
AF	179	Account 879	OX_879	8,140	7,467	664	0	0	0	0	0	6	3
AF	180	Account 880	OX_880	19,955	13,469	5,233	3	23	0	1	6	841	380
AF	181	Account 887	MX_887	26,734	16,319	7,840	6	49	0	1	10	1,784	725
AF	182	Account 889	MX_889	1,537	938	451	0	3	0	0	1	103	42
AF	183	Account 892	MX_892	2,864	2,229	626	0	0	0	0	0	5	3
AF	184	Account 893	MX_893	243	175	58	0	0	0	0	0	5	5
AF	185	Account 894	MX_894	680	459	178	0	1	0	0	0	29	13
AF	186	O&M Accounts 870-880	OX_DIST	55,422	39,652	12,811	6	43	0	1	17	1,962	928
AF	187	O&M Accounts 887-894	MX_DIST	32,058	20,120	9,153	7	53	0	1	11	1,926	788
AF	188												
AF	189												
AF	190												
AF	191												
AF	192												
AF	193												
AF	194												
AF	195												
AF	196												
AF	197												
AF	198												
AF	199												
AF	200												
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	203												
AF	204	**Customer Distribution Expense Related**											
AF	205	Account 902	OX_902	163	149	13	0	0	0	0	0	0	0
AF	206	Account 903	OX_903	20,632	17,887	1,841	11	6	0	2	4	569	313
AF	207	Account 904	OX_904	2,378	2,158	206	1	2	0	0	2	6	3
AF	208	O&M Accounts 902-905	OX_CA	24,173	21,112	2,142	11	7	0	2	6	576	317
AF	209												
AF	210	Account908	OX_908	7,183	6,836	137	3	0	0	0	0	134	73

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	211	Account909	OX_909	345	329	7	0	0	0	0	0	6	4
AF	212	Account910	OX_910	54	52	1	0	0	0	0	0	1	1
AF	213	O&M Accounts 908-910	OX_CS	7,583	7,216	145	3	0	0	0	0	142	78
AF	214	Accounts 901-916	X_CACS	32,530	29,064	2,301	14	8	0	2	6	732	402
AF	215												
AF	216	Total O&M less Purchased Gas	OMXPP	167,687	123,018	35,534	38	166	1	7	47	6,100	2,776
AF	217												
AF	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	104,154	76,486	21,918	24	99	0	4	30	3,830	1,764
AF	219												
AF	220	Base Taxable Income	EBT	114,935	68,925	35,353	114	204	2	63	592	5,197	4,485
AF	221												
AF	222												
AF	223	**Salaries and Wages Expense Related**											
AF	224	Salaries & Wages Accounts 870-880	SALWAGDO	19,406	14,456	4,083	2	16	0	0	5	576	267
AF	225	Salaries & Wages Accounts 887-894	SALWAGDM	14,907	9,348	4,259	3	25	0	1	5	898	367
AF	226	Salaries & Wages Accounts 902-905	SALWAGCA	7,583	6,587	675	4	2	0	1	2	202	111
AF	227	Salaries & Wages Accounts 908-910	SALWAGCS	439	417	8	0	0	0	0	0	8	4
AF	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	45,678	33,145	10,016	10	49	0	2	12	1,691	753
AF	229	Total Salaries and Wages Expense	SALWAGES	52,472	38,074	11,506	12	56	0	2	13	1,943	865
AF	230												
AF	231												
AF	232												
AF	233												
AF	234												
AF	235												
AF	236												
AF	237												
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AF	243												
AF	244												
AF	245												
AF	246												
AF	247												
AF	248												
AF	249												
AF	250												
AF	251	**REVENUES AND BILLING DETERMINANTS**											
AF	252												
AF	253	Base Rate Sales Revenue	SALESREV	481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
AF	254												
AF	255	Residential	SREVRES	327,766	327,766	0	0	0	0	0	0	0	0
AF	256	Small Commercial and Industrilal	SREVCI	122,676	0	122,676	0	0	0	0	0	0	0
AF	257	Large High Load Factor	SREVLHLF	184	0	0	184	0	0	0	0	0	0
AF	258	Motor Vehicle - Firm	SREVMVF	611	0	0	0	611	0	0	0	0	0

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	259	Motor Vehicle - Interruptible	SREVMVI	4	0	0	0	0	4	0	0	0	0
AF	260	Interruptible Service	SREVIS	75	0	0	0	0	0	75	0	0	0
AF	261	Temperature Control	SREVTC	697	0	0	0	0	0	0	697	0	0
AF	262	Transportation Service - Firm	SREVTSF	19,121	0	0	0	0	0	0	0	19,121	0
AF	263	Transportation Service - Interruptible	SREVTSI	10,848	0	0	0	0	0	0	0	0	10,848
AF	264												
AF	265												
AF	266	Claimed Rate Sales Revenue	CLAIMREV	854,065	606,302	210,980	210	2,160	11	100	803	23,328	10,170
AF	267												
AF	268												
AF	269												
AF	270												
AF	271												
AF	272	**PRESENT REVENUES FROM SALES INPUT**											
AF	273												
AF	274	Total Sales of Gas Revenues		742,897	521,656	187,363	291	2,094	12	158	1,353	19,121	10,848
AF	275	Sales of Gas Revenues - Distribution		481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
AF	276	Sales of Gas Revenues - PGC		234,407	176,887	55,442	99	1,289	8	77	606	0	0
AF	277	Sales of Gas Revenues - BSC		26,508	17,003	9,245	8	194	1	6	50	0	0
AF	278												
AF	279												
AF	280	Sales of Gas Revenues - Transmission		0	0	0	0	0	0	0	0	0	0
AF	281												
AF	282												
AF	283	**BILLING DETERMINATE INPUTS**											
AF	284	Number of Customer Bills	SCH AF, LN 94	6,706,945	6,151,911	547,071	96	180	12	12	237	4,800	2,626
AF	285	Annual Booked Throughput Sales (Mcf)	SCH AF, LN 55	93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
AF	286												
AF	287												
AF	288												
AF	289	**RATE OF RETURN**											
AF	290	Rate of Return (Equalized)	SCH AF, LN 290	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
AF	291												
AF	292												
AF	293												
AF	294												
AF	295												
AF	296												
AF	297												
AF	298												
AF	299												
AF	300												
AP	1	**ALLOCATION PROPORTIONS TABLE**											
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	3												
AP	4	**CAPACITY**											
AP	5	CAPACITY - PRODUCTION RELATED (LPG)											
AP	6	Capacity Production - Design Peak Day Sendout	DPKDAYP	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	7												
AP	8												
AP	9	CAPACITY - STORAGE RELATED (LNG)											
AP	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	11												
AP	12												
AP	13												
AP	14	CAPACITY - TRANSMISSION RELATED											
AP	15	Capacity Transmission - Design Peak Day Sendout	DTRAN	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	16												
AP	17												
AP	18												
AP	19												
AP	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincident Peak Capacity)											
AP	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	1.00000	0.64820	0.30111	0.00023	0.00056	0.00000	0.00000	0.00000	0.04990	0.00000
AP	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	[redacted]	
AP	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.14097	0.85903
AP	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.52493	0.47507
AP	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	[redacted]	
AP	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.12743	0.87257
AP	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.55348	0.44652
AP	29												
AP	30	Capacity Avg Daily Del excl Direct	DAVGDD	1.00000	0.50880	0.27666	0.00024	0.00583	0.00001	0.00019	0.00150	0.10698	0.09979
AP	31												
AP	32												
AP	33												
AP	34												
AP	35												
AP	36												
AP	37												
AP	38												
AP	39												
AP	40												
AP	41												
AP	42												
AP	43												
AP	44												
AP	45												
AP	46												
AP	47												
AP	48												
AP	49												
AP	50												
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	53												
AP	54	**COMMODITY**											

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	1.00000	0.46866	0.25483	0.00022	0.00537	0.00001	0.00018	0.00138	0.12685	0.14250
AP	56	Annual Gas Deliveries - Firm	ETHRUPUTF	1.00000	0.54754	0.29772	0.00026	0.00627	0.00000	0.00000	0.00000	0.14821	0.00000
AP	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.47096	0.52904
AP	58												
AP	59	Commodity Gas Storage	ESTORAGE	1.00000	0.69467	0.28718	0.00000	0.00035	0.00000	0.00000	0.00000	0.00838	0.00942
AP	60												
AP	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA	1.00000	0.64237	0.34960	0.00057	0.00746	0.00000	0.00000	0.00000	0.00000	0.00000
AP	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA	1.00000	0.88083	0.11917	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	63	Total Account 880DA and 904DA	OX_880904DA	1.00000	0.73963	0.25561	0.00034	0.00442	0.00000	0.00000	0.00000	0.00000	0.00000
AP	64												
AP	65												
AP	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67												
AP	68	Annual Gas Cost (PGC)	EGAS	1.00000	0.75461	0.23652	0.00042	0.00550	0.00003	0.00033	0.00258	0.00000	0.00000
AP	69	Commodity - Balancing Service Charge (BSC)	EBSC	1.00000	0.64143	0.34877	0.00031	0.00732	0.00004	0.00024	0.00189	0.00000	0.00000
AP	70												
AP	71	**CUSTOMER**											
AP	72	380-Services	CSERVICE	1.00000	0.77830	0.21854	0.00004	0.00007	0.00000	0.00000	0.00009	0.00191	0.00103
AP	73	381-Meters (Avg Cost per meter)	CMETERS	1.00000	0.72381	0.23926	0.00008	0.00088	0.00001	0.00001	0.00067	0.01992	0.01537
AP	74	381-Meters Direct Assignment	CMETERSDA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	[redacted]	
AP	75	382-Meters Installations Direct Assignment	CMETINSTDA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		
AP	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.44389	0.55611
AP	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.15615	0.84385
AP	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.53353	0.46647
AP	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.21501	0.78499
AP	80												
AP	81	Customer Deposits	CUSTDEP	1.00000	0.30460	0.66860	0.00033	0.00022	0.00001	0.00004	0.00029	0.01674	0.00916
AP	82	Customer Deposits Interest	CUSTDEPINT	1.00000	0.40726	0.56990	0.00029	0.00019	0.00001	0.00004	0.00025	0.01427	0.00780
AP	83												
AP	84	879-Customer Installation Expense	CUSTINSTALL	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	85	902-Meter Reading Expense	CMETRDG	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	86	903-Customer Records and Collections	CUSTREC	1.00000	0.86696	0.08924	0.00052	0.00028	0.00000	0.00007	0.00021	0.02757	0.01515
AP	87	905-Miscellaneous Customer Accounts	CUSTCAM	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	88	908-Customer Assistance	CUSTASST	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	90	909-Informational and Instructional Advertising	CUSTADVT	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	91	910-Miscellaneous Customer Service	CUSTCSM	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	92	916-Miscellaneous Sales Expense	CUSTSALES	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	93												
AP	94	Number of Bills	CUSTBILLS	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	95	Number of Customers (Average Annual)	CUST	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	96												
AP	97	Gas Energy Efficiency Program	CSEHPDA	1.00000	1.08975	-0.08975	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	98												
AP	99												
AP	100												
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	103	**Plant Related**											
AP	104	Intangible Plant	INTPLT	1.00000	0.67533	0.26467	0.00016	0.00119	0.00000	0.00003	0.00029	0.04018	0.01815
AP	105	Production Plant	PRODPLT	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	106	Storage Plant	STORPLT	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	107	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	108	Distribution Plant in Service	DISTPLT	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	109	General Plant in Service	GENLPLT	1.00000	0.72562	0.21928	0.00022	0.00108	0.00000	0.00004	0.00025	0.03702	0.01649
AP	110	Total Gas Plant In Service	TOTPLT	1.00000	0.67533	0.26467	0.00016	0.00119	0.00000	0.00003	0.00029	0.04018	0.01815
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	112	Total Transmission and Distribution Plant	TDPLT	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	1.00000	0.67533	0.26467	0.00016	0.00119	0.00000	0.00003	0.00029	0.04018	0.01815
AP	114	Total Distribution and General Plant	DGPLT	1.00000	0.67538	0.26188	0.00015	0.00115	0.00000	0.00003	0.00031	0.04208	0.01902
AP	115	Rate Base	RATEBASE	1.00000	0.67735	0.26209	0.00016	0.00120	0.00000	0.00003	0.00029	0.04140	0.01748
AP	116	Distribution Plant in Service - Capacity Related	DDISTPLT	1.00000	0.60758	0.29189	0.00023	0.00182	0.00000	0.00005	0.00036	0.06900	0.02907
AP	117												
AP	118	Account 374	PLT_374	1.00000	0.60758	0.29189	0.00023	0.00182	0.00000	0.00005	0.00036	0.06900	0.02907
AP	119	Account 375	PLT_375	1.00000	0.60758	0.29189	0.00023	0.00182	0.00000	0.00005	0.00036	0.06900	0.02907
AP	120	Account 376-General Excess	PLT_376GE	1.00000	0.64820	0.30111	0.00023	0.00056	0.00000	0.00000	0.00000	0.04990	0.00000
AP	121	Account 376-General AverageAccount 376-General Average	PLT_376GA	1.00000	0.50880	0.27666	0.00024	0.00583	0.00001	0.00019	0.00150	[redacted]	
AP	122	Account 376-DA	PLT_376DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		
AP	123	Account 376	PLT_376	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	0.06674	0.02712
AP	124	Account 378	PLT_378	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	0.06674	0.02712
AP	125	Account 379-City Gate	PLT_379CG	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	[redacted]	
AP	126	Account 379-DA	PLT_379DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		
AP	127	Account 379	PLT_379	1.00000	0.49721	0.23887	0.00019	0.00149	0.00000	0.00004	0.00029	0.15701	0.10490
AP	128	Account 380	PLT_380	1.00000	0.77830	0.21854	0.00004	0.00007	0.00000	0.00000	0.00009	0.00191	0.00103
AP	129	Account 381	PLT_381	1.00000	0.72145	0.23848	0.00008	0.00088	0.00001	0.00001	0.00067	0.02159	0.01684
AP	130	Account 382	PLT_382	1.00000	0.71694	0.23699	0.00008	0.00087	0.00001	0.00001	0.00066	0.02177	0.02267
AP	131	Account 387	PLT_387	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	132	Account 388-Asset Retirement Costs for Distribution	PLT_388	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	1.00000	0.60758	0.29189	0.00023	0.00182	0.00000	0.00005	0.00036	0.06900	0.02907
AP	134	Accounts 376 & 380 - Mains & Services	PLT_376380	1.00000	0.67324	0.26529	0.00016	0.00117	0.00000	0.00003	0.00026	0.04248	0.01736
AP	135	Accounts 380 & 381 - Services & Meters	PLT_380381	1.00000	0.77193	0.22078	0.00004	0.00016	0.00000	0.00001	0.00016	0.00412	0.00280
AP	136	Accounts 374 & 375 - Land & Structures	PLT_374375	1.00000	0.60758	0.29189	0.00023	0.00182	0.00000	0.00005	0.00036	0.06900	0.02907
AP	137	Accounts 381 through 385	PLT_3815	1.00000	0.71866	0.23756	0.00008	0.00088	0.00001	0.00001	0.00067	0.02170	0.02045
AP	138	Accounts 378, 379, & 387	PLT_378387	1.00000	0.53424	0.25522	0.00020	0.00158	0.00000	0.00004	0.00031	0.12811	0.08030
AP	139												
AP	140	Residential	DPLTRES	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	141	Small Commercial and Industrilal	DPLTCI	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	142	Large High Load Factor	DPLTLHLF	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	143	Motor Vehicle - Firm	DPLTMVF	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	144	Motor Vehicle - Interruptible	DPLTMVI	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	145	Interruptible Service	DPLTIS	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	146	Temperature Control	DPLTTC	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	147	Transportation Service - Firm	DPLTTSF	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	148	Transportation Service - Interruptible	DPLTTSI	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	149												
AP	150												

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	153												
AP	154	**Production Expense Related**											
AP	155	Account 717	OX_717	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	156	Account 741	MX_741	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	157	Account 742	MX_742	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	158	Manufactured Gas Production Operation Expense	OX_PRODM	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	159	Manufactured Gas Production Maintenance Expense	MX_PRODM	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	160	Other Production Operation Expense	OX_PRODO	1.00000	0.74311	0.24793	0.00041	0.00568	0.00003	0.00032	0.00251	0.00000	0.00000
AP	161												
AP	162												
AP	163	**Storage Expense Related**											
AP	164	Storage Operation Expense	OX_STOR	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165	Storage Maintenance Expense	MX_STOR	1.00000	0.67416	0.32361	0.00026	0.00198	0.00000	0.00000	0.00000	0.00000	0.00000
AP	166												
AP	167												
AP	168	**Transmission Expense Related**											
AP	169	Transmission Operation Expense	OX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	170	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	173												
AP	174												
AP	175	**Distribution Expense Related**											
AP	176	Account 874	OX_874	1.00000	0.67324	0.26529	0.00016	0.00117	0.00000	0.00003	0.00026	0.04248	0.01736
AP	177	Account 875	OX_875	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	0.06674	0.02712
AP	178	Account 878	OX_878	1.00000	0.71866	0.23756	0.00008	0.00088	0.00001	0.00001	0.00067	0.02170	0.02045
AP	179	Account 879	OX_879	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	180	Account 880	OX_880	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	181	Account 887	MX_887	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	0.06674	0.02712
AP	182	Account 889	MX_889	1.00000	0.61041	0.29325	0.00023	0.00183	0.00000	0.00005	0.00036	0.06674	0.02712
AP	183	Account 892	MX_892	1.00000	0.77830	0.21854	0.00004	0.00007	0.00000	0.00000	0.00009	0.00191	0.00103
AP	184	Account 893	MX_893	1.00000	0.71866	0.23756	0.00008	0.00088	0.00001	0.00001	0.00067	0.02170	0.02045
AP	185	Account 894	MX_894	1.00000	0.67497	0.26223	0.00015	0.00115	0.00000	0.00003	0.00031	0.04213	0.01904
AP	186	O&M Accounts 870-880	OX_DIST	1.00000	0.71546	0.23116	0.00011	0.00078	0.00000	0.00002	0.00031	0.03540	0.01674
AP	187	O&M Accounts 887-894	MX_DIST	1.00000	0.62761	0.28550	0.00021	0.00165	0.00000	0.00004	0.00034	0.06009	0.02457
AP	188												
AP	189												
AP	190												
AP	191												
AP	192												
AP	193												
AP	194												
AP	195												
AP	196												
AP	197												
AP	198												

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	199												
AP	200												
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	203												
AP	204	**Customer Distribution Expense Related**											
AP	205	Account 902	OX_902	1.00000	0.91724	0.08157	0.00001	0.00003	0.00000	0.00000	0.00004	0.00072	0.00039
AP	206	Account 903	OX_903	1.00000	0.86696	0.08924	0.00052	0.00028	0.00000	0.00007	0.00021	0.02757	0.01515
AP	207	Account 904	OX_904	1.00000	0.90756	0.08650	0.00022	0.00073	0.00000	0.00009	0.00083	0.00259	0.00147
AP	208	O&M Accounts 902-905	OX_CA	1.00000	0.87337	0.08860	0.00046	0.00031	0.00000	0.00007	0.00026	0.02382	0.01310
AP	209												
AP	210	Account908	OX_908	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	211	Account909	OX_909	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	212	Account910	OX_910	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	213	O&M Accounts 908-910	OX_CS	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	214	Accounts 901-916	X_CACS	1.00000	0.89346	0.07074	0.00044	0.00023	0.00000	0.00007	0.00020	0.02250	0.01236
AP	215												
AP	216	Total O&M less Purchased Gas	OMXPP	1.00000	0.73362	0.21191	0.00023	0.00099	0.00000	0.00004	0.00028	0.03638	0.01655
AP	217												
AP	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	1.00000	0.73435	0.21044	0.00023	0.00095	0.00000	0.00004	0.00029	0.03677	0.01693
AP	219												
AP	220	Base Taxable Income	EBT	1.00000	0.59969	0.30759	0.00099	0.00177	0.00002	0.00054	0.00515	0.04521	0.03903
AP	221												
AP	222												
AP	223	**Salaries and Wages Expense Related**											
AP	224	Salaries & Wages Accounts 870-880	SALWAGDO	1.00000	0.74492	0.21038	0.00011	0.00085	0.00000	0.00002	0.00025	0.02971	0.01376
AP	225	Salaries & Wages Accounts 887-894	SALWAGDM	1.00000	0.62709	0.28574	0.00021	0.00165	0.00000	0.00004	0.00034	0.06027	0.02465
AP	226	Salaries & Wages Accounts 902-905	SALWAGCA	1.00000	0.86859	0.08899	0.00050	0.00027	0.00000	0.00007	0.00021	0.02670	0.01467
AP	227	Salaries & Wages Accounts 908-910	SALWAGCS	1.00000	0.95157	0.01907	0.00037	0.00001	0.00000	0.00005	0.00001	0.01869	0.01023
AP	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	1.00000	0.72562	0.21928	0.00022	0.00108	0.00000	0.00004	0.00025	0.03702	0.01649
AP	229	Total Salaries and Wages Expense	SALWAGES	1.00000	0.72562	0.21928	0.00022	0.00108	0.00000	0.00004	0.00025	0.03702	0.01649
AP	230												
AP	231												
AP	232												
AP	233												
AP	234												
AP	235												
AP	236												
AP	237												
AP	238												
AP	239												
AP	240												
AP	241												
AP	242												
AP	243												
AP	244												
AP	245												
AP	246												

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	247												
AP	248												
AP	249												
AP	250												
AP	251	**REVENUES AND BILLING DETERMINANTS**											
AP	252												
AP	253	Base Rate Sales Revenue	SALESREV	1.00000	0.68004	0.25452	0.00038	0.00127	0.00001	0.00015	0.00145	0.03967	0.02251
AP	254												
AP	255	Residential	SREVRES	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	256	Small Commercial and Industrilal	SREVCI	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	257	Large High Load Factor	SREVLHLF	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	258	Motor Vehicle - Firm	SREVMVF	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	259	Motor Vehicle - Interruptible	SREVMVI	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	260	Interruptible Service	SREVIS	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	261	Temperature Control	SREVTC	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	262	Transportation Service - Firm	SREVTSF	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	263	Transportation Service - Interruptible	SREVTSI	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	264												
AP	265												
AP	266	Claimed Rate Sales Revenue	CLAIMREV	1.00000	0.70990	0.24703	0.00025	0.00253	0.00001	0.00012	0.00094	0.02731	0.01191
AP	267												
AP	268												
AP	269												
AP	270												
AP	271												
AP	272	**PRESENT REVENUES FROM SALES INPUT**											
AP	273												
AP	274	Total Sales of Gas Revenues		1.00000	0.70219	0.25221	0.00039	0.00282	0.00002	0.00021	0.00182	0.02574	0.01460
AP	275	Sales of Gas Revenues - Distribution		1.00000	0.68004	0.25452	0.00038	0.00127	0.00001	0.00015	0.00145	0.03967	0.02251
AP	276	Sales of Gas Revenues - PGC		1.00000	0.75461	0.23652	0.00042	0.00550	0.00003	0.00033	0.00258	0.00000	0.00000
AP	277	Sales of Gas Revenues - BSC		1.00000	0.64143	0.34877	0.00031	0.00732	0.00004	0.00024	0.00189	0.00000	0.00000
AP	278												
AP	279												
AP	280	Sales of Gas Revenues - Transmission		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	281												
AP	282												
AP	283												
AP	284												
AP	285												
AP	286												
AP	287												
AP	288												
AP	289												
AP	290												
AP	291												
AP	292												
AP	293												
AP	294												

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	295												
AP	296												
AP	297												
AP	298												
AP	299												
AP	300												
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**											
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
ADA	3												
ADA	4	**Net Write-Offs**											
ADA	5	Residential	SREVRES	0.88	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	6	Small Commercial and Industrilal	SREVCI	0.11	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	7	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	8	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	9	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	10	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	11	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	12	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	13	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	14												
ADA	15	Total Write-Offs	EXP_904	1.00	0.88	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	16												
ADA	17	Total Write-Offs	EXP_904	1.00000	0.88095	0.11442	0.00017	0.00057	0.00000	0.00007	0.00065	0.00202	0.00115
ADA	18												
ADA	19												
ADA	20	**Net Write-Offs - Pre-Program Arrearages (PPA)**											
ADA	21	Residential	SREVRES	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	22	Small Commercial and Industrilal	SREVCI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	23	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	24	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	25	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	26	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	27	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	28	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	29	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	30												
ADA	31	Total Write-Offs	EXP_904PPA	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	32												
ADA	33	Total Write-Offs	EXP_904PPA	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ADA	34												
ADA	35												
ADA	36	**Forfeited Discounts - Account 487**											
ADA	37	Residential	SREVRES	909	909	0	0	0	0	0	0	0	0
ADA	38	Small Commercial and Industrilal	SREVCI	371	0	371	0	0	0	0	0	0	0
ADA	39	Large High Load Factor	SREVLHLF	1	0	0	1	0	0	0	0	0	0
ADA	40	Motor Vehicle - Firm	SREVMVF	2	0	0	0	2	0	0	0	0	0
ADA	41	Motor Vehicle - Interruptible	SREVMVI	0	0	0	0	0	0	0	0	0	0
ADA	42	Interruptible Service	SREVIS	0	0	0	0	0	0	0	0	0	0

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
ADA	43	Temperature Control	SREVTC	2	0	0	0	0	0	0	2	0	0
ADA	44	Transportation Service - Firm	SREVTSF	57	0	0	0	0	0	0	0	57	0
ADA	45	Transportation Service - Interruptible	SREVTSI	32	0	0	0	0	0	0	0	0	32
ADA	46												
ADA	47	Total Forfeited Discounts	REV_487	1,373	909	371	1	2	0	0	2	57	32
ADA	48												
ADA	49	Total Forfeited Discounts	REV_487	1.00000	0.66192	0.26993	0.00040	0.00134	0.00001	0.00016	0.00153	0.04129	0.02342
ADA	50												
ADA	51	**ALLOCATED DIRECT ASSIGNMENTS**											
ADA	52	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
ADA	53												
ADA	54	**Purchase of Receivables (POR)**											
ADA	55	Residential	SREVRES	48,229	48,229	0	0	0	0	0	0	0	0
ADA	56	Small Commercial and Industrilal	SREVCI	33,888	0	33,888	0	0	0	0	0	0	0
ADA	57	Large High Load Factor	SREVLHLF	0	0	0	0	0	0	0	0	0	0
ADA	58	Motor Vehicle - Firm	SREVMVF	169	0	0	0	169	0	0	0	0	0
ADA	59	Motor Vehicle - Interruptible	SREVMVI	1	0	0	0	0	1	0	0	0	0
ADA	60	Interruptible Service	SREVIS	0	0	0	0	0	0	0	0	0	0
ADA	61	Temperature Control	SREVTC	193	0	0	0	0	0	0	193	0	0
ADA	62	Transportation Service - Firm	SREVTSF	0	0	0	0	0	0	0	0	0	0
ADA	63	Transportation Service - Interruptible	SREVTSI	0	0	0	0	0	0	0	0	0	0
ADA	64												
ADA	65	Purchase of Receivables	REV_POR	82,479	48,229	33,888	0	169	1	0	193	0	0
ADA	66												
ADA	67	Purchase of Receivables	REV_POR	1.00000	0.58474	0.41086	0.00000	0.00205	0.00001	0.00000	0.00234	0.00000	0.00000
ADA	68												
ADA	69												
ADA	70	**DIRECT ASSIGN TO CLASSES W/SALES DIST PLT FUNCTIONS**											
ADA	71												
ADA	72	**Customer Advances for Construction**											
ADA	73	Residential	DPLTRES	878	878	0	0	0	0	0	0	0	0
ADA	74	Small Commercial and Industrilal	DPLTCI	191	0	191	0	0	0	0	0	0	0
ADA	75	Large High Load Factor	DPLTLHLF	0	0	0	0	0	0	0	0	0	0
ADA	76	Motor Vehicle - Firm	DPLTMVF	0	0	0	0	0	0	0	0	0	0
ADA	77	Motor Vehicle - Interruptible	DPLTMVI	0	0	0	0	0	0	0	0	0	0
ADA	78	Interruptible Service	DPLTIS	0	0	0	0	0	0	0	0	0	0
ADA	79	Temperature Control	DPLTTC	0	0	0	0	0	0	0	0	0	0
ADA	80	Transportation Service - Firm	DPLTTSF	189	0	0	0	0	0	0	0	189	0
ADA	81	Transportation Service - Interruptible	DPLTTSI	59	0	0	0	0	0	0	0	0	59
ADA	82												
ADA	83	Customer Advances for Construction	CUSTADV	1,318	878	191	0	0	0	0	0	189	59
ADA	84												
ADA	85	Customer Advances for Construction	CUSTADV	1.00000	0.66673	0.14474	0.00000	0.00000	0.00000	0.00000	0.00000	0.14368	0.04484
ADA	86												
ADA	87												
ADA	88												
ADA	89												
ADA	90												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
ADA	91												
ADA	92												
ADA	93												
ADA	94												
ADA	95												
ADA	96												
ADA	97												
ADA	98												
ADA	99												
ADA	100												
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**											
RRW	2												
RRW	3	PRESENT RATES - Excludes Purchased Gas											
RRW	4	----------											
RRW	5	RATE BASE		3,513,974	2,379,433	921,218	561	4,182	12	99	993	145,891	61,585
RRW	6	NET OPER INC (PRESENT RATES)		204,311	131,629	57,539	104	294	2	50	480	8,745	5,467
RRW	7	RATE OF RETURN (PRES RATES)		5.81%	5.53%	6.25%	18.59%	7.03%	17.52%	50.89%	48.30%	5.99%	8.88%
RRW	8	RELATIVE RATE OF RETURN		1.00	0.95	1.07	3.20	1.21	3.01	8.75	8.31	1.03	1.53
RRW	9	SALES REVENUE (PRE RATES)		481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
RRW	10	REVENUE PRES RATES $/Mcf		$5.1493	$7.4718	$5.1431	$8.7604	$1.2156	$3.3718	$4.5390	$5.3941	$1.6103	$0.8133
RRW	11	REVENUE REQUIRED - $/MO/CUST		$71.86	$53.28	$224.24	$1,916.34	$3,394.34	$298.91	$6,218.44	$2,941.97	$3,983.48	$4,131.40
RRW	12												
RRW	13												
RRW	14	CLAIMED RATE OF RETURN											
RRW	15	----------											
RRW	16	CLAIMED RATE OF RETURN		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	17	RETURN REQ FOR CLAIMED ROR - Excludes Purchased Gas		283,930	192,259	74,435	45	338	1	8	80	11,788	4,976
RRW	18	SALES REVENUE REQ CLAIMED ROR - Excludes Purchased Gas		592,085	411,609	146,041	102	672	2	16	145	23,328	10,170
RRW	19	REVENUE DEFICIENCY SALES REV		111,168	84,646	23,617	(81)	67	(2)	(58)	(550)	4,208	(678)
RRW	20	PERCENT INCREASE REQUIRED		23.06%	25.83%	19.25%	-44.12%	10.90%	-44.25%	-78.07%	-78.84%	22.01%	-6.25%
RRW	21	ANNUAL BOOKED THROUGHPUT SALES (Mcf)		93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
RRW	22	SALES REV REQUIRED $/Mcf		$6.3256	$9.3831	$6.1227	$4.8742	$1.3366	$1.8480	$0.9742	$1.1203	$1.9647	$0.7625
RRW	23	REVENUE DEFICIENCY $/Mcf		$1.1877	$1.9296	$0.9901	($3.8651)	$0.1325	($1.4920)	($3.5438)	($4.2529)	$0.3544	($0.0509)
RRW	24	SALES REVENUE REQ CLAIMED ROR - Purchased Gas		261,980	194,693	64,940	107	1,489	9	84	659	0	0
RRW	25												
RRW	26	SALES REVENUE REQ CLAIMED ROR - COMPOSITE		854,065	606,302	210,980	210	2,160	11	100	803	23,328	10,170
RRW	27												
RRW	28												
RRW	29												
RRW	30												
RRW	31												
RRW	32												
RRW	33												
RRW	34												
RRW	35												
RRW	36												
RRW	37												
RRW	38												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RRW	39												
RRW	40												
RRW	41												
RRW	42												
RRW	43												
RRW	44												
RRW	45												
RRW	46												
RRW	47												
RRW	48												
RRW	49												
RRW	50												

PECO Exhibit JD-3:

Gas Class Cost of Service Study for FPFTY Ended December 31, 2025 - Allocation By Functional Classification

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
S	1	**SUMMARY AT PRESENT RATES**									
S	2										
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**									
S	4	**OPERATING REVENUE**									
S	5	Sales of Gas Revenue - Base	SCH RBC, LN 54	481,982	267,594	4,671	209,717	917	26,276	240,401	2,147
S	6	Other Operating Revenue	SCH RBC, LN 64	3,549	1,981	13	1,555	5	104	1,871	6
S	7	TOTAL OPERATING REVENUE		485,530	269,575	4,684	211,272	922	26,380	242,273	2,153
S	8										
S	9	**OPERATING EXPENSES**									
S	10	Operation and Maintenance Expense Excl Pur Gas	SCH E, LN 99	167,687	83,561	(1,769)	85,895	660	8,935	73,966	1,140
S	11	Depreciation and Amortization Expense	SCH D, LN 45	118,763	65,605	1,459	51,698	281	8,265	57,059	0
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 10	9,067	4,901	230	3,936	39	463	4,398	227
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 18	0	0	0	0	0	0	0	0
S	14	Income Taxes	SCH TI, LN 61	14,297	7,422	(874)	7,749	153	268	7,001	(189)
S	15	TOTAL OPERATING EXPENSES		281,220	146,646	794	133,780	828	17,396	128,422	1,555
S	16										
S	17	**OPERATING INCOME (RETURN)**		204,311	122,929	3,890	77,492	94	8,984	113,851	598
S	18										
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**									
S	20	Gas Plant in Service	SCH RBP, LN 65	4,630,050	2,717,409	0	1,912,641	15,819	196,517	2,505,074	0
S	21	Less: Accumulated Depreciation	SCH RBD, LN 37	1,022,690	529,458	0	493,232	14,057	37,399	478,002	0
S	22	Plus: Rate Base Additions Excl Purchased Gas	SCH RBO, LN 13	253,066	102,013	58,095	92,958	1,088	11,910	89,015	1,136
S	23	Less: Rate Base Deductions	SCH RBO, LN 26	346,452	193,656	0	152,796	1,209	14,873	177,574	0
S	24	TOTAL RATE BASE EXCL PURCHASED GAS	SCH RBO, LN 29	3,513,974	2,096,308	58,095	1,359,571	1,640	156,155	1,938,514	1,136
S	25										
S	26	RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		5.81%	5.86%	6.70%	5.70%	5.75%	5.75%	5.87%	52.62%
S	27	INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	28										
S	29										
S	30	**DEVELOPMENT OF PURCHASED GAS RETURN**									
S	31	Purchased Gas Revenues (PGC)	SCH RBC, LN 55	234,407	0	234,407	0	0	0	0	234,407
S	32	Other Sales of Gas Revenue (BSC)	SCH RBC, LN 56	26,508	0	26,508	0	0	0	0	26,508
S	33	Purchased Gas O&M Expense	SCH E, LN 98	260,932	0	260,932	0	0	0	0	260,915
S	34	Purchased Gas Income Taxes (Fed & State PP)		57	0	57	0	0	0	0	53
S	35	**PURCHASED GAS OPERATING INCOME (RETURN)**		40	0	40	0	0	0	0	53
S	36	RATE BASE - PURCHASED GAS CASH WORKING CAPITAL		10,032	0	10,032	0	0	0	0	10,032
S	37	PURCHASED GAS RATE OF RETURN (PRESENT)		0.40%	0.00%	0.40%	0.00%	0.00%	0.00%	0.00%	0.53%
S	38										
S	39										
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	41	Total Distribution Sales Revenue at Current Rates		742,897	267,594	265,586	209,717	917	26,276	240,401	263,062
S	42	Total Distribution Operating Revenues		746,445	269,575	265,599	211,272	922	26,380	242,273	263,068
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes		556,449	154,068	260,852	141,529	981	17,664	135,423	262,281
S	44	Plus: Total Federal & State Taxes		14,354	7,422	(817)	7,749	153	268	7,001	(136)
S	45	Total Operating Income (Return)		204,351	122,929	3,930	77,492	94	8,984	113,851	651
S	46	Total Rate Base		3,524,006	2,096,308	68,126	1,359,571	1,640	156,155	1,938,514	11,167
S	47										
S	48	COMPOSITE RATE OF RETURN (PRESENT)		5.80%	5.86%	5.77%	5.70%	5.75%	5.75%	5.87%	5.83%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

PECO Energy Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
S	1	**SUMMARY AT PRESENT RATES**							
S	2								
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**							
S	4	**OPERATING REVENUE**							
S	5	Sales of Gas Revenue - Base	SCH RBC, LN 54	2,524	110,977	41,015	16,209	9,844	31,670
S	6	Other Operating Revenue	SCH RBC, LN 64	7	915	326	107	35	172
S	7	TOTAL OPERATING REVENUE		2,531	111,892	41,342	16,317	9,879	31,842
S	8								
S	9	**OPERATING EXPENSES**							
S	10	Operation and Maintenance Expense Excl Pur Gas	SCH E, LN 99	(2,909)	22,498	12,848	13,079	9,091	28,379
S	11	Depreciation and Amortization Expense	SCH D, LN 45	1,459	34,332	13,958	1,243	484	1,680
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 10	4	1,817	698	567	81	774
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 18	0	0	0	0	0	0
S	14	Income Taxes	SCH TI, LN 61	(685)	5,370	2,428	(81)	(17)	50
S	15	TOTAL OPERATING EXPENSES		(761)	53,278	25,075	14,971	9,673	30,783
S	16								
S	17	**OPERATING INCOME (RETURN)**		3,292	58,614	16,267	1,346	206	1,059
S	18								
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**							
S	20	Gas Plant in Service	SCH RBP, LN 65	0	1,427,289	474,352	4,431	582	5,987
S	21	Less: Accumulated Depreciation	SCH RBD, LN 37	0	317,626	170,726	1,966	258	2,656
S	22	Plus: Rate Base Additions Excl Purchased Gas	SCH RBO, LN 13	56,959	21,410	11,220	23,938	3,670	32,719
S	23	Less: Rate Base Deductions	SCH RBO, LN 26	0	99,330	34,478	2,270	298	16,420
S	24	TOTAL RATE BASE EXCL PURCHASED GAS	SCH RBO, LN 29	56,959	1,031,744	280,369	24,134	3,696	19,629
S	25								
S	26	RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		5.78%	5.68%	5.80%	5.58%	5.58%	5.39%
S	27	INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		1.00	1.00	1.00	1.00	1.00	1.00
S	28								
S	29								
S	30	**DEVELOPMENT OF PURCHASED GAS RETURN**							
S	31	Purchased Gas Revenues (PGC)	SCH RBC, LN 55	0	0	0	0	0	0
S	32	Other Sales of Gas Revenue (BSC)	SCH RBC, LN 56	0	0	0	0	0	0
S	33	Purchased Gas O&M Expense	SCH E, LN 98	17	0	0	0	0	0
S	34	Purchased Gas Income Taxes (Fed & State PP)		4	0	0	0	0	0
S	35	**PURCHASED GAS OPERATING INCOME (RETURN)**		(13)	0	0	0	0	0
S	36	RATE BASE - PURCHASED GAS CASH WORKING CAPITAL		0	0	0	0	0	0
S	37	PURCHASED GAS RATE OF RETURN (PRESENT)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	38								
S	39								
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**							
S	41	Total Distribution Sales Revenue at Current Rates		2,524	110,977	41,015	16,209	9,844	31,670
S	42	Total Distribution Operating Revenues		2,531	111,892	41,342	16,317	9,879	31,842
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes		(1,429)	58,647	27,503	14,889	9,656	30,833
S	44	Plus: Total Federal & State Taxes		(681)	5,370	2,428	(81)	(17)	50
S	45	Total Operating Income (Return)		3,279	58,614	16,267	1,346	206	1,059
S	46	Total Rate Base		56,959	1,031,744	280,369	24,134	3,696	19,629
S	47								
S	48	COMPOSITE RATE OF RETURN (PRESENT)		5.76%	5.68%	5.80%	5.58%	5.58%	5.39%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)		1.00	1.00	1.00	1.00	1.00	1.00

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
S	50										
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	52										
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)**									
S	54										
S	55	Rate Base Excluding Purchased Gas	SCH S, LN 24	3,513,974	2,096,308	58,095	1,359,571	1,640	156,155	1,938,514	1,136
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		79,618	46,137	1,339	32,143	38	3,608	42,491	25
S	57			8.08%	8.06%	9.00%	8.06%	8.06%	8.06%	8.07%	54.82%
S	58	**OPERATING REVENUES**									
S	59	**Change in Revenue (Change in Return * 1.383)**		110,103	63,802	1,852	44,450	52	4,989	58,760	34
S	60	Distribution Base Rate Revenue (Present Rates)	SCH S, LN 5	481,982	267,594	4,671	209,717	917	26,276	240,401	2,147
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	592,085	331,396	6,523	254,167	969	31,265	299,161	2,182
S	62										
S	63	Forfeited Discounts Revenues	CALCULATED	179	103	5	72	0	8	95	2
S	64	Other Operating Revenue (Present Rates)	SCH S, LN 6	3,549	1,981	13	1,555	5	104	1,871	6
S	65	**TOTAL OPERATING REVENUES**		595,813	333,480	6,540	255,793	975	31,378	301,127	2,189
S	66										
S	67	**OPERATING EXPENSES**									
S	68	Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 10	167,687	83,561	(1,769)	85,895	660	8,935	73,966	1,140
S	69	Depreciation and Amortization Expense	SCH S, LN 11	118,763	65,605	1,459	51,698	281	8,265	57,059	0
S	70	Additional Bad Debt Expense	CALCULATED	406	236	7	164	0	18	217	0
S	71	Additional PUC / OTS & SBA Fee Expense	CALCULATED	340	197	6	137	0	15	181	0
S	72	Taxes Other Than Income Taxes-General	SCH S, LN 12	9,067	4,901	230	3,936	39	463	4,398	227
S	73	Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 13	0	0	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**		296,263	154,500	(67)	141,831	981	17,698	135,821	1,367
S	75	State and Federal Income Taxes @ Effective Tax Ra	CALCULATED	(14,297)	(7,422)	874	(7,749)	(153)	(268)	(7,001)	189
S	76	State and Federal Income Taxes @ Statutory Rates	CALCULATED	29,917	17,336	504	12,077	14	1,356	15,966	10
S	77	**TOTAL OPERATING EXPENSES**		311,883	164,414	1,310	146,159	842	18,785	144,786	1,566
S	78										
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**		283,930	169,066	5,230	109,635	132	12,592	156,341	624
S	80										
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**		592,085	331,396	6,523	254,167	969	31,265	299,161	2,182
S	82										
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**		110,283	63,905	1,856	44,521	52	4,998	58,855	36
S	84	REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVEI		22.88%	23.88%	39.74%	21.23%	5.72%	19.02%	24.48%	1.69%
S	85										
S	86										
S	87										
S	88										
S	89										
S	90										
S	91										
S	92										
S	93										
S	94										
S	95										
S	96										
S	97										
S	98										

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
S	50								
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**							
S	52								
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED R**							
S	54								
S	55	Rate Base Excluding Purchased Gas	SCH S, LN 24	56,959	1,031,744	280,369	24,134	3,696	19,629
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		1,314	24,585	6,342	600	92	524
S	57			8.09%	8.06%	8.06%	8.06%	8.06%	8.06%
S	58	**OPERATING REVENUES**							
S	59	**Change in Revenue (Change in Return * 1.383)**		1,817	33,998	8,770	830	127	725
S	60	Distribution Base Rate Revenue (Present Rates)	SCH S, LN 5	2,524	110,977	41,015	16,209	9,844	31,670
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	4,341	144,975	49,786	17,039	9,971	32,395
S	62								
S	63	Forfeited Discounts Revenues	CALCULATED	3	55	14	1	0	1
S	64	Other Operating Revenue (Present Rates)	SCH S, LN 6	7	915	326	107	35	172
S	65	**TOTAL OPERATING REVENUES**		4,351	145,945	50,126	17,148	10,007	32,568
S	66								
S	67	**OPERATING EXPENSES**							
S	68	Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 10	(2,909)	22,498	12,848	13,079	9,091	28,379
S	69	Depreciation and Amortization Expense	SCH S, LN 11	1,459	34,332	13,958	1,243	484	1,680
S	70	Additional Bad Debt Expense	CALCULATED	7	126	32	3	0	3
S	71	Additional PUC / OTS & SBA Fee Expense	CALCULATED	6	105	27	3	0	2
S	72	Taxes Other Than Income Taxes-General	SCH S, LN 12	4	1,817	698	567	81	774
S	73	Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 13	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**		(1,434)	58,878	27,563	14,895	9,657	30,838
S	75	State and Federal Income Taxes @ Effective Tax Ra	CALCULATED	685	(5,370)	(2,428)	81	17	(50)
S	76	State and Federal Income Taxes @ Statutory Rates	CALCULATED	494	9,238	2,383	225	35	197
S	77	**TOTAL OPERATING EXPENSES**		(255)	62,746	27,517	15,202	9,708	30,985
S	78								
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**		4,606	83,199	22,609	1,946	298	1,583
S	80								
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**		4,341	144,975	49,786	17,039	9,971	32,395
S	82								
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**		1,820	34,053	8,784	831	127	726
S	84	REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVEI		72.12%	30.68%	21.42%	5.13%	1.29%	2.29%
S	85								
S	86								
S	87								
S	88								
S	89								
S	90								
S	91								
S	92								
S	93								
S	94								
S	95								
S	96								
S	97								
S	98								

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
S	99										
S	100										
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	102										
S	103	**DEVELOPMENT OF PURCHASED GAS RETURN (EQUALIZED RATE)**									
S	104										
S	105	Rate Base for Purchased Gas	SCH S, LN 36	10,032	0	10,032	0	0	0	0	10,032
S	106	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		770	0	770	0	0	0	0	758
S	107										
S	108	**OPERATING REVENUES**									
S	109	**Change in Revenue (Change in Return * 1.383)**		1,065	0	1,065	0	0	0	0	1,048
S	110	Distribution Base Rate Revenue (Present Rates)	CALCULATED	260,915	0	260,915	0	0	0	0	260,915
S	111	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	261,980	0	261,980	0	0	0	0	261,963
S	112										
S	113	**OPERATING EXPENSES**									
S	114	Purchased Gas O&M Expense	SCH S, LN 33	260,932	0	260,932	0	0	0	0	260,915
S	115	Additional Bad Debt Expense	CALCULATED	4	0	4	0	0	0	0	4
S	116	Additional PUC / OTS & SBA Fee Expense	CALCULATED	3	0	3	0	0	0	0	3
S	117	**TOTAL OPERATING EXPENSES BEFORE TAXES**		260,939	0	260,939	0	0	0	0	260,922
S	118	State and Federal Inc Taxes @ Effective Tax Rate	CALCULATED	(57)	0	(57)	0	0	0	0	(53)
S	119	State and Federal Income Taxes @ Statutory Rates	CALCULATED	289	0	289	0	0	0	0	284
S	120	**TOTAL OPERATING EXPENSES**		261,171	0	261,171	0	0	0	0	261,153
S	121										
S	122	**NET OPERATING INCOME FOR PURCHASED GAS**		809	0	809	0	0	0	0	809
S	123										
S	124	**EQUALS TOTAL PURCHASED GAS COST OF SERVICE @ ROR**		261,980	0	261,980	0	0	0	0	261,963
S	125										
S	126	**TOTAL SALES PURCH GAS INCREASE/DECREASE**		1,065	0	1,065	0	0	0	0	1,048
S	127	SALES REVENUE INCREASE TO RURCHASED GAS REVENUES (%)		0.45%	0.00%	0.45%	0.00%	0.00%	0.00%	0.00%	0.45%
S	128										
S	129										
S	130										
S	131										
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	133	**Total Composite Base Rate Sales Revenue Requirement**		854,065	331,396	268,503	254,167	969	31,265	299,161	264,144
S	134	**Other Operating Revenue**		3,728	2,084	18	1,627	6	112	1,966	8
S	135	**Total Revenue**		857,793	333,480	268,520	255,793	975	31,378	301,127	264,152
S	136	**Total Operating Expense before Income Taxes**		557,202	154,500	260,872	141,831	981	17,698	135,821	262,289
S	137	**OIBIT**		300,591	178,980	7,649	113,962	(6)	13,680	165,306	1,863
S	138	**Total Income Taxes**		15,851	9,914	1,609	4,328	(139)	1,088	8,965	430
S	139	**Net Operating Income**		284,739	169,066	6,039	109,635	132	12,592	156,341	1,433
S	140	**Total Increase (Decrease) Base Sales Required w/ Addt'l Forfeited Di**		111,348	63,905	2,922	44,521	52	4,998	58,855	1,084
S	141	**TOTAL INCREASE (DECREASE) BASE SALES REQUIRED W/O ADDT**		111,168	63,802	2,917	44,450	52	4,989	58,760	1,082
S	142	**RATE OF RETURN (PROPOSED)**		8.08%	8.06%	8.86%	8.06%	8.06%	8.06%	8.07%	12.83%
S	143										
S	144										
S	145										
S	146										
S	147										

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
S	99								
S	100								
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**							
S	102								
S	103	**DEVELOPMENT OF PURCHASED GAS RETURN (EQUALIZED RATE)**							
S	104								
S	105	Rate Base for Purchased Gas	SCH S, LN 36	0	0	0	0	0	0
S	106	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		0	0	0	0	0	0
S	107								
S	108	**OPERATING REVENUES**							
S	109	**Change in Revenue (Change in Return * 1.383)**		0	0	0	0	0	0
S	110	Distribution Base Rate Revenue (Present Rates)	CALCULATED	0	0	0	0	0	0
S	111	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	0	0	0	0	0	0
S	112								
S	113	**OPERATING EXPENSES**							
S	114	Purchased Gas O&M Expense	SCH S, LN 33	17	0	0	0	0	0
S	115	Additional Bad Debt Expense	CALCULATED	0	0	0	0	0	0
S	116	Additional PUC / OTS & SBA Fee Expense	CALCULATED	0	0	0	0	0	0
S	117	**TOTAL OPERATING EXPENSES BEFORE TAXES**		17	0	0	0	0	0
S	118	State and Federal Inc Taxes @ Effective Tax Rate	CALCULATED	(4)	0	0	0	0	0
S	119	State and Federal Income Taxes @ Statutory Rates	CALCULATED	0	0	0	0	0	0
S	120	**TOTAL OPERATING EXPENSES**		13	0	0	0	0	0
S	121								
S	122	**NET OPERATING INCOME FOR PURCHASED GAS**		(13)	0	0	0	0	0
S	123								
S	124	**EQUALS TOTAL PURCHASED GAS COST OF SERVICE @ ROR**		0	0	0	0	0	0
S	125								
S	126	**TOTAL SALES PURCH GAS INCREASE/DECREASE**		0	0	0	0	0	0
S	127	SALES REVENUE INCREASE TO RURCHASED GAS REVENUES (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	128								
S	129								
S	130								
S	131								
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**							
S	133	**Total Composite Base Rate Sales Revenue Requirement**		4,341	144,975	49,786	17,039	9,971	32,395
S	134	**Other Operating Revenue**		10	970	340	109	35	173
S	135	**Total Revenue**		4,351	145,945	50,126	17,148	10,007	32,568
S	136	**Total Operating Expense before Income Taxes**		(1,417)	58,878	27,563	14,895	9,657	30,838
S	137	**OIBIT**		5,768	87,067	22,563	2,253	349	1,730
S	138	**Total Income Taxes**		1,175	3,868	(45)	307	51	147
S	139	**Net Operating Income**		4,593	83,199	22,609	1,946	298	1,583
S	140	**Total Increase (Decrease) Base Sales Required w/ Addt'l Forfeited Di**		1,820	34,053	8,784	831	127	726
S	141	**TOTAL INCREASE (DECREASE) BASE SALES REQUIRED W/O ADDT**		1,817	33,998	8,770	830	127	725
S	142	**RATE OF RETURN (PROPOSED)**		8.06%	8.06%	8.06%	8.06%	8.06%	8.06%
S	143								
S	144								
S	145								
S	146								
S	147								

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
S	148										
S	149										
S	150										
RBP	1	**DEVELOPMENT OF RATE BASE**									
RBP	2										
RBP	3	**GAS PLANT IN SERVICE**									
RBP	4	INTANGIBLE PLANT									
RBP	5	301-Organization	TOTPLT	16,406	9,629	0	6,777	56	696	8,876	0
RBP	6	303-Miscellaneous Intangible Plant	TOTPLT	0	0	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT		16,406	9,629	0	6,777	56	696	8,876	0
RBP	8										
RBP	9	PRODUCTION PLANT (LPG)									
RBP	10	305-Land and Land Rights	DPKDAYP	1,225	1,225	0	0	1,225	0	0	0
RBP	11	311- Liquefied Petroleum Gas Equipment	DPKDAYP	14,334	14,334	0	0	14,334	0	0	0
RBP	12	320-Other Equipment (SNG Plant)	DPKDAYP	0	0	0	0	0	0	0	0
RBP	13	TOTAL PRODUCTION PLANT		15,559	15,559	0	0	15,559	0	0	0
RBP	14										
RBP	15	STORAGE PLANT (LNG)									
RBP	16	360-Land and Land Rights	DPKDAYS	16	16	0	0	0	16	0	0
RBP	17	361-Structures and Improvements	DPKDAYS	14,932	14,932	0	0	0	14,932	0	0
RBP	18	362-Gas Holders.	DPKDAYS	7,084	7,084	0	0	0	7,084	0	0
RBP	19	363-Purification Equipment	DPKDAYS	0	0	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYS	171,597	171,597	0	0	0	171,597	0	0
RBP	21	TOTAL STORAGE PLANT		193,629	193,629	0	0	0	193,629	0	0
RBP	22										
RBP	23	TRANSMISSION PLANT									
RBP	24	371- Transmission Related Plant	DTRAN	0	0	0	0	0	0	0	0
RBP	25	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
RBP	26										
RBP	27	DISTRIBUTION PLANT									
RBP	28	374-Land & Land Rights	DDISTPLT	3,915	3,915	0	0	0	0	3,915	0
RBP	29	375-Structures & Improvements	DDISTPLT	16,785	16,785	0	0	0	0	16,785	0
RBP	30	376-Mains									
RBP	31	General - Excess	DEXCESS	1,784,138	1,784,138	0	0	0	0	1,784,138	0
RBP	32	General - Average	DAVGDD	570,169	570,169	0	0	0	0	570,169	0
RBP	33	Direct Assignment	DAMAINS	15,529	15,529	0	0	0	0	15,529	0
RBP	34	Total Account 376		2,369,836	2,369,836	0	0	0	0	2,369,836	0
RBP	35	378-Measuring & Regulating Station Equip-General	PLT_376	26,029	26,029	0	0	0	0	26,029	0
RBP	36	379-Measuring & Regulating Station Equip-City Gate									
RBP	37	City Gate	PLT_376	50,069	50,069	0	0	0	0	50,069	0
RBP	38	Direct Assignment	DAMR	11,399	11,399	0	0	0	0	11,399	0
RBP	39	Total Account 379		61,468	61,468	0	0	0	0	61,468	0
RBP	40	380-Services	CSERVICE	1,417,248	0	0	1,417,248	0	0	0	0
RBP	41	381-Meters	CMETERS	178,422	0	0	178,422	0	0	0	0
RBP	42	Direct Assignment	CMETERSDA	583	0	0	583	0	0	0	0
RBP	43	Total Account 381		179,005	0	0	179,005	0	0	0	0
RBP	44	382-Meter Installations	CMETERS	288,504	0	0	288,504	0	0	0	0
RBP	45	Direct Assignment	CMETINSTDA	2,764	0	0	2,764	0	0	0	0
RBP	46	Total Account 382		291,268	0	0	291,268	0	0	0	0

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
S	148								
S	149								
S	150								
RBP	1	**DEVELOPMENT OF RATE BASE**							
RBP	2								
RBP	3	**GAS PLANT IN SERVICE**							
RBP	4	INTANGIBLE PLANT							
RBP	5	301-Organization	TOTPLT	0	5,057	1,681	16	2	21
RBP	6	303-Miscellaneous Intangible Plant	TOTPLT	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT		0	5,057	1,681	16	2	21
RBP	8								
RBP	9	PRODUCTION PLANT (LPG)							
RBP	10	305-Land and Land Rights	DPKDAYP	0	0	0	0	0	0
RBP	11	311- Liquefied Petroleum Gas Equipment	DPKDAYP	0	0	0	0	0	0
RBP	12	320-Other Equipment (SNG Plant)	DPKDAYP	0	0	0	0	0	0
RBP	13	TOTAL PRODUCTION PLANT		0	0	0	0	0	0
RBP	14								
RBP	15	STORAGE PLANT (LNG)							
RBP	16	360-Land and Land Rights	DPKDAYS	0	0	0	0	0	0
RBP	17	361-Structures and Improvements	DPKDAYS	0	0	0	0	0	0
RBP	18	362-Gas Holders.	DPKDAYS	0	0	0	0	0	0
RBP	19	363-Purification Equipment	DPKDAYS	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYS	0	0	0	0	0	0
RBP	21	TOTAL STORAGE PLANT		0	0	0	0	0	0
RBP	22								
RBP	23	TRANSMISSION PLANT							
RBP	24	371- Transmission Related Plant	DTRAN	0	0	0	0	0	0
RBP	25	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0
RBP	26								
RBP	27	DISTRIBUTION PLANT							
RBP	28	374-Land & Land Rights	DDISTPLT	0	0	0	0	0	0
RBP	29	375-Structures & Improvements	DDISTPLT	0	0	0	0	0	0
RBP	30	376-Mains							
RBP	31	General - Excess	DEXCESS	0	0	0	0	0	0
RBP	32	General - Average	DAVGDD	0	0	0	0	0	0
RBP	33	Direct Assignment	DAMAINS	0	0	0	0	0	0
RBP	34	Total Account 376		0	0	0	0	0	0
RBP	35	378-Measuring & Regulating Station Equip-General	PLT_376	0	0	0	0	0	0
RBP	36	379-Measuring & Regulating Station Equip-City Gate							
RBP	37	City Gate	PLT_376	0	0	0	0	0	0
RBP	38	Direct Assignment	DAMR	0	0	0	0	0	0
RBP	39	Total Account 379		0	0	0	0	0	0
RBP	40	380-Services	CSERVICE	0	1,417,248	0	0	0	0
RBP	41	381-Meters	CMETERS	0	0	178,422	0	0	0
RBP	42	Direct Assignment	CMETERSDA	0	0	583	0	0	0
RBP	43	Total Account 381		0	0	179,005	0	0	0
RBP	44	382-Meter Installations	CMETERS	0	0	288,504	0	0	0
RBP	45	Direct Assignment	CMETINSTDA	0	0	2,764	0	0	0
RBP	46	Total Account 382		0	0	291,268	0	0	0

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBP	47	387-Other Equipment	DISTPLT	2,084	1,183	0	901	0	0	1,183	0
RBP	48	388-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	884	502	0	382	0	0	502	0
RBP	49	TOTAL DISTRIBUTION PLANT		4,368,523	2,479,718	0	1,888,805	0	0	2,479,718	0
RBP	50										
RBP	51	**GAS PLANT IN SERVICE CONTINUED**									
RBP	52										
RBP	53	GENERAL PLANT									
RBP	54	389-Land and Land Rights	SALWAGES	0	0	0	0	0	0	0	0
RBP	55	390-Structures and Improvements	SALWAGES	11,508	6,044	0	5,463	65	702	5,277	0
RBP	56	391-Office Furniture & Equipment	SALWAGES	1,783	937	0	846	10	109	818	0
RBP	57	393-Store Equipment	SALWAGES	0	0	0	0	0	0	0	0
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	16,536	8,686	0	7,850	94	1,009	7,583	0
RBP	59	395-Laboratory Equipment	SALWAGES	69	36	0	33	0	4	32	0
RBP	60	397-Communication Equipment	SALWAGES	5,786	3,039	0	2,747	33	353	2,654	0
RBP	61	398-Miscellaneous Equipment	SALWAGES	252	132	0	120	1	15	116	0
RBP	62	TOTAL GENERAL PLANT		35,933	18,874	0	17,059	203	2,192	16,479	0
RBP	63										
RBP	64										
RBP	65	**TOTAL GAS PLANT IN SERVICE**		4,630,050	2,717,409	0	1,912,641	15,819	196,517	2,505,074	0
RBP	66										
RBP	67										
RBP	68										
RBP	69										
RBP	70										
RBP	71										
RBP	72										
RBP	73										
RBP	74										
RBP	75										
RBP	76										
RBP	77										
RBP	78										
RBP	79										
RBP	80										
RBP	81										
RBP	82										
RBP	83										
RBP	84										
RBP	85										
RBP	86										
RBP	87										
RBP	88										
RBP	89										
RBP	90										
RBP	91										
RBP	92										
RBP	93										
RBP	94										
RBP	95										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBP	47	387-Other Equipment	DISTPLT	0	677	225	0	0	0
RBP	48	388-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	0	287	95	0	0	0
RBP	49	TOTAL DISTRIBUTION PLANT		0	1,418,212	470,593	0	0	0
RBP	50								
RBP	51	**GAS PLANT IN SERVICE CONTINUED**							
RBP	52								
RBP	53	GENERAL PLANT							
RBP	54	389-Land and Land Rights	SALWAGES	0	0	0	0	0	0
RBP	55	390-Structures and Improvements	SALWAGES	0	1,287	666	1,414	186	1,910
RBP	56	391-Office Furniture & Equipment	SALWAGES	0	199	103	219	29	296
RBP	57	393-Store Equipment	SALWAGES	0	0	0	0	0	0
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	0	1,850	956	2,032	267	2,745
RBP	59	395-Laboratory Equipment	SALWAGES	0	8	4	8	1	11
RBP	60	397-Communication Equipment	SALWAGES	0	647	335	711	93	961
RBP	61	398-Miscellaneous Equipment	SALWAGES	0	28	15	31	4	42
RBP	62	TOTAL GENERAL PLANT		0	4,020	2,079	4,415	580	5,966
RBP	63								
RBP	64								
RBP	65	**TOTAL GAS PLANT IN SERVICE**		0	1,427,289	474,352	4,431	582	5,987
RBP	66								
RBP	67								
RBP	68								
RBP	69								
RBP	70								
RBP	71								
RBP	72								
RBP	73								
RBP	74								
RBP	75								
RBP	76								
RBP	77								
RBP	78								
RBP	79								
RBP	80								
RBP	81								
RBP	82								
RBP	83								
RBP	84								
RBP	85								
RBP	86								
RBP	87								
RBP	88								
RBP	89								
RBP	90								
RBP	91								
RBP	92								
RBP	93								
RBP	94								
RBP	95								

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBP	96										
RBP	97										
RBP	98										
RBP	99										
RBP	100										
RBD	1	**LESS: ACCUMULATED DEPRECIATION**									
RBD	2										
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATIC	INTPLT	8,018	4,706	0	3,312	27	340	4,338	0
RBD	4										
RBD	5	PRODUCTION PLANT ACCUMULATED DEPRECIAT	PRODPLT	13,939	13,939	0	0	13,939	0	0	0
RBD	6										
RBD	7	STORAGE PLANT ACCUMULATED DEPRECIATION	STORPLT	36,086	36,086	0	0	0	36,086	0	0
RBD	8										
RBD	9	TRANSMISSION PLANT ACCUMULATED DEPRECIA	TRANPLT	0	0	0	0	0	0	0	0
RBD	10										
RBD	11	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION									
RBD	12	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0
RBD	13	375-Structures & Improvements	PLT_375	6,841	6,841	0	0	0	0	6,841	0
RBD	14	376-Mains									
RBD	15	General - Excess	PLT_376GE	319,532	319,532	0	0	0	0	319,532	0
RBD	16	General - Average	PLT_376GA	102,115	102,115	0	0	0	0	102,115	0
RBD	17	Direct Assignment	DAMAINSAD	2,855	2,855	0	0	0	0	2,855	0
RBD	18	Total Account 376		424,502	424,502	0	0	0	0	424,502	0
RBD	19	378-Measuring & Regulating Station Equip-General	PLT_378	5,942	5,942	0	0	0	0	5,942	0
RBD	20	379-Measuring & Regulating Station Equip-City Gate									
RBD	21	City Gate	PLT_379CG	24,325	24,325	0	0	0	0	24,325	0
RBD	22	Direct Assignment	DAMRAD	3,423	3,423	0	0	0	0	3,423	0
RBD	23	Total Account 379		27,748	27,748	0	0	0	0	27,748	0
RBD	24	380-Services	PLT_380	312,616	0	0	312,616	0	0	0	0
RBD	25	381-Meters	CMETERS	88,212	0	0	88,212	0	0	0	0
RBD	26	Direct Assignment	CMETERSDAA	63	0	0	63	0	0	0	0
RBD	27	Total Account 381		88,274	0	0	88,274	0	0	0	0
RBD	28	382-Meter Installations	CMETERS	80,125	0	0	80,125	0	0	0	0
RBD	29	Direct Assignment	CMETINSTDAA	332	0	0	332	0	0	0	0
RBD	30	Total Account 382		80,458	0	0	80,458	0	0	0	0
RBD	31	387-Other Equipment	PLT_387	1,716	974	0	742	0	0	974	0
RBD	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	608	345	0	263	0	0	345	0
RBD	33	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		948,707	466,354	0	482,353	0	0	466,354	0
RBD	34										
RBD	35	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	15,939	8,372	0	7,567	90	972	7,310	0
RBD	36										
RBD	37	**TOTAL ACCUMULATED DEPRECIATION**		1,022,690	529,458	0	493,232	14,057	37,399	478,002	0
RBD	38										
RBD	39										
RBD	40										
RBD	41	**NET GAS PLANT IN SERVICE**		3,607,360	2,187,951	(0)	1,419,409	1,762	159,118	2,027,072	(0)
RBD	42										
RBD	43										
RBD	44										

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBP	96								
RBP	97								
RBP	98								
RBP	99								
RBP	100								
RBD	1	**LESS: ACCUMULATED DEPRECIATION**							
RBD	2								
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATIC	INTPLT	0	2,472	821	8	1	10
RBD	4								
RBD	5	PRODUCTION PLANT ACCUMULATED DEPRECIAT	PRODPLT	0	0	0	0	0	0
RBD	6								
RBD	7	STORAGE PLANT ACCUMULATED DEPRECIATION	STORPLT	0	0	0	0	0	0
RBD	8								
RBD	9	TRANSMISSION PLANT ACCUMULATED DEPRECIA	TRANPLT	0	0	0	0	0	0
RBD	10								
RBD	11	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION							
RBD	12	374-Land Rights	PLT_374	0	0	0	0	0	0
RBD	13	375-Structures & Improvements	PLT_375	0	0	0	0	0	0
RBD	14	376-Mains							
RBD	15	General - Excess	PLT_376GE	0	0	0	0	0	0
RBD	16	General - Average	PLT_376GA	0	0	0	0	0	0
RBD	17	Direct Assignment	DAMAINSAD	0	0	0	0	0	0
RBD	18	Total Account 376		0	0	0	0	0	0
RBD	19	378-Measuring & Regulating Station Equip-General	PLT_378	0	0	0	0	0	0
RBD	20	379-Measuring & Regulating Station Equip-City Gate							
RBD	21	City Gate	PLT_379CG	0	0	0	0	0	0
RBD	22	Direct Assignment	DAMRAD	0	0	0	0	0	0
RBD	23	Total Account 379		0	0	0	0	0	0
RBD	24	380-Services	PLT_380	0	312,616	0	0	0	0
RBD	25	381-Meters	CMETERS	0	0	88,212	0	0	0
RBD	26	Direct Assignment	CMETERSDAA	0	0	63	0	0	0
RBD	27	Total Account 381		0	0	88,274	0	0	0
RBD	28	382-Meter Installations	CMETERS	0	0	80,125	0	0	0
RBD	29	Direct Assignment	CMETINSTDAA	0	0	332	0	0	0
RBD	30	Total Account 382		0	0	80,458	0	0	0
RBD	31	387-Other Equipment	PLT_387	0	557	185	0	0	0
RBD	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	0	197	66	0	0	0
RBD	33	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		0	313,371	168,982	0	0	0
RBD	34								
RBD	35	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	0	1,783	922	1,958	257	2,646
RBD	36								
RBD	37	**TOTAL ACCUMULATED DEPRECIATION**		0	317,626	170,726	1,966	258	2,656
RBD	38								
RBD	39								
RBD	40								
RBD	41	**NET GAS PLANT IN SERVICE**		(0)	1,109,664	303,627	2,465	324	3,330
RBD	42								
RBD	43								
RBD	44								

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBD	45										
RBD	46										
RBD	47										
RBD	48										
RBD	49										
RBD	50										
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
RBO	2										
RBO	3	**PLUS: ADDITIONS TO RATE BASE**									
RBO	4										
RBO	5	COMMON PLANT	SALWAGES	190,266	99,940	0	90,326	1,077	11,604	87,258	0
RBO	6										
RBO	7	**WORKING CAPITAL**									
RBO	8	Cash Working Capital - Purchased Gas	SCH RBC, LN 37	10,032	0	10,032	0	0	0	0	10,032
RBO	9	Cash Working Capital	SCH RBC, LN 22	3,705	827	1,123	1,755	3	216	608	1,136
RBO	10	Gas Storage Inventory	ESTORAGE	56,972	0	56,972	0	0	0	0	0
RBO	11	Materials and Supplies	TOTPLT	2,123	1,246	0	877	7	90	1,149	0
RBO	12	TOTAL WORKING CAPITAL		72,832	2,073	68,126	2,632	10	306	1,757	11,167
RBO	13	TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS		253,066	102,013	58,095	92,958	1,088	11,910	89,015	1,136
RBO	14	TOTAL ADDITIONS TO RATE BASE		263,098	102,013	68,126	92,958	1,088	11,910	89,015	11,167
RBO	15										
RBO	16	**LESS: DEDUCTIONS TO RATE BASE**									
RBO	17	Customer Deposits	CUSTDEP	13,354	0	0	13,354	0	0	0	0
RBO	18	Customer Advances for Construction	CUSTADV	1,323	886	0	437	0	0	886	0
RBO	19	Deferred Income Taxes and Credits									
RBO	20	Plant	TOTPLT	377,436	221,520	0	155,916	1,290	16,020	204,211	0
RBO	21	Common Plant	SALWAGES	15,921	8,362	0	7,558	90	971	7,301	0
RBO	22	Pension Assets / (Liability)	SALWAGES	0	0	0	0	0	0	0	0
RBO	23	Corporate Alternative Minimum Tax	TOTPLT	(49,890)	(29,281)	(0)	(20,609)	(170)	(2,118)	(26,993)	(0)
RBO	24	Contributions in Aid of Construction (CIAC)	CUSTADV	(11,690)	(7,831)	0	(3,859)	0	0	(7,831)	0
RBO	25	Total Deferred Income Taxes and Credits		331,776	192,770	0	139,006	1,209	14,873	176,688	0
RBO	26	TOTAL DEDUCTIONS TO RATE BASE		346,452	193,656	0	152,796	1,209	14,873	177,574	0
RBO	27										
RBO	28	TOTAL PURCHASED GAS RATE BASE		10,032	0	10,032	0	0	0	0	10,032
RBO	29	TOTAL RATE BASE EXCLUDING PURCHASED GAS		3,513,974	2,096,308	58,095	1,359,571	1,640	156,155	1,938,514	1,136
RBO	30										
RBO	31	**TOTAL RATE BASE**		3,524,006	2,096,308	68,126	1,359,571	1,640	156,155	1,938,514	11,167
RBO	32										
RBO	33										
RBO	34										
RBO	35										
RBO	36										
RBO	37										
RBO	38										
RBO	39										
RBO	40										
RBO	41										
RBO	42										
RBO	43										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBD	45								
RBD	46								
RBD	47								
RBD	48								
RBD	49								
RBD	50								
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
RBO	2								
RBO	3	**PLUS: ADDITIONS TO RATE BASE**							
RBO	4								
RBO	5	COMMON PLANT	SALWAGES	0	21,286	11,006	23,377	3,069	31,588
RBO	6								
RBO	7	**WORKING CAPITAL**							
RBO	8	Cash Working Capital - Purchased Gas	SCH RBC, LN 37	0	0	0	0	0	0
RBO	9	Cash Working Capital	SCH RBC, LN 22	(13)	(531)	(3)	559	601	1,128
RBO	10	Gas Storage Inventory	ESTORAGE	56,972	0	0	0	0	0
RBO	11	Materials and Supplies	TOTPLT	0	655	218	2	0	3
RBO	12	TOTAL WORKING CAPITAL		56,959	124	215	561	601	1,131
RBO	13	TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS		56,959	21,410	11,220	23,938	3,670	32,719
RBO	14	TOTAL ADDITIONS TO RATE BASE		56,959	21,410	11,220	23,938	3,670	32,719
RBO	15								
RBO	16	**LESS: DEDUCTIONS TO RATE BASE**							
RBO	17	Customer Deposits	CUSTDEP	0	0	0	0	0	13,354
RBO	18	Customer Advances for Construction	CUSTADV	0	437	0	0	0	0
RBO	19	Deferred Income Taxes and Credits							
RBO	20	Plant	TOTPLT	0	116,351	38,669	361	47	488
RBO	21	Common Plant	SALWAGES	0	1,781	921	1,956	257	2,643
RBO	22	Pension Assets / (Liability)	SALWAGES	0	0	0	0	0	0
RBO	23	Corporate Alternative Minimum Tax	TOTPLT	(0)	(15,380)	(5,111)	(48)	(6)	(65)
RBO	24	Contributions in Aid of Construction (CIAC)	CUSTADV	0	(3,859)	0	0	0	0
RBO	25	Total Deferred Income Taxes and Credits		0	98,894	34,478	2,270	298	3,067
RBO	26	TOTAL DEDUCTIONS TO RATE BASE		0	99,330	34,478	2,270	298	16,420
RBO	27								
RBO	28	TOTAL PURCHASED GAS RATE BASE		0	0	0	0	0	0
RBO	29	TOTAL RATE BASE EXCLUDING PURCHASED GAS		56,959	1,031,744	280,369	24,134	3,696	19,629
RBO	30								
RBO	31	**TOTAL RATE BASE**		56,959	1,031,744	280,369	24,134	3,696	19,629
RBO	32								
RBO	33								
RBO	34								
RBO	35								
RBO	36								
RBO	37								
RBO	38								
RBO	39								
RBO	40								
RBO	41								
RBO	42								
RBO	43								

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBO	44										
RBO	45										
RBO	46										
RBO	47										
RBO	48										
RBO	49										
RBO	50										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**									
RBC	2										
RBC	3	**TOTAL EXCLUDING PURCHASED GAS**									
RBC	4	O&M EXPENSE RELATED CASH WORKING CAPITAL									
RBC	5	Payroll (Distribution Only)	SALWAGES	52,481	27,566	0	24,914	297	3,201	24,068	0
RBC	6	Pension	SALWAGES	973	511	0	462	6	59	446	0
RBC	7	Other Expenses									
RBC	8	Other Expenses	OMXPPPP	111,873	53,312	(645)	59,206	330	5,380	47,602	1,206
RBC	9	BSC	EBSC	26,508	0	26,508	0	0	0	0	26,508
RBC	10	Purchase of Recievables (POR)	POR	82,479	46,281	803	35,395	174	5,006	41,102	390
RBC	11	TOTAL EXPENSES		274,313	127,670	26,666	119,978	806	13,646	113,218	28,104
RBC	12										
RBC	13	TOTAL EXPENSES PER DAY		752	350	73	329	2	37	310	77
RBC	14										
RBC	15	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		7,812	3,636	759	3,417	23	389	3,224	800
RBC	16										
RBC	17	AVERAGE PREPAYMENTS		2,733	1,178	337	1,217	7	113	1,057	331
RBC	18	DISTRIBUTION ACCRUED TAXES		1,896	1,140	26	730	3	85	1,053	4
RBC	19	INTEREST PAYMENTS	TOTPLT	(8,736)	(5,127)	(0)	(3,609)	(30)	(371)	(4,726)	(0)
RBC	20										
RBC	21										
RBC	22	NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT		3,705	827	1,123	1,755	3	216	608	1,136
RBC	23										
RBC	24										
RBC	25	**PURCHASED GAS**									
RBC	26	O&M EXPENSE RELATED CASH WORKING CAPITAL									
RBC	27	Commodity Purchased - Contract Purchases	EGAS	234,407	0	234,407	0	0	0	0	234,407
RBC	28	Commodity Purchased - Spot Market Purchases	ETHRUPUTF	0	0	0	0	0	0	0	0
RBC	29	TOTAL EXPENSES		234,407	0	234,407	0	0	0	0	234,407
RBC	30										
RBC	31	TOTAL EXPENSES PER DAY		642	0	642	0	0	0	0	642
RBC	32										
RBC	33	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		10,032	0	10,032	0	0	0	0	10,032
RBC	34										
RBC	35	PURCHASED GAS ACCRUED TAXES	ETHRUPUTF	0	0	0	0	0	0	0	0
RBC	36										
RBC	37	NET PURCHASED GAS CASH WORKING CAPITAL REQUIREMENT		10,032	0	10,032	0	0	0	0	10,032
RBC	38										
RBC	39										
RBC	40	**TOTAL NET CASH WORKING CAPITAL**		13,737	827	11,155	1,755	3	216	608	11,167
RBC	41										
RBC	42										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBO	44								
RBO	45								
RBO	46								
RBO	47								
RBO	48								
RBO	49								
RBO	50								
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**							
RBC	2								
RBC	3	**TOTAL EXCLUDING PURCHASED GAS**							
RBC	4	O&M EXPENSE RELATED CASH WORKING CAPITAL							
RBC	5	Payroll (Distribution Only)	SALWAGES	0	5,871	3,036	6,448	847	8,713
RBC	6	Pension	SALWAGES	0	109	56	120	16	161
RBC	7	Other Expenses							
RBC	8	Other Expenses	OMXPPPP	(1,851)	15,845	9,665	5,817	8,605	19,274
RBC	9	BSC	EBSC	0	0	0	0	0	0
RBC	10	Purchase of Recievables (POR)	POR	413	19,606	7,054	2,554	1,427	4,753
RBC	11	TOTAL EXPENSES		(1,438)	41,431	19,812	14,939	10,895	32,901
RBC	12								
RBC	13	TOTAL EXPENSES PER DAY		(4)	113	54	41	30	90
RBC	14								
RBC	15	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		(41)	1,180	564	425	310	937
RBC	16								
RBC	17	AVERAGE PREPAYMENTS		6	432	165	134	290	196
RBC	18	DISTRIBUTION ACCRUED TAXES		22	551	163	8	1	6
RBC	19	INTEREST PAYMENTS	TOTPLT	(0)	(2,693)	(895)	(8)	(1)	(11)
RBC	20								
RBC	21								
RBC	22	NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT		(13)	(531)	(3)	559	601	1,128
RBC	23								
RBC	24								
RBC	25	**PURCHASED GAS**							
RBC	26	O&M EXPENSE RELATED CASH WORKING CAPITAL							
RBC	27	Commodity Purchased - Contract Purchases	EGAS	0	0	0	0	0	0
RBC	28	Commodity Purchased - Spot Market Purchases	ETHRUPUTF	0	0	0	0	0	0
RBC	29	TOTAL EXPENSES		0	0	0	0	0	0
RBC	30								
RBC	31	TOTAL EXPENSES PER DAY		0	0	0	0	0	0
RBC	32								
RBC	33	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		0	0	0	0	0	0
RBC	34								
RBC	35	PURCHASED GAS ACCRUED TAXES	ETHRUPUTF	0	0	0	0	0	0
RBC	36								
RBC	37	NET PURCHASED GAS CASH WORKING CAPITAL REQUIREMENT		0	0	0	0	0	0
RBC	38								
RBC	39								
RBC	40	**TOTAL NET CASH WORKING CAPITAL**		(13)	(531)	(3)	559	601	1,128
RBC	41								
RBC	42								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBC	43										
RBC	44										
RBC	45										
RBC	46										
RBC	47										
RBC	48										
RBC	49										
RBC	50										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**									
RBC	2										
RBC	3	**LAG/LEAD DAYS**		NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS
RBC	4	REVENUE LAG DAYS	48.86								
RBC	5	EXPENSE LEAD DAYS	38.46	10	10	10	10	10	10	10	10
RBC	6										
RBC	7	PURCHASED GAS EXP LEAD DAYS	33.24	16	16	16	16	16	16	16	16
RBC	8										
RBC	9										
RBC	10										
RBC	11										
RBC	12										
RBC	13										
RBC	14										
RBC	15										
RBC	16	DISTRIBUTION ACCRUED TAXES									
RBC	17	Federal Income Tax	EBT	304,366	187,637	8,727	108,001	(248)	14,274	173,611	1,453
RBC	18	State Income Tax	EBT	32,373	19,957	928	11,487	(26)	1,518	18,466	155
RBC	19	PURTA Taxes	TOTPLT	228,094	133,870	0	94,224	779	9,681	123,409	0
RBC	20	PA Capital Stock Tax	TOTPLT	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	TOTPLT	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	127,229	74,672	0	52,558	435	5,400	68,837	0
RBC	23	TOTAL ACCRUED TAXES		692,062	416,136	9,656	266,270	940	30,873	384,323	1,607
RBC	24	TOTAL ACCRUED TAXES PER DAY		1,896	1,140	26	730	3	85	1,053	4
RBC	25										
RBC	26	DISTRIBUTION AVERAGE PREPAYMENTS									
RBC	27	AGA Membership Dues	SALESREV	161	90	2	70	0	9	80	1
RBC	28	EAPA Membership Dues	CLAIMREV	38	15	12	11	0	1	13	12
RBC	29	PUC Assess - Gas	CLAIMREV	1,029	399	323	306	1	38	360	318
RBC	30	Cellent Gas Meter Reading	PLT_381	0	0	0	0	0	0	0	0
RBC	31	Gas Software Maintenance	DISTPLT	27	15	0	12	0	0	15	0
RBC	32	Customer and Research	CUSTBILLS	67	0	0	67	0	0	0	0
RBC	33	VEBA Adjustment	SALWAGES	774	407	0	367	4	47	355	0
RBC	34	Facility Contracts	DISTPLT	13	7	0	6	0	0	7	0
RBC	35	IT License & Maintenance	TOTPLT	283	166	0	117	1	12	153	0
RBC	36	Fleet Activities	GENLPLT	100	52	0	47	1	6	46	0
RBC	37	Prepaid Rent	DISTPLT	47	27	0	20	0	0	27	0
RBC	38	Postage	CUSTBILLS	194	0	0	194	0	0	0	0
RBC	39	TOTAL AVERAGE PREPAYMENTS		2,733	1,178	337	1,217	7	113	1,057	331
RBC	40										
RBC	41										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBC	43								
RBC	44								
RBC	45								
RBC	46								
RBC	47								
RBC	48								
RBC	49								
RBC	50								
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**							
RBC	2								
RBC	3	**LAG/LEAD DAYS**		NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS	NET DAYS
RBC	4	REVENUE LAG DAYS	48.86						
RBC	5	EXPENSE LEAD DAYS	38.46	10	10	10	10	10	10
RBC	6								
RBC	7	PURCHASED GAS EXP LEAD DAYS	33.24	16	16	16	16	16	16
RBC	8								
RBC	9								
RBC	10								
RBC	11								
RBC	12								
RBC	13								
RBC	14								
RBC	15								
RBC	16	DISTRIBUTION ACCRUED TAXES							
RBC	17	Federal Income Tax	EBT	7,274	82,804	20,832	2,418	382	1,565
RBC	18	State Income Tax	EBT	774	8,807	2,216	257	41	166
RBC	19	PURTA Taxes	TOTPLT	0	70,314	23,368	218	29	295
RBC	20	PA Capital Stock Tax	TOTPLT	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	TOTPLT	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	0	39,221	13,035	122	16	165
RBC	23	TOTAL ACCRUED TAXES		8,048	201,145	59,451	3,016	467	2,191
RBC	24	TOTAL ACCRUED TAXES PER DAY		22	551	163	8	1	6
RBC	25								
RBC	26	DISTRIBUTION AVERAGE PREPAYMENTS							
RBC	27	AGA Membership Dues	SALESREV	1	37	14	5	3	11
RBC	28	EAPA Membership Dues	CLAIMREV	0	7	2	1	0	1
RBC	29	PUC Assess - Gas	CLAIMREV	5	175	60	21	12	39
RBC	30	Cellent Gas Meter Reading	PLT_381	0	0	0	0	0	0
RBC	31	Gas Software Maintenance	DISTPLT	0	9	3	0	0	0
RBC	32	Customer and Research	CUSTBILLS	0	0	0	0	67	0
RBC	33	VEBA Adjustment	SALWAGES	0	87	45	95	12	128
RBC	34	Facility Contracts	DISTPLT	0	4	1	0	0	0
RBC	35	IT License & Maintenance	TOTPLT	0	87	29	0	0	0
RBC	36	Fleet Activities	GENLPLT	0	11	6	12	2	17
RBC	37	Prepaid Rent	DISTPLT	0	15	5	0	0	0
RBC	38	Postage	CUSTBILLS	0	0	0	0	194	0
RBC	39	TOTAL AVERAGE PREPAYMENTS		6	432	165	134	290	196
RBC	40								
RBC	41								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBC	42										
RBC	43										
RBC	44										
RBC	45										
RBC	46										
RBC	47										
RBC	48										
RBC	49										
RBC	50										
RBC	51	**OPERATING REVENUES**									
RBC	52										
RBC	53	**SALES REVENUES**									
RBC	54	Sales of Gas Revenues - Base		481,982	267,594	4,671	209,717	917	26,276	240,401	2,147
RBC	55	Sales Revenues - Purchased Gas-PGC	EGAS	234,407	0	234,407	0	0	0	0	234,407
RBC	56	Sales Revenues - Balancing Service Charge-BSC	EBSC	26,508	0	26,508	0	0	0	0	26,508
RBC	57	TOTAL SALES OF GAS		742,897	267,594	265,586	209,717	917	26,276	240,401	263,062
RBC	58										
RBC	59	**OTHER OPERATING REVENUES**									
RBC	60	487-Forfeited Discounts	REV_487	1,329	743	13	573	3	73	667	6
RBC	61	489-Revenues from Transportation of Gas of Others	PLT_376	0	0	0	0	0	0	0	0
RBC	62	493-Rent from Gas Property	DISTPLT	1,703	967	0	736	0	0	967	0
RBC	63	495-Other Gas Revenues	SALWAGES	517	272	0	246	3	32	237	0
RBC	64	TOTAL OTHER OPERATING REV		3,549	1,981	13	1,555	5	104	1,871	6
RBC	65										
RBC	66	**TOTAL OPERATING REVENUES**		746,445	269,575	265,599	211,272	922	26,380	242,273	263,068
RBC	67										
RBC	68										
RBC	69										
RBC	70										
RBC	71										
RBC	72										
RBC	73										
RBC	74										
RBC	75										
RBC	76										
RBC	77										
RBC	78										
RBC	79										
RBC	80										
RBC	81										
RBC	82										
RBC	83										
RBC	84										
RBC	85										
RBC	86										
RBC	87										
RBC	88										
RBC	89										
RBC	90										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBC	42								
RBC	43								
RBC	44								
RBC	45								
RBC	46								
RBC	47								
RBC	48								
RBC	49								
RBC	50								
RBC	51	**OPERATING REVENUES**							
RBC	52								
RBC	53	**SALES REVENUES**							
RBC	54	Sales of Gas Revenues - Base		2,524	110,977	41,015	16,209	9,844	31,670
RBC	55	Sales Revenues - Purchased Gas-PGC	EGAS	0	0	0	0	0	0
RBC	56	Sales Revenues - Balancing Service Charge-BSC	EBSC	0	0	0	0	0	0
RBC	57	TOTAL SALES OF GAS		2,524	110,977	41,015	16,209	9,844	31,670
RBC	58								
RBC	59	**OTHER OPERATING REVENUES**							
RBC	60	487-Forfeited Discounts	REV_487	7	304	113	44	27	86
RBC	61	489-Revenues from Transportation of Gas of Others	PLT_376	0	0	0	0	0	0
RBC	62	493-Rent from Gas Property	DISTPLT	0	553	183	0	0	0
RBC	63	495-Other Gas Revenues	SALWAGES	0	58	30	64	8	86
RBC	64	TOTAL OTHER OPERATING REV		7	915	326	107	35	172
RBC	65								
RBC	66	**TOTAL OPERATING REVENUES**		2,531	111,892	41,342	16,317	9,879	31,842
RBC	67								
RBC	68								
RBC	69								
RBC	70								
RBC	71								
RBC	72								
RBC	73								
RBC	74								
RBC	75								
RBC	76								
RBC	77								
RBC	78								
RBC	79								
RBC	80								
RBC	81								
RBC	82								
RBC	83								
RBC	84								
RBC	85								
RBC	86								
RBC	87								
RBC	88								
RBC	89								
RBC	90								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RBC	91										
RBC	92										
RBC	93										
RBC	94										
RBC	95										
RBC	96										
RBC	97										
RBC	98										
RBC	99										
RBC	100										
E	1	**OPERATION & MAINTENANCE EXPENSE**									
E	2	PRODUCTION EXPENSE									
E	3	Manufactured Gas Production Expense									
E	4	Operation									
E	5	710-Operations Labor	DPKDAYP	7	7	0	0	7	0	0	0
E	6	717-Liquefied Petroleum Gas Expenses	DPKDAYP	129	129	0	0	129	0	0	0
E	7	Total Operation		137	137	0	0	137	0	0	0
E	8	Maintenance									
E	9	741-Maintenance of Structures and Improvements	DPKDAYP	86	86	0	0	86	0	0	0
E	10	742-Maintenance of Production Equipment	DPKDAYP	215	215	0	0	215	0	0	0
E	11	Total Maintenance		302	302	0	0	302	0	0	0
E	12	Total Manufactured Gas Production Expense		439	439	0	0	439	0	0	0
E	13	Other Gas Supply Expense									
E	14	Operation									
E	15	804-Natural Gas Purchases-PGC	EGAS	234,407	0	234,407	0	0	0	0	234,407
E	16	804-Natural Gas Purchases-BSC	EBSC	26,508	0	26,508	0	0	0	0	26,508
E	17	805-Other Natural Gas Purchases	ETHRUPUT	0	0	0	0	0	0	0	0
E	18	807-Purchased Gas Expenses	ESTORAGE	17	0	17	0	0	0	0	0
E	19	808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	0	0	0	0	0	0	0	0
E	20	808.1 Gas withdrawn from storage—Direct	ETHRUPUTT	0	0	0	0	0	0	0	0
E	21	Total Other Gas Supply Expense		260,932	0	260,932	0	0	0	0	260,915
E	22	TOTAL PRODUCTION EXPENSE		261,371	439	260,932	0	439	0	0	260,915
E	23										
E	24	NATURAL GAS STORAGE EXPENSE									
E	25	Operation									
E	26	840-Operation Supervision and Engineering	DPKDAYS	363	363	0	0	0	363	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYS	929	929	0	0	0	929	0	0
E	28	Total Operation		1,292	1,292	0	0	0	1,292	0	0
E	29	Maintenance									
E	30	843-Maintenance Expense	DPKDAYS	5,043	5,043	0	0	0	5,043	0	0
E	31	Total Maintenance		5,043	5,043	0	0	0	5,043	0	0
E	32	Total Natural Gas Storage Expense		6,335	6,335	0	0	0	6,335	0	0
E	33										
E	34	TRANSMISSION EXPENSES									
E	35	Operation Expense	TRANPLT	0	0	0	0	0	0	0	0
E	36	Maintenance Expense	TRANPLT	0	0	0	0	0	0	0	0
E	37	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0
E	38										
E	39	DISTRIBUTION EXPENSES									

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RBC	91								
RBC	92								
RBC	93								
RBC	94								
RBC	95								
RBC	96								
RBC	97								
RBC	98								
RBC	99								
RBC	100								
E	1	**OPERATION & MAINTENANCE EXPENSE**							
E	2	PRODUCTION EXPENSE							
E	3	Manufactured Gas Production Expense							
E	4	Operation							
E	5	710-Operations Labor	DPKDAYP	0	0	0	0	0	0
E	6	717-Liquefied Petroleum Gas Expenses	DPKDAYP	0	0	0	0	0	0
E	7	Total Operation		0	0	0	0	0	0
E	8	Maintenance							
E	9	741-Maintenance of Structures and Improvements	DPKDAYP	0	0	0	0	0	0
E	10	742-Maintenance of Production Equipment	DPKDAYP	0	0	0	0	0	0
E	11	Total Maintenance		0	0	0	0	0	0
E	12	Total Manufactured Gas Production Expense		0	0	0	0	0	0
E	13	Other Gas Supply Expense							
E	14	Operation							
E	15	804-Natural Gas Purchases-PGC	EGAS	0	0	0	0	0	0
E	16	804-Natural Gas Purchases-BSC	EBSC	0	0	0	0	0	0
E	17	805-Other Natural Gas Purchases	ETHRUPUT	0	0	0	0	0	0
E	18	807-Purchased Gas Expenses	ESTORAGE	17	0	0	0	0	0
E	19	808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	0	0	0	0	0	0
E	20	808.1 Gas withdrawn from storage—Direct	ETHRUPUTT	0	0	0	0	0	0
E	21	Total Other Gas Supply Expense		17	0	0	0	0	0
E	22	TOTAL PRODUCTION EXPENSE		17	0	0	0	0	0
E	23								
E	24	NATURAL GAS STORAGE EXPENSE							
E	25	Operation							
E	26	840-Operation Supervision and Engineering	DPKDAYS	0	0	0	0	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYS	0	0	0	0	0	0
E	28	Total Operation		0	0	0	0	0	0
E	29	Maintenance							
E	30	843-Maintenance Expense	DPKDAYS	0	0	0	0	0	0
E	31	Total Maintenance		0	0	0	0	0	0
E	32	Total Natural Gas Storage Expense		0	0	0	0	0	0
E	33								
E	34	TRANSMISSION EXPENSES							
E	35	Operation Expense	TRANPLT	0	0	0	0	0	0
E	36	Maintenance Expense	TRANPLT	0	0	0	0	0	0
E	37	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0
E	38								
E	39	DISTRIBUTION EXPENSES							

PECO Energy Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
E	40	Operation									
E	41	870-Operation Supervision and Engineering	SALWAGDO	538	210	0	328	0	0	210	0
E	42	874-Mains and Services Expenses	PLT_376380	19,001	11,890	0	7,111	0	0	11,890	0
E	43	875-Measuring & Reg. Station Exp.-General	PLT_378	1,901	1,901	0	0	0	0	1,901	0
E	44	877-Measuring & Reg. Station Exp.-City Gate Sta.	PLT_379	0	0	0	0	0	0	0	0
E	45	878-Meter & House Regulator Expenses	PLT_3815	7,627	0	0	7,627	0	0	0	0
E	46	879-Customer Installations Expenses	CUSTINSTALL	8,140	0	0	8,140	0	0	0	0
E	47	880-Other Expenses	DISTPLT	19,955	11,327	0	8,628	0	0	11,327	0
E	48	880-Other Expenses - GPC	E880DA	(1,742)	0	(1,742)	0	0	0	0	0
E	49	Total Distribution Operation		55,422	25,330	(1,742)	31,834	0	0	25,330	0
E	50										
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
E	52	DISTRIBUTION EXPENSES CONTINUED									
E	53	Maintenance									
E	54	887-Maintenance of Mains	PLT_376	26,734	26,734	0	0	0	0	26,734	0
E	55	889-Maint. of Measuring & Reg. Station Equip.-Gen	PLT_378	1,537	1,537	0	0	0	0	1,537	0
E	56	892-Maintenance of Services	PLT_380	2,864	0	0	2,864	0	0	0	0
E	57	893-Maint. of Meters & House Regulators	PLT_3815	243	0	0	243	0	0	0	0
E	58	894-Maintenance of Other Equipment	DISTPLT	680	386	0	294	0	0	386	0
E	59	Total Distribution Maintenance		32,058	28,657	0	3,402	0	0	28,657	0
E	60	TOTAL DISTRIBUTION PLANT O&M EXPENSES		87,480	53,986	(1,742)	35,236	0	0	53,986	0
E	61	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		355,186	60,760	259,190	35,236	439	6,335	53,986	260,915
E	62										
E	63	CUSTOMER ACCOUNTS EXPENSES									
E	64	902-Meter Reading	CMETRDG	163	0	0	163	0	0	0	0
E	65	903-Customer Records and Collection Expense	CUSTREC	20,632	0	0	20,632	0	0	0	0
E	66	904-Uncollectible Accounts	EXP_904	3,047	1,548	27	1,473	6	168	1,374	14
E	67	904-Uncollectible Accounts - MFC/POR	E904DA	(1,200)	0	(1,200)	0	0	0	0	0
E	68	904-Uncollectible Accounts - PPA	EXP_904PPA	530	258	4	268	1	28	228	3
E	69	905-Miscellaneous CA	CUSTCAM	1,001	0	0	1,001	0	0	0	0
E	70	TOTAL CUSTOMER ACCTS EXPENSE		24,173	1,805	(1,169)	23,537	7	196	1,602	17
E	71										
E	72	CUSTOMER SERVICE & SALES EXPENSES									
E	73	908-Customer Assistance	CUSTASST	7,183	0	0	7,183	0	0	0	0
E	74	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0	0	0	0	0	0	0	0
E	75	909-Advertisement	CUSTADVT	345	0	0	345	0	0	0	0
E	76	910-Miscellaneous CS	CUSTCSM	54	0	0	54	0	0	0	0
E	77	912-Demonstrating and Selling Expenses	CUSTSALES	774	0	0	774	0	0	0	0
E	78	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0	0	0
E	79	TOTAL CUSTOMER SERVICE & SALES EXP		8,357	0	0	8,357	0	0	0	0
E	80	TOTAL OPER & MAINT EXCL A&G		387,716	62,565	258,021	67,129	445	6,532	55,588	260,932
E	81										
E	82	ADMINISTRATIVE & GENERAL EXPENSE									
E	83	920-Administrative Salaries	SALWAGES	7,180	3,771	0	3,409	41	438	3,293	0
E	84	921-Office Supplies & Expense	SALWAGES	1,197	629	0	568	7	73	549	0
E	85	923-Outside Service Employed	SALWAGES	17,810	9,355	0	8,455	101	1,086	8,168	0
E	86	924-Property Insurance	PSTDGPLT	148	87	0	61	1	6	80	0
E	87	925-Injuries and Damages	SALWAGES	410	215	0	195	2	25	188	0
E	88	926-Employee Pensions & Benefits	SALWAGES	8,683	4,561	0	4,122	49	530	3,982	0

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
E	40	Operation							
E	41	870-Operation Supervision and Engineering	SALWAGDO	0	104	69	156	0	0
E	42	874-Mains and Services Expenses	PLT_376380	0	7,111	0	0	0	0
E	43	875-Measuring & Reg. Station Exp.-General	PLT_378	0	0	0	0	0	0
E	44	877-Measuring & Reg. Station Exp.-City Gate Sta.	PLT_379	0	0	0	0	0	0
E	45	878-Meter & House Regulator Expenses	PLT_3815	0	0	7,627	0	0	0
E	46	879-Customer Installations Expenses	CUSTINSTALL	0	0	0	8,140	0	0
E	47	880-Other Expenses	DISTPLT	0	6,478	2,150	0	0	0
E	48	880-Other Expenses - GPC	E880DA	(1,742)	0	0	0	0	0
E	49	Total Distribution Operation		(1,742)	13,693	9,845	8,296	0	0
E	50								
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
E	52	DISTRIBUTION EXPENSES CONTINUED							
E	53	Maintenance							
E	54	887-Maintenance of Mains	PLT_376	0	0	0	0	0	0
E	55	889-Maint. of Measuring & Reg. Station Equip.-Gen	PLT_378	0	0	0	0	0	0
E	56	892-Maintenance of Services	PLT_380	0	2,864	0	0	0	0
E	57	893-Maint. of Meters & House Regulators	PLT_3815	0	0	243	0	0	0
E	58	894-Maintenance of Other Equipment	DISTPLT	0	221	73	0	0	0
E	59	Total Distribution Maintenance		0	3,085	316	0	0	0
E	60	TOTAL DISTRIBUTION PLANT O&M EXPENSES		(1,742)	16,778	10,162	8,296	0	0
E	61	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		(1,725)	16,778	10,162	8,296	0	0
E	62								
E	63	CUSTOMER ACCOUNTS EXPENSES							
E	64	902-Meter Reading	CMETRDG	0	0	0	0	0	163
E	65	903-Customer Records and Collection Expense	CUSTREC	0	0	0	0	0	20,632
E	66	904-Uncollectible Accounts	EXP_904	12	768	265	125	78	237
E	67	904-Uncollectible Accounts - MFC/POR	E904DA	(1,200)	0	0	0	0	0
E	68	904-Uncollectible Accounts - PPA	EXP_904PPA	2	137	46	24	15	45
E	69	905-Miscellaneous CA	CUSTCAM	0	0	0	0	0	1,001
E	70	TOTAL CUSTOMER ACCTS EXPENSE		(1,186)	905	312	150	93	22,078
E	71								
E	72	CUSTOMER SERVICE & SALES EXPENSES							
E	73	908-Customer Assistance	CUSTASST	0	0	0	0	7,183	0
E	74	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0	0	0	0	0	0
E	75	909-Advertisement	CUSTADVT	0	0	0	0	345	0
E	76	910-Miscellaneous CS	CUSTCSM	0	0	0	0	54	0
E	77	912-Demonstrating and Selling Expenses	CUSTSALES	0	0	0	0	774	0
E	78	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0
E	79	TOTAL CUSTOMER SERVICE & SALES EXP		0	0	0	0	8,357	0
E	80	TOTAL OPER & MAINT EXCL A&G		(2,911)	17,683	10,473	8,446	8,450	22,078
E	81								
E	82	ADMINISTRATIVE & GENERAL EXPENSE							
E	83	920-Administrative Salaries	SALWAGES	0	803	415	882	116	1,192
E	84	921-Office Supplies & Expense	SALWAGES	0	134	69	147	19	199
E	85	923-Outside Service Employed	SALWAGES	0	1,993	1,030	2,188	287	2,957
E	86	924-Property Insurance	PSTDGPLT	0	46	15	0	0	0
E	87	925-Injuries and Damages	SALWAGES	0	46	24	50	7	68
E	88	926-Employee Pensions & Benefits	SALWAGES	0	971	502	1,067	140	1,442

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
E	89	928-Regulatory Commission	CLAIMREV	3,637	1,411	1,144	1,082	4	133	1,274	1,125
E	90	929-Duplicate Charges-Credit	CLAIMREV	(7)	(3)	(2)	(2)	(0)	(0)	(2)	(2)
E	91	930.1-General Advertising	CLAIMREV	0	0	0	0	0	0	0	0
E	92	930.2-Miscellaneous General	SALWAGES	828	435	0	393	5	51	380	0
E	93	932-Maintenance of General Plant	GENLPLT	1,015	533	0	482	6	62	466	0
E	94	TOTAL A&G EXPENSE		40,903	20,996	1,141	18,766	215	2,403	18,377	1,123
E	95										
E	96	**TOTAL OPERATION & MAINTENANCE EXPENSES**		428,619	83,561	259,163	85,895	660	8,935	73,966	262,055
E	97										
E	98	**TOTAL PURCHASED GAS O&M EXPENSES**		260,932	0	260,932	0	0	0	0	260,915
E	99	**TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS**		167,687	83,561	(1,769)	85,895	660	8,935	73,966	1,140
E	100										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**									
D	2										
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	15,857	9,306	0	6,550	54	673	8,579	0
D	4										
D	5	PRODUCTION PLANT EXPENSE	PRODPLT	170	170	0	0	170	0	0	0
D	6										
D	7	LOCAL STORAGE PLANT EXPENSE	STORPLT	6,983	6,983	0	0	0	6,983	0	0
D	8										
D	9	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0	0	0
D	10										
D	11	DISTRIBUTION PLANT EXPENSE									
D	12	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0
D	13	375-Structures & Improvements	PLT_375	361	361	0	0	0	0	361	0
D	14	376-Mains									
D	15	General - Excess	PLT_376GE	31,515	31,515	0	0	0	0	31,515	0
D	16	General - Average	PLT_376GA	10,072	10,072	0	0	0	0	10,072	0
D	17	Direct Assignment	DAMAINSDE	222	222	0	0	0	0	222	0
D	18	Total Account 376		41,809	41,809	0	0	0	0	41,809	0
D	19	378-Measuring & Regulating Station Equip-General	PLT_378	584	584	0	0	0	0	584	0
D	20	379-Measuring & Regulating Station Equip-City Gate									
D	21	City Gate	PLT_379CG	822	822	0	0	0	0	822	0
D	22	Direct Assignment	DAMRDE	228	228	0	0	0	0	228	0
D	23	Total Account 379		1,050	1,050	0	0	0	0	1,050	0
D	24	380-Services	PLT_380	28,325	0	0	28,325	0	0	0	0
D	25	381-Meters	CMETERS	5,749	0	0	5,749	0	0	0	0
D	26	Direct Assignment	CMETERSDAE	15	0	0	15	0	0	0	0
D	27	Total Account 381		5,763	0	0	5,763	0	0	0	0
D	28	382-Meter Installations	CMETERS	5,922	0	0	5,922	0	0	0	0
D	29	Direct Assignment	CMETINSTDAE	69	0	0	69	0	0	0	0
D	30	Total Account 382		5,992	0	0	5,992	0	0	0	0
D	31	387-Other Equipment	PLT_378387	93	92	0	1	0	0	92	0
D	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	0	0	0	0	0	0	0	0
D	33	TOTAL DISTRIBUTION PLANT EXPENSE		83,975	43,895	0	40,080	0	0	43,895	0
D	34										
D	35	GENERAL PLANT EXPENSE	GENLPLT	1,927	1,012	0	915	11	118	884	0
D	36										
D	37	COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	8,070	4,239	0	3,831	46	492	3,701	0

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
E	89	928-Regulatory Commission	CLAIMREV	18	617	212	73	42	138
E	90	929-Duplicate Charges-Credit	CLAIMREV	(0)	(1)	(0)	(0)	(0)	(0)
E	91	930.1-General Advertising	CLAIMREV	0	0	0	0	0	0
E	92	930.2-Miscellaneous General	SALWAGES	0	93	48	102	13	137
E	93	932-Maintenance of General Plant	GENLPLT	0	114	59	125	16	169
E	94	TOTAL A&G EXPENSE		18	4,815	2,374	4,634	641	6,301
E	95								
E	96	**TOTAL OPERATION & MAINTENANCE EXPENSES**		(2,892)	22,498	12,848	13,079	9,091	28,379
E	97								
E	98	**TOTAL PURCHASED GAS O&M EXPENSES**		17	0	0	0	0	0
E	99	**TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS**		(2,909)	22,498	12,848	13,079	9,091	28,379
E	100								
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**							
D	2								
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	0	4,888	1,625	15	2	21
D	4								
D	5	PRODUCTION PLANT EXPENSE	PRODPLT	0	0	0	0	0	0
D	6								
D	7	LOCAL STORAGE PLANT EXPENSE	STORPLT	0	0	0	0	0	0
D	8								
D	9	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0
D	10								
D	11	DISTRIBUTION PLANT EXPENSE							
D	12	374-Land Rights	PLT_374	0	0	0	0	0	0
D	13	375-Structures & Improvements	PLT_375	0	0	0	0	0	0
D	14	376-Mains							
D	15	General - Excess	PLT_376GE	0	0	0	0	0	0
D	16	General - Average	PLT_376GA	0	0	0	0	0	0
D	17	Direct Assignment	DAMAINSDE	0	0	0	0	0	0
D	18	Total Account 376		0	0	0	0	0	0
D	19	378-Measuring & Regulating Station Equip-General	PLT_378	0	0	0	0	0	0
D	20	379-Measuring & Regulating Station Equip-City Gate							
D	21	City Gate	PLT_379CG	0	0	0	0	0	0
D	22	Direct Assignment	DAMRDE	0	0	0	0	0	0
D	23	Total Account 379		0	0	0	0	0	0
D	24	380-Services	PLT_380	0	28,325	0	0	0	0
D	25	381-Meters	CMETERS	0	0	5,749	0	0	0
D	26	Direct Assignment	CMETERSDAE	0	0	15	0	0	0
D	27	Total Account 381		0	0	5,763	0	0	0
D	28	382-Meter Installations	CMETERS	0	0	5,922	0	0	0
D	29	Direct Assignment	CMETINSTDAE	0	0	69	0	0	0
D	30	Total Account 382		0	0	5,992	0	0	0
D	31	387-Other Equipment	PLT_378387	0	1	0	0	0	0
D	32	388-Asset Retirement Costs for Distribution Plant	PLT_388	0	0	0	0	0	0
D	33	TOTAL DISTRIBUTION PLANT EXPENSE		0	28,325	11,755	0	0	0
D	34								
D	35	GENERAL PLANT EXPENSE	GENLPLT	0	216	111	237	31	320
D	36								
D	37	COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	0	903	467	991	130	1,340

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
D	38										
D	39	NET MANUFACTURED GAS PLANT EXP	ETHRUPUT	1,431	0	1,431	0	0	0	0	0
D	40	NET AMORTIZATION OF CUSTOMER PROGRAMS	TOTPLT	0	0	0	0	0	0	0	0
D	41	Direct Assignment - EE	CSEHPDA	321	0	0	321	0	0	0	0
D	42	Direct Assignment - Gas Unbundling	OX_880904DA	28	0	28	0	0	0	0	0
D	43	TOTAL NET AMORTIZATION OF CUSTOMER PROGRAMS		349	0	28	321	0	0	0	0
D	44										
D	45	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		118,763	65,605	1,459	51,698	281	8,265	57,059	0
D	46										
D	47										
D	48										
D	49										
D	50										
TO	1	**OTHER OPERATING EXPENSES**									
TO	2										
TO	3	**TAXES OTHER THAN INCOME TAXES**									
TO	4	**General Taxes**									
TO	5	PURTA Taxes	TOTPLT	2,076	1,219	0	858	7	88	1,123	0
TO	6	Capital Stock	TOTPLT	0	0	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	4,463	2,344	0	2,119	25	272	2,047	0
TO	8	Real Estate Tax	TOTPLT	1,796	1,054	0	742	6	76	972	0
TO	9	PA and Local Use Tax	CLAIMREV	732	284	230	218	1	27	257	227
TO	10	Total General Taxes		9,067	4,901	230	3,936	39	463	4,398	227
TO	11										
TO	12										
TO	13	**Franchise and Revenue Taxes**									
TO	14	Retail Revenue		0	0	0	0	0	0	0	0
TO	15	Forfeited Discounts		0	0	0	0	0	0	0	0
TO	16	Less: Bad Debt		0	0	0	0	0	0	0	0
TO	17	Total Revenue	CALCULATED	0	0	0	0	0	0	0	0
TO	18	Total Distribution @ GRT Rate 0.00%	CALCULATED	0	0	0	0	0	0	0	0
TO	19	Total Franchise and Revenue Taxes		0	0	0	0	0	0	0	0
TO	20										
TO	21	**TOTAL TAXES OTHER THAN INCOME**		9,067	4,901	230	3,936	39	463	4,398	227
TO	22										
TO	23										
TO	24										
TO	25										
TO	26										
TO	27										
TO	28										
TO	29										
TO	30										
TO	31										
TO	32										
TO	33										
TO	34										
TO	35										
TO	36										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
D	38								
D	39	NET MANUFACTURED GAS PLANT EXP	ETHRUPUT	1,431	0	0	0	0	0
D	40	NET AMORTIZATION OF CUSTOMER PROGRAMS	TOTPLT	0	0	0	0	0	0
D	41	Direct Assignment - EE	CSEHPDA	0	0	0	0	321	0
D	42	Direct Assignment - Gas Unbundling	OX_880904DA	28	0	0	0	0	0
D	43	TOTAL NET AMORTIZATION OF CUSTOMER PROGRAMS		28	0	0	0	321	0
D	44								
D	45	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		1,459	34,332	13,958	1,243	484	1,680
D	46								
D	47								
D	48								
D	49								
D	50								
TO	1	**OTHER OPERATING EXPENSES**							
TO	2								
TO	3	**TAXES OTHER THAN INCOME TAXES**							
TO	4	**General Taxes**							
TO	5	PURTA Taxes	TOTPLT	0	640	213	2	0	3
TO	6	Capital Stock	TOTPLT	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	0	499	258	548	72	741
TO	8	Real Estate Tax	TOTPLT	0	554	184	2	0	2
TO	9	PA and Local Use Tax	CLAIMREV	4	124	43	15	9	28
TO	10	Total General Taxes		4	1,817	698	567	81	774
TO	11								
TO	12								
TO	13	**Franchise and Revenue Taxes**							
TO	14	Retail Revenue		0	0	0	0	0	0
TO	15	Forfeited Discounts		0	0	0	0	0	0
TO	16	Less: Bad Debt		0	0	0	0	0	0
TO	17	Total Revenue	CALCULATED	0	0	0	0	0	0
TO	18	Total Distribution @ GRT Rate 0.00%	CALCULATED	0	0	0	0	0	0
TO	19	Total Franchise and Revenue Taxes		0	0	0	0	0	0
TO	20								
TO	21	**TOTAL TAXES OTHER THAN INCOME**		4	1,817	698	567	81	774
TO	22								
TO	23								
TO	24								
TO	25								
TO	26								
TO	27								
TO	28								
TO	29								
TO	30								
TO	31								
TO	32								
TO	33								
TO	34								
TO	35								
TO	36								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
TO	37										
TO	38										
TO	39										
TO	40										
TO	41										
TO	42										
TO	43										
TO	44										
TO	45										
TO	46										
TO	47										
TO	48										
TO	49										
TO	50										
TI	1	**DEVELOPMENT OF INCOME TAXES**									
TI	2										
TI	3	TOTAL OPERATING REVENUES EXCL PURCHASED GAS		485,530	269,575	4,684	211,272	922	26,380	242,273	2,153
TI	4	LESS:									
TI	5	OPER. & MAINT. EXP. EXCL PURCHASED GAS	SCH E, LN 99	167,687	83,561	(1,769)	85,895	660	8,935	73,966	1,140
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	SCH D, LN 45	118,763	65,605	1,459	51,698	281	8,265	57,059	0
TI	7	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 21	9,067	4,901	230	3,936	39	463	4,398	227
TI	8	NET OPERATING INCOME BEFORE TAXES		190,014	115,507	4,764	69,743	(59)	8,716	106,850	786
TI	9	LESS:									
TI	10	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		74,848	44,651	1,237	28,959	35	3,326	41,290	24
TI	11										
TI	12	**BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS**		115,166	70,856	3,526	40,784	(94)	5,390	65,559	762
TI	13										
TI	14	**FEDERAL & STATE TAX ADJUSTMENTS**									
TI	15	Regulatory Asset Programs M-1 (Pension & Post Ret	SALWAGES	3,619	1,901	0	1,718	20	221	1,660	0
TI	16	Other Property Basis Adjustment (CIAC/ICM)	DISTPLT	21,960	12,465	0	9,495	0	0	12,465	0
TI	17	Removal Costs/Software	TOTPLT	2,426	1,424	0	1,002	8	103	1,313	0
TI	18	AFUDC Equity	TOTPLT	7,418	4,354	0	3,064	25	315	4,013	0
TI	19	Permanent Adjustments	TOTPLT	(805)	(473)	(0)	(333)	(3)	(34)	(436)	(0)
TI	20	Repair Deduction	TOTPLT	151,000	88,623	0	62,377	516	6,409	81,698	0
TI	21	TOTAL FEDERAL & STATE TAX ADJUSTMENTS		185,617	108,294	0	77,323	567	7,013	100,713	0
TI	22										
TI	23	**CALCULATION OF PA STATE INCOME TAXES**									
TI	24	BASE TAXABLE INCOME	SCH TI, LN 12	115,166	70,856	3,526	40,784	(94)	5,390	65,559	762
TI	25	LESS:									
TI	26	State Tax Depreciation (Over) Under Book	TOTPLT	3,125	1,834	0	1,291	11	133	1,691	0
TI	27	Total Tax Adjustments	SCH TI, LN 21	185,617	108,294	0	77,323	567	7,013	100,713	0
TI	28	PA STATE TAXALBE DISTRIBUTION INCOME		(73,576)	(39,272)	3,526	(37,830)	(671)	(1,756)	(36,844)	762
TI	29	**PA STATE INCOME TAXES @ Tax Rate 7.99%**		(5,879)	(3,138)	282	(3,023)	(54)	(140)	(2,944)	61
TI	30	**PLUS: DEFERRED STATE INCOME TAXES**									
TI	31	Net Operating Loss Utilization	CALCULATED	2,351	1,255	(113)	1,209	21	56	1,178	(24)
TI	32	**TOTAL STATE INCOME TAX**		3,527	1,883	(169)	1,814	32	84	1,766	(37)
TI	33	Deferred Taxes on Timing Differences - State	TOTPLT	(2,044)	(1,199)	(0)	(844)	(7)	(87)	(1,106)	(0)
TI	34	Excess Deferred Amortization	TOTPLT	271	159	0	112	1	12	147	0
TI	35	Deferred Taxes on State NOL	TOTPLT	2,359	1,384	0	974	8	100	1,276	0

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
TO	37								
TO	38								
TO	39								
TO	40								
TO	41								
TO	42								
TO	43								
TO	44								
TO	45								
TO	46								
TO	47								
TO	48								
TO	49								
TO	50								
TI	1	**DEVELOPMENT OF INCOME TAXES**							
TI	2								
TI	3	TOTAL OPERATING REVENUES EXCL PURCHASED GAS		2,531	111,892	41,342	16,317	9,879	31,842
TI	4	LESS:							
TI	5	OPER. & MAINT. EXP. EXCL PURCHASED GAS	SCH E, LN 99	(2,909)	22,498	12,848	13,079	9,091	28,379
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	SCH D, LN 45	1,459	34,332	13,958	1,243	484	1,680
TI	7	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 21	4	1,817	698	567	81	774
TI	8	NET OPERATING INCOME BEFORE TAXES		3,977	53,245	13,839	1,427	223	1,009
TI	9	LESS:							
TI	10	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		1,213	21,976	5,972	514	79	418
TI	11								
TI	12	**BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS**		2,764	31,268	7,867	913	144	591
TI	13								
TI	14	**FEDERAL & STATE TAX ADJUSTMENTS**							
TI	15	Regulatory Asset Programs M-1 (Pension & Post Ret	SALWAGES	0	405	209	445	58	601
TI	16	Other Property Basis Adjustment (CIAC/ICM)	DISTPLT	0	7,129	2,366	0	0	0
TI	17	Removal Costs/Software	TOTPLT	0	748	249	2	0	3
TI	18	AFUDC Equity	TOTPLT	0	2,287	760	7	1	10
TI	19	Permanent Adjustments	TOTPLT	(0)	(248)	(83)	(1)	(0)	(1)
TI	20	Repair Deduction	TOTPLT	0	46,548	15,470	144	19	195
TI	21	TOTAL FEDERAL & STATE TAX ADJUSTMENTS		0	56,868	18,971	598	78	808
TI	22								
TI	23	**CALCULATION OF PA STATE INCOME TAXES**							
TI	24	BASE TAXABLE INCOME	SCH TI, LN 12	2,764	31,268	7,867	913	144	591
TI	25	LESS:							
TI	26	State Tax Depreciation (Over) Under Book	TOTPLT	0	963	320	3	0	4
TI	27	Total Tax Adjustments	SCH TI, LN 21	0	56,868	18,971	598	78	808
TI	28	PA STATE TAXALBE DISTRIBUTION INCOME		2,764	(26,563)	(11,424)	313	65	(221)
TI	29	**PA STATE INCOME TAXES @ Tax Rate 7.99%**		221	(2,122)	(913)	25	5	(18)
TI	30	**PLUS: DEFERRED STATE INCOME TAXES**							
TI	31	Net Operating Loss Utilization	CALCULATED	(88)	849	365	(10)	(2)	7
TI	32	**TOTAL STATE INCOME TAX**		(133)	1,273	548	(15)	(3)	11
TI	33	Deferred Taxes on Timing Differences - State	TOTPLT	(0)	(630)	(209)	(2)	(0)	(3)
TI	34	Excess Deferred Amortization	TOTPLT	0	84	28	0	0	0
TI	35	Deferred Taxes on State NOL	TOTPLT	0	727	242	2	0	3

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
TI	36	**TOTAL STATE INCOME TAX EXPENSE**		4,113	2,227	(169)	2,056	34	109	2,084	(37)
TI	37										
TI	38	**CALCULATION OF FEDERAL INCOME TAXES**									
TI	39	BASE TAXABLE INCOME	SCH TI, LN 12	115,166	70,856	3,526	40,784	(94)	5,390	65,559	762
TI	40	LESS:									
TI	41	PA State Income Taxes	CALCULATED	(3,527)	(1,883)	169	(1,814)	(32)	(84)	(1,766)	37
TI	42	Federal Tax Depreciation (Over) Under Book	TOTPLT	(4,332)	(2,542)	(0)	(1,789)	(15)	(184)	(2,344)	(0)
TI	43	Total Tax Adjustments	SCH TI, LN 21	185,617	108,294	0	77,323	567	7,013	100,713	0
TI	44	FEDERAL TAXALBE DISTRIBUTION INCOME		(62,592)	(33,013)	3,357	(32,937)	(614)	(1,355)	(31,044)	726
TI	45	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		13,144	6,933	(705)	6,917	129	285	6,519	(152)
TI	46										
TI	47										
TI	48										
TI	49										
TI	50										
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**									
TI	52										
TI	53	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**	SCH TI, LN 45	13,144	6,933	(705)	6,917	129	285	6,519	(152)
TI	54	**PLUS: DEFERRED FEDERAL INCOME TAXES**									
TI	55	Deferred Taxes on Timing Differences - Federal	TOTPLT	(5,037)	(2,957)	(0)	(2,081)	(17)	(214)	(2,726)	(0)
TI	56	Excess Deferred Amortization	TOTPLT	3,023	1,774	0	1,249	10	128	1,636	0
TI	57	FIT Expense on Flow Through Adjustments	TOTPLT	(951)	(558)	(0)	(393)	(3)	(40)	(515)	(0)
TI	58	**LESS: OTHER FEDERAL TAX ADJUSTMENTS**									
TI	59	Amortization of ITC - Gas Plant	TOTPLT	(5)	(3)	(0)	(2)	(0)	(0)	(2)	(0)
TI	60	**TOTAL FEDERAL INCOME TAX EXPENSE**		10,184	5,195	(705)	5,694	119	159	4,917	(152)
TI	61	**TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS**		14,297	7,422	(874)	7,749	153	268	7,001	(189)
TI	62										
TI	63	**DEVELOPMENT OF PURCHASED GAS TAXES**									
TI	64	PURCHASED GAS OPERATING REVENUES		260,915	0	260,915	0	0	0	0	260,915
TI	65	LESS:									
TI	66	OPERATION & MAINTAINENCE EXPENSE		260,932	0	260,932	0	0	0	0	260,915
TI	67	NET OPERATING INCOME BEFORE TAXES		(17)	0	(17)	0	0	0	0	0
TI	68	LESS:									
TI	69	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		214	0	214	0	0	0	0	214
TI	70	**BASE TAXABLE PURCHASED GAS INCOME**		(231)	0	(231)	0	0	0	0	(214)
TI	71	LESS:									
TI	72	**PA STATE PURCHASED GAS INCOME TAXES @ Tax Rate 7.99%**		(18)	0	(18)	0	0	0	0	(17)
TI	73	Net Operating Loss Utilization	CALCULATED	7	0	7	0	0	0	0	7
TI	74	**TOTAL STATE INCOME TAX**		11	0	11	0	0	0	0	10
TI	75	EQUALS:									
TI	76	**FEDERAL PURCHASED GAS INCOME TAXES @ Tax Rate 21.00%**		46	0	46	0	0	0	0	43
TI	77										
TI	78	**TOTAL PA INCOME TAX EXPENSE**		4,125	2,227	(158)	2,056	34	109	2,084	(26)
TI	79	**TOTAL FEDERAL INCOME TAX EXPENSE**		10,230	5,195	(659)	5,694	119	159	4,917	(110)
TI	80	**TOTAL INCOME TAX EXPENSE**		14,354	7,422	(817)	7,749	153	268	7,001	(136)
TI	81										
TI	82	**TOTAL OTHER TAX EXPENSE**		9,067	4,901	230	3,936	39	463	4,398	227
TI	83										
TI	84	**TOTAL TAX EXPENSE**		23,422	12,323	(587)	11,686	192	731	11,399	91

PECO Energy Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
TI	36	**TOTAL STATE INCOME TAX EXPENSE**		(133)	1,454	608	(14)	(3)	11
TI	37								
TI	38	**CALCULATION OF FEDERAL INCOME TAXES**							
TI	39	BASE TAXABLE INCOME	SCH TI, LN 12	2,764	31,268	7,867	913	144	591
TI	40	LESS:							
TI	41	PA State Income Taxes	CALCULATED	133	(1,273)	(548)	15	3	(11)
TI	42	Federal Tax Depreciation (Over) Under Book	TOTPLT	(0)	(1,335)	(444)	(4)	(1)	(6)
TI	43	Total Tax Adjustments	SCH TI, LN 21	0	56,868	18,971	598	78	808
TI	44	FEDERAL TAXALBE DISTRIBUTION INCOME		2,632	(22,991)	(10,113)	305	63	(201)
TI	45	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		(553)	4,828	2,124	(64)	(13)	42
TI	46								
TI	47								
TI	48								
TI	49								
TI	50								
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
TI	52								
TI	53	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**	SCH TI, LN 45	(553)	4,828	2,124	(64)	(13)	42
TI	54	**PLUS: DEFERRED FEDERAL INCOME TAXES**							
TI	55	Deferred Taxes on Timing Differences - Federal	TOTPLT	(0)	(1,553)	(516)	(5)	(1)	(7)
TI	56	Excess Deferred Amortization	TOTPLT	0	932	310	3	0	4
TI	57	FIT Expense on Flow Through Adjustments	TOTPLT	(0)	(293)	(97)	(1)	(0)	(1)
TI	58	**LESS: OTHER FEDERAL TAX ADJUSTMENTS**							
TI	59	Amortization of ITC - Gas Plant	TOTPLT	(0)	(1)	(0)	(0)	(0)	(0)
TI	60	**TOTAL FEDERAL INCOME TAX EXPENSE**		(553)	3,916	1,820	(67)	(14)	38
TI	61	**TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS**		(685)	5,370	2,428	(81)	(17)	50
TI	62								
TI	63	**DEVELOPMENT OF PURCHASED GAS TAXES**							
TI	64	PURCHASED GAS OPERATING REVENUES		0	0	0	0	0	0
TI	65	LESS:							
TI	66	OPERATION & MAINTAINENCE EXPENSE		17	0	0	0	0	0
TI	67	NET OPERATING INCOME BEFORE TAXES		(17)	0	0	0	0	0
TI	68	LESS:							
TI	69	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)		0	0	0	0	0	0
TI	70	**BASE TAXABLE PURCHASED GAS INCOME**		(17)	0	0	0	0	0
TI	71	LESS:							
TI	72	**PA STATE PURCHASED GAS INCOME TAXES @ Tax Rate 7.99%**		(1)	0	0	0	0	0
TI	73	Net Operating Loss Utilization	CALCULATED	1	0	0	0	0	0
TI	74	**TOTAL STATE INCOME TAX**		1	0	0	0	0	0
TI	75	EQUALS:							
TI	76	**FEDERAL PURCHASED GAS INCOME TAXES @ Tax Rate 21.00%**		3	0	0	0	0	0
TI	77								
TI	78	**TOTAL PA INCOME TAX EXPENSE**		(132)	1,454	608	(14)	(3)	11
TI	79	**TOTAL FEDERAL INCOME TAX EXPENSE**		(549)	3,916	1,820	(67)	(14)	38
TI	80	**TOTAL INCOME TAX EXPENSE**		(681)	5,370	2,428	(81)	(17)	50
TI	81								
TI	82	**TOTAL OTHER TAX EXPENSE**		4	1,817	698	567	81	774
TI	83								
TI	84	**TOTAL TAX EXPENSE**		(677)	7,187	3,126	485	64	823

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
TI	85										
TI	86										
TI	87										
TI	88										
TI	89										
TI	90	**TAX RATES & FACTORS**									
TI	91	GROSS RECEIPTS TAX RATE	0.00%								
TI	92	STATE TAX RATE	7.99%								
TI	93	FEDERAL TAX RATE - CURRENT	21.00%								
TI	94										
TI	95	LPC REVENUE FACTOR	0.00161								
TI	96	GROSS REVENUE CONVERSION FACTOR	1.38289								
TI	97	UNCOLLECTIBLES EXPENSE FACTOR	0.00369								
TI	98	PUC / OTS & SBA FEE AS % OF REV FACTOR	0.00309								
TI	99	WEIGHTED COST OF DEBT	2.13%								
TI	100										
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**									
SW	2										
SW	3	**PRODUCTION SALARIES & WAGES EXPENSE**									
SW	4	Manufactured Gas Production Expense									
SW	5	Operation - Acct 717	OX_PRODM	80	80	0	0	80	0	0	0
SW	6	Maintenance - Accts 741-742	MX_PRODM	179	179	0	0	179	0	0	0
SW	7	Total Manufactured Gas Production Expense		259	259	0	0	259	0	0	0
SW	8										
SW	9	Other Gas Supply Expense									
SW	10	Operation - Accounts 804-808	OX_PRODO	0	0	0	0	0	0	0	0
SW	11	Total Other Gas Supply		0	0	0	0	0	0	0	0
SW	12	TOTAL PRODUCTION S&W EXP		259	259	0	0	259	0	0	0
SW	13										
SW	14	**STORAGE SALARIES & WAGES EXPENSE**									
SW	15	Operation - Accts 840-841	OX_STOR	678	678	0	0	0	678	0	0
SW	16	Maintenance - Acct 843	MX_STOR	2,108	2,108	0	0	0	2,108	0	0
SW	17	TOTALSTORAGE S&W EXP		2,786	2,786	0	0	0	2,786	0	0
SW	18										
SW	19	**TRANSMISSION SALARIES & WAGES EXPENSE**									
SW	20	Operation	OX_TRAN	0	0	0	0	0	0	0	0
SW	21	Maintenance	MX_TRAN	0	0	0	0	0	0	0	0
SW	22	TOTAL TRANSMISSION S&W EXP		0	0	0	0	0	0	0	0
SW	23										
SW	24	**DISTRIBUTION SALARIES & WAGES EXPENSE**									
SW	25	Operation									
SW	26	874-Mains and Services Expenses	OX_874	6,263	3,919	0	2,344	0	0	3,919	0
SW	27	875-Measuring & Reg. Station Exp.-General	OX_875	1,228	1,228	0	0	0	0	1,228	0
SW	28	878-Meter & House Regulator Expenses	OX_878	2,012	0	0	2,012	0	0	0	0
SW	29	879-Customer Installations Expenses	OX_879	5,612	0	0	5,612	0	0	0	0
SW	30	880-Other Expenses	OX_880	4,291	2,436	0	1,855	0	0	2,436	0
SW	31	880-Other Expenses - GPC	E880DA	0	0	0	0	0	0	0	0
SW	32	Total Operation		19,406	7,583	0	11,824	0	0	7,583	0
SW	33	Maintenance									

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
TI	85								
TI	86								
TI	87								
TI	88								
TI	89								
TI	90	**TAX RATES & FACTORS**							
TI	91	GROSS RECEIPTS TAX RATE	0.00%						
TI	92	STATE TAX RATE	7.99%						
TI	93	FEDERAL TAX RATE - CURRENT	21.00%						
TI	94								
TI	95	LPC REVENUE FACTOR	0.00161						
TI	96	GROSS REVENUE CONVERSION FACTOR	1.38289						
TI	97	UNCOLLECTIBLES EXPENSE FACTOR	0.00369						
TI	98	PUC / OTS & SBA FEE AS % OF REV FACTOR	0.00309						
TI	99	WEIGHTED COST OF DEBT	2.13%						
TI	100								
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**							
SW	2								
SW	3	**PRODUCTION SALARIES & WAGES EXPENSE**							
SW	4	Manufactured Gas Production Expense							
SW	5	Operation - Acct 717	OX_PRODM	0	0	0	0	0	0
SW	6	Maintenance - Accts 741-742	MX_PRODM	0	0	0	0	0	0
SW	7	Total Manufactured Gas Production Expense		0	0	0	0	0	0
SW	8								
SW	9	Other Gas Supply Expense							
SW	10	Operation - Accounts 804-808	OX_PRODO	0	0	0	0	0	0
SW	11	Total Other Gas Supply		0	0	0	0	0	0
SW	12	TOTAL PRODUCTION S&W EXP		0	0	0	0	0	0
SW	13								
SW	14	**STORAGE SALARIES & WAGES EXPENSE**							
SW	15	Operation - Accts 840-841	OX_STOR	0	0	0	0	0	0
SW	16	Maintenance - Acct 843	MX_STOR	0	0	0	0	0	0
SW	17	TOTALSTORAGE S&W EXP		0	0	0	0	0	0
SW	18								
SW	19	**TRANSMISSION SALARIES & WAGES EXPENSE**							
SW	20	Operation	OX_TRAN	0	0	0	0	0	0
SW	21	Maintenance	MX_TRAN	0	0	0	0	0	0
SW	22	TOTAL TRANSMISSION S&W EXP		0	0	0	0	0	0
SW	23								
SW	24	**DISTRIBUTION SALARIES & WAGES EXPENSE**							
SW	25	Operation							
SW	26	874-Mains and Services Expenses	OX_874	0	2,344	0	0	0	0
SW	27	875-Measuring & Reg. Station Exp.-General	OX_875	0	0	0	0	0	0
SW	28	878-Meter & House Regulator Expenses	OX_878	0	0	2,012	0	0	0
SW	29	879-Customer Installations Expenses	OX_879	0	0	0	5,612	0	0
SW	30	880-Other Expenses	OX_880	0	1,393	462	0	0	0
SW	31	880-Other Expenses - GPC	E880DA	0	0	0	0	0	0
SW	32	Total Operation		0	3,737	2,475	5,612	0	0
SW	33	Maintenance							

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
SW	34	887-Maintenance of Mains	MX_887	12,525	12,525	0	0	0	0	12,525	0
SW	35	889-Maint. of Measuring & Reg. Station Equip.-Gen	MX_889	770	770	0	0	0	0	770	0
SW	36	892-Maintenance of Services	MX_892	1,334	0	0	1,334	0	0	0	0
SW	37	893-Maint. of Meters & House Regulators	MX_893	154	0	0	154	0	0	0	0
SW	38	894-Maintenance of Other Equipment	MX_894	124	70	0	53	0	0	70	0
SW	39	Total Distribution Maintenance		14,907	13,366	0	1,541	0	0	13,366	0
SW	40	TOTAL DISTRIBUTION S&W EXP		34,313	20,948	0	13,365	0	0	20,948	0
SW	41	TOTAL OPER & MAINT S&W EXP (PROD, STOR, TRAN,& DIST)		37,358	23,993	0	13,365	259	2,786	20,948	0
SW	42										
SW	43										
SW	44										
SW	45										
SW	46										
SW	47										
SW	48										
SW	49										
SW	50										
SW	51	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR CONTINUED**									
SW	52										
SW	53	CUSTOMER ACCOUNTS EXPENSES									
SW	54	902-Meter Reading	CMETRDG	0	0	0	0	0	0	0	0
SW	55	903-Customer Records and Collection Expense	CUSTREC	7,338	0	0	7,338	0	0	0	0
SW	56	904-Uncollectible Accounts	EXP_904	0	0	0	0	0	0	0	0
SW	57	904-Uncollectible Accounts - PPA	EXP_904	0	0	0	0	0	0	0	0
SW	58	904-Uncollectible Accounts - MFC/POR	E904DA	0	0	0	0	0	0	0	0
SW	59	905-Miscellaneous CA	CUSTCAM	245	0	0	245	0	0	0	0
SW	60	TOTAL CUSTOMER ACCTS S&W EXPENSE		7,583	0	0	7,583	0	0	0	0
SW	61										
SW	62	CUSTOMER SERVICE & SALES EXPENSES									
SW	63	908-Customer Assistance	CUSTASST	397	0	0	397	0	0	0	0
SW	64	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0
SW	65	910-Miscellaneous CS	CUSTCSM	42	0	0	42	0	0	0	0
SW	66	912-Demonstrating and Selling Expenses	CUSTSALES	298	0	0	298	0	0	0	0
SW	67	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0	0	0
SW	68	TOTAL CUST SERVICE & SALES S&W EXP		737	0	0	737	0	0	0	0
SW	69										
SW	70	TOTAL OPER & MAINT S&W EXP EXCL A&G		45,678	23,993	0	21,685	259	2,786	20,948	0
SW	71										
SW	72	ADMINISTRATIVE & GENERAL EXPENSE									
SW	73	920-Administrative Salaries	SALWAGXAG	6,396	3,360	0	3,037	36	390	2,933	0
SW	74	921-Office Supplies & Expense	SALWAGXAG	0	0	0	0	0	0	0	0
SW	75	923-Outside Service Employed	SALWAGXAG	0	0	0	0	0	0	0	0
SW	76	924-Property Insurance	PSTDGPLT	0	0	0	0	0	0	0	0
SW	77	925-Injuries and Damages	SALWAGXAG	160	84	0	76	1	10	74	0
SW	78	926-Employee Pensions & Benefits	SALWAGXAG	0	0	0	0	0	0	0	0
SW	79	928-Regulatory Commission	CLAIMREV	0	0	0	0	0	0	0	0
SW	80	929-Duplicate Charges-Credit	CLAIMREV	0	0	0	0	0	0	0	0
SW	81	930.1-General Advertising	SALWAGXAG	0	0	0	0	0	0	0	0
SW	82	930.2-Miscellaneous General	SALWAGXAG	9	5	0	4	0	1	4	0

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
SW	34	887-Maintenance of Mains	MX_887	0	0	0	0	0	0
SW	35	889-Maint. of Measuring & Reg. Station Equip.-Gen	MX_889	0	0	0	0	0	0
SW	36	892-Maintenance of Services	MX_892	0	1,334	0	0	0	0
SW	37	893-Maint. of Meters & House Regulators	MX_893	0	0	154	0	0	0
SW	38	894-Maintenance of Other Equipment	MX_894	0	40	13	0	0	0
SW	39	Total Distribution Maintenance		0	1,374	168	0	0	0
SW	40	TOTAL DISTRIBUTION S&W EXP		0	5,110	2,642	5,612	0	0
SW	41	TOTAL OPER & MAINT S&W EXP (PROD, STOR, TRAN,& DIST)		0	5,110	2,642	5,612	0	0
SW	42								
SW	43								
SW	44								
SW	45								
SW	46								
SW	47								
SW	48								
SW	49								
SW	50								
SW	51	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR COI**							
SW	52								
SW	53	CUSTOMER ACCOUNTS EXPENSES							
SW	54	902-Meter Reading	CMETRDG	0	0	0	0	0	0
SW	55	903-Customer Records and Collection Expense	CUSTREC	0	0	0	0	0	7,338
SW	56	904-Uncollectible Accounts	EXP_904	0	0	0	0	0	0
SW	57	904-Uncollectible Accounts - PPA	EXP_904	0	0	0	0	0	0
SW	58	904-Uncollectible Accounts - MFC/POR	E904DA	0	0	0	0	0	0
SW	59	905-Miscellaneous CA	CUSTCAM	0	0	0	0	0	245
SW	60	TOTAL CUSTOMER ACCTS S&W EXPENSE		0	0	0	0	0	7,583
SW	61								
SW	62	CUSTOMER SERVICE & SALES EXPENSES							
SW	63	908-Customer Assistance	CUSTASST	0	0	0	0	397	0
SW	64	909-Advertisement	CUSTADVT	0	0	0	0	0	0
SW	65	910-Miscellaneous CS	CUSTCSM	0	0	0	0	42	0
SW	66	912-Demonstrating and Selling Expenses	CUSTSALES	0	0	0	0	298	0
SW	67	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0
SW	68	TOTAL CUST SERVICE & SALES S&W EXP		0	0	0	0	737	0
SW	69								
SW	70	TOTAL OPER & MAINT S&W EXP EXCL A&G		0	5,110	2,642	5,612	737	7,583
SW	71								
SW	72	ADMINISTRATIVE & GENERAL EXPENSE							
SW	73	920-Administrative Salaries	SALWAGXAG	0	716	370	786	103	1,062
SW	74	921-Office Supplies & Expense	SALWAGXAG	0	0	0	0	0	0
SW	75	923-Outside Service Employed	SALWAGXAG	0	0	0	0	0	0
SW	76	924-Property Insurance	PSTDGPLT	0	0	0	0	0	0
SW	77	925-Injuries and Damages	SALWAGXAG	0	18	9	20	3	27
SW	78	926-Employee Pensions & Benefits	SALWAGXAG	0	0	0	0	0	0
SW	79	928-Regulatory Commission	CLAIMREV	0	0	0	0	0	0
SW	80	929-Duplicate Charges-Credit	CLAIMREV	0	0	0	0	0	0
SW	81	930.1-General Advertising	SALWAGXAG	0	0	0	0	0	0
SW	82	930.2-Miscellaneous General	SALWAGXAG	0	1	1	1	0	2

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
SW	83	932-Maintenance of General Plant	GENLPLT	228	120	0	108	1	14	105	0
SW	84	TOTAL A&G S&W EXPENSE		6,794	3,569	0	3,225	38	414	3,116	0
SW	85										
SW	86	**TOTAL OPER & MAINTENANCE SALARIES & WAGES EXP**		52,472	27,562	0	24,910	297	3,200	24,064	0
SW	87										
SW	88										
SW	89										
SW	90										
SW	91										
SW	92										
SW	93										
SW	94										
SW	95										
SW	96										
SW	97										
SW	98										
SW	99										
SW	100										
AF	1	**ALLOCATION FACTOR TABLE**									
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	3										
AF	4	**CAPACITY**									
AF	5	CAPACITY - PRODUCTION RELATED (LPG)									
AF	6	Capacity Production - Design Peak Day Sendout	DPKDAYP	912,000							
AF	7										
AF	8										
AF	9	CAPACITY - STORAGE RELATED (LNG)									
AF	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS	912,000							
AF	11										
AF	12										
AF	13										
AF	14	CAPACITY - TRANSMISSION RELATED									
AF	15	Capacity Transmission - Design Peak Day Sendout	DTRAN	912,000							
AF	16										
AF	17										
AF	18										
AF	19										
AF	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincident Peak Capacity)									
AF	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	739,136							
AF	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	15,529							
AF	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	2,855							
AF	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	222							
AF	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY	912,000							
AF	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR	11,399							
AF	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	3,423							
AF	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	228							
AF	29										
AF	30	Capacity Avg Daily Del excl Direct	DAVGDD	236,211							
AF	31										

PECO Energy Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
SW	83	932-Maintenance of General Plant	GENLPLT	0	26	13	28	4	38
SW	84	TOTAL A&G S&W EXPENSE		0	760	393	835	110	1,128
SW	85								
SW	86	**TOTAL OPER & MAINTENANCE SALARIES & WAGES EXP**		0	5,870	3,035	6,447	846	8,711
SW	87								
SW	88								
SW	89								
SW	90								
SW	91								
SW	92								
SW	93								
SW	94								
SW	95								
SW	96								
SW	97								
SW	98								
SW	99								
SW	100								
AF	1	**ALLOCATION FACTOR TABLE**							
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
AF	3								
AF	4	**CAPACITY**							
AF	5	CAPACITY - PRODUCTION RELATED (LPG)							
AF	6	Capacity Production - Design Peak Day Sendout	DPKDAYP						
AF	7								
AF	8								
AF	9	CAPACITY - STORAGE RELATED (LNG)							
AF	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS						
AF	11								
AF	12								
AF	13								
AF	14	CAPACITY - TRANSMISSION RELATED							
AF	15	Capacity Transmission - Design Peak Day Sendout	DTRAN						
AF	16								
AF	17								
AF	18								
AF	19								
AF	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincident Peak Capacity)							
AF	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS						
AF	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS						
AF	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD						
AF	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE						
AF	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY						
AF	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR						
AF	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD						
AF	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE						
AF	29								
AF	30	Capacity Avg Daily Del excl Direct	DAVGDD						
AF	31								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	32										
AF	33										
AF	34										
AF	35										
AF	36										
AF	37										
AF	38										
AF	39										
AF	40										
AF	41										
AF	42										
AF	43										
AF	44										
AF	45										
AF	46										
AF	47										
AF	48										
AF	49										
AF	50										
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	53										
AF	54	**COMMODITY**									
AF	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	93,602,070							
AF	56	Annual Gas Deliveries - Firm	ETHRUPUTF	80,117,169							
AF	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT	25,211,944							
AF	58										
AF	59	Commodity Gas Storage	ESTORAGE	1.0000							
AF	60										
AF	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA	1,742							
AF	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA	1,200							
AF	63	Total Account 880DA and 904DA	OX_880904DA	2,942							
AF	64										
AF	65										
AF	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA	-							
AF	67										
AF	68	Annual Gas Cost (PGC)	EGAS	234,407							
AF	69	Commodity - Balancing Service Charge (BSC)	EBSC	26,508							
AF	70										
AF	71	**CUSTOMER**									
AF	72	380-Services	CSERVICE	4,425,936							
AF	73	381-Meters (Avg Cost per meter)	CMETERS	244,046							
AF	74	381-Meters Direct Assignment	CMETERSDA	583							
AF	75	382-Meters Installations Direct Assignment	CMETINSTDA	2,764							
AF	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA	63							
AF	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA	332							
AF	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE	15							
AF	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE	69							
AF	80										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	32								
AF	33								
AF	34								
AF	35								
AF	36								
AF	37								
AF	38								
AF	39								
AF	40								
AF	41								
AF	42								
AF	43								
AF	44								
AF	45								
AF	46								
AF	47								
AF	48								
AF	49								
AF	50								
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**							
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
AF	53								
AF	54	**COMMODITY**							
AF	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT						
AF	56	Annual Gas Deliveries - Firm	ETHRUPUTF						
AF	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT						
AF	58								
AF	59	Commodity Gas Storage	ESTORAGE						
AF	60								
AF	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA						
AF	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA						
AF	63	Total Account 880DA and 904DA	OX_880904DA						
AF	64								
AF	65								
AF	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA						
AF	67								
AF	68	Annual Gas Cost (PGC)	EGAS						
AF	69	Commodity - Balancing Service Charge (BSC)	EBSC						
AF	70								
AF	71	**CUSTOMER**							
AF	72	380-Services	CSERVICE						
AF	73	381-Meters (Avg Cost per meter)	CMETERS						
AF	74	381-Meters Direct Assignment	CMETERSDA						
AF	75	382-Meters Installations Direct Assignment	CMETINSTDA						
AF	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA						
AF	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA						
AF	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE						
AF	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE						
AF	80								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	81	Customer Deposits	CUSTDEP	10,867							
AF	82	Customer Deposits Interest	CUSTDEPINT	650							
AF	83										
AF	84	879-Customer Installation Expense	CUSTINSTALL	558,912							
AF	85	902-Meter Reading Expense	CMETRDG	558,912							
AF	86	903-Customer Records and Collections	CUSTREC	1.0000							
AF	87	905-Miscellaneous Customer Accounts	CUSTCAM	558,912							
AF	88	908-Customer Assistance	CUSTASST	1.0000							
AF	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0							
AF	90	909-Informational and Instructional Advertising	CUSTADVT	1.0000							
AF	91	910-Miscellaneous Customer Service	CUSTCSM	1.0000							
AF	92	916-Miscellaneous Sales Expense	CUSTSALES	1.0000							
AF	93										
AF	94	Number of Bills	CUSTBILLS	6,706,945							
AF	95	Number of Customers (Average Annual)	CUST	558,912							
AF	96										
AF	97	Gas Energy Efficiency Program	CSEHPDA	321							
AF	98										
AF	99										
AF	100										
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	103	**Plant Related**									
AF	104	Intangible Plant	INTPLT	16,406							
AF	105	Production Plant	PRODPLT	15,559							
AF	106	Storage Plant	STORPLT	193,629							
AF	107	Transmission Plant in Service	TRANPLT	0							
AF	108	Distribution Plant in Service	DISTPLT	4,368,523							
AF	109	General Plant in Service	GENLPLT	35,933							
AF	110	Total Gas Plant In Service	TOTPLT	4,630,050							
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	4,367,639							
AF	112	Total Transmission and Distribution Plant	TDPLT	4,368,523							
AF	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	4,613,644							
AF	114	Total Distribution and General Plant	DGPLT	4,404,456							
AF	115	Rate Base	RATEBASE	3,524,006							
AF	116	Distribution Plant in Service - Capacity Related	DDISTPLT	2,457,334							
AF	117										
AF	118	Account 374	PLT_374	3,915							
AF	119	Account 375	PLT_375	16,785							
AF	120	Account 376-General Excess	PLT_376GE	1,784,138							
AF	121	Account 376-General Average	PLT_376GA	570,169							
AF	122	Account 376-DA	PLT_376DA	15,529							
AF	123	Account 376	PLT_376	2,369,836							
AF	124	Account 378	PLT_378	26,029							
AF	125	Account 379-City Gate	PLT_379CG	50,069							
AF	126	Account 379-DA	PLT_379DA	11,399							
AF	127	Account 379	PLT_379	61,468							
AF	128	Account 380	PLT_380	1,417,248							
AF	129	Account 381	PLT_381	179,005							

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	81	Customer Deposits	CUSTDEP						
AF	82	Customer Deposits Interest	CUSTDEPINT						
AF	83								
AF	84	879-Customer Installation Expense	CUSTINSTALL						
AF	85	902-Meter Reading Expense	CMETRDG						
AF	86	903-Customer Records and Collections	CUSTREC						
AF	87	905-Miscellaneous Customer Accounts	CUSTCAM						
AF	88	908-Customer Assistance	CUSTASST						
AF	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA						
AF	90	909-Informational and Instructional Advertising	CUSTADVT						
AF	91	910-Miscellaneous Customer Service	CUSTCSM						
AF	92	916-Miscellaneous Sales Expense	CUSTSALES						
AF	93								
AF	94	Number of Bills	CUSTBILLS						
AF	95	Number of Customers (Average Annual)	CUST						
AF	96								
AF	97	Gas Energy Efficiency Program	CSEHPDA						
AF	98								
AF	99								
AF	100								
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**							
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AF	103	**Plant Related**							
AF	104	Intangible Plant	INTPLT						
AF	105	Production Plant	PRODPLT						
AF	106	Storage Plant	STORPLT						
AF	107	Transmission Plant in Service	TRANPLT						
AF	108	Distribution Plant in Service	DISTPLT						
AF	109	General Plant in Service	GENLPLT						
AF	110	Total Gas Plant In Service	TOTPLT						
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR						
AF	112	Total Transmission and Distribution Plant	TDPLT						
AF	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT						
AF	114	Total Distribution and General Plant	DGPLT						
AF	115	Rate Base	RATEBASE						
AF	116	Distribution Plant in Service - Capacity Related	DDISTPLT						
AF	117								
AF	118	Account 374	PLT_374						
AF	119	Account 375	PLT_375						
AF	120	Account 376-General Excess	PLT_376GE						
AF	121	Account 376-General Average	PLT_376GA						
AF	122	Account 376-DA	PLT_376DA						
AF	123	Account 376	PLT_376						
AF	124	Account 378	PLT_378						
AF	125	Account 379-City Gate	PLT_379CG						
AF	126	Account 379-DA	PLT_379DA						
AF	127	Account 379	PLT_379						
AF	128	Account 380	PLT_380						
AF	129	Account 381	PLT_381						

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	130	Account 382	PLT_382	291,268							
AF	131	Account 387	PLT_387	2,084							
AF	132	Account 388-Asset Retirement Costs for Distribution	PLT_388	884							
AF	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	2,457,334							
AF	134	Accounts 376 & 380 - Mains & Services	PLT_376380	3,787,085							
AF	135	Accounts 380 & 381 - Services & Meters	PLT_380381	1,596,253							
AF	136	Accounts 374 & 375 - Land & Structures	PLT_374375	20,699							
AF	137	Accounts 381 through 385	PLT_3815	470,273							
AF	138	Accounts 378, 379, & 387	PLT_378387	89,582							
AF	139										
AF	140	Residential	DPLTRES	2,596,082							
AF	141	Small Commercial and Industrilal	DPLTCI	1,027,003							
AF	142	Large High Load Factor	DPLTLHLF	621							
AF	143	Motor Vehicle - Firm	DPLTMVF	4,569							
AF	144	Motor Vehicle - Interruptible	DPLTMVI	14							
AF	145	Interruptible Service	DPLTIS	119							
AF	146	Temperature Control	DPLTTC	1,016							
AF	147	Transportation Service - Firm	DPLTTSF	172,271							
AF	148	Transportation Service - Interruptible	DPLTTSI	72,886							
AF	149										
AF	150										
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	153										
AF	154	**Production Expense Related**									
AF	155	Account 717	OX_717	129							
AF	156	Account 741	MX_741	86							
AF	157	Account 742	MX_742	215							
AF	158	Manufactured Gas Production Operation Expense	OX_PRODM	137							
AF	159	Manufactured Gas Production Maintenance Expense	MX_PRODM	302							
AF	160	Other Production Operation Expense	OX_PRODO	260,932							
AF	161										
AF	162										
AF	163	**Storage Expense Related**									
AF	164	Storage Operation Expense	OX_STOR	1,292							
AF	165	Storage Maintenance Expense	MX_STOR	5,043							
AF	166										
AF	167										
AF	168	**Transmission Expense Related**									
AF	169	Transmission Operation Expense	OX_TRAN	0							
AF	170	Transmission Maintenance Expense	MX_TRAN	0							
AF	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0							
AF	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0							
AF	173										
AF	174										
AF	175	**Distribution Expense Related**									
AF	176	Account 874	OX_874	19,001							
AF	177	Account 875	OX_875	1,901							
AF	178	Account 878	OX_878	7,627							

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	130	Account 382	PLT_382						
AF	131	Account 387	PLT_387						
AF	132	Account 388-Asset Retirement Costs for Distribution	PLT_388						
AF	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379						
AF	134	Accounts 376 & 380 - Mains & Services	PLT_376380						
AF	135	Accounts 380 & 381 - Services & Meters	PLT_380381						
AF	136	Accounts 374 & 375 - Land & Structures	PLT_374375						
AF	137	Accounts 381 through 385	PLT_3815						
AF	138	Accounts 378, 379, & 387	PLT_378387						
AF	139								
AF	140	Residential	DPLTRES						
AF	141	Small Commercial and Industrilal	DPLTCI						
AF	142	Large High Load Factor	DPLTLHLF						
AF	143	Motor Vehicle - Firm	DPLTMVF						
AF	144	Motor Vehicle - Interruptible	DPLTMVI						
AF	145	Interruptible Service	DPLTIS						
AF	146	Temperature Control	DPLTTC						
AF	147	Transportation Service - Firm	DPLTTSF						
AF	148	Transportation Service - Interruptible	DPLTTSI						
AF	149								
AF	150								
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**							
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AF	153								
AF	154	**Production Expense Related**							
AF	155	Account 717	OX_717						
AF	156	Account 741	MX_741						
AF	157	Account 742	MX_742						
AF	158	Manufactured Gas Production Operation Expense	OX_PRODM						
AF	159	Manufactured Gas Production Maintenance Expense	MX_PRODM						
AF	160	Other Production Operation Expense	OX_PRODO						
AF	161								
AF	162								
AF	163	**Storage Expense Related**							
AF	164	Storage Operation Expense	OX_STOR						
AF	165	Storage Maintenance Expense	MX_STOR						
AF	166								
AF	167								
AF	168	**Transmission Expense Related**							
AF	169	Transmission Operation Expense	OX_TRAN						
AF	170	Transmission Maintenance Expense	MX_TRAN						
AF	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO						
AF	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM						
AF	173								
AF	174								
AF	175	**Distribution Expense Related**							
AF	176	Account 874	OX_874						
AF	177	Account 875	OX_875						
AF	178	Account 878	OX_878						

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	179	Account 879	OX_879	8,140							
AF	180	Account 880	OX_880	19,955							
AF	181	Account 887	MX_887	26,734							
AF	182	Account 889	MX_889	1,537							
AF	183	Account 892	MX_892	2,864							
AF	184	Account 893	MX_893	243							
AF	185	Account 894	MX_894	680							
AF	186	O&M Accounts 870-880	OX_DIST	55,422							
AF	187	O&M Accounts 887-894	MX_DIST	32,058							
AF	188										
AF	189										
AF	190										
AF	191										
AF	192										
AF	193										
AF	194										
AF	195										
AF	196										
AF	197										
AF	198										
AF	199										
AF	200										
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	203										
AF	204	**Customer Distribution Expense Related**									
AF	205	Account 902	OX_902	163							
AF	206	Account 903	OX_903	20,632							
AF	207	Account 904	OX_904	2,378							
AF	208	O&M Accounts 902-905	OX_CA	24,173							
AF	209										
AF	210	Account908	OX_908	7,183							
AF	211	Account909	OX_909	345							
AF	212	Account910	OX_910	54							
AF	213	O&M Accounts 908-910	OX_CS	7,583							
AF	214	Accounts 901-916	X_CACS	32,530							
AF	215										
AF	216	Total O&M less Purchased Gas	OMXPP	167,687							
AF	217										
AF	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	104,154							
AF	219										
AF	220	Base Taxable Income	EBT	114,935							
AF	221										
AF	222										
AF	223	**Salaries and Wages Expense Related**									
AF	224	Salaries & Wages Accounts 870-880	SALWAGDO	19,406							
AF	225	Salaries & Wages Accounts 887-894	SALWAGDM	14,907							
AF	226	Salaries & Wages Accounts 902-905	SALWAGCA	7,583							
AF	227	Salaries & Wages Accounts 908-910	SALWAGCS	439							

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	179	Account 879	OX_879						
AF	180	Account 880	OX_880						
AF	181	Account 887	MX_887						
AF	182	Account 889	MX_889						
AF	183	Account 892	MX_892						
AF	184	Account 893	MX_893						
AF	185	Account 894	MX_894						
AF	186	O&M Accounts 870-880	OX_DIST						
AF	187	O&M Accounts 887-894	MX_DIST						
AF	188								
AF	189								
AF	190								
AF	191								
AF	192								
AF	193								
AF	194								
AF	195								
AF	196								
AF	197								
AF	198								
AF	199								
AF	200								
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**							
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AF	203								
AF	204	**Customer Distribution Expense Related**							
AF	205	Account 902	OX_902						
AF	206	Account 903	OX_903						
AF	207	Account 904	OX_904						
AF	208	O&M Accounts 902-905	OX_CA						
AF	209								
AF	210	Account908	OX_908						
AF	211	Account909	OX_909						
AF	212	Account910	OX_910						
AF	213	O&M Accounts 908-910	OX_CS						
AF	214	Accounts 901-916	X_CACS						
AF	215								
AF	216	Total O&M less Purchased Gas	OMXPP						
AF	217								
AF	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP						
AF	219								
AF	220	Base Taxable Income	EBT						
AF	221								
AF	222								
AF	223	**Salaries and Wages Expense Related**							
AF	224	Salaries & Wages Accounts 870-880	SALWAGDO						
AF	225	Salaries & Wages Accounts 887-894	SALWAGDM						
AF	226	Salaries & Wages Accounts 902-905	SALWAGCA						
AF	227	Salaries & Wages Accounts 908-910	SALWAGCS						

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	45,678							
AF	229	Total Salaries and Wages Expense	SALWAGES	52,472							
AF	230										
AF	231										
AF	232										
AF	233										
AF	234										
AF	235										
AF	236										
AF	237										
AF	238										
AF	239										
AF	240										
AF	241										
AF	242										
AF	243										
AF	244										
AF	245										
AF	246										
AF	247										
AF	248										
AF	249										
AF	250										
AF	251	**REVENUES AND BILLING DETERMINANTS**									
AF	252										
AF	253	Base Rate Sales Revenue	SALESREV	481,982							
AF	254										
AF	255	Residential	SREVRES	327,766							
AF	256	Small Commercial and Industrilal	SREVCI	122,676							
AF	257	Large High Load Factor	SREVLHLF	184							
AF	258	Motor Vehicle - Firm	SREVMVF	611							
AF	259	Motor Vehicle - Interruptible	SREVMVI	4							
AF	260	Interruptible Service	SREVIS	75							
AF	261	Temperature Control	SREVTC	697							
AF	262	Transportation Service - Firm	SREVTSF	19,121							
AF	263	Transportation Service - Interruptible	SREVTSI	10,848							
AF	264										
AF	265										
AF	266	Claimed Rate Sales Revenue	CLAIMREV	854,065							
AF	267										
AF	268										
AF	269										
AF	270										
AF	271										
AF	272	**PRESENT REVENUES FROM SALES INPUT**									
AF	273										
AF	274	Total Sales of Gas Revenues		742,897							
AF	275	Sales of Gas Revenues - Distribution		481,982							
AF	276	Sales of Gas Revenues - PGC		234,407							

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG						
AF	229	Total Salaries and Wages Expense	SALWAGES						
AF	230								
AF	231								
AF	232								
AF	233								
AF	234								
AF	235								
AF	236								
AF	237								
AF	238								
AF	239								
AF	240								
AF	241								
AF	242								
AF	243								
AF	244								
AF	245								
AF	246								
AF	247								
AF	248								
AF	249								
AF	250								
AF	251	**REVENUES AND BILLING DETERMINANTS**							
AF	252								
AF	253	Base Rate Sales Revenue	SALESREV						
AF	254								
AF	255	Residential	SREVRES						
AF	256	Small Commercial and Industrilal	SREVCI						
AF	257	Large High Load Factor	SREVLHLF						
AF	258	Motor Vehicle - Firm	SREVMVF						
AF	259	Motor Vehicle - Interruptible	SREVMVI						
AF	260	Interruptible Service	SREVIS						
AF	261	Temperature Control	SREVTC						
AF	262	Transportation Service - Firm	SREVTSF						
AF	263	Transportation Service - Interruptible	SREVTSI						
AF	264								
AF	265								
AF	266	Claimed Rate Sales Revenue	CLAIMREV						
AF	267								
AF	268								
AF	269								
AF	270								
AF	271								
AF	272	**PRESENT REVENUES FROM SALES INPUT**							
AF	273								
AF	274	Total Sales of Gas Revenues							
AF	275	Sales of Gas Revenues - Distribution							
AF	276	Sales of Gas Revenues - PGC							

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AF	277	Sales of Gas Revenues - BSC		26,508							
AF	278										
AF	279										
AF	280	Sales of Gas Revenues - Transmission		0							
AF	281										
AF	282										
AF	283	**BILLING DETERMINATE INPUTS**									
AF	284	Number of Customer Bills	SCH AF, LN 94	6,706,945							
AF	285	Annual Booked Throughput Sales (Mcf)	SCH AF, LN 55	93,602,070							
AF	286										
AF	287										
AF	288										
AF	289	**RATE OF RETURN**									
AF	290	Rate of Return (Equalized)	SCH AF, LN 290	8.08%							
AF	291										
AF	292										
AF	293										
AF	294										
AF	295										
AF	296										
AF	297										
AF	298										
AF	299										
AF	300										
AP	1	**ALLOCATION PROPORTIONS TABLE**									
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACTOR**									
AP	3										
AP	4	**CAPACITY**									
AP	5	CAPACITY - PRODUCTION RELATED (LPG)									
AP	6	Capacity Production - Design Peak Day Sendout	DPKDAYP	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	7										
AP	8										
AP	9	CAPACITY - STORAGE RELATED (LNG)									
AP	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	11										
AP	12										
AP	13										
AP	14	CAPACITY - TRANSMISSION RELATED									
AP	15	Capacity Transmission - Design Peak Day Sendout	DTRAN	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	16										
AP	17										
AP	18										
AP	19										
AP	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincid									
AP	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AF	277	Sales of Gas Revenues - BSC							
AF	278								
AF	279								
AF	280	Sales of Gas Revenues - Transmission							
AF	281								
AF	282								
AF	283	**BILLING DETERMINATE INPUTS**							
AF	284	Number of Customer Bills	SCH AF, LN 94						
AF	285	Annual Booked Throughput Sales (Mcf)	SCH AF, LN 55						
AF	286								
AF	287								
AF	288								
AF	289	**RATE OF RETURN**							
AF	290	Rate of Return (Equalized)	SCH AF, LN 290						
AF	291								
AF	292								
AF	293								
AF	294								
AF	295								
AF	296								
AF	297								
AF	298								
AF	299								
AF	300								
AP	1	**ALLOCATION PROPORTIONS TABLE**							
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACTOR**							
AP	3								
AP	4	**CAPACITY**							
AP	5	CAPACITY - PRODUCTION RELATED (LPG)							
AP	6	Capacity Production - Design Peak Day Sendout	DPKDAYP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	7								
AP	8								
AP	9	CAPACITY - STORAGE RELATED (LNG)							
AP	10	Capacity Storage - Design Peak Day Sendout	DPKDAYS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	11								
AP	12								
AP	13								
AP	14	CAPACITY - TRANSMISSION RELATED							
AP	15	Capacity Transmission - Design Peak Day Sendout	DTRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	16								
AP	17								
AP	18								
AP	19								
AP	20	CAPACITY - DISTRIBUTION RELATED (Non-Coincid							
AP	21	Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	22	Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	23	Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	24	Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	25	Capacity Distribution (Des Peak Day Sendout)	DESDAY	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	29										
AP	30	Capacity Avg Daily Del excl Direct	DAVGDD	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	31										
AP	32										
AP	33										
AP	34										
AP	35										
AP	36										
AP	37										
AP	38										
AP	39										
AP	40										
AP	41										
AP	42										
AP	43										
AP	44										
AP	45										
AP	46										
AP	47										
AP	48										
AP	49										
AP	50										
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	53										
AP	54	**COMMODITY**									
AP	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	56	Annual Gas Deliveries - Firm	ETHRUPUTF	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	58										
AP	59	Commodity Gas Storage	ESTORAGE	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	60										
AP	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	63	Total Account 880DA and 904DA	OX_880904DA	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	64										
AP	65										
AP	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67										
AP	68	Annual Gas Cost (PGC)	EGAS	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	69	Commodity - Balancing Service Charge (BSC)	EBSC	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	70										
AP	71	**CUSTOMER**									
AP	72	380-Services	CSERVICE	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	73	381-Meters (Avg Cost per meter)	CMETERS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	74	381-Meters Direct Assignment	CMETERSDA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000

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Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	26	Capacity Distribution M&R (Direct Assign Plant)	DAMR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	27	Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	28	Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	29								
AP	30	Capacity Avg Daily Del excl Direct	DAVGDD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	31								
AP	32								
AP	33								
AP	34								
AP	35								
AP	36								
AP	37								
AP	38								
AP	39								
AP	40								
AP	41								
AP	42								
AP	43								
AP	44								
AP	45								
AP	46								
AP	47								
AP	48								
AP	49								
AP	50								
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
AP	53								
AP	54	**COMMODITY**							
AP	55	Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	56	Annual Gas Deliveries - Firm	ETHRUPUTF	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	57	Annual Gas Deliveries - Transportation Only	ETHRUPUTT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	58								
AP	59	Commodity Gas Storage	ESTORAGE	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	60								
AP	61	880-Other Expenses-DA (Gas Procurement Charge)	E880DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	62	904-Uncollectible-DA (MFC/Purch of Rec)	E904DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	63	Total Account 880DA and 904DA	OX_880904DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	64								
AP	65								
AP	66	807-Purchased Gas Expenses - Direct Assignment	EPGEDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67								
AP	68	Annual Gas Cost (PGC)	EGAS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	69	Commodity - Balancing Service Charge (BSC)	EBSC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	70								
AP	71	**CUSTOMER**							
AP	72	380-Services	CSERVICE	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	73	381-Meters (Avg Cost per meter)	CMETERS	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	74	381-Meters Direct Assignment	CMETERSDA	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	75	382-Meters Installations Direct Assignment	CMETINSTDA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	80										
AP	81	Customer Deposits	CUSTDEP	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	82	Customer Deposits Interest	CUSTDEPINT	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	83										
AP	84	879-Customer Installation Expense	CUSTINSTALL	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	85	902-Meter Reading Expense	CMETRDG	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	86	903-Customer Records and Collections	CUSTREC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	87	905-Miscellaneous Customer Accounts	CUSTCAM	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	88	908-Customer Assistance	CUSTASST	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	90	909-Informational and Instructional Advertising	CUSTADVT	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	91	910-Miscellaneous Customer Service	CUSTCSM	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	92	916-Miscellaneous Sales Expense	CUSTSALES	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	93										
AP	94	Number of Bills	CUSTBILLS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	95	Number of Customers (Average Annual)	CUST	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	96										
AP	97	Gas Energy Efficiency Program	CSEHPDA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	98										
AP	99										
AP	100										
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	103	**Plant Related**									
AP	104	Intangible Plant	INTPLT	1.00000	0.58691	0.00000	0.41309	0.00342	0.04244	0.54105	0.00000
AP	105	Production Plant	PRODPLT	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	106	Storage Plant	STORPLT	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	107	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	108	Distribution Plant in Service	DISTPLT	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	109	General Plant in Service	GENLPLT	1.00000	0.52526	0.00000	0.47474	0.00566	0.06099	0.45861	0.00000
AP	110	Total Gas Plant In Service	TOTPLT	1.00000	0.58691	0.00000	0.41309	0.00342	0.04244	0.54105	0.00000
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	112	Total Transmission and Distribution Plant	TDPLT	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	1.00000	0.58691	0.00000	0.41309	0.00342	0.04244	0.54105	0.00000
AP	114	Total Distribution and General Plant	DGPLT	1.00000	0.56729	0.00000	0.43271	0.00005	0.00050	0.56674	0.00000
AP	115	Rate Base	RATEBASE	1.00000	0.59487	0.01933	0.38580	0.00047	0.04431	0.55009	0.00317
AP	116	Distribution Plant in Service - Capacity Related	DDISTPLT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	117										
AP	118	Account 374	PLT_374	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	119	Account 375	PLT_375	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	120	Account 376-General Excess	PLT_376GE	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	121	Account 376-General Average	PLT_376GA	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	122	Account 376-DA	PLT_376DA	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	123	Account 376	PLT_376	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	75	382-Meters Installations Direct Assignment	CMETINSTDA	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	76	381-Meters Direct Assignment (Acc Dep)	CMETERSDAA	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	77	382-Meters Installations Direct Assignment (Acc Dep)	CMETINSTDAA	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	78	381-Meters Direct Assignment (Dep Exp)	CMETERSDAE	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	79	382-Meters Installations Direct Assignment (Dep Exp)	CMETINSTDAE	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	80								
AP	81	Customer Deposits	CUSTDEP	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	82	Customer Deposits Interest	CUSTDEPINT	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	83								
AP	84	879-Customer Installation Expense	CUSTINSTALL	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	85	902-Meter Reading Expense	CMETRDG	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	86	903-Customer Records and Collections	CUSTREC	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	87	905-Miscellaneous Customer Accounts	CUSTCAM	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	88	908-Customer Assistance	CUSTASST	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	89	908-Customer Assistance - Direct Assignment	CUSTASSTDA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	90	909-Informational and Instructional Advertising	CUSTADVT	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	91	910-Miscellaneous Customer Service	CUSTCSM	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	92	916-Miscellaneous Sales Expense	CUSTSALES	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	93								
AP	94	Number of Bills	CUSTBILLS	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	95	Number of Customers (Average Annual)	CUST	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	96								
AP	97	Gas Energy Efficiency Program	CSEHPDA	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	98								
AP	99								
AP	100								
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AP	103	**Plant Related**							
AP	104	Intangible Plant	INTPLT	0.00000	0.30827	0.10245	0.00096	0.00013	0.00129
AP	105	Production Plant	PRODPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	106	Storage Plant	STORPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	107	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	108	Distribution Plant in Service	DISTPLT	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	109	General Plant in Service	GENLPLT	0.00000	0.11188	0.05784	0.12286	0.01613	0.16602
AP	110	Total Gas Plant In Service	TOTPLT	0.00000	0.30827	0.10245	0.00096	0.00013	0.00129
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	112	Total Transmission and Distribution Plant	TDPLT	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	113	Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	0.00000	0.30827	0.10245	0.00096	0.00013	0.00129
AP	114	Total Distribution and General Plant	DGPLT	0.00000	0.32291	0.10732	0.00100	0.00013	0.00135
AP	115	Rate Base	RATEBASE	0.01616	0.29278	0.07956	0.00685	0.00105	0.00557
AP	116	Distribution Plant in Service - Capacity Related	DDISTPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	117								
AP	118	Account 374	PLT_374	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	119	Account 375	PLT_375	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	120	Account 376-General Excess	PLT_376GE	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	121	Account 376-General Average	PLT_376GA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	122	Account 376-DA	PLT_376DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	123	Account 376	PLT_376	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	124	Account 378	PLT_378	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	125	Account 379-City Gate	PLT_379CG	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	126	Account 379-DA	PLT_379DA	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	127	Account 379	PLT_379	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	128	Account 380	PLT_380	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	129	Account 381	PLT_381	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	130	Account 382	PLT_382	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	131	Account 387	PLT_387	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	132	Account 388-Asset Retirement Costs for Distribution	PLT_388	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	134	Accounts 376 & 380 - Mains & Services	PLT_376380	1.00000	0.62577	0.00000	0.37423	0.00000	0.00000	0.62577	0.00000
AP	135	Accounts 380 & 381 - Services & Meters	PLT_380381	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	136	Accounts 374 & 375 - Land & Structures	PLT_374375	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	137	Accounts 381 through 385	PLT_3815	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	138	Accounts 378, 379, & 387	PLT_378387	1.00000	0.98994	0.00000	0.01006	0.00000	0.00000	0.98994	0.00000
AP	139										
AP	140	Residential	DPLTRES	1.00000	0.57511	0.00000	0.42489	0.00000	0.00000	0.57511	0.00000
AP	141	Small Commercial and Industrilal	DPLTCI	1.00000	0.69842	0.00000	0.30158	0.00000	0.00000	0.69842	0.00000
AP	142	Large High Load Factor	DPLTLHLF	1.00000	0.91254	0.00000	0.08746	0.00000	0.00000	0.91254	0.00000
AP	143	Motor Vehicle - Firm	DPLTMVF	1.00000	0.97770	0.00000	0.02230	0.00000	0.00000	0.97770	0.00000
AP	144	Motor Vehicle - Interruptible	DPLTMVI	1.00000	0.51663	0.00000	0.48337	0.00000	0.00000	0.51663	0.00000
AP	145	Interruptible Service	DPLTIS	1.00000	0.94291	0.00000	0.05709	0.00000	0.00000	0.94291	0.00000
AP	146	Temperature Control	DPLTTC	1.00000	0.86799	0.00000	0.13201	0.00000	0.00000	0.86799	0.00000
AP	147	Transportation Service - Firm	DPLTTSF	1.00000	0.98426	0.00000	0.01574	0.00000	0.00000	0.98426	0.00000
AP	148	Transportation Service - Interruptible	DPLTTSI	1.00000	0.97998	0.00000	0.02002	0.00000	0.00000	0.97998	0.00000
AP	149										
AP	150										
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	153										
AP	154	**Production Expense Related**									
AP	155	Account 717	OX_717	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	156	Account 741	MX_741	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	157	Account 742	MX_742	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	158	Manufactured Gas Production Operation Expense	OX_PRODM	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	159	Manufactured Gas Production Maintenance Expense	MX_PRODM	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	160	Other Production Operation Expense	OX_PRODO	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.99993
AP	161										
AP	162										
AP	163	**Storage Expense Related**									
AP	164	Storage Operation Expense	OX_STOR	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	165	Storage Maintenance Expense	MX_STOR	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	166										
AP	167										
AP	168	**Transmission Expense Related**									
AP	169	Transmission Operation Expense	OX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	170	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	124	Account 378	PLT_378	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	125	Account 379-City Gate	PLT_379CG	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	126	Account 379-DA	PLT_379DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	127	Account 379	PLT_379	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	128	Account 380	PLT_380	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	129	Account 381	PLT_381	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	130	Account 382	PLT_382	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	131	Account 387	PLT_387	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	132	Account 388-Asset Retirement Costs for Distribution	PLT_388	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	133	Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	134	Accounts 376 & 380 - Mains & Services	PLT_376380	0.00000	0.37423	0.00000	0.00000	0.00000	0.00000
AP	135	Accounts 380 & 381 - Services & Meters	PLT_380381	0.00000	0.88786	0.11214	0.00000	0.00000	0.00000
AP	136	Accounts 374 & 375 - Land & Structures	PLT_374375	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	137	Accounts 381 through 385	PLT_3815	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	138	Accounts 378, 379, & 387	PLT_378387	0.00000	0.00755	0.00251	0.00000	0.00000	0.00000
AP	139								
AP	140	Residential	DPLTRES	0.00000	0.42489	0.00000	0.00000	0.00000	0.00000
AP	141	Small Commercial and Industrilal	DPLTCI	0.00000	0.30158	0.00000	0.00000	0.00000	0.00000
AP	142	Large High Load Factor	DPLTLHLF	0.00000	0.08746	0.00000	0.00000	0.00000	0.00000
AP	143	Motor Vehicle - Firm	DPLTMVF	0.00000	0.02230	0.00000	0.00000	0.00000	0.00000
AP	144	Motor Vehicle - Interruptible	DPLTMVI	0.00000	0.48337	0.00000	0.00000	0.00000	0.00000
AP	145	Interruptible Service	DPLTIS	0.00000	0.05709	0.00000	0.00000	0.00000	0.00000
AP	146	Temperature Control	DPLTTC	0.00000	0.13201	0.00000	0.00000	0.00000	0.00000
AP	147	Transportation Service - Firm	DPLTTSF	0.00000	0.01574	0.00000	0.00000	0.00000	0.00000
AP	148	Transportation Service - Interruptible	DPLTTSI	0.00000	0.02002	0.00000	0.00000	0.00000	0.00000
AP	149								
AP	150								
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AP	153								
AP	154	**Production Expense Related**							
AP	155	Account 717	OX_717	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	156	Account 741	MX_741	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	157	Account 742	MX_742	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	158	Manufactured Gas Production Operation Expense	OX_PRODM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	159	Manufactured Gas Production Maintenance Expense	MX_PRODM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	160	Other Production Operation Expense	OX_PRODO	0.00007	0.00000	0.00000	0.00000	0.00000	0.00000
AP	161								
AP	162								
AP	163	**Storage Expense Related**							
AP	164	Storage Operation Expense	OX_STOR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165	Storage Maintenance Expense	MX_STOR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	166								
AP	167								
AP	168	**Transmission Expense Related**							
AP	169	Transmission Operation Expense	OX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	170	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	171	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	172	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	173										
AP	174										
AP	175	**Distribution Expense Related**									
AP	176	Account 874	OX_874	1.00000	0.62577	0.00000	0.37423	0.00000	0.00000	0.62577	0.00000
AP	177	Account 875	OX_875	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	178	Account 878	OX_878	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	179	Account 879	OX_879	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	180	Account 880	OX_880	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	181	Account 887	MX_887	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	182	Account 889	MX_889	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	183	Account 892	MX_892	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	184	Account 893	MX_893	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	185	Account 894	MX_894	1.00000	0.56763	0.00000	0.43237	0.00000	0.00000	0.56763	0.00000
AP	186	O&M Accounts 870-880	OX_DIST	1.00000	0.45703	-0.03143	0.57440	0.00000	0.00000	0.45703	0.00000
AP	187	O&M Accounts 887-894	MX_DIST	1.00000	0.89389	0.00000	0.10611	0.00000	0.00000	0.89389	0.00000
AP	188										
AP	189										
AP	190										
AP	191										
AP	192										
AP	193										
AP	194										
AP	195										
AP	196										
AP	197										
AP	198										
AP	199										
AP	200										
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	203										
AP	204	**Customer Distribution Expense Related**									
AP	205	Account 902	OX_902	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	206	Account 903	OX_903	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	207	Account 904	OX_904	1.00000	0.75927	-0.49163	0.73236	0.00290	0.08245	0.67392	0.00716
AP	208	O&M Accounts 902-905	OX_CA	1.00000	0.07468	-0.04835	0.97368	0.00029	0.00811	0.06628	0.00070
AP	209										
AP	210	Account908	OX_908	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	211	Account909	OX_909	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	212	Account910	OX_910	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	213	O&M Accounts 908-910	OX_CS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	214	Accounts 901-916	X_CACS	1.00000	0.05549	-0.03593	0.98044	0.00021	0.00603	0.04925	0.00052
AP	215										
AP	216	Total O&M less Purchased Gas	OMXPP	1.00000	0.49832	-0.01055	0.51224	0.00394	0.05328	0.44110	0.00680
AP	217										
AP	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	1.00000	0.47654	-0.00577	0.52923	0.00295	0.04809	0.42550	0.01078
AP	219										
AP	220	Base Taxable Income	EBT	1.00000	0.61649	0.02867	0.35484	-0.00081	0.04690	0.57040	0.00477
AP	221										

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	173								
AP	174								
AP	175	**Distribution Expense Related**							
AP	176	Account 874	OX_874	0.00000	0.37423	0.00000	0.00000	0.00000	0.00000
AP	177	Account 875	OX_875	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	178	Account 878	OX_878	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	179	Account 879	OX_879	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	180	Account 880	OX_880	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	181	Account 887	MX_887	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	182	Account 889	MX_889	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	183	Account 892	MX_892	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	184	Account 893	MX_893	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	185	Account 894	MX_894	0.00000	0.32464	0.10772	0.00000	0.00000	0.00000
AP	186	O&M Accounts 870-880	OX_DIST	-0.03143	0.24707	0.17764	0.14969	0.00000	0.00000
AP	187	O&M Accounts 887-894	MX_DIST	0.00000	0.09624	0.00987	0.00000	0.00000	0.00000
AP	188								
AP	189								
AP	190								
AP	191								
AP	192								
AP	193								
AP	194								
AP	195								
AP	196								
AP	197								
AP	198								
AP	199								
AP	200								
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
AP	203								
AP	204	**Customer Distribution Expense Related**							
AP	205	Account 902	OX_902	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	206	Account 903	OX_903	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	207	Account 904	OX_904	-0.49879	0.38059	0.13104	0.06289	0.03906	0.11877
AP	208	O&M Accounts 902-905	OX_CA	-0.04906	0.03743	0.01289	0.00619	0.00384	0.91333
AP	209								
AP	210	Account908	OX_908	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	211	Account909	OX_909	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	212	Account910	OX_910	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	213	O&M Accounts 908-910	OX_CS	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	214	Accounts 901-916	X_CACS	-0.03645	0.02782	0.00958	0.00460	0.25975	0.67870
AP	215								
AP	216	Total O&M less Purchased Gas	OMXPP	-0.01735	0.13417	0.07662	0.07800	0.05421	0.16924
AP	217								
AP	218	Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	-0.01655	0.14163	0.08640	0.05200	0.07692	0.17228
AP	219								
AP	220	Base Taxable Income	EBT	0.02390	0.27205	0.06844	0.00795	0.00125	0.00514
AP	221								

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	222										
AP	223	**Salaries and Wages Expense Related**									
AP	224	Salaries & Wages Accounts 870-880	SALWAGDO	1.00000	0.39074	0.00000	0.60926	0.00000	0.00000	0.39074	0.00000
AP	225	Salaries & Wages Accounts 887-894	SALWAGDM	1.00000	0.89661	0.00000	0.10339	0.00000	0.00000	0.89661	0.00000
AP	226	Salaries & Wages Accounts 902-905	SALWAGCA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	227	Salaries & Wages Accounts 908-910	SALWAGCS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	1.00000	0.52526	0.00000	0.47474	0.00566	0.06099	0.45861	0.00000
AP	229	Total Salaries and Wages Expense	SALWAGES	1.00000	0.52526	0.00000	0.47474	0.00566	0.06099	0.45861	0.00000
AP	230										
AP	231										
AP	232										
AP	233										
AP	234										
AP	235										
AP	236										
AP	237										
AP	238										
AP	239										
AP	240										
AP	241										
AP	242										
AP	243										
AP	244										
AP	245										
AP	246										
AP	247										
AP	248										
AP	249										
AP	250										
AP	251	**REVENUES AND BILLING DETERMINANTS**									
AP	252										
AP	253	Base Rate Sales Revenue	SALESREV	1.00000	0.55519	0.00969	0.43511	0.00190	0.05452	0.49878	0.00445
AP	254										
AP	255	Residential	SREVRES	1.00000	0.48563	0.00836	0.50601	0.00188	0.05315	0.43061	0.00478
AP	256	Small Commercial and Industrilal	SREVCI	1.00000	0.66630	0.01152	0.32218	0.00243	0.07161	0.59225	0.00442
AP	257	Large High Load Factor	SREVLHLF	1.00000	0.78094	0.00531	0.21361	0.00165	0.07305	0.70638	0.00897
AP	258	Motor Vehicle - Firm	SREVMVF	1.00000	0.89022	0.01551	0.09426	0.00304	0.09282	0.79437	0.02133
AP	259	Motor Vehicle - Interruptible	SREVMVI	1.00000	0.43444	0.03776	0.52139	0.00000	0.00000	0.43444	0.03320
AP	260	Interruptible Service	SREVIS	1.00000	0.83197	0.04102	0.12792	0.00000	0.00000	0.83197	0.03763
AP	261	Temperature Control	SREVTC	1.00000	0.67424	0.03319	0.29257	0.00000	0.00000	0.67424	0.03034
AP	262	Transportation Service - Firm	SREVTSF	1.00000	0.87554	0.01135	0.11311	0.00000	0.00000	0.87554	0.00000
AP	263	Transportation Service - Interruptible	SREVTSI	1.00000	0.80364	0.02437	0.17199	0.00000	0.00000	0.80364	0.00000
AP	264										
AP	265										
AP	266	Claimed Rate Sales Revenue	CLAIMREV	1.00000	0.38802	0.31438	0.29760	0.00113	0.03661	0.35028	0.30928
AP	267										
AP	268										
AP	269										
AP	270										

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	222								
AP	223	**Salaries and Wages Expense Related**							
AP	224	Salaries & Wages Accounts 870-880	SALWAGDO	0.00000	0.19255	0.12752	0.28919	0.00000	0.00000
AP	225	Salaries & Wages Accounts 887-894	SALWAGDM	0.00000	0.09215	0.01124	0.00000	0.00000	0.00000
AP	226	Salaries & Wages Accounts 902-905	SALWAGCA	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	227	Salaries & Wages Accounts 908-910	SALWAGCS	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	228	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	0.00000	0.11188	0.05784	0.12286	0.01613	0.16602
AP	229	Total Salaries and Wages Expense	SALWAGES	0.00000	0.11188	0.05784	0.12286	0.01613	0.16602
AP	230								
AP	231								
AP	232								
AP	233								
AP	234								
AP	235								
AP	236								
AP	237								
AP	238								
AP	239								
AP	240								
AP	241								
AP	242								
AP	243								
AP	244								
AP	245								
AP	246								
AP	247								
AP	248								
AP	249								
AP	250								
AP	251	**REVENUES AND BILLING DETERMINANTS**							
AP	252								
AP	253	Base Rate Sales Revenue	SALESREV	0.00524	0.23025	0.08510	0.03363	0.02042	0.06571
AP	254								
AP	255	Residential	SREVRES	0.00358	0.25859	0.08766	0.04533	0.02872	0.08571
AP	256	Small Commercial and Industrilal	SREVCI	0.00711	0.20991	0.08203	0.01085	0.00125	0.01814
AP	257	Large High Load Factor	SREVLHLF	-0.00366	0.05937	0.03615	0.00157	0.02036	0.09616
AP	258	Motor Vehicle - Firm	SREVMVF	-0.00582	0.01500	0.06454	0.00072	0.00010	0.01390
AP	259	Motor Vehicle - Interruptible	SREVMVI	0.00456	0.35557	0.14333	0.00983	0.00118	0.01148
AP	260	Interruptible Service	SREVIS	0.00339	0.04549	0.03016	0.00072	0.00704	0.04450
AP	261	Temperature Control	SREVTC	0.00285	0.09254	0.18692	0.00148	0.00014	0.01140
AP	262	Transportation Service - Firm	SREVTSF	0.01135	0.01150	0.04788	0.00061	0.00922	0.04390
AP	263	Transportation Service - Interruptible	SREVTSI	0.02437	0.01466	0.10390	0.00062	0.00901	0.04380
AP	264								
AP	265								
AP	266	Claimed Rate Sales Revenue	CLAIMREV	0.00508	0.16975	0.05829	0.01995	0.01168	0.03793
AP	267								
AP	268								
AP	269								
AP	270								

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
AP	271										
AP	272	**PRESENT REVENUES FROM SALES INPUT**									
AP	273										
AP	274	Total Sales of Gas Revenues		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	275	Sales of Gas Revenues - Distribution		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	276	Sales of Gas Revenues - PGC		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	277	Sales of Gas Revenues - BSC		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	278										
AP	279										
AP	280	Sales of Gas Revenues - Transmission		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	281										
AP	282										
AP	283										
AP	284										
AP	285										
AP	286										
AP	287										
AP	288										
AP	289										
AP	290										
AP	291										
AP	292										
AP	293										
AP	294										
AP	295										
AP	296										
AP	297										
AP	298										
AP	299										
AP	300										
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**									
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
ADA	3										
ADA	4	**Net Write-Offs**									
ADA	5	Residential	SREVRES	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
ADA	6	Small Commercial and Industrilal	SREVCI	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
ADA	7	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	8	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	9	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	10	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	11	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	12	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	13	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	14										
ADA	15	Total Write-Offs	EXP_904	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADA	16										
ADA	17	Total Write-Offs	EXP_904	1.00000	0.50789	0.00877	0.48335	0.00194	0.05508	0.45087	0.00475
ADA	18										
ADA	19										

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
AP	271								
AP	272	**PRESENT REVENUES FROM SALES INPUT**							
AP	273								
AP	274	Total Sales of Gas Revenues		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	275	Sales of Gas Revenues - Distribution		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	276	Sales of Gas Revenues - PGC		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	277	Sales of Gas Revenues - BSC		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	278								
AP	279								
AP	280	Sales of Gas Revenues - Transmission		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	281								
AP	282								
AP	283								
AP	284								
AP	285								
AP	286								
AP	287								
AP	288								
AP	289								
AP	290								
AP	291								
AP	292								
AP	293								
AP	294								
AP	295								
AP	296								
AP	297								
AP	298								
AP	299								
AP	300								
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**							
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
ADA	3								
ADA	4	**Net Write-Offs**							
ADA	5	Residential	SREVRES	0.88	0.88	0.88	0.88	0.88	0.88
ADA	6	Small Commercial and Industrilal	SREVCI	0.11	0.11	0.11	0.11	0.11	0.11
ADA	7	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	8	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	9	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00
ADA	10	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00
ADA	11	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00
ADA	12	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	13	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00
ADA	14								
ADA	15	Total Write-Offs	EXP_904	1.00	1.00	1.00	1.00	1.00	1.00
ADA	16								
ADA	17	Total Write-Offs	EXP_904	0.00401	0.25195	0.08699	0.04118	0.02547	0.07776
ADA	18								
ADA	19								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
ADA	20	**Net Write-Offs - Pre-Program Arrearages (PPA)**									
ADA	21	Residential	SREVRES	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADA	22	Small Commercial and Industrilal	SREVCI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	23	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	24	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	25	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	26	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	27	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	28	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	29	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADA	30										
ADA	31	Total Write-Offs	EXP_904PPA	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADA	32										
ADA	33	Total Write-Offs	EXP_904PPA	1.00000	0.48563	0.00836	0.50601	0.00188	0.05315	0.43061	0.00478
ADA	34										
ADA	35										
ADA	36	**Forfeited Discounts - Account 487**									
ADA	37	Residential	SREVRES	909	909	909	909	909	909	909	909
ADA	38	Small Commercial and Industrilal	SREVCI	371	371	371	371	371	371	371	371
ADA	39	Large High Load Factor	SREVLHLF	1	1	1	1	1	1	1	1
ADA	40	Motor Vehicle - Firm	SREVMVF	2	2	2	2	2	2	2	2
ADA	41	Motor Vehicle - Interruptible	SREVMVI	0	0	0	0	0	0	0	0
ADA	42	Interruptible Service	SREVIS	0	0	0	0	0	0	0	0
ADA	43	Temperature Control	SREVTC	2	2	2	2	2	2	2	2
ADA	44	Transportation Service - Firm	SREVTSF	57	57	57	57	57	57	57	57
ADA	45	Transportation Service - Interruptible	SREVTSI	32	32	32	32	32	32	32	32
ADA	46										
ADA	47	Total Forfeited Discounts	REV_487	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373
ADA	48										
ADA	49	Total Forfeited Discounts	REV_487	1.00000	0.55895	0.00976	0.43129	0.00191	0.05466	0.50238	0.00444
ADA	50										
ADA	51	**ALLOCATED DIRECT ASSIGNMENTS**									
ADA	52	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
ADA	53										
ADA	54	**Purchase of Receivables (POR)**									
ADA	55	Residential	SREVRES	48,229	48,229	48,229	48,229	48,229	48,229	48,229	48,229
ADA	56	Small Commercial and Industrilal	SREVCI	33,888	33,888	33,888	33,888	33,888	33,888	33,888	33,888
ADA	57	Large High Load Factor	SREVLHLF	0	0	0	0	0	0	0	0
ADA	58	Motor Vehicle - Firm	SREVMVF	169	169	169	169	169	169	169	169
ADA	59	Motor Vehicle - Interruptible	SREVMVI	1	1	1	1	1	1	1	1
ADA	60	Interruptible Service	SREVIS	0	0	0	0	0	0	0	0
ADA	61	Temperature Control	SREVTC	193	193	193	193	193	193	193	193
ADA	62	Transportation Service - Firm	SREVTSF	0	0	0	0	0	0	0	0
ADA	63	Transportation Service - Interruptible	SREVTSI	0	0	0	0	0	0	0	0
ADA	64										
ADA	65	Purchase of Receivables	REV_POR	82,479	82,479	82,479	82,479	82,479	82,479	82,479	82,479
ADA	66										
ADA	67	Purchase of Receivables	REV_POR	1.00000	0.56113	0.00973	0.42914	0.00211	0.06069	0.49833	0.00472
ADA	68										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
ADA	20	**Net Write-Offs - Pre-Program Arrearages (PPA)**							
ADA	21	Residential	SREVRES	1.00	1.00	1.00	1.00	1.00	1.00
ADA	22	Small Commercial and Industrilal	SREVCI	0.00	0.00	0.00	0.00	0.00	0.00
ADA	23	Large High Load Factor	SREVLHLF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	24	Motor Vehicle - Firm	SREVMVF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	25	Motor Vehicle - Interruptible	SREVMVI	0.00	0.00	0.00	0.00	0.00	0.00
ADA	26	Interruptible Service	SREVIS	0.00	0.00	0.00	0.00	0.00	0.00
ADA	27	Temperature Control	SREVTC	0.00	0.00	0.00	0.00	0.00	0.00
ADA	28	Transportation Service - Firm	SREVTSF	0.00	0.00	0.00	0.00	0.00	0.00
ADA	29	Transportation Service - Interruptible	SREVTSI	0.00	0.00	0.00	0.00	0.00	0.00
ADA	30								
ADA	31	Total Write-Offs	EXP_904PPA	1.00	1.00	1.00	1.00	1.00	1.00
ADA	32								
ADA	33	Total Write-Offs	EXP_904PPA	0.00358	0.25859	0.08766	0.04533	0.02872	0.08571
ADA	34								
ADA	35								
ADA	36	**Forfeited Discounts - Account 487**							
ADA	37	Residential	SREVRES	909	909	909	909	909	909
ADA	38	Small Commercial and Industrilal	SREVCI	371	371	371	371	371	371
ADA	39	Large High Load Factor	SREVLHLF	1	1	1	1	1	1
ADA	40	Motor Vehicle - Firm	SREVMVF	2	2	2	2	2	2
ADA	41	Motor Vehicle - Interruptible	SREVMVI	0	0	0	0	0	0
ADA	42	Interruptible Service	SREVIS	0	0	0	0	0	0
ADA	43	Temperature Control	SREVTC	2	2	2	2	2	2
ADA	44	Transportation Service - Firm	SREVTSF	57	57	57	57	57	57
ADA	45	Transportation Service - Interruptible	SREVTSI	32	32	32	32	32	32
ADA	46								
ADA	47	Total Forfeited Discounts	REV_487	1,373	1,373	1,373	1,373	1,373	1,373
ADA	48								
ADA	49	Total Forfeited Discounts	REV_487	0.00532	0.22884	0.08497	0.03298	0.01995	0.06455
ADA	50								
ADA	51	**ALLOCATED DIRECT ASSIGNMENTS**							
ADA	52	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
ADA	53								
ADA	54	**Purchase of Receivables (POR)**							
ADA	55	Residential	SREVRES	48,229	48,229	48,229	48,229	48,229	48,229
ADA	56	Small Commercial and Industrilal	SREVCI	33,888	33,888	33,888	33,888	33,888	33,888
ADA	57	Large High Load Factor	SREVLHLF	0	0	0	0	0	0
ADA	58	Motor Vehicle - Firm	SREVMVF	169	169	169	169	169	169
ADA	59	Motor Vehicle - Interruptible	SREVMVI	1	1	1	1	1	1
ADA	60	Interruptible Service	SREVIS	0	0	0	0	0	0
ADA	61	Temperature Control	SREVTC	193	193	193	193	193	193
ADA	62	Transportation Service - Firm	SREVTSF	0	0	0	0	0	0
ADA	63	Transportation Service - Interruptible	SREVTSI	0	0	0	0	0	0
ADA	64								
ADA	65	Purchase of Receivables	REV_POR	82,479	82,479	82,479	82,479	82,479	82,479
ADA	66								
ADA	67	Purchase of Receivables	REV_POR	0.00501	0.23771	0.08553	0.03097	0.01731	0.05763
ADA	68								

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION						
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
ADA	69										
ADA	70	**DIRECT ASSIGN TO CLASSES W/SALES DIST PLT FUNCTIONS**									
ADA	71										
ADA	72	**Customer Advances for Construction**									
ADA	73	Residential	DPLTRES	878	878	878	878	878	878	878	878
ADA	74	Small Commercial and Industrilal	DPLTCI	191	191	191	191	191	191	191	191
ADA	75	Large High Load Factor	DPLTLHLF	0	0	0	0	0	0	0	0
ADA	76	Motor Vehicle - Firm	DPLTMVF	0	0	0	0	0	0	0	0
ADA	77	Motor Vehicle - Interruptible	DPLTMVI	0	0	0	0	0	0	0	0
ADA	78	Interruptible Service	DPLTIS	0	0	0	0	0	0	0	0
ADA	79	Temperature Control	DPLTTC	0	0	0	0	0	0	0	0
ADA	80	Transportation Service - Firm	DPLTTSF	189	189	189	189	189	189	189	189
ADA	81	Transportation Service - Interruptible	DPLTTSI	59	59	59	59	59	59	59	59
ADA	82										
ADA	83	Customer Advances for Construction	CUSTADV	1,318	1,318	1,318	1,318	1,318	1,318	1,318	1,318
ADA	84										
ADA	85	Customer Advances for Construction	CUSTADV	1.00000	0.66990	0.00000	0.33010	0.00000	0.00000	0.66990	0.00000
ADA	86										
ADA	87										
ADA	88										
ADA	89										
ADA	90										
ADA	91										
ADA	92										
ADA	93										
ADA	94										
ADA	95										
ADA	96										
ADA	97										
ADA	98										
ADA	99										
ADA	100										
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RRW	2										
RRW	3	PRESENT RATES - Excludes Purchased Gas									
RRW	4	----------									
RRW	5	RATE BASE		3,513,974	2,096,308	58,095	1,359,571	1,640	156,155	1,938,514	1,136
RRW	6	NET OPER INC (PRESENT RATES)		204,311	122,929	3,890	77,492	94	8,984	113,851	598
RRW	7	RATE OF RETURN (PRES RATES)		5.81%	5.86%	6.70%	5.70%	5.75%	5.75%	5.87%	52.62%
RRW	8	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
RRW	9	SALES REVENUE (PRE RATES)		481,982	267,594	4,671	209,717	917	26,276	240,401	2,147
RRW	10	REVENUE PRES RATES $/Mcf		$5.1493	$2.8588	$0.0499	$2.2405	$0.0098	$0.2807	$2.5683	$0.0229
RRW	11	REVENUE REQUIRED - $/MO/CUST		$71.86	$39.90	$0.70	$31.27	$0.14	$3.92	$35.84	$0.32
RRW	12										
RRW	13										
RRW	14	CLAIMED RATE OF RETURN									
RRW	15	----------									
RRW	16	CLAIMED RATE OF RETURN		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	17	RETURN REQ FOR CLAIMED ROR - Excludes Purchased Gas		283,930	169,066	5,230	109,635	132	12,592	156,341	624

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
ADA	69								
ADA	70	**DIRECT ASSIGN TO CLASSES W/SALES DIST PLT FUNCTIONS**							
ADA	71								
ADA	72	**Customer Advances for Construction**							
ADA	73	Residential	DPLTRES	878	878	878	878	878	878
ADA	74	Small Commercial and Industrilal	DPLTCI	191	191	191	191	191	191
ADA	75	Large High Load Factor	DPLTLHLF	0	0	0	0	0	0
ADA	76	Motor Vehicle - Firm	DPLTMVF	0	0	0	0	0	0
ADA	77	Motor Vehicle - Interruptible	DPLTMVI	0	0	0	0	0	0
ADA	78	Interruptible Service	DPLTIS	0	0	0	0	0	0
ADA	79	Temperature Control	DPLTTC	0	0	0	0	0	0
ADA	80	Transportation Service - Firm	DPLTTSF	189	189	189	189	189	189
ADA	81	Transportation Service - Interruptible	DPLTTSI	59	59	59	59	59	59
ADA	82								
ADA	83	Customer Advances for Construction	CUSTADV	1,318	1,318	1,318	1,318	1,318	1,318
ADA	84								
ADA	85	Customer Advances for Construction	CUSTADV	0.00000	0.33010	0.00000	0.00000	0.00000	0.00000
ADA	86								
ADA	87								
ADA	88								
ADA	89								
ADA	90								
ADA	91								
ADA	92								
ADA	93								
ADA	94								
ADA	95								
ADA	96								
ADA	97								
ADA	98								
ADA	99								
ADA	100								
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**							
RRW	2								
RRW	3	PRESENT RATES - Excludes Purchased Gas							
RRW	4	----------							
RRW	5	RATE BASE		56,959	1,031,744	280,369	24,134	3,696	19,629
RRW	6	NET OPER INC (PRESENT RATES)		3,292	58,614	16,267	1,346	206	1,059
RRW	7	RATE OF RETURN (PRES RATES)		5.78%	5.68%	5.80%	5.58%	5.58%	5.39%
RRW	8	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
RRW	9	SALES REVENUE (PRE RATES)		2,524	110,977	41,015	16,209	9,844	31,670
RRW	10	REVENUE PRES RATES $/Mcf		$0.0270	$1.1856	$0.4382	$0.1732	$0.1052	$0.3384
RRW	11	REVENUE REQUIRED - $/MO/CUST		$0.38	$16.55	$6.12	$2.42	$1.47	$4.72
RRW	12								
RRW	13								
RRW	14	CLAIMED RATE OF RETURN							
RRW	15	----------							
RRW	16	CLAIMED RATE OF RETURN		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	17	RETURN REQ FOR CLAIMED ROR - Excludes Purchased Gas		4,606	83,199	22,609	1,946	298	1,583

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	CLASSIFICATION							
					CAPACITY	COMMODITY	CUSTOMER	PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
RRW	18	SALES REVENUE REQ CLAIMED ROR - Excludes Purchased Gas		592,085	331,396	6,523	254,167	969	31,265	299,161	2,182
RRW	19	REVENUE DEFICIENCY SALES REV		111,168	63,802	2,917	44,450	52	4,989	58,760	1,082
RRW	20	PERCENT INCREASE REQUIRED		23.06%	23.84%	62.45%	21.19%	5.72%	18.99%	24.44%	50.40%
RRW	21	ANNUAL BOOKED THROUGHPUT SALES (Mcf)		93,602,070	93,602,070	93,602,070	93,602,070	93,602,070	93,602,070	93,602,070	93,602,070
RRW	22	SALES REV REQUIRED $/Mcf		$6.3256	$3.5405	$0.0697	$2.7154	$0.0104	$0.3340	$3.1961	$0.0233
RRW	23	REVENUE DEFICIENCY $/Mcf		$1.1877	$0.6816	$0.0312	$0.4749	$0.0006	$0.0533	$0.6278	$0.0116
RRW	24	SALES REVENUE REQ CLAIMED ROR - Purchased Gas		261,980	0	261,980	0	0	0	0	261,963
RRW	25										
RRW	26	SALES REVENUE REQ CLAIMED ROR - COMPOSITE		854,065	331,396	268,503	254,167	969	31,265	299,161	264,144
RRW	27										
RRW	28										
RRW	29										
RRW	30										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	COMOTH	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(q)
RRW	18	SALES REVENUE REQ CLAIMED ROR - Excludes Purchased Gas		4,341	144,975	49,786	17,039	9,971	32,395
RRW	19	REVENUE DEFICIENCY SALES REV		1,817	33,998	8,770	830	127	725
RRW	20	PERCENT INCREASE REQUIRED		72.01%	30.64%	21.38%	5.12%	1.29%	2.29%
RRW	21	ANNUAL BOOKED THROUGHPUT SALES (Mcf)		93,602,070	93,602,070	93,602,070	93,602,070	93,602,070	93,602,070
RRW	22	SALES REV REQUIRED $/Mcf		$0.0464	$1.5488	$0.5319	$0.1820	$0.1065	$0.3461
RRW	23	REVENUE DEFICIENCY $/Mcf		$0.0194	$0.3632	$0.0937	$0.0089	$0.0014	$0.0077
RRW	24	SALES REVENUE REQ CLAIMED ROR - Purchased Gas		0	0	0	0	0	0
RRW	25								
RRW	26	SALES REVENUE REQ CLAIMED ROR - COMPOSITE		4,341	144,975	49,786	17,039	9,971	32,395
RRW	27								
RRW	28								
RRW	29								
RRW	30								

PECO Exhibit JD-4:

Gas Class Cost of Service Study for FPFTY Ended December 31, 2025 - Unitized Functionally Classified Revenue Requirement

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

LINE NO.	DESCRIPTION		TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**											
2												
3	**RATE OF RETURN**		5.81%	5.53%	6.25%	18.59%	7.03%	17.52%	50.89%	48.30%	5.99%	8.88%
4												
5	**REVENUES REQUIRED**											
6	**CAPACITY COMPONENT**	267,594	267,594	159,175	81,739	144	544	2	62	470	16,741	8,718
7	CAPACITY PRODUCTION COMPONENT		917	616	299	0	2	0	0	0	0	0
8	CAPACITY STORAGE COMPONENT		26,276	17,421	8,785	13	57	0	0	0	0	0
9	CAPACITY TRANSMISSION COMPONENT		0	0	0	0	0	0	0	0	0	0
10	CAPACITY DISTRIBUTION COMPONENT		240,401	141,138	72,655	130	485	2	62	470	16,741	8,718
11	**COMMODITY COMPONENT**	4,671	4,671	2,739	1,413	1	9	0	3	23	217	264
12	COMMODITY PURCHASED GAS		2,147	1,567	542	2	13	0	3	21	0	0
13	COMMODITY OTHER COMMODITY		2,524	1,173	872	(1)	(4)	0	0	2	217	264
14	**CUSTOMER COMPONENT**	209,717	209,717	165,852	39,524	39	58	2	10	204	2,163	1,866
15	CUSTOMER SERVICES INVESTMENT		110,977	84,758	25,751	11	9	1	3	65	220	159
16	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		41,015	28,731	10,063	7	39	1	2	130	915	1,127
17	CUSTOMER INSTALLATION EXPENSE		16,209	14,858	1,331	0	0	0	0	1	12	7
18	CUSTOMER SERVICE & SALES EXPENSE		9,844	9,413	153	4	0	0	1	0	176	98
19	CUSTOMER ACCOUNTS EXPENSE		31,670	28,093	2,226	18	8	0	3	8	839	475
20												
21												
22	**TOTAL COMPANY**	481,982	481,982	327,766	122,676	184	611	4	75	697	19,121	10,848
23												
24												
25												
26												
27	Annual Booked Throughput Sales (Mcf)		93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
28												
29	Number of Customer Bills		6,706,945	6,151,911	547,071	96	180	12	12	237	4,800	2,626
30												
31	Use per Month per Customer (Mcf)		14	7	44	219	2,792	89	1,370	545	2,474	5,080
32												
33												
34												
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PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

LINE NO.	DESCRIPTION		TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - UNIT COST**											
2												
3	**RATE OF RETURN**		5.81%	5.53%	6.25%	18.59%	7.03%	17.52%	50.89%	48.30%	5.99%	8.88%
4												
5	**$/Mcf**											
6	**CAPACITY COMPONENT**	$2.8588	$2.8588	$3.6286	$3.4268	$6.8414	$1.0822	$1.4648	$3.7763	$3.6370	$1.4099	$0.6536
7	CAPACITY PRODUCTION COMPONENT		$0.0098	$0.0140	$0.0125	$0.0144	$0.0037	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	CAPACITY STORAGE COMPONENT		$0.2807	$0.3971	$0.3683	$0.6400	$0.1128	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	CAPACITY TRANSMISSION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	CAPACITY DISTRIBUTION COMPONENT		$2.5683	$3.2174	$3.0460	$6.1882	$0.9657	$1.4648	$3.7763	$3.6370	$1.4099	$0.6536
11	**COMMODITY COMPONENT**	$0.0499	$0.0499	$0.0624	$0.0593	$0.0465	$0.0189	$0.1273	$0.1862	$0.1790	$0.0183	$0.0198
12	COMMODITY PURCHASED GAS		$0.0229	$0.0357	$0.0227	$0.0786	$0.0259	$0.1120	$0.1708	$0.1636	$0.0000	$0.0000
13	COMMODITY OTHER COMMODITY		$0.0270	$0.0267	$0.0365	($0.0321)	($0.0071)	$0.0154	$0.0154	$0.0154	$0.0183	$0.0198
14	**CUSTOMER COMPONENT**	$2.2405	$2.2405	$3.7808	$1.6570	$1.8713	$0.1146	$1.7580	$0.5806	$1.5782	$0.1821	$0.1399
15	CUSTOMER SERVICES INVESTMENT		$1.1856	$1.9321	$1.0796	$0.5201	$0.0182	$1.1989	$0.2065	$0.4992	$0.0185	$0.0119
16	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		$0.4382	$0.6549	$0.4219	$0.3167	$0.0785	$0.4833	$0.1369	$1.0083	$0.0771	$0.0845
17	CUSTOMER INSTALLATION EXPENSE		$0.1732	$0.3387	$0.0558	$0.0137	$0.0009	$0.0331	$0.0033	$0.0080	$0.0010	$0.0005
18	CUSTOMER SERVICE & SALES EXPENSE		$0.1052	$0.2146	$0.0064	$0.1784	$0.0001	$0.0040	$0.0320	$0.0008	$0.0148	$0.0073
19	CUSTOMER ACCOUNTS EXPENSE		$0.3384	$0.6404	$0.0933	$0.8424	$0.0169	$0.0387	$0.2020	$0.0615	$0.0707	$0.0356
20												
21												
22	**TOTAL COMPANY**	$5.1493	$5.1493	$7.4718	$5.1431	$8.7604	$1.2156	$3.3718	$4.5390	$5.3941	$1.6103	$0.8133
23												
24	**$/MONTH/CUSTOMER**											
25	**CUSTOMER COMPONENTS**	$31.27	$31.27	$26.96	$72.25	$409.34	$319.96	$155.85	$795.83	860.73	$450.55	710.56
26	CUSTOMER SERVICES INVESTMENT		$16.55	$13.78	$47.07	$113.75	$50.90	$106.28	$282.50	272.24	$45.82	60.55
27	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		$6.12	$4.67	$18.39	$69.27	$219.08	$42.84	$187.50	549.79	$190.71	429.27
28	CUSTOMER INSTALLATION EXPENSE		$2.42	$2.42	$2.43	$3.13	$2.46	$2.94	$4.17	4.35	$2.41	2.55
29	CUSTOMER SERVICE & SALES EXPENSE		$1.47	$1.53	$0.28	$39.02	$0.33	$0.35	$44.17	0.42	$36.72	37.23
30	CUSTOMER ACCOUNTS EXPENSE		$4.72	$4.57	$4.07	$184.27	$47.19	$3.43	$276.67	33.53	$174.89	180.96
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PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

LINE NO.	DESCRIPTION		TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**											
2												
3	**RATE OF RETURN**		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
4												
5	**REVENUES REQUIRED**											
6	**CAPACITY COMPONENT**	331,396	331,396	204,447	97,380	73	600	1	10	80	20,674	8,131
7	CAPACITY PRODUCTION COMPONENT		969	655	312	0	2	0	0	0	0	0
8	CAPACITY STORAGE COMPONENT		31,265	21,129	10,067	8	61	0	0	0	0	0
9	CAPACITY TRANSMISSION COMPONENT		0	0	0	0	0	0	0	0	0	0
10	CAPACITY DISTRIBUTION COMPONENT		299,161	182,663	87,001	65	536	1	10	80	20,674	8,131
11	**COMMODITY COMPONENT**	268,485	268,503	198,853	66,777	108	1,498	9	87	680	231	258
12	COMMODITY PURCHASED GAS		264,144	196,274	65,486	109	1,502	9	87	678	0	0
13	COMMODITY OTHER COMMODITY		4,341	2,567	1,287	-1	-3	0	0	2	231	258
14	**CUSTOMER COMPONENT**	254,167	254,167	203,002	46,823	29	62	1	4	43	2,423	1,780
15	CUSTOMER SERVICES INVESTMENT		144,975	113,059	31,465	5	10	1	0	10	277	147
16	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		49,786	35,809	11,748	4	43	0	0	26	1,097	1,058
17	CUSTOMER INSTALLATION EXPENSE		17,039	15,638	1,381	0	0	0	0	1	12	7
18	CUSTOMER SERVICE & SALES EXPENSE		9,971	9,536	155	4	0	0	0	0	178	97
19	CUSTOMER ACCOUNTS EXPENSE		32,395	28,959	2,074	16	9	0	2	6	858	471
20												
21												
22	**TOTAL COMPANY**	854,047	854,065	411,609	146,041	102	672	2	16	145	23,328	10,170
23												
24												
25												
26												
27	Annual Booked Throughput Sales (Mcf)		93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
28												
29	Number of Customer Bills		6,706,945	6,151,911	547,071	96	180	12	12	237	4,800	2,626
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PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

LINE NO.	DESCRIPTION		TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - UNIT COSTS**											
2												
3	**RATE OF RETURN**		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
4												
5	**$/Mcf**											
6	**CAPACITY COMPONENT**	$3.5405	$3.5405	$4.6606	$4.0826	$3.4720	$1.1930	$0.7640	$0.5834	$0.6224	$1.7412	$0.6096
7	CAPACITY PRODUCTION COMPONENT		$0.0104	$0.0149	$0.0131	$0.0115	$0.0038	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	CAPACITY STORAGE COMPONENT		$0.3340	$0.4817	$0.4221	$0.3640	$0.1218	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	CAPACITY TRANSMISSION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	CAPACITY DISTRIBUTION COMPONENT		$3.1961	$4.1640	$3.6475	$3.0975	$1.0674	$0.7640	$0.5834	$0.6224	$1.7412	$0.6096
11	**COMMODITY COMPONENT**	$0.0697	$0.0697	$0.0948	$0.0770	$0.0441	$0.0196	$0.1259	$0.1741	$0.1676	$0.0194	$0.0194
12	COMMODITY PURCHASED GAS		$0.0233	$0.0363	$0.0231	$0.0762	$0.0262	$0.1105	$0.1587	$0.1522	$0.0000	$0.0000
13	COMMODITY OTHER COMMODITY		$0.0464	$0.0585	$0.0539	($0.0320)	($0.0065)	$0.0154	$0.0154	$0.0154	$0.0194	$0.0194
14	**CUSTOMER COMPONENT**	$2.7154	$2.7154	$4.6276	$1.9630	$1.3578	$0.1240	$0.9493	$0.2171	$0.3304	$0.2041	$0.1335
15	CUSTOMER SERVICES INVESTMENT		$1.5488	$2.5773	$1.3191	$0.2480	$0.0204	$0.5938	$0.0283	$0.0766	$0.0234	$0.0110
16	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		$0.5319	$0.8163	$0.4925	$0.1701	$0.0855	$0.2700	$0.0248	$0.1999	$0.0924	$0.0793
17	CUSTOMER INSTALLATION EXPENSE		$0.1820	$0.3565	$0.0579	$0.0113	$0.0009	$0.0279	$0.0017	$0.0044	$0.0010	$0.0005
18	CUSTOMER SERVICE & SALES EXPENSE		$0.1065	$0.2174	$0.0065	$0.1696	$0.0001	$0.0038	$0.0267	$0.0006	$0.0150	$0.0073
19	CUSTOMER ACCOUNTS EXPENSE		$0.3461	$0.6602	$0.0869	$0.7597	$0.0171	$0.0538	$0.1356	$0.0488	$0.0723	$0.0353
20	AVAILABLE COMPONENT											
21	AVAILABLE COMPONENT											
22	**TOTAL COMPANY**	$6.3256	$6.3256	$9.3831	$6.1227	$4.8742	$1.3366	$1.8480	$0.9742	$1.1203	$1.9647	$0.7625
23												
24	**$/MONTH/CUSTOMER**											
25	**CUSTOMER COMPONENTS**	$37.90	$37.90	$33.00	$85.59	$297.01	$346.27	$84.16	$297.41	$180.17	$504.83	$678.04
26	CUSTOMER SERVICES INVESTMENT		$21.62	$18.38	$57.52	$54.05	$56.87	$52.64	$38.79	$41.81	57.78	$56.06
27	CUSTOMER METERS, REGUL & INSTALL INVESTMENT		$7.42	$5.82	$21.47	$37.22	$238.87	$23.94	$34.01	$109.03	228.62	$402.93
28	CUSTOMER INSTALLATION EXPENSE		$2.54	$2.54	$2.52	$2.49	$2.51	$2.48	$2.36	$2.38	2.52	$2.51
29	CUSTOMER SERVICE & SALES EXPENSE		$1.49	$1.55	$0.28	$37.08	$0.34	$0.33	$36.53	$0.33	37.10	$37.09
30	CUSTOMER ACCOUNTS EXPENSE		$4.83	$4.71	$3.79	$166.18	$47.67	$4.77	$185.72	$26.63	178.81	$179.45
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PECO Exhibit JD-5:

Customer-Related Revenue Requirement and Customer Charge

Customer-Related Revenue Requirement and Customer Charge

Line	Description	Residential	GC	Transportation Firm	Transportation Interruptible	All Other
1	Customer Services Investment($000)	$ 113,059	$ 31,465	$ 277	$ 147	$ 26
2	Customer Meter Investment($000)	$ 35,809	$ 11,748	$ 1,097	$ 1,058	$ 73
3	Customer Installation Expense($000)	$ 15,638	$ 1,381	$ 12	$ 7	$ 1
4	Customer Service Expense($000)	$ 9,536	$ 155	$ 178	$ 97	$ 4
5	Customer Record & Collection Expense and Uncollectible Accounts($000)	$ 28,959	$ 2,074	$ 858	$ 471	$ 33
6	Total Revenue Requirement($000)	$ 203,002	$ 46,823	$ 2,423	$ 1,780	$ 138
7	Number of Customer Bills	6,151,911	547,071	4,800	2,626	$ 537
8	$/Month/Customer (Line 6/Line 7*1000)	$ 33.00	$ 85.59	$ 504.83	$ 678.04	$ 257.21

Notes:

1.) Above costs included allocated payroll, administrative, pension and benefits and working capital supporting general plant.

2.) Line 1 through line 5 from PECO Exhibit JD-4, page 3, lines 15 to 19.

3.) Lines with no measures of value have been hidden from pages 2 through 19.

4.) Pages 2 through 10 included Residential and GC customer-related costs; pages 11 through 19 included TSF and TSI customer-related costs.

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
S	1	**SUMMARY AT PRESENT RATES**												
S	2													
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**												
S	4	**OPERATING REVENUE**												
S	5	Sales of Gas Revenue - Base	84,758	28,731	14,858	9,413	28,093	165,852	25,751	10,063	1,331	153	2,226	39,524
S	6	Other Operating Revenue	703	230	98	33	150	1,214	209	80	9	1	14	313
S	7	TOTAL OPERATING REVENUE	85,460	28,961	14,957	9,446	28,243	167,067	25,960	10,143	1,340	154	2,240	39,837
S	8													
S	9	**OPERATING EXPENSES**												
S	10	Operation and Maintenance Expense Excl Pur Gas	17,638	9,291	12,006	8,655	24,706	72,296	4,791	3,006	1,058	172	2,500	11,528
S	11	Depreciation and Amortization Expense	26,721	10,031	1,141	505	1,459	39,857	7,503	3,316	101	(26)	150	11,044
S	12	Taxes Other Than Income Taxes-General	1,415	501	520	77	673	3,186	397	166	46	2	68	678
S	13	Taxes Other Than Income Taxes-Distribution GRT	0	0	0	0	0	0	0	0	0	0	0	0
S	14	Income Taxes	4,615	1,942	(70)	(15)	(48)	6,424	768	485	(11)	(1)	104	1,345
S	15	TOTAL OPERATING EXPENSES	41,159	17,881	13,736	9,252	26,887	108,915	11,923	6,003	1,217	148	2,613	21,905
S	16													
S	17	**OPERATING INCOME (RETURN)**	44,302	11,080	1,221	194	1,356	58,152	14,037	4,140	123	5	(373)	17,932
S	18													
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**												
S	20	Gas Plant in Service	1,110,865	340,897	4,064	554	5,200	1,461,579	311,919	112,686	361	11	533	425,510
S	21	Less: Accumulated Depreciation	247,209	123,277	1,803	246	2,307	374,842	69,414	40,750	160	5	236	110,565
S	22	Plus: Rate Base Additions Excl Purchased Gas	16,570	8,033	21,953	3,484	28,424	78,465	4,773	2,700	1,957	87	2,913	12,429
S	23	Less: Rate Base Deductions	77,036	24,778	2,082	284	6,731	110,910	22,003	8,191	185	6	9,201	39,585
S	24	**TOTAL RATE BASE EXCL PURCHASED GAS**	803,190	200,875	22,132	3,509	24,586	1,054,291	225,275	66,445	1,973	87	(5,992)	287,789
S	25													
S	26	**RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**	5.53%	5.53%	5.53%	5.53%	5.53%	5.52%	6.25%	6.25%	6.25%	6.25%	6.25%	6.23%
S	27	**INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**	0.97	0.95	0.99	0.99	1.03		1.10	1.08	1.12	1.12	1.16	
S	28													
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**												
S	41	**Total Distribution Sales Revenue at Current Rates**	84,758	28,731	14,858	9,413	28,093	165,852	25,751	10,063	1,331	153	2,226	39,524
S	42	Total Distribution Operating Revenues	85,460	28,961	14,957	9,446	28,243	167,067	25,960	10,143	1,340	154	2,240	39,837
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes	45,774	19,823	13,666	9,237	26,839	115,339	12,691	6,488	1,206	148	2,717	23,250
S	44	Plus: Total Federal & State Taxes	4,615	1,942	(70)	(15)	(48)	6,424	768	485	(11)	(1)	104	1,345
S	45	Total Operating Income (Return)	44,302	11,080	1,221	194	1,356	58,152	14,037	4,140	123	5	(373)	17,932
S	46	Total Rate Base	803,190	200,875	22,132	3,509	24,586	1,054,291	225,275	66,445	1,973	87	(5,992)	287,789
S	47													
S	48	COMPOSITE RATE OF RETURN (PRESENT)	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)	0.97	0.95	0.99	0.99	1.02		1.10	1.07	1.12	1.12	1.16	
S	50													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**												
S	52													
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED R**												
S	54													
S	55	**Rate Base Excluding Purchased Gas**	803,190	200,875	22,132	3,509	24,586	1,054,291	225,275	66,445	1,973	87	(5,992)	287,789
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**	20,466	5,118	564	89	626	26,864	4,132	1,219	36	2	(110)	5,278
S	57		0	0	0	0	0	0	0	0	0	0	0	0
S	58	**OPERATING REVENUES**												
S	59	**Change in Revenue (Change in Return * 1.383)**	28,302	7,078	780	124	866	37,150	5,714	1,685	50	2	(152)	7,299
S	60	Distribution Base Rate Revenue (Present Rates)	84,758	28,731	14,858	9,413	28,093	165,852	25,751	10,063	1,331	153	2,226	39,524
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	113,059	35,809	15,638	9,536	28,959	203,002	31,465	11,748	1,381	155	2,074	46,823
S	62													
S	63	Forfeited Discounts Revenues	46	11	1	0	1	60	9	3	0	0	(0)	12
S	64	Other Operating Revenue (Present Rates)	703	230	98	33	150	1,214	209	80	9	1	14	313
S	65	**TOTAL OPERATING REVENUES**	113,808	36,051	15,738	9,570	29,110	204,276	31,683	11,831	1,390	156	2,088	47,148
S	66													
S	67	**OPERATING EXPENSES**												
S	68	Operation and Maintenance Expense Excl Pur Gas	17,638	9,291	12,006	8,655	24,706	72,296	4,791	3,006	1,058	172	2,500	11,528
S	69	Depreciation and Amortization Expense	26,721	10,031	1,141	505	1,459	39,857	7,503	3,316	101	(26)	150	11,044
S	70	Additional Bad Debt Expense	104	26	3	0	3	137	21	6	0	0	(1)	27
S	71	Additional PUC / OTS & SBA Fee Expense	87	22	2	0	3	115	18	5	0	0	(0)	23
S	72	Taxes Other Than Income Taxes-General	1,415	501	520	77	673	3,186	397	166	46	2	68	678
S	73	Taxes Other Than Income Taxes-Distribution GRT	0	0	0	0	0	0	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**	45,965	19,871	13,671	9,238	26,845	115,591	12,730	6,499	1,206	148	2,716	23,299
S	75	State and Federal Income Taxes @ Effective Tax Rate	(4,615)	(1,942)	70	15	48	(6,424)	(768)	(485)	11	1	(104)	(1,345)
S	76	State and Federal Income Taxes @ Statutory Rates	7,690	1,923	212	34	235	10,094	1,552	458	14	1	(41)	1,983
S	77	**TOTAL OPERATING EXPENSES**	49,040	19,853	13,953	9,287	27,128	119,261	13,515	6,472	1,231	149	2,571	23,938
S	78													
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**	64,767	16,198	1,785	283	1,983	85,015	18,168	5,359	159	7	(483)	23,210
S	80													
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**	113,059	35,809	15,638	9,536	28,959	203,002	31,465	11,748	1,381	155	2,074	46,823
S	82													
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**	28,347	7,090	781	124	868	37,210	5,723	1,688	50	2	(152)	7,311
S	84	**REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVEN**	33.45%	24.68%	5.26%	1.32%	3.09%	22.44%	22.22%	16.77%	3.77%	1.44%	-6.84%	18.50%
S	85													
S	86													
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**												
S	133	**Total Composite Base Rate Sales Revenue Requirement**	113,059	35,809	15,638	9,536	28,959	203,002	31,465	11,748	1,381	155	2,074	46,823
S	134													
S	135													
S	136	**Total Operating Expense before Income Taxes**	45,965	19,871	13,671	9,238	26,845	115,591	12,730	6,499	1,206	148	2,716	23,299
S	146	**NUMBER OF CUSTOMER BILLS**	6,151,911	6,151,911	6,151,911	6,151,911	6,151,911	6,151,911	547,071	547,071	547,071	547,071	547,071	547,071
S	147													
S	148	**$/MONTH/CUSTOMER**	$18.38	$5.82	$2.54	$1.55	$4.71	**$33.00**	$57.52	$21.47	$2.52	$0.28	$3.79	**$85.59**
S	149													
S	150													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
RBP	1	**DEVELOPMENT OF RATE BASE**												
RBP	2													
RBP	3	**GAS PLANT IN SERVICE**												
RBP	4	INTANGIBLE PLANT												
RBP	5	301-Organization	3,936	1,208	14	2	18	5,179	1,105	399	1	0	2	1,508
RBP	6	303-Miscellaneous Intangible Plant	0	0	0	0	0	0	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT	3,936	1,208	14	2	18	5,179	1,105	399	1	0	2	1,508
RBP	8													
RBP	9	PRODUCTION PLANT (LPG)												
RBP	27	DISTRIBUTION PLANT												
RBP	40	380-Services	1,103,049	0	0	0	0	1,103,049	309,725	0	0	0	0	309,725
RBP	41	381-Meters	0	129,144	0	0	0	129,144	0	42,689	0	0	0	42,689
RBP	42	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
RBP	43	Total Account 381	0	129,144	0	0	0	129,144	0	42,689	0	0	0	42,689
RBP	44	382-Meter Installations	0	208,822	0	0	0	208,822	0	69,028	0	0	0	69,028
RBP	45	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
RBP	46	Total Account 382	0	208,822	0	0	0	208,822	0	69,028	0	0	0	69,028
RBP	47	387-Other Equipment	527	161	0	0	0	688	148	53	0	0	0	201
RBP	48	388-Asset Retirement Costs for Distribution Plant	223	68	0	0	0	292	63	23	0	0	0	85
RBP	49	TOTAL DISTRIBUTION PLANT	1,103,799	338,195	0	0	0	1,441,995	309,935	111,793	0	0	0	421,728
RBP	50													
RBP	53	GENERAL PLANT												
RBP	54	389-Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0
RBP	55	390-Structures and Improvements	1,002	478	1,297	177	1,659	4,613	281	158	115	4	170	728
RBP	56	391-Office Furniture & Equipment	155	74	201	27	257	715	44	25	18	1	26	113
RBP	57	393-Store Equipment	0	0	0	0	0	0	0	0	0	0	0	0
RBP	58	394-Tools, Shop & Garage Equip.	1,440	687	1,863	254	2,384	6,629	404	227	166	5	244	1,047
RBP	59	395-Laboratory Equipment	6	3	8	1	10	28	2	1	1	0	1	4
RBP	60	397-Communication Equipment	504	241	652	89	834	2,320	141	80	58	2	85	366
RBP	61	398-Miscellaneous Equipment	22	10	28	4	36	101	6	3	3	0	4	16
RBP	62	TOTAL GENERAL PLANT	3,129	1,494	4,050	552	5,182	14,405	879	494	360	11	531	2,274
RBP	63													
RBP	65	**TOTAL GAS PLANT IN SERVICE**	1,110,865	340,897	4,064	554	5,200	1,461,579	311,919	112,686	361	11	533	425,510

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**												
RBD	2													
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	1,924	590	7	1	9	2,531	540	195	1	0	1	737
RBD	10													
RBD	11	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION												
RBD	23	Total Account 379	0	0	0	0	0	0	0	0	0	0	0	0
RBD	24	380-Services	243,310	0	0	0	0	243,310	68,319	0	0	0	0	68,319
RBD	25	381-Meters	0	63,848	0	0	0	63,848	0	21,106	0	0	0	21,106
RBD	26	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
RBD	27	Total Account 381	0	63,848	0	0	0	63,848	0	21,106	0	0	0	21,106
RBD	28	382-Meter Installations	0	57,996	0	0	0	57,996	0	19,171	0	0	0	19,171
RBD	29	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
RBD	30	Total Account 382	0	57,996	0	0	0	57,996	0	19,171	0	0	0	19,171
RBD	31	387-Other Equipment	434	133	0	0	0	566	122	44	0	0	0	166
RBD	32	388-Asset Retirement Costs for Distribution Plant	154	47	0	0	0	201	43	16	0	0	0	59
RBD	33	**TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION**	243,898	122,024	0	0	0	365,921	68,484	40,336	0	0	0	108,820
RBD	34													
RBD	35	GENERAL PLANT ACCUMULATED DEPRECIATION	1,388	663	1,796	245	2,298	6,390	390	219	160	5	235	1,009
RBD	37	**TOTAL ACCUMULATED DEPRECIATION**	247,209	123,277	1,803	246	2,307	374,842	69,414	40,750	160	5	236	110,565
RBD	38													
RBD	39													
RBD	50													
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**												
RBO	2													
RBO	3	**PLUS: ADDITIONS TO RATE BASE**												
RBO	4													
RBO	5	COMMON PLANT	16,567	7,909	21,442	2,921	27,437	76,277	4,652	2,615	1,907	59	2,811	12,043
RBO	6													
RBO	7	**WORKING CAPITAL**												
RBO	8	Cash Working Capital - Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0
RBO	9	Cash Working Capital	(507)	(33)	509	564	985	1,518	(22)	34	50	28	101	191
RBO	10	Gas Storage Inventory	0	0	0	0	0	0	0	0	0	0	0	0
RBO	11	Materials and Supplies	509	156	2	0	2	670	143	52	0	0	0	195
RBO	12	TOTAL WORKING CAPITAL	3	124	511	564	987	2,188	121	85	50	28	101	386
RBO	13	TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS	16,570	8,033	21,953	3,484	28,424	78,465	4,773	2,700	1,957	87	2,913	12,429
RBO	14	TOTAL ADDITIONS TO RATE BASE	16,570	8,033	21,953	3,484	28,424	78,465	4,773	2,700	1,957	87	2,913	12,429
RBO	15													
RBO	16	**LESS: DEDUCTIONS TO RATE BASE**												
RBO	17	Customer Deposits	0	0	0	0	4,067	4,067	0	0	0	0	8,928	8,928
RBO	18	Customer Advances for Construction	375	0	0	0	0	375	58	0	0	0	0	58
RBO	19	Deferred Income Taxes and Credits												
RBO	20	Plant	90,556	27,789	331	45	424	119,146	25,427	9,186	29	1	43	34,687
RBO	21	Common Plant	1,386	662	1,794	244	2,296	6,382	389	219	160	5	235	1,008
RBO	22	Pension Assets / (Liability)	0	0	0	0	0	0	0	0	0	0	0	0
RBO	23	Corporate Alternative Minimum Tax	(11,970)	(3,673)	(44)	(6)	(56)	(15,749)	(3,361)	(1,214)	(4)	(0)	(6)	(4,585)
RBO	24	Contributions in Aid of Construction (CIAC)	(3,312)	0	0	0	0	(3,312)	(510)	0	0	0	0	(510)
RBO	25	Total Deferred Income Taxes and Credits	76,661	24,778	2,082	284	2,664	106,468	21,945	8,191	185	6	273	30,599
RBO	26	TOTAL DEDUCTIONS TO RATE BASE	77,036	24,778	2,082	284	6,731	110,910	22,003	8,191	185	6	9,201	39,585
RBO	27													
RBO	28	TOTAL PURCHASED GAS RATE BASE	0	0	0	0	0	0	0	0	0	0	0	0
RBO	29	TOTAL RATE BASE EXCLUDING PURCHASED GAS	803,190	200,875	22,132	3,509	24,586	1,054,291	225,275	66,445	1,973	87	(5,992)	287,789
RBO	30													
RBO	31	**TOTAL RATE BASE**	803,190	200,875	22,132	3,509	24,586	1,054,291	225,275	66,445	1,973	87	(5,992)	287,789
RBO	32													
RBO	50													

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**												
RBC	2													
RBC	3	**TOTAL EXCLUDING PURCHASED GAS**												
RBC	4	O&M EXPENSE RELATED CASH WORKING CAPITAL												
RBC	5	Payroll (Distribution Only)	4,570	2,182	5,914	806	7,568	21,039	1,283	721	526	16	775	3,322
RBC	6	Pension	85	40	110	15	140	390	24	13	10	0	14	62
RBC	7	Other Expenses												
RBC	8	Other Expenses	12,333	6,946	5,336	8,189	16,769	49,573	3,462	2,296	474	164	1,708	8,104
RBC	9	BSC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	10	Purchase of Recievables (POR)	12,472	4,228	2,186	1,385	4,134	24,404	7,113	2,780	368	42	615	10,918
RBC	11	TOTAL EXPENSES	29,459	13,396	13,546	10,394	28,611	95,407	11,882	5,810	1,378	223	3,112	22,405
RBC	12													
RBC	13	TOTAL EXPENSES PER DAY	81	37	37	28	78	261	33	16	4	1	9	61
RBC	14													
RBC	15	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	839	381	386	296	815	2,717	338	165	39	6	89	638
RBC	16													
RBC	17	AVERAGE PREPAYMENTS	336	118	123	267	172	1,016	95	39	11	22	16	183
RBC	18	DISTRIBUTION ACCRUED TAXES	415	111	7	1	8	542	134	42	1	0	(3)	173
RBC	19	INTEREST PAYMENTS	(2,096)	(643)	(8)	(1)	(10)	(2,758)	(589)	(213)	(1)	(0)	(1)	(803)
RBC	20													
RBC	21													
RBC	22	**NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT**	(507)	(33)	509	564	985	1,518	(22)	34	50	28	101	191
RBC	23													
RBC	40	TOTAL NET CASH WORKING CAPITAL	(507)	(33)	509	564	985	1,518	(22)	34	50	28	101	191
RBC	15													
RBC	16	DISTRIBUTION ACCRUED TAXES												
RBC	17	Federal Income Tax	59,792	12,868	2,170	354	2,331	77,515	22,432	5,932	243	11	(927)	27,691
RBC	18	State Income Tax	6,360	1,369	231	38	248	8,245	2,386	631	26	1	(99)	2,945
RBC	19	PURTA Taxes	54,725	16,794	200	27	256	72,003	15,366	5,551	18	1	26	20,962
RBC	20	PA Capital Stock Tax	0	0	0	0	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	0	0	0	0	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	30,526	9,368	112	15	143	40,163	8,571	3,097	10	0	15	11,693
RBC	23	TOTAL ACCRUED TAXES	151,403	40,398	2,712	435	2,978	197,925	48,755	15,211	297	13	(984)	63,292
RBC	24	TOTAL ACCRUED TAXES PER DAY	415	111	7	1	8	542	134	42	1	0	(3)	173
RBC	25													
RBC	26	DISTRIBUTION AVERAGE PREPAYMENTS												
RBC	27	AGA Membership Dues	28	10	5	3	9	55	9	3	0	0	1	13
RBC	28	EAPA Membership Dues	5	2	1	0	1	9	1	1	0	0	0	2
RBC	29	PUC Assess - Gas	136	43	19	11	35	245	38	14	2	0	2	56
RBC	30	Cellent Gas Meter Reading	0	0	0	0	0	0	0	0	0	0	0	0
RBC	31	Gas Software Maintenance	7	2	0	0	0	9	2	1	0	0	0	3
RBC	32	Customer and Research	0	0	0	61	0	61	0	0	0	5	0	5
RBC	33	VEBA Adjustment	67	32	87	12	112	310	19	11	8	0	11	49
RBC	34	Facility Contracts	3	1	0	0	0	4	1	0	0	0	0	1
RBC	35	IT License & Maintenance	68	21	0	0	0	89	19	7	0	0	0	26
RBC	36	Fleet Activities	9	4	11	2	14	40	2	1	1	0	1	6
RBC	37	Prepaid Rent	12	4	0	0	0	15	3	1	0	0	0	5
RBC	38	Postage	0	0	0	178	0	178	0	0	0	16	0	16
RBC	39	TOTAL AVERAGE PREPAYMENTS	336	118	123	267	172	1,016	95	39	11	22	16	183
RBC	49													
RBC	50													

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
RBC	51	**OPERATING REVENUES**												
RBC	52													
RBC	53	**SALES REVENUES**												
RBC	54	Sales of Gas Revenues - Base	84,758	28,731	14,858	9,413	28,093	165,852	25,751	10,063	1,331	153	2,226	39,524
RBC	55	Sales Revenues - Purchased Gas-PGC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	56	Sales Revenues - Balancing Service Charge-BSC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	57	TOTAL SALES OF GAS	84,758	28,731	14,858	9,413	28,093	165,852	25,751	10,063	1,331	153	2,226	39,524
RBC	58													
RBC	59	**OTHER OPERATING REVENUES**												
RBC	60	487-Forfeited Discounts	227	77	40	25	75	445	75	29	4	0	7	116
RBC	61	489-Revenues from Transportation of Gas of Others	0	0	0	0	0	0	0	0	0	0	0	0
RBC	62	493-Rent from Gas Property	430	132	0	0	0	562	121	44	0	0	0	164
RBC	63	495-Other Gas Revenues	45	21	58	8	75	207	13	7	5	0	8	33
RBC	64	TOTAL OTHER OPERATING REV	703	230	98	33	150	1,214	209	80	9	1	14	313
RBC	65													
RBC	66	**TOTAL OPERATING REVENUES**	85,460	28,961	14,957	9,446	28,243	167,067	25,960	10,143	1,340	154	2,240	39,837
RBC	67													
RBC	100													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
E	1	**OPERATION & MAINTENANCE EXPENSE**												
E	2	**PRODUCTION EXPENSE**												
E	40	Operation												
E	41	870-Operation Supervision and Engineering	81	49	143	0	0	273	23	16	13	0	0	52
E	42	874-Mains and Services Expenses	5,534	0	0	0	0	5,534	1,554	0	0	0	0	1,554
E	43	875-Measuring & Reg. Station Exp.-General	0	0	0	0	0	0	0	0	0	0	0	0
E	44	877-Measuring & Reg. Station Exp.-City Gate Sta.	0	0	0	0	0	0	0	0	0	0	0	0
E	45	878-Meter & House Regulator Expenses	0	5,481	0	0	0	5,481	0	1,812	0	0	0	1,812
E	46	879-Customer Installations Expenses	0	0	7,467	0	0	7,467	0	0	664	0	0	664
E	47	880-Other Expenses	5,042	1,545	0	0	0	6,587	1,416	511	0	0	0	1,926
E	48	880-Other Expenses - GPC	0	0	0	0	0	0	0	0	0	0	0	0
E	49	Total Distribution Operation	10,657	7,075	7,610	0	0	25,342	2,992	2,339	677	0	0	6,008
E	50													
E	53	Maintenance												
E	54	887-Maintenance of Mains	0	0	0	0	0	0	0	0	0	0	0	0
E	55	889-Maint. of Measuring & Reg. Station Equip.-Gen	0	0	0	0	0	0	0	0	0	0	0	0
E	56	892-Maintenance of Services	2,229	0	0	0	0	2,229	626	0	0	0	0	626
E	57	893-Maint. of Meters & House Regulators	0	175	0	0	0	175	0	58	0	0	0	58
E	58	894-Maintenance of Other Equipment	172	53	0	0	0	224	48	17	0	0	0	66
E	59	Total Distribution Maintenance	2,401	227	0	0	0	2,629	674	75	0	0	0	749
E	60	TOTAL DISTRIBUTION PLANT O&M EXPENSES	13,058	7,303	7,610	0	0	27,971	3,667	2,414	677	0	0	6,757
E	61	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)	13,058	7,303	7,610	0	0	27,971	3,667	2,414	677	0	0	6,757
E	62													
E	63	CUSTOMER ACCOUNTS EXPENSES												
E	64	902-Meter Reading	0	0	0	0	149	149	0	0	0	0	13	13
E	65	903-Customer Records and Collection Expense	0	0	0	0	17,887	17,887	0	0	0	0	1,841	1,841
E	66	904-Uncollectible Accounts	694	235	122	77	230	1,358	73	29	4	0	6	112
E	67	904-Uncollectible Accounts - MFC/POR	0	0	0	0	0	0	0	0	0	0	0	0
E	68	904-Uncollectible Accounts - PPA	137	46	24	15	45	268	0	0	0	0	0	0
E	69	905-Miscellaneous CA	0	0	0	0	918	918	0	0	0	0	82	82
E	70	TOTAL CUSTOMER ACCTS EXPENSE	831	282	146	92	19,230	20,581	73	29	4	0	1,942	2,048
E	71													
E	72	CUSTOMER SERVICE & SALES EXPENSES												
E	73	908-Customer Assistance	0	0	0	6,836	0	6,836	0	0	0	137	0	137
E	74	908-Customer Assistance - Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
E	75	909-Advertisement	0	0	0	329	0	329	0	0	0	7	0	7
E	76	910-Miscellaneous CS	0	0	0	52	0	52	0	0	0	1	0	1
E	77	912-Demonstrating and Selling Expenses	0	0	0	736	0	736	0	0	0	15	0	15
E	78	916 Miscellaneous Sales Expenses	0	0	0	0	0	0	0	0	0	0	0	0
E	79	TOTAL CUSTOMER SERVICE & SALES EXP	0	0	0	7,952	0	7,952	0	0	0	159	0	159
E	80	TOTAL OPER & MAINT EXCL A&G	13,890	7,585	7,755	8,044	19,230	56,504	3,740	2,443	680	160	1,942	8,965
E	81													
E	82	ADMINISTRATIVE & GENERAL EXPENSE												
E	83	920-Administrative Salaries	625	298	809	110	1,035	2,878	176	99	72	2	106	454
E	84	921-Office Supplies & Expense	104	50	135	18	173	480	29	16	12	0	18	76
E	85	923-Outside Service Employed	1,551	740	2,007	273	2,568	7,140	435	245	178	5	263	1,127
E	86	924-Property Insurance	36	11	0	0	0	47	10	4	0	0	0	14
E	87	925-Injuries and Damages	36	17	46	6	59	164	10	6	4	0	6	26
E	88	926-Employee Pensions & Benefits	756	361	979	133	1,252	3,481	212	119	87	3	128	550
E	89	928-Regulatory Commission	482	153	67	41	123	865	134	50	6	1	9	199
E	90	929-Duplicate Charges-Credit	(1)	(0)	(0)	(0)	(0)	(2)	(0)	(0)	(0)	(0)	(0)	(0)
E	91	930.1-General Advertising	0	0	0	0	0	0	0	0	0	0	0	0
E	92	930.2-Miscellaneous General	72	34	93	13	119	332	20	11	8	0	12	52
E	93	932-Maintenance of General Plant	88	42	114	16	146	407	25	14	10	0	15	64
E	94	TOTAL A&G EXPENSE	3,749	1,706	4,250	610	5,477	15,792	1,051	564	378	12	557	2,562
E	95													
E	96	TOTAL OPERATION & MAINTENANCE EXPENSES	17,638	9,291	12,006	8,655	24,706	72,296	4,791	3,006	1,058	172	2,500	11,528
E	97													
E	98	**TOTAL PURCHASED GAS O&M EXPENSES**	0	0	0	0	0	0	0	0	0	0	0	0
E	99	**TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS**	17,638	9,291	12,006	8,655	24,706	72,296	4,791	3,006	1,058	172	2,500	11,528
E	100													

PECO Energy Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**												
D	2													
D	3	INTANGIBLE PLANT EXPENSE	3,804	1,167	14	2	18	5,006	1,068	386	1	0	2	1,457
D	4													
D	24	380-Services	22,045	0	0	0	0	22,045	6,190	0	0	0	0	6,190
D	25	381-Meters	0	4,161	0	0	0	4,161	0	1,375	0	0	0	1,375
D	26	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
D	27	Total Account 381	0	4,161	0	0	0	4,161	0	1,375	0	0	0	1,375
D	28	382-Meter Installations	0	4,287	0	0	0	4,287	0	1,417	0	0	0	1,417
D	29	Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
D	30	Total Account 382	0	4,287	0	0	0	4,287	0	1,417	0	0	0	1,417
D	31	387-Other Equipment	1	0	0	0	0	1	0	0	0	0	0	0
D	32	388-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0	0	0	0	0
D	33	TOTAL DISTRIBUTION PLANT EXPENSE	22,046	8,448	0	0	0	30,494	6,190	2,793	0	0	0	8,983
D	34													
D	35	GENERAL PLANT EXPENSE	168	80	217	30	278	773	47	26	19	1	28	122
D	36													
D	37	COMMON PLANT DEPRECIATION/AMORTIZATION	703	335	909	124	1,164	3,235	197	111	81	2	119	511
D	38													
D	39	**NET MANUFACTURED GAS PLANT EXP**	0	0	0	0	0	0	0	0	0	0	0	0
D	40	**NET AMORTIZATION OF CUSTOMER PROGRAMS**	0	0	0	0	0	0	0	0	0	0	0	0
D	41	**Direct Assignment - EE**	0	0	0	350	0	350	0	0	0	(29)	0	(29)
D	42	**Direct Assignment - Gas Unbundling**	0	0	0	0	0	0	0	0	0	0	0	0
D	50													
TO	1	**OTHER OPERATING EXPENSES**												
TO	2													
TO	3	**TAXES OTHER THAN INCOME TAXES**												
TO	4	**General Taxes**												
TO	5	PURTA Taxes	498	153	2	0	2	655	140	51	0	0	0	191
TO	6	Capital Stock	0	0	0	0	0	0	0	0	0	0	0	0
TO	7	Payroll Related	389	186	503	69	644	1,789	109	61	45	1	66	282
TO	8	Real Estate Tax	431	132	2	0	2	567	121	44	0	0	0	165
TO	9	PA and Local Use Tax	97	31	13	8	25	174	27	10	1	0	2	40
TO	10	Total General Taxes	1,415	501	520	77	673	3,186	397	166	46	2	68	678
TO	11													
TO	12													
TO	20													
TO	21	**TOTAL TAXES OTHER THAN INCOME**	1,415	501	520	77	673	3,186	397	166	46	2	68	678
TO	22													
TO	50													
TI	1	**DEVELOPMENT OF INCOME TAXES**												
TI	2													
TI	3	TOTAL OPERATING REVENUES EXCL PURCHASED GAS	85,460	28,961	14,957	9,446	28,243	167,067	25,960	10,143	1,340	154	2,240	39,837
TI	4	LESS:												
TI	5	OPER. & MAINT. EXP. EXCL PURCHASED GAS	17,638	9,291	12,006	8,655	24,706	72,296	4,791	3,006	1,058	172	2,500	11,528
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	26,721	10,031	1,141	505	1,459	39,857	7,503	3,316	101	(26)	150	11,044
TI	7	TAXES OTHER THAN INCOME TAXES	1,415	501	520	77	673	3,186	397	166	46	2	68	678
TI	8	NET OPERATING INCOME BEFORE TAXES	39,687	9,138	1,291	209	1,404	51,728	13,269	3,655	134	6	(478)	16,587
TI	9	LESS:												
TI	10	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)	17,108	4,279	471	75	524	22,456	4,798	1,415	42	2	(128)	6,130
TI	11													

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	GC CUSTOMER RELATED COSTS SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
TI	12	**BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS**	22,579	4,859	819	134	880	29,271	8,471	2,240	92	4	(350)	10,457
TI	13													
TI	14	**FEDERAL & STATE TAX ADJUSTMENTS**												
TI	15	Regulatory Asset Programs M-1 (Pension & Post Ret)	315	150	408	56	522	1,451	88	50	36	1	53	229
TI	16	Other Property Basis Adjustment (CIAC/ICM)	5,549	1,700	0	0	0	7,249	1,558	562	0	0	0	2,120
TI	17	Removal Costs/Software	582	179	2	0	3	766	163	59	0	0	0	223
TI	18	AFUDC Equity	1,780	546	7	1	8	2,342	500	181	1	0	1	682
TI	19	Permanent Adjustments	(193)	(59)	(1)	(0)	(1)	(254)	(54)	(20)	(0)	(0)	(0)	(74)
TI	20	Repair Deduction	36,229	11,118	133	18	170	47,667	10,173	3,675	12	0	17	13,877
TI	21	**TOTAL FEDERAL & STATE TAX ADJUSTMENTS**	44,261	13,634	548	75	702	59,219	12,428	4,507	49	1	72	17,057
TI	22													
TI	23	CALCULATION OF PA STATE INCOME TAXES												
TI	24	BASE TAXABLE INCOME	22,579	4,859	819	134	880	29,271	8,471	2,240	92	4	(350)	10,457
TI	25	LESS:												
TI	26	State Tax Depreciation (Over) Under Book	750	230	3	0	4	986	211	76	0	0	0	287
TI	27	Total Tax Adjustments	44,261	13,634	548	75	702	59,219	12,428	4,507	49	1	72	17,057
TI	28	**PA STATE TAXALBE DISTRIBUTION INCOME**	(22,432)	(9,005)	268	59	175	(30,934)	(4,168)	(2,343)	43	3	(422)	(6,887)
TI	29	**PA STATE INCOME TAXES @ Tax Rate 7.99%**	(1,792)	(719)	21	5	14	(2,472)	(333)	(187)	3	0	(34)	(550)
TI	30	PLUS: DEFERRED STATE INCOME TAXES												
TI	31	**Net Operating Loss Utilization**	717	288	(9)	(2)	(6)	989	133	75	(1)	(0)	13	220
TI	32	**TOTAL STATE INCOME TAX**	1,075	432	(13)	(3)	(8)	1,483	200	112	(2)	(0)	20	330
TI	33	Deferred Taxes on Timing Differences - State	(490)	(150)	(2)	(0)	(2)	(645)	(138)	(50)	(0)	(0)	(0)	(188)
TI	34	**Excess Deferred Amortization**	65	20	0	0	0	86	18	7	0	0	0	25
TI	35	Deferred Taxes on State NOL	566	174	2	0	3	745	159	57	0	0	0	217
TI	36	TOTAL STATE INCOME TAX EXPENSE	1,216	475	(12)	(3)	(8)	1,668	239	127	(2)	(0)	20	384
TI	37													
TI	38	CALCULATION OF FEDERAL INCOME TAXES												
TI	39	BASE TAXABLE INCOME	22,579	4,859	819	134	880	29,271	8,471	2,240	92	4	(350)	10,457
TI	40	LESS:												
TI	41	**PA State Income Taxes**	(1,075)	(432)	13	3	8	(1,483)	(200)	(112)	2	0	(20)	(330)
TI	42	**Federal Tax Depreciation (Over) Under Book**	(1,039)	(319)	(4)	(1)	(5)	(1,367)	(292)	(105)	(0)	(0)	(0)	(398)
TI	43	Total Tax Adjustments	44,261	13,634	548	75	702	59,219	12,428	4,507	49	1	72	17,057
TI	44	**FEDERAL TAXALBE DISTRIBUTION INCOME**	(19,567)	(8,024)	262	57	175	(27,097)	(3,466)	(2,049)	41	3	(401)	(5,872)
TI	50													
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**												
TI	52													
TI	53	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**	4,109	1,685	(55)	(12)	(37)	5,690	728	430	(9)	(1)	84	1,233
TI	54	PLUS: DEFERRED FEDERAL INCOME TAXES												
TI	55	Deferred Taxes on Timing Differences - Federal	(1,209)	(371)	(4)	(1)	(6)	(1,590)	(339)	(123)	(0)	(0)	(1)	(463)
TI	56	Excess Deferred Amortization	725	223	3	0	3	954	204	74	0	0	0	278
TI	57	FIT Expense on Flow Through Adjustments	(228)	(70)	(1)	(0)	(1)	(300)	(64)	(23)	(0)	(0)	(0)	(87)
TI	58	LESS: OTHER FEDERAL TAX ADJUSTMENTS												
TI	59	Amortization of ITC - Gas Plant	(1)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
TI	60	**TOTAL FEDERAL INCOME TAX EXPENSE**	3,399	1,467	(58)	(12)	(40)	4,756	528	358	(9)	(1)	84	961
TI	61	TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS	4,615	1,942	(70)	(15)	(48)	6,424	768	485	(11)	(1)	104	1,345
TI	62													
TI	78	**TOTAL PA INCOME TAX EXPENSE**	1,216	475	(12)	(3)	(8)	1,668	239	127	(2)	(0)	20	384
TI	79	**TOTAL FEDERAL INCOME TAX EXPENSE**	3,399	1,467	(58)	(12)	(40)	4,756	528	358	(9)	(1)	84	961
TI	80	**TOTAL INCOME TAX EXPENSE**	4,615	1,942	(70)	(15)	(48)	6,424	768	485	(11)	(1)	104	1,345
TI	81													
TI	82	**TOTAL OTHER TAX EXPENSE**	1,415	501	520	77	673	3,186	397	166	46	2	68	678
TI	83													
TI	84	**TOTAL TAX EXPENSE**	6,029	2,443	450	62	625	9,609	1,165	650	35	1	172	2,023
TI	85													
S	133	Total Composite Base Rate Sales Revenue Requirement	113,059	35,809	15,638	9,536	28,959	203,002	31,465	11,748	1,381	155	2,074	46,823
S	146	NUMBER OF CUSTOMER BILLS	6,151,911	6,151,911	6,151,911	6,151,911	6,151,911	6,151,911	547,071	547,071	547,071	547,071	547,071	547,071
S	148	**$/MONTH/CUSTOMER**	$ 18.38	$ 5.82	$ 2.54	$ 1.55	$ 4.71	**$ 33.00**	$ 57.52	$ 21.47	$ 2.52	$ 0.28	$ 3.79	**$ 85.59**

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
S	1	**SUMMARY AT PRESENT RATES**												
S	2													
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**												
S	4	**OPERATING REVENUE**												
S	5	Sales of Gas Revenue - Base	220	915	12	176	839	2,163	159	1,127	7	98	475	1,866
S	6	Other Operating Revenue	2	7	0	1	5	14	1	8	0	0	3	12
S	7	TOTAL OPERATING REVENUE	222	923	12	177	844	2,177	160	1,135	7	98	478	1,877
S	8													
S	9	**OPERATING EXPENSES**												
S	10	Operation and Maintenance Expense Excl Pur Gas	41	272	9	168	738	1,229	22	257	5	92	406	782
S	11	Depreciation and Amortization Expense	66	303	1	3	45	417	35	285	0	2	25	348
S	12	Taxes Other Than Income Taxes-General	3	15	0	2	21	41	2	14	0	1	11	29
S	13	Taxes Other Than Income Taxes-Distribution GRT	0	0	0	0	0	0	0	0	0	0	0	0
S	14	Income Taxes	8	46	(0)	(0)	(1)	52	(6)	(21)	(0)	(1)	(4)	(31)
S	15	TOTAL OPERATING EXPENSES	102	544	11	173	805	1,636	65	577	6	95	446	1,189
S	16													
S	17	**OPERATING INCOME (RETURN)**	119	378	1	4	39	541	95	557	1	3	32	688
S	18													
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**												
S	20	Gas Plant in Service	2,730	10,294	3	11	160	13,197	1,470	9,701	2	6	88	11,266
S	21	Less: Accumulated Depreciation	608	3,476	1	5	71	4,160	327	2,943	1	3	39	3,312
S	22	Plus: Rate Base Additions Excl Purchased Gas	40	239	17	63	870	1,229	22	228	9	35	478	772
S	23	Less: Rate Base Deductions	173	748	2	6	305	1,234	96	705	1	3	167	973
S	24	**TOTAL RATE BASE EXCL PURCHASED GAS**	1,989	6,309	17	64	653	9,032	1,068	6,281	9	35	360	7,753
S	25													
S	26	**RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	8.88%	8.88%	8.88%	8.88%	8.88%	8.88%
S	27	**INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**	1.06	1.03	1.07	1.07	1.11		1.56	1.53	1.59	1.59	1.65	
S	28													
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**												
S	41	**Total Distribution Sales Revenue at Current Rates**	220	915	12	176	839	2,163	159	1,127	7	98	475	1,866
S	42	Total Distribution Operating Revenues	222	923	12	177	844	2,177	160	1,135	7	98	478	1,877
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes	111	590	11	173	804	1,688	60	557	6	95	442	1,158
S	44	Plus: Total Federal & State Taxes	8	46	(0)	(0)	(1)	52	(6)	(21)	(0)	(1)	(4)	(31)
S	45	Total Operating Income (Return)	119	378	1	4	39	541	95	557	1	3	32	688
S	46	Total Rate Base	1,989	6,309	17	64	653	9,032	1,068	6,281	9	35	360	7,753
S	47													
S	48	COMPOSITE RATE OF RETURN (PRESENT)	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	8.88%	8.88%	8.88%	8.88%	8.88%	8.88%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)	1.06	1.03	1.07	1.07	1.11		1.56	1.53	1.59	1.59	1.65	
S	50													

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**												
S	52													
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED R/**												
S	54													
S	55	**Rate Base Excluding Purchased Gas**	1,989	6,309	17	64	653	9,032	1,068	6,281	9	35	360	7,753
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**	41	132	0	1	14	188	(9)	(50)	(0)	(0)	(3)	(62)
S	57		0	0	0	0	0	0	0	0	0	0	0	0
S	58	**OPERATING REVENUES**												
S	59	**Change in Revenue (Change in Return * 1.383)**	57	182	0	2	19	261	(12)	(69)	(0)	(0)	(4)	(85)
S	60	Distribution Base Rate Revenue (Present Rates)	220	915	12	176	839	2,163	159	1,127	7	98	475	1,866
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	277	1,097	12	178	858	2,423	147	1,058	7	97	471	1,780
S	62													
S	63	Forfeited Discounts Revenues	0	0	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)
S	64	Other Operating Revenue (Present Rates)	2	7	0	1	5	14	1	8	0	0	3	12
S	65	**TOTAL OPERATING REVENUES**	279	1,105	12	179	863	2,438	148	1,065	7	98	474	1,792
S	66													
S	67	**OPERATING EXPENSES**												
S	68	Operation and Maintenance Expense Excl Pur Gas	41	272	9	168	738	1,229	22	257	5	92	406	782
S	69	Depreciation and Amortization Expense	66	303	1	3	45	417	35	285	0	2	25	348
S	70	Additional Bad Debt Expense	0	1	0	0	0	1	(0)	(0)	(0)	(0)	(0)	(0)
S	71	Additional PUC / OTS & SBA Fee Expense	0	1	0	0	0	1	(0)	(0)	(0)	(0)	(0)	(0)
S	72	Taxes Other Than Income Taxes-General	3	15	0	2	21	41	2	14	0	1	11	29
S	73	Taxes Other Than Income Taxes-Distribution GRT	0	0	0	0	0	0	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**	111	592	11	173	804	1,690	59	556	6	95	442	1,158
S	75	State and Federal Income Taxes @ Effective Tax Rate	(8)	(46)	0	0	1	(52)	6	21	0	1	4	31
S	76	State and Federal Income Taxes @ Statutory Rates	16	49	0	0	5	71	(3)	(19)	(0)	(0)	(1)	(23)
S	77	**TOTAL OPERATING EXPENSES**	118	595	11	174	810	1,708	62	558	6	95	445	1,166
S	78													
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**	161	510	1	5	53	730	86	507	1	3	29	626
S	80													
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**	277	1,097	12	178	858	2,423	147	1,058	7	97	471	1,780
S	82													
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**	57	182	0	2	19	261	(12)	(69)	(0)	(0)	(4)	(86)
S	84	**REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVEN**	26.13%	19.91%	4.28%	1.04%	2.25%	12.07%	-7.41%	-6.15%	-1.55%	-0.39%	-0.84%	-4.58%
S	85													
S	86													
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**												
S	133	**Total Composite Base Rate Sales Revenue Requirement**	277	1,097	12	178	858	2,423	147	1,058	7	97	471	1,780
S	134													
S	135													
S	136	**Total Operating Expense before Income Taxes**	111	592	11	173	804	1,690	59	556	6	95	442	1,158
S	146	**NUMBER OF CUSTOMER BILLS**	4,800	4,800	4,800	4,800	4,800	4,800	2,626	2,626	2,626	2,626	2,626	2,626
S	147													
S	148	**$/MONTH/CUSTOMER**	$57.77	$228.62	$2.52	$37.10	$178.81	**$504.82**	$56.07	$402.92	$2.51	$37.08	$179.45	**$678.04**
S	149													
S	150													

PECO Energy Company
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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
RBP	1	**DEVELOPMENT OF RATE BASE**												
RBP	2													
RBP	3	**GAS PLANT IN SERVICE**												
RBP	4	INTANGIBLE PLANT												
RBP	5	301-Organization	10	36	0	0	1	47	5	34	0	0	0	40
RBP	6	303-Miscellaneous Intangible Plant	0	0	0	0	0	0	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT	10	36	0	0	1	47	5	34	0	0	0	40
RBP	8													
RBP	9	PRODUCTION PLANT (LPG)												
RBP	27	DISTRIBUTION PLANT												
RBP	40	380-Services	2,711	0	0	0	0	2,711	1,459	0	0	0	0	1,459
RBP	41	381-Meters	0	3,554	0	0	0	3,554	0	2,742	0	0	0	2,742
RBP	42	Direct Assignment	0	311	0	0	0	311	0	272	0	0	0	272
RBP	43	Total Account 381	0	3,865	0	0	0	3,865	0	3,014	0	0	0	3,014
RBP	44	382-Meter Installations	0	5,746	0	0	0	5,746	0	4,433	0	0	0	4,433
RBP	45	Direct Assignment	0	594	0	0	0	594	0	2,170	0	0	0	2,170
RBP	46	Total Account 382	0	6,340	0	0	0	6,340	0	6,603	0	0	0	6,603
RBP	47	387-Other Equipment	1	5	0	0	0	6	1	5	0	0	0	5
RBP	48	388-Asset Retirement Costs for Distribution Plant	1	2	0	0	0	3	0	2	0	0	0	2
RBP	49	TOTAL DISTRIBUTION PLANT	2,713	10,212	0	0	0	12,924	1,460	9,624	0	0	0	11,084
RBP	50													
RBP	53	GENERAL PLANT												
RBP	54	389-Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0
RBP	55	390-Structures and Improvements	2	14	1	3	51	72	1	14	1	2	28	45
RBP	56	391-Office Furniture & Equipment	0	2	0	1	8	11	0	2	0	0	4	7
RBP	57	393-Store Equipment	0	0	0	0	0	0	0	0	0	0	0	0
RBP	58	394-Tools, Shop & Garage Equip.	4	21	1	5	73	104	2	20	1	3	40	65
RBP	59	395-Laboratory Equipment	0	0	0	0	0	0	0	0	0	0	0	0
RBP	60	397-Communication Equipment	1	7	1	2	26	36	1	7	0	1	14	23
RBP	61	398-Miscellaneous Equipment	0	0	0	0	1	2	0	0	0	0	1	1
RBP	62	TOTAL GENERAL PLANT	8	45	3	11	159	226	4	43	2	6	88	142
RBP	63													
RBP	65	**TOTAL GAS PLANT IN SERVICE**	2,730	10,294	3	11	160	13,197	1,470	9,701	2	6	88	11,266

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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**												
RBD	2													
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	5	18	0	0	0	23	3	17	0	0	0	20
RBD	10													
RBD	11	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION												
RBD	23	Total Account 379	0	0	0	0	0	0	0	0	0	0	0	0
RBD	24	380-Services	598	0	0	0	0	598	322	0	0	0	0	322
RBD	25	381-Meters	0	1,757	0	0	0	1,757	0	1,356	0	0	0	1,356
RBD	26	Direct Assignment	0	28	0	0	0	28	0	35	0	0	0	35
RBD	27	Total Account 381	0	1,785	0	0	0	1,785	0	1,390	0	0	0	1,390
RBD	28	382-Meter Installations	0	1,596	0	0	0	1,596	0	1,231	0	0	0	1,231
RBD	29	Direct Assignment	0	52	0	0	0	52	0	280	0	0	0	280
RBD	30	Total Account 382	0	1,648	0	0	0	1,648	0	1,512	0	0	0	1,512
RBD	31	387-Other Equipment	1	4	0	0	0	5	1	4	0	0	0	4
RBD	32	388-Asset Retirement Costs for Distribution Plant	0	1	0	0	0	2	0	1	0	0	0	2
RBD	33	**TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION**	599	3,438	0	0	0	4,037	323	2,907	0	0	0	3,230
RBD	34													
RBD	35	GENERAL PLANT ACCUMULATED DEPRECIATION	3	20	1	5	71	100	2	19	1	3	39	63
RBD	37	**TOTAL ACCUMULATED DEPRECIATION**	608	3,476	1	5	71	4,160	327	2,943	1	3	39	3,312
RBD	38													
RBD	39													
RBD	50													
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**												
RBO	2													
RBO	3	**PLUS: ADDITIONS TO RATE BASE**												
RBO	4													
RBO	5	COMMON PLANT	41	239	17	57	843	1,197	22	225	9	31	464	751
RBO	6													
RBO	7	**WORKING CAPITAL**												
RBO	8	Cash Working Capital - Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0
RBO	9	Cash Working Capital	(2)	(4)	0	6	26	26	(1)	(2)	0	3	15	15
RBO	10	Gas Storage Inventory	0	0	0	0	0	0	0	0	0	0	0	0
RBO	11	Materials and Supplies	1	5	0	0	0	6	1	4	0	0	0	5
RBO	12	TOTAL WORKING CAPITAL	(1)	1	0	6	26	32	(0)	3	0	3	15	21
RBO	13	TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS	40	239	17	63	870	1,229	22	228	9	35	478	772
RBO	14	TOTAL ADDITIONS TO RATE BASE	40	239	17	63	870	1,229	22	228	9	35	478	772
RBO	15													
RBO	16	**LESS: DEDUCTIONS TO RATE BASE**												
RBO	17	Customer Deposits	0	0	0	0	224	224	0	0	0	0	122	122
RBO	18	Customer Advances for Construction	3	0	0	0	0	3	1	0	0	0	0	1
RBO	19	Deferred Income Taxes and Credits												
RBO	20	Plant	223	839	0	1	13	1,076	120	791	0	0	7	918
RBO	21	Common Plant	3	20	1	5	71	100	2	19	1	3	39	63
RBO	22	Pension Assets / (Liability)	0	0	0	0	0	0	0	0	0	0	0	0
RBO	23	Corporate Alternative Minimum Tax	(29)	(111)	(0)	(0)	(2)	(142)	(16)	(105)	(0)	(0)	(1)	(121)
RBO	24	Contributions in Aid of Construction (CIAC)	(26)	0	0	0	0	(26)	(10)	0	0	0	0	(10)
RBO	25	Total Deferred Income Taxes and Credits	170	748	2	6	82	1,007	95	705	1	3	45	849
RBO	26	TOTAL DEDUCTIONS TO RATE BASE	173	748	2	6	305	1,234	96	705	1	3	167	973
RBO	27													
RBO	28	TOTAL PURCHASED GAS RATE BASE	0	0	0	0	0	0	0	0	0	0	0	0
RBO	29	TOTAL RATE BASE EXCLUDING PURCHASED GAS	1,989	6,309	17	64	653	9,032	1,068	6,281	9	35	360	7,753
RBO	30													
RBO	31	**TOTAL RATE BASE**	1,989	6,309	17	64	653	9,032	1,068	6,281	9	35	360	7,753
RBO	32													
RBO	50													

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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**												
RBC	2													
RBC	3	**TOTAL EXCLUDING PURCHASED GAS**												
RBC	4	O&M EXPENSE RELATED CASH WORKING CAPITAL												
RBC	5	Payroll (Distribution Only)	11	66	5	16	233	330	6	62	3	9	128	207
RBC	6	Pension	0	1	0	0	4	6	0	1	0	0	2	4
RBC	7	Other Expenses												
RBC	8	Other Expenses	30	210	4	161	501	906	16	198	2	88	276	580
RBC	9	BSC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	10	Purchase of Recievables (POR)	0	0	0	0	0	0	0	0	0	0	0	0
RBC	11	TOTAL EXPENSES	42	277	9	177	738	1,243	22	261	5	97	406	791
RBC	12													
RBC	13	TOTAL EXPENSES PER DAY	0	1	0	0	2	3	0	1	0	0	1	2
RBC	14													
RBC	15	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	1	8	0	5	21	35	1	7	0	3	12	23
RBC	16													
RBC	17	AVERAGE PREPAYMENTS	1	4	0	1	5	10	0	4	0	0	3	7
RBC	18	DISTRIBUTION ACCRUED TAXES	1	4	0	0	0	5	1	6	0	0	0	7
RBC	19	INTEREST PAYMENTS	(5)	(19)	(0)	(0)	(0)	(25)	(3)	(18)	(0)	(0)	(0)	(21)
RBC	20													
RBC	21													
RBC	22	**NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT**	(2)	(4)	0	6	26	26	(1)	(2)	0	3	15	15
RBC	23													
RBC	40	TOTAL NET CASH WORKING CAPITAL	(2)	(4)	0	6	26	26	(1)	(2)	0	3	15	15
RBC	15													
RBC	16	DISTRIBUTION ACCRUED TAXES												
RBC	17	Federal Income Tax	182	524	2	7	70	786	206	1,177	2	8	75	1,468
RBC	18	State Income Tax	19	56	0	1	7	84	22	125	0	1	8	156
RBC	19	PURTA Taxes	134	507	0	1	8	650	72	478	0	0	4	555
RBC	20	PA Capital Stock Tax	0	0	0	0	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	0	0	0	0	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	75	283	0	0	4	363	40	267	0	0	2	310
RBC	23	TOTAL ACCRUED TAXES	411	1,370	2	9	90	1,882	341	2,046	2	9	90	2,488
RBC	24	TOTAL ACCRUED TAXES PER DAY	1	4	0	0	0	5	1	6	0	0	0	7
RBC	25													
RBC	26	DISTRIBUTION AVERAGE PREPAYMENTS												
RBC	27	AGA Membership Dues	0	0	0	0	0	1	0	0	0	0	0	1
RBC	28	EAPA Membership Dues	0	0	0	0	0	0	0	0	0	0	0	0
RBC	29	PUC Assess - Gas	0	1	0	0	1	3	0	1	0	0	1	2
RBC	30	Cellent Gas Meter Reading	0	0	0	0	0	0	0	0	0	0	0	0
RBC	31	Gas Software Maintenance	0	0	0	0	0	0	0	0	0	0	0	0
RBC	32	Customer and Research	0	0	0	0	0	0	0	0	0	0	0	0
RBC	33	VEBA Adjustment	0	1	0	0	3	5	0	1	0	0	2	3
RBC	34	Facility Contracts	0	0	0	0	0	0	0	0	0	0	0	0
RBC	35	IT License & Maintenance	0	1	0	0	0	1	0	1	0	0	0	1
RBC	36	Fleet Activities	0	0	0	0	0	1	0	0	0	0	0	0
RBC	37	Prepaid Rent	0	0	0	0	0	0	0	0	0	0	0	0
RBC	38	Postage	0	0	0	0	0	0	0	0	0	0	0	0
RBC	39	TOTAL AVERAGE PREPAYMENTS	1	4	0	1	5	10	0	4	0	0	3	7
RBC	49													
RBC	50													

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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
RBC	51	**OPERATING REVENUES**												
RBC	52													
RBC	53	**SALES REVENUES**												
RBC	54	Sales of Gas Revenues - Base	220	915	12	176	839	2,163	159	1,127	7	98	475	1,866
RBC	55	Sales Revenues - Purchased Gas-PGC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	56	Sales Revenues - Balancing Service Charge-BSC	0	0	0	0	0	0	0	0	0	0	0	0
RBC	57	TOTAL SALES OF GAS	220	915	12	176	839	2,163	159	1,127	7	98	475	1,866
RBC	58													
RBC	59	**OTHER OPERATING REVENUES**												
RBC	60	487-Forfeited Discounts	1	3	0	1	2	6	0	3	0	0	1	5
RBC	61	489-Revenues from Transportation of Gas of Others	0	0	0	0	0	0	0	0	0	0	0	0
RBC	62	493-Rent from Gas Property	1	4	0	0	0	5	1	4	0	0	0	4
RBC	63	495-Other Gas Revenues	0	1	0	0	2	3	0	1	0	0	1	2
RBC	64	TOTAL OTHER OPERATING REV	2	7	0	1	5	14	1	8	0	0	3	12
RBC	65													
RBC	66	**TOTAL OPERATING REVENUES**	222	923	12	177	844	2,177	160	1,135	7	98	478	1,877
RBC	67													
RBC	100													

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SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
E	1	**OPERATION & MAINTENANCE EXPENSE**												
E	2	**PRODUCTION EXPENSE**												
E	40	Operation												
E	41	870-Operation Supervision and Engineering	0	1	0	0	0	2	0	1	0	0	0	2
E	42	874-Mains and Services Expenses	14	0	0	0	0	14	7	0	0	0	0	7
E	43	875-Measuring & Reg. Station Exp.-General	0	0	0	0	0	0	0	0	0	0	0	0
E	44	877-Measuring & Reg. Station Exp.-City Gate Sta.	0	0	0	0	0	0	0	0	0	0	0	0
E	45	878-Meter & House Regulator Expenses	0	166	0	0	0	166	0	156	0	0	0	156
E	46	879-Customer Installations Expenses	0	0	6	0	0	6	0	0	3	0	0	3
E	47	880-Other Expenses	12	47	0	0	0	59	7	44	0	0	0	51
E	48	880-Other Expenses - GPC	0	0	0	0	0	0	0	0	0	0	0	0
E	49	Total Distribution Operation	26	214	6	0	0	246	14	201	3	0	0	219
E	50													
E	53	Maintenance												
E	54	887-Maintenance of Mains	0	0	0	0	0	0	0	0	0	0	0	0
E	55	889-Maint. of Measuring & Reg. Station Equip.-Gen	0	0	0	0	0	0	0	0	0	0	0	0
E	56	892-Maintenance of Services	5	0	0	0	0	5	3	0	0	0	0	3
E	57	893-Maint. of Meters & House Regulators	0	5	0	0	0	5	0	5	0	0	0	5
E	58	894-Maintenance of Other Equipment	0	2	0	0	0	2	0	1	0	0	0	2
E	59	Total Distribution Maintenance	6	7	0	0	0	13	3	6	0	0	0	10
E	60	TOTAL DISTRIBUTION PLANT O&M EXPENSES	32	221	6	0	0	259	17	208	3	0	0	228
E	61	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)	32	221	6	0	0	259	17	208	3	0	0	228
E	62													
E	63	CUSTOMER ACCOUNTS EXPENSES												
E	64	902-Meter Reading	0	0	0	0	0	0	0	0	0	0	0	0
E	65	903-Customer Records and Collection Expense	0	0	0	0	569	569	0	0	0	0	313	313
E	66	904-Uncollectible Accounts	0	0	0	0	0	1	0	0	0	0	0	1
E	67	904-Uncollectible Accounts - MFC/POR	0	0	0	0	0	0	0	0	0	0	0	0
E	68	904-Uncollectible Accounts - PPA	0	0	0	0	0	0	0	0	0	0	0	0
E	69	905-Miscellaneous CA	0	0	0	0	1	1	0	0	0	0	0	0
E	70	TOTAL CUSTOMER ACCTS EXPENSE	0	0	0	0	570	570	0	0	0	0	313	314
E	71													
E	72	CUSTOMER SERVICE & SALES EXPENSES												
E	73	908-Customer Assistance	0	0	0	134	0	134	0	0	0	73	0	73
E	74	908-Customer Assistance - Direct Assignment	0	0	0	0	0	0	0	0	0	0	0	0
E	75	909-Advertisement	0	0	0	6	0	6	0	0	0	4	0	4
E	76	910-Miscellaneous CS	0	0	0	1	0	1	0	0	0	1	0	1
E	77	912-Demonstrating and Selling Expenses	0	0	0	14	0	14	0	0	0	8	0	8
E	78	916 Miscellaneous Sales Expenses	0	0	0	0	0	0	0	0	0	0	0	0
E	79	TOTAL CUSTOMER SERVICE & SALES EXP	0	0	0	156	0	156	0	0	0	85	0	85
E	80	TOTAL OPER & MAINT EXCL A&G	32	221	6	156	570	985	17	208	3	85	313	627
E	81													
E	82	ADMINISTRATIVE & GENERAL EXPENSE												
E	83	920-Administrative Salaries	2	9	1	2	32	45	1	8	0	1	17	28
E	84	921-Office Supplies & Expense	0	2	0	0	5	8	0	1	0	0	3	5
E	85	923-Outside Service Employed	4	22	2	5	79	112	2	21	1	3	43	70
E	86	924-Property Insurance	0	0	0	0	0	0	0	0	0	0	0	0
E	87	925-Injuries and Damages	0	1	0	0	2	3	0	0	0	0	1	2
E	88	926-Employee Pensions & Benefits	2	11	1	3	38	55	1	10	0	1	21	34
E	89	928-Regulatory Commission	1	5	0	1	4	10	1	5	0	0	2	8
E	90	929-Duplicate Charges-Credit	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
E	91	930.1-General Advertising	0	0	0	0	0	0	0	0	0	0	0	0
E	92	930.2-Miscellaneous General	0	1	0	0	4	5	0	1	0	0	2	3
E	93	932-Maintenance of General Plant	0	1	0	0	5	6	0	1	0	0	2	4
E	94	TOTAL A&G EXPENSE	9	52	3	12	168	244	5	49	2	7	92	154
E	95													
E	96	TOTAL OPERATION & MAINTENANCE EXPENSES	41	272	9	168	738	1,229	22	257	5	92	406	782
E	97													
E	98	**TOTAL PURCHASED GAS O&M EXPENSES**	0	0	0	0	0	0	0	0	0	0	0	0
E	99	**TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS**	41	272	9	168	738	1,229	22	257	5	92	406	782
E	100													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**												
D	2													
D	3	INTANGIBLE PLANT EXPENSE	9	35	0	0	1	45	5	33	0	0	0	39
D	4													
D	24	380-Services	54	0	0	0	0	54	29	0	0	0	0	29
D	25	381-Meters	0	114	0	0	0	114	0	88	0	0	0	88
D	26	Direct Assignment	0	8	0	0	0	8	0	7	0	0	0	7
D	27	Total Account 381	0	122	0	0	0	122	0	95	0	0	0	95
D	28	382-Meter Installations	0	118	0	0	0	118	0	91	0	0	0	91
D	29	Direct Assignment	0	15	0	0	0	15	0	54	0	0	0	54
D	30	Total Account 382	0	133	0	0	0	133	0	145	0	0	0	145
D	31	387-Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0
D	32	388-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0	0	0	0	0
D	33	TOTAL DISTRIBUTION PLANT EXPENSE	54	255	0	0	0	309	29	240	0	0	0	270
D	34													
D	35	GENERAL PLANT EXPENSE	0	2	0	1	9	12	0	2	0	0	5	8
D	36													
D	37	COMMON PLANT DEPRECIATION/AMORTIZATION	2	10	1	2	36	51	1	10	0	1	20	32
D	38													
D	39	**NET MANUFACTURED GAS PLANT EXP**	0	0	0	0	0	0	0	0	0	0	0	0
D	40	**NET AMORTIZATION OF CUSTOMER PROGRAMS**	0	0	0	0	0	0	0	0	0	0	0	0
D	41	**Direct Assignment - EE**	0	0	0	0	0	0	0	0	0	0	0	0
D	42	**Direct Assignment - Gas Unbundling**	0	0	0	0	0	0	0	0	0	0	0	0
D	50													
TO	1	**OTHER OPERATING EXPENSES**												
TO	2													
TO	3	**TAXES OTHER THAN INCOME TAXES**												
TO	4	**General Taxes**												
TO	5	PURTA Taxes	1	5	0	0	0	6	1	4	0	0	0	5
TO	6	Capital Stock	0	0	0	0	0	0	0	0	0	0	0	0
TO	7	Payroll Related	1	6	0	1	20	28	1	5	0	1	11	18
TO	8	Real Estate Tax	1	4	0	0	0	5	1	4	0	0	0	4
TO	9	PA and Local Use Tax	0	1	0	0	1	2	0	1	0	0	0	2
TO	10	Total General Taxes	3	15	0	2	21	41	2	14	0	1	11	29
TO	11													
TO	12													
TO	20													
TO	21	**TOTAL TAXES OTHER THAN INCOME**	3	15	0	2	21	41	2	14	0	1	11	29
TO	22													
TO	50													
TI	1	**DEVELOPMENT OF INCOME TAXES**												
TI	2													
TI	3	TOTAL OPERATING REVENUES EXCL PURCHASED GAS	222	923	12	177	844	2,177	160	1,135	7	98	478	1,877
TI	4	LESS:												
TI	5	OPER. & MAINT. EXP. EXCL PURCHASED GAS	41	272	9	168	738	1,229	22	257	5	92	406	782
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	66	303	1	3	45	417	35	285	0	2	25	348
TI	7	TAXES OTHER THAN INCOME TAXES	3	15	0	2	21	41	2	14	0	1	11	29
TI	8	NET OPERATING INCOME BEFORE TAXES	111	332	1	4	41	489	101	578	1	4	36	719
TI	9	LESS:												
TI	10	INTEREST EXPENSE (Rate Base * 2.13% Weighted Cost of Debt)	42	134	0	1	14	192	23	134	0	1	8	165
TI	11													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	TSF CUSTOMER RELATED COSTS						TSI CUSTOMER RELATED COSTS					
			SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL	SERVICES	METERS	CUSTINSTALL	CUSTSERV	CUSTACCT	TOTAL
		(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
TI	12	**BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS**	69	198	1	3	27	297	78	444	1	3	28	554
TI	13													
TI	14	**FEDERAL & STATE TAX ADJUSTMENTS**												
TI	15	Regulatory Asset Programs M-1 (Pension & Post Ret)	1	5	0	1	16	23	0	4	0	1	9	14
TI	16	Other Property Basis Adjustment (CIAC/ICM)	14	51	0	0	0	65	7	48	0	0	0	56
TI	17	Removal Costs/Software	1	5	0	0	0	7	1	5	0	0	0	6
TI	18	AFUDC Equity	4	16	0	0	0	21	2	16	0	0	0	18
TI	19	Permanent Adjustments	(0)	(2)	(0)	(0)	(0)	(2)	(0)	(2)	(0)	(0)	(0)	(2)
TI	20	Repair Deduction	89	336	0	0	5	430	48	316	0	0	3	367
TI	21	**TOTAL FEDERAL & STATE TAX ADJUSTMENTS**	109	412	0	1	22	544	59	388	0	1	12	459
TI	22													
TI	23	CALCULATION OF PA STATE INCOME TAXES												
TI	24	BASE TAXABLE INCOME	69	198	1	3	27	297	78	444	1	3	28	554
TI	25	LESS:												
TI	26	State Tax Depreciation (Over) Under Book	2	7	0	0	0	9	1	7	0	0	0	8
TI	27	Total Tax Adjustments	109	412	0	1	22	544	59	388	0	1	12	459
TI	28	**PA STATE TAXALBE DISTRIBUTION INCOME**	(42)	(221)	0	1	5	(256)	18	50	1	2	17	87
TI	29	**PA STATE INCOME TAXES @ Tax Rate 7.99%**	(3)	(18)	0	0	0	(20)	1	4	0	0	1	7
TI	30	PLUS: DEFERRED STATE INCOME TAXES												
TI	31	**Net Operating Loss Utilization**	1	7	(0)	(0)	(0)	8	(1)	(2)	(0)	(0)	(1)	(3)
TI	32	**TOTAL STATE INCOME TAX**	2	11	(0)	(0)	(0)	12	(1)	(2)	(0)	(0)	(1)	(4)
TI	33	Deferred Taxes on Timing Differences - State	(1)	(5)	(0)	(0)	(0)	(6)	(1)	(4)	(0)	(0)	(0)	(5)
TI	34	**Excess Deferred Amortization**	0	1	0	0	0	1	0	1	0	0	0	1
TI	35	Deferred Taxes on State NOL	1	5	0	0	0	7	1	5	0	0	0	6
TI	36	TOTAL STATE INCOME TAX EXPENSE	2	12	(0)	(0)	(0)	14	(1)	(1)	(0)	(0)	(1)	(3)
TI	37													
TI	38	CALCULATION OF FEDERAL INCOME TAXES												
TI	39	BASE TAXABLE INCOME	69	198	1	3	27	297	78	444	1	3	28	554
TI	40	LESS:												
TI	41	**PA State Income Taxes**	(2)	(11)	0	0	0	(12)	1	2	0	0	1	4
TI	42	**Federal Tax Depreciation (Over) Under Book**	(3)	(10)	(0)	(0)	(0)	(12)	(1)	(9)	(0)	(0)	(0)	(11)
TI	43	Total Tax Adjustments	109	412	0	1	22	544	59	388	0	1	12	459
TI	44	**FEDERAL TAXALBE DISTRIBUTION INCOME**	(35)	(194)	0	1	5	(222)	20	63	1	2	16	101
TI	50													
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**												
TI	52													
TI	53	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**	7	41	(0)	(0)	(1)	47	(4)	(13)	(0)	(0)	(3)	(21)
TI	54	PLUS: DEFERRED FEDERAL INCOME TAXES												
TI	55	Deferred Taxes on Timing Differences - Federal	(3)	(11)	(0)	(0)	(0)	(14)	(2)	(11)	(0)	(0)	(0)	(12)
TI	56	Excess Deferred Amortization	2	7	0	0	0	9	1	6	0	0	0	7
TI	57	FIT Expense on Flow Through Adjustments	(1)	(2)	(0)	(0)	(0)	(3)	(0)	(2)	(0)	(0)	(0)	(2)
TI	58	LESS: OTHER FEDERAL TAX ADJUSTMENTS												
TI	59	Amortization of ITC - Gas Plant	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
TI	60	**TOTAL FEDERAL INCOME TAX EXPENSE**	6	34	(0)	(0)	(1)	38	(5)	(19)	(0)	(0)	(3)	(28)
TI	61	TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS	8	46	(0)	(0)	(1)	52	(6)	(21)	(0)	(1)	(4)	(31)
TI	62													
TI	78	**TOTAL PA INCOME TAX EXPENSE**	2	12	(0)	(0)	(0)	14	(1)	(1)	(0)	(0)	(1)	(3)
TI	79	**TOTAL FEDERAL INCOME TAX EXPENSE**	6	34	(0)	(0)	(1)	38	(5)	(19)	(0)	(0)	(3)	(28)
TI	80	**TOTAL INCOME TAX EXPENSE**	8	46	(0)	(0)	(1)	52	(6)	(21)	(0)	(1)	(4)	(31)
TI	81													
TI	82	**TOTAL OTHER TAX EXPENSE**	3	15	0	2	21	41	2	14	0	1	11	29
TI	83													
TI	84	**TOTAL TAX EXPENSE**	12	61	0	1	19	93	(4)	(6)	0	0	7	(3)
TI	85													
S	133	Total Composite Base Rate Sales Revenue Requirement	277	1,097	12	178	858	2,423	147	1,058	7	97	471	1,780
S	146	NUMBER OF CUSTOMER BILLS	4,800	4,800	4,800	4,800	4,800	4,800	2,626	2,626	2,626	2,626	2,626	2,626
S	148	**$/MONTH/CUSTOMER**	$ 57.77	$ 228.62	$ 2.52	$ 37.10	$ 178.81	**$ 504.82**	$ 56.07	$ 402.92	$ 2.51	$ 37.08	$ 179.45	**$ 678.04**

PECO Exhibit JD-6:

FPFTY Test Year 2025 – Cost of Service Study - External Allocation Factors

PECO Energy Company (Gas)
Fully Projected Future Test Year 2025
Cost of Service Study

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PECO Energy Company (Gas)
Cost of Service Study
Summary of External Allocator Values by Class

Line	Unit	Allocator Name	Total	Residential	GC	Large	Motor Vehicle Firm	Motor Vehicle Interruptible	Interruptible Services	Temperature Control	Transportation Firm	Transportation Interruptible
1	#	Cust_Avg	558,912	512,659	45,589	8	15	1	1	20	400	219
2	#	Cust_Excl. Ind	558,284	512,659	45,589		15	1		20		
3	#	Cust_Res	512,659	512,659								
4	#	Cust_Comm	45,625		45,589		15	1		20		
5	#	Cust_Ind	628			8			1		400	219
6	Mcf	Gas_Deliveries	93,602,070	43,867,240	23,852,516	21,000	502,606	1,064	16,440	129,260	11,873,807	13,338,137
7	Mcf	Gas_Deliveries_Firm	80,117,169	43,867,240	23,852,516	21,000	502,606				11,873,807	
8	Mcf	Gas_Sales_Firm	68,243,362	43,867,240	23,852,516	21,000	502,606					
9	Mcfd	Daily_Del_Excl. Dir	236,211	120,184	65,349	58	1,377	3	45	354	25,270	23,571
10	Mcfd	Excess_Demand	739,136	479,108	222,561	170	416	0	0	0	36,881	0
11	Mcfd	Peak_Sendout	912,000	614,831	295,129	233	1,807	0	0	0	0	0
12	Mcfd	Peak_Mains	975,347	614,831	295,129	233	1,807	0	0	0	63,347	0
13	Mcfd	Peaks_NCP	999,320	614,831	295,129	233	1,807	3	45	354	63,347	23,571
14	Mcf	Winter_FirmSales	10,098,232	6,775,524	3,277,520	1,750	43,438	0	0	0	0	0
15	%	Storage	100.00%	69.5%	28.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.9%
16	%	AR Over60-Day	100.00%	74.3%	21.2%	0.0%	0.1%	0.0%	0.0%	0.1%	2.7%	1.5%
17	%	WriteOff	100.00%	88.1%	11.4%	0.0%	0.1%	0.0%	0.0%	0.1%	0.2%	0.1%
18	%	Account903	100.00%	86.7%	8.9%	0.1%	0.0%	0.0%	0.0%	0.0%	2.8%	1.5%
19	%	Account908-916	100.00%	95.2%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.0%
20	$000	Meter_Invest	244,046	176,643	58,391	19	215	2	3	164	4,861	3,750
21	$000	Service_Invest	4,425,936	3,444,722	967,241	170	318	21	21	419	8,465	4,558
22	Minutes	Call Center	2,653,695	2,454,884	196,922	0	1,462	6	0	421	0	0
23	$000	Deposits	10,867	3,310	7,265	4	2	0	0	3	182	100
24	$000	Deposit_Interest	650	265	371	0	0	0	0	0	9	5
25	$000	Advances	1,318	878	191	0	0	0	0	0	189	59
26	$000	Forfeited Discounts	1,373	909	371	1	2	0	0	2	57	32
27	$000	Purchased Gas Cost	234,407	176,887	55,442	99	1,289	8	77	606	0	0
28	$000	Balancing Service Cost	26,508	17,003	9,245	8	194	1	6	50	0	0
29	$000	Purchase of Receivables (POR)	82,479	48,229	33,888	0	169	1	0	193	0	0
30	Mcfd	Design Day Demand	987,000	614,831	295,129	233	1,807	0	0	0	75,000	0
31	$000	Gas Energy Efficiency Program	321	350	(29)	0	0	0	0	0	0	0
32	$000	Gas Procurement Charge	1,742	1,119	609	1	13	0	0	0	0	0
33	$000	Merchant Function Charge/POR	1,200	1,057	143	0	0	0	0	0	0	0
34	$000	Base Customer Charges	481,982	327,766	122,676	184	611	4	75	697	19,121	10,848

PECO Energy Company (Gas)
Cost of Service Study
Gas Deliveries Allocator
Deliveries for All Customer Classes (Mcf)

	Class	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	TOTAL
1	Residential	8,806,830	7,581,260	6,168,410	3,197,270	1,587,740	932,810	792,390	765,760	830,280	1,883,370	4,249,180	7,071,940	43,867,240
2	GC	4,163,574	3,541,960	2,971,757	1,775,772	1,122,944	847,155	796,789	782,257	826,058	1,313,941	2,271,852	3,438,457	23,852,516
3	Large	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	21,000
4	Motor Vehicles- Firm	45,783	40,404	38,389	37,870	40,035	41,472	39,217	41,602	43,029	42,191	45,434	47,180	502,606
5	Motor Vehicles- Interr	97	86	81	80	85	88	83	88	91	89	96	100	1,064
6	Interruptible	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	16,440
7	Temperature	20,170	21,880	20,600	14,960	11,810	8,000	4,460	4,460	4,080	2,730	4,670	11,440	129,260
8	Transport- Firm	1,269,444	1,174,374	1,199,604	941,221	841,158	795,176	836,563	823,830	789,381	922,284	1,068,594	1,212,177	11,873,807
9	Transport- Interr	1,425,998	1,319,203	1,347,544	1,057,297	944,894	893,240	939,732	925,428	886,731	1,036,025	1,200,378	1,361,668	13,338,137
10	**TOTAL**	**15,735,016**	**13,682,288**	**11,749,504**	**7,027,590**	**4,551,786**	**3,521,061**	**3,412,355**	**3,346,545**	**3,382,769**	**5,203,750**	**8,843,325**	**13,146,082**	**93,602,070**

PECO Energy Company (Gas)
Cost of Service Study
Customers Allocator
Number of Customers in Each Rate Class

	Class	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Average
1	Residential	511,355	512,205	512,747	512,863	512,682	512,628	512,582	512,593	512,460	512,637	513,202	513,957	512,659
2	GC	45,669	45,706	45,710	45,628	45,516	45,436	45,391	45,363	45,398	45,570	45,767	45,917	45,589
3	Large	8	8	8	8	8	8	8	8	8	8	8	8	8
4	Motor Vehicles- Firm	15	15	15	15	15	15	15	15	15	15	15	15	15
5	Motor Vehicles- Interr	1	1	1	1	1	1	1	1	1	1	1	1	1
6	Interruptible	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Temperature	21	20	20	20	20	20	20	20	19	19	19	19	20
8	Transport- Firm	400	401	399	399	399	400	400	400	400	401	402	399	400
9	Transport- Interr	219	219	219	218	218	219	219	219	219	220	220	218	219
10	**TOTAL**	**557,689**	**558,576**	**559,120**	**559,154**	**558,860**	**558,727**	**558,637**	**558,619**	**558,521**	**558,872**	**559,634**	**560,535**	**558,912**

PECO Energy Company (Gas)
Cost of Service Study
Demand Allocators

	Class	Peak_Sendout	Peak_Mains	Daily_Del-Excl. Dir	Peaks_NCP	Excess Demand Allocation Basis NCP vs. Daily_Del-Excl. Dir	Ratio of Excess Demand Allocation Basis NCP vs. Daily_Del-Excl. Dir	Excess Demand	Excess Demand by Class	Average & Excess Demand	Ratio of Average & Excess Demand
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Max of (B) or (C)	(D) - (C)		(B) - (C)	(F) * (G)	(C) + (H)	
1	Residential	614,831	614,831	120,184	614,831	494,647	64.8%		479,108	599,292	61.4%
2	GC	295,129	295,129	65,349	295,129	229,779	30.1%		222,561	287,910	29.5%
3	Large	233	233	58	233	176	0.0%		170	228	0.0%
4	Motor Vehicles- Firm	1,807	1,807	1,377	1,807	430	0.1%		416	1,793	0.2%
5	Motor Vehicles- Interr			3	3	0	0.0%		0	3	0.0%
6	Interruptible			45	45	0	0.0%		0	45	0.0%
7	Temperature			354	354	0	0.0%		0	354	0.0%
8	Transport- Firm		63,347	25,270	63,347	38,077	5.0%		36,881	62,151	6.4%
9	Transport- Interr			23,571	23,571	0	0.0%		0	23,571	2.4%
10	**TOTAL**	**912,000**	**975,347**	**236,211**	**999,320**	**763,109**	**100%**	**739,136**	**739,136**	**975,347**	**100%**
11	**System Load Factor**					24.22%					

12 (A) & (B) Peak_Sendout and Peak_Mains from PECO Exhibit JD-6, page 18, line 32; TSF reduced by TCQ of one customer with directly assigned main
13 (C) Daily_Del_Excl. Dir (average daily deliveries excluding direct) = daily amounts from PECO Exhibit JD-6,Page 3, with TSF & TSI totals reduced by volumes of customers with directly assigned mains Used for main deliveries portion allocation
14 (D) Peaks_NCP (estimated non-coincident peaks) = Greater of Peak_Mains (B) and Daily_Del_Excl. Dir (C)
15 (E) Excess Demand Allocation Basis = Peak_NCP (D) minus Daily_Del-Excl. Dir (C)
16 (F) Ratio of Excess Demand Allocation Basis
17 (G) Excess Demand = Peak_Mains (B) minus Daily_Del-Excl. Dir (C)
18 (H) Excess Demand by Rate Class = Ratios (F) multiple Excess Demand (G). Used for main capacity excess portion allocation
19 (I) Average and Excess Demand by Rate Class = Daily_Del-Excl. Dir (C) plus Excess Demand (H). Used for measuring and regulating station equipment allocation
20 (J) Ratio of Average & Excess Demand

21 System Load Factor = Total from (C) 236,211 / Total from (B) 975,347

PECO Energy Company (Gas)
Cost of Service Study
Storage Allocator

	Class	Average Winter_FirmSales (b)	Average Monthly Sales	Excess Winter_FirmSales	% of Winter_FirmSales	Average Monthly Deliveries	% of Average Monthly Deliveries	Storage Allocator
1	Residential	6,775,524	3,655,603	3,119,921	70.7%		0.0%	69.5%
2	GC	3,277,520	1,987,710	1,289,810	29.2%		0.0%	28.7%
3	Large	1,750	1,750	-	0.0%		0.0%	0.0%
4	Motor Vehicles- Firm	43,438	41,884	1,554	0.0%		0.0%	0.0%
5	Motor Vehicles- Interr				0.0%		0.0%	0.0%
6	Interruptible				0.0%		0.0%	0.0%
7	Temperature				0.0%		0.0%	0.0%
8	Transport- Firm				0.0%	989,484	47.1%	0.8%
9	Transport- Interr				0.0%	1,111,511	52.9%	0.9%
10	**TOTAL**	**10,098,232**	**5,686,947**	**4,411,285**	**100.0%**	**2,100,995**	**100.0%**	**100.0%**
11	Storage Fraction (a)				**98.22%**		**1.78%**	

12 (a) Usage of Storage as split between Winter sales and Transportation
13 (b) Average Sales (Mcf) from January-March and November and December

PECO Energy Company (Gas)
Cost of Service Study
Mains, M&R and Meter Direct Assignments

	Customer	Installed	Length (ft)	Capacity (mcfd)	Cost	Depreciation Expense 2023 (a)	Accumulated Depreciation 12/31/2023	Annual Usage (Mcf) (b)
	Mains (Account 376)					**$ 000s**		
1	Customer 2	1988,2015, 2022	13,900	14,000	1,877	27	404	
2	Customer 2	2001	14,400	48,000	2,300	33	723	
3	Customer 4	1994	4,900	133,000	3,200	46	1,326	
4	Total Customers 2 & 4		33,200	195,000	7,377	105	2,452	4,734,868
5	Customer 3	2020	7,301	7,500	8,152	116	402	2,650,270
	Measuring & Regulating (Account 378 & 379)							
6	Customer 2	1988			290	6	203	
7	Customer 2		Served by Customer 1 station					
8	Customer 4	1994			4,800	96	2,784	
9	Total Customers 2 & 4				5,090	102	2,987	
10	Customer 3	2020			6,309	126	436	
	Meters (Account 381)							
11	Customer 3	2020			311	8	28	
12	Customer 1	2018			272	7	35	
	Meter Installations (Account 382)							
13	Customer 3	2020			594	15	52	
14	Customer 1	2018			2,170	54	280	
15	(a) Depreciation expenses for Steel Mains, Measuring & Regulating and Meters were based on 70, 50 and 40 year-life respectively							
16	(b) Customers 1,2 and 4 are Rate TSI customers and customer 3 is a Rate TSF customer							

PECO Energy Company (Gas)
Cost of Service Study
Service Investment Allocator

	Class	Service	Average Service Cost ($)	Average Customer Numbers	Investments ($000s)	Ratio
1	Residential	Residential	6,719	512,659	3,444,722	77.8%
2	GC	C&I	21,216	45,589	967,241	21.9%
3	Large	C&I	21,216	8	170	0.0%
4	Motor Vehicles- Firm	C&I	21,216	15	318	0.0%
5	Motor Vehicles- Interr	C&I	21,216	1	21	0.0%
6	Interruptible	C&I	21,216	1	21	0.0%
7	Temperature	C&I	21,216	20	419	0.0%
8	Transport- Firm	C&I	21,216	399	8,465	0.2%
9	Transport- Interr	C&I	21,216	215	4,558	0.1%
10	**Total**			**558,907**	**4,425,936**	**100%**

11	**Services Costs**		Residential			C&I		
12			Dollars	Services	Average	Dollars	Services	Average
13		2019	$36,987,726	6,449	$5,735	$5,183,009	255	$20,326
14		2020	$35,054,553	4,784	$7,327	$4,046,237	159	$25,448
15		2021	$38,997,781	5,659	$6,891	$3,847,240	212	$18,147
16		2022	$52,026,900	7,943	$6,550	$4,567,764	207	$22,066
17		2023	$21,895,801	2,692	$8,134	$5,163,417	242	$21,336
18			$184,962,762	27,527	$6,719	$22,807,667	1,075	$21,216

PECO Energy Company (Gas)
Cost of Service Study
Meter Investment Allocator
Costs of Meters for 2023

	Class	Average Cost ($) (a)	Average Customers Excl. Dir (b)	Cost ($000s)	Ratio
1	Residential	345	512,659	176,643	72.4%
2	GC	1,281	45,589	58,391	23.9%
3	Large	2,329	8	19	0.0%
4	Motor Vehicles- Firm	14,355	15	215	0.1%
5	Motor Vehicles- Interr	1,529	1	2	0.0%
6	Interruptible	2,729	1	3	0.0%
7	Temperature	8,287	20	164	0.1%
8	Transport- Firm	12,182	399	4,861	2.0%
9	Transport- Interr	17,297	217	3,750	1.5%
10	**Total**		**558,909**	**244,046**	**100.0%**

11 (a) Cost includes materials and labor
12 (b) Average customer numbers excluding directly assigned in Transport-Firm and Transport-Interr.

PECO Energy Company (Gas)
Cost of Service Study
Customer Records and Collection Expenses (Account 903) Allocator

Listed below is a listing of the activities in Account 903, and the allocation base used for each activity.

		2022			
	Customer Records & Collection-Account 903	**Percentage (%)**	**Dollars ($000s)**	**Sub-Allocator**	**Description**
1	Mailing Bills	9.3%	1,393	Cust_Avg	Customer Count - Average
2	Financial Call Center	8.5%	1,281	AR Over60-Day	Delinquencies
3	CAP Rates	5.5%	832	Cust_Res	Residential Customers
4	Customer Billing	18.4%	2,769	Cust_Avg	Customer Count - Average
5	Manage and Support Recoveries	4.4%	664	AR Over60-Day	Delinquencies
6	Call Center	22.7%	3,413	Call Center	Call Center Calls
7	Customer Payments	2.9%	443	Cust_Avg	Customer Count - Average
8	Meter Records	6.4%	963	Cust_Avg	Customer Count - Average
9	Customer Care Center	4.4%	662	Cust_Excl. Ind	Customer Count - Non Large
10	ESO Activities	3.7%	561	Cust_Ind	Customer Count - LC&I
11	Balance-C&MS & Field Vendor Activities	13.8%	2,078	Cust_Avg	Customer Count - Average
12	**Account Balance**	100.0%	15,057		

		Amount	Residential	GC	Large	MV Firm	MV Interr	Interr	Temperature	Trans Firm	Trans Interr
13	Cust_Avg	7,645	7,013	624	0	0	0	0	0	5	3
14	Call Center	3,413	3,157	253	0	2	0	0	1	0	0
15	AR Over60-Day	1,944	1,444	413	1	2	0	0	2	52	30
16	Cust_Res	832	832	0	0	0	0	0	0	0	0
17	Cust_Excl. Ind	662	608	54	0	0	0	0	0	0	0
18	Cust_Ind	561	0	0	7	0	0	1	0	357	195
19		15,057	13,054	1,344	8	4	0	1	3	415	228
20	**Acct903 Allocator**	**100.0%**	**86.7%**	**8.9%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**2.8%**	**1.5%**

PECO Energy Company (Gas)
Cost of Service Study
Accounts 908-916 Allocator

Listed below is a listing of the activities in Accounts 908-916, and the allocation base used for each activity.

2022

	Customer Service & Informational Expenses	**Percentage (%)**	**Dollars ($000s)**	**Sub-Allocator**	**Description**
1	Residential Marketing	24.3%	1,109	Cust_Res	Residential Customers
2	LIURP	49.4%	2,250	Cust_Res	Residential Customers
3	Marketing- Residential & Small C&I	3.0%	136	Cust_Excl. Ind	Non-Large Customers
4	LC&I Marketing	2.9%	133	Cust_Ind	LC&I Customers
5	Balance-Marketing	20.4%	929	Cust_Avg	Customer Count - Average
6	**Account Balance**	100.0%	4,557		

		Amount	Residential	GC	Large	MV Firm	MV Interr	Interr	Temperature	Trans Firm	Trans Interr
7	Cust_Res	3,359	3,358.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Cust_Excl. Ind	136	125.3	11.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Cust_Ind	133	0.0	0.0	1.7	0.0	0.0	0.2	0.0	84.5	46.2
10	Cust_Avg	929	852.0	75.8	0.0	0.0	0.0	0.0	0.0	0.7	0.4
11		4,557	4,336	87	2	0	0	0	0	85	47
12	**Acct908-916 Allocator**	**100.0%**	**95.2%**	**1.9%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**1.9%**	**1.0%**

PECO Energy Company (Gas)
Cost of Service Study
Accounts Receivable Over 60-Day Allocator
Accounts Receivable Aging for 2023

	Class	Average Over 2 Months ($000)	Over60-Day Allocator
1	Residential	4,367	74.3%
2	GC	1,248	21.2%
3	Large	2	0.0%
4	Motor Vehicles- Firm	6	0.1%
5	Motor Vehicles- Interr	0	0.0%
6	Interruptible	1	0.0%
7	Temperature	7	0.1%
8	Transport- Firm	159	2.7%
9	Transport- Interr	90	1.5%
10	**Total**	**5,880**	**100.0%**

PECO Energy Company (Gas)
Cost of Service Study
Write-Offs Allocator
Write-Off % Excluding Pre-Program Arrearages

	Class	2019	2020	2021	2022	2023	Write-Off Allocator - Average
1	Residential	91.1%	84.0%	88.8%	87.1%	89.5%	88.1%
2	GC	8.1%	15.3%	10.8%	12.7%	10.4%	11.4%
3	Large	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	Motor Vehicles- Firm	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
5	Motor Vehicles- Interr	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	Interruptible	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	Temperature	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
8	Transport- Firm	0.5%	0.4%	0.1%	0.0%	0.0%	0.2%
9	Transport- Interr	0.3%	0.2%	0.1%	0.0%	0.0%	0.1%
10	**Totals**	100.0%	100.0%	100.0%	100.0%	100.0%	**100.0%**

PECO Energy Company (Gas)
Cost of Service Study
Deposits, Interest, Advances, Forfeited Discounts, EE, GPC, MFC/POR

	Class	Deposits ($000s)	Interest on Deposits ($000s)	Advances ($000s)	Forfeited Discounts ($000s)	EE Program ($000s)	GPC ($000s)	MFC/POR ($000s)
1	Residential	3,310	265	878	909	350	1,119	1,057
2	GC	7,265	371	191	371	(29)	609	143
3	Large	4	0	0	1	0	1	0
4	Motor Vehicles- Firm	2	0	0	2	0	13	0
5	Motor Vehicles- Interr	0	0	0	0	0	0	0
6	Interruptible	0	0	0	0	0	0	0
7	Temperature	3	0	0	2	0	0	0
8	Transport- Firm	182	9	189	57	0	0	0
9	Transport- Interr	100	5	59	32	0	0	0
10	**Totals**	**10,867**	**650**	**1,318**	**1,373**	**321**	**1,742**	**1,200**

PECO Energy Company (Gas)
Cost of Service Study
Purchased Gas Cost (PGC)

	Class	PGC ($000s)
1	Residential	176,887
2	GC	55,442
3	Large	99
4	Motor Vehicles- Firm	1,289
5	Motor Vehicles- Interr	8
6	Interruptible	77
7	Temperature	606
8	Transport- Firm	0
9	Transport- Interr	0
10	**Totals**	**234,407**

PECO Energy Company (Gas)
Cost of Service Study
Balancing Service Cost (BSC)

	Class	BSC ($000s)
1	Residential	17,003
2	GC	9,245
3	Large	8
4	Motor Vehicles- Firm	194
5	Motor Vehicles- Interr	1
6	Interruptible	6
7	Temperature	50
8	Transport- Firm	0
9	Transport- Interr	0
10	**Totals**	**26,508**

PECO Energy Company (Gas)
Cost of Service Study
Purchase of Receivables (POR)

	Class	POR ($000)
1	Residential	48,229
2	GC	33,888
3	Large	0
4	Motor Vehicles- Firm	169
5	Motor Vehicles- Interr	1
6	Interruptible	0
7	Temperature	193
8	Transport- Firm	0
9	Transport- Interr	0
10	**Total**	**82,479**

PECO Energy Company (Gas)
Cost of Service Study
Design Day Demand

	Historical_2019-2023	**Residential**	**GC**	**Large**	**Motor Vehicles- Firm**	**Transport- Firm**	**Total**	**Calibration Factor**
1	Calendar Sales Jan & Feb (Ccf/Cust/Day)	4.9	27.0	236.0	893.7			
2	Non-Heating Usage Jul & Aug (Ccf/Cust/Day)	0.5	4.1	59.6	765.2			
3	Heating Usage (Ccf/Cust/Day) = Line 1 - Line 2	4.4	22.9	176.4	128.5			
4	Jan & Feb Degree Day Deficient (DDD/Day)	27.0	27.0	27.0	27.0			
5	Design Day DDD	65.0	65.0	65.0	65.0			
6	Heating Use per Degree Day (Ccf/Cust) = Line 3 / Line 4	0.2	0.8	6.5	4.8			
7	Peak Day Heating Usage (Ccf/Cust) = Line 5 * Line 6	10.7	55.1	424.6	309.3			
8	Peak Day Non-Heating Usage (Ccf/Cust) = Line 2	0.5	4.1	59.6	765.2			
9	Peak Day Usage (Ccf/Cust) = Line7 + Line 8	11.2	59.2	484.2	1,074.6			
10	Average Day Usage (Ccf/Cust/Day)	2.2	13.1	119.1	816.4			
11	Historical Load Factor = Line 10 / Line 9	19.5%	22.1%	24.6%	76.0%			
12								
13	FPFTY_2025							
14	Annual Usage (Mcf)	43,867,240	23,852,516	21,000	502,606			
15	Annual Number of Customers (Average)	512,659	45,589	8	15			
16	Jan & Feb Number of Customers (Average)	511,780	45,688	8	15			
17	Average Day Usage (Ccf/Cust/Day) = Line 14 * 10 / Line 15 / 365	2.3	14.3	71.9	918.0			
18	Historical Load Factor = Line 11	19.5%	22.1%	24.6%	76.0%			
19	Average Peak Day Usage (Ccf/Cust) = Line 17 / Line 18	12.1	64.8	292.4	1,208.3			
20	Peak Day Usage (Mcf) = Line 16 * Line 19 / 10	616,843	296,094	234	1,812		914,984	
21	System Losses (2.1448%) = Line 20 * 2.1448% (a)	13,230	6,351	5	39		19,625	
22	Peak Day Usage including Loss (Mcf) = Line 20 + Line 21	630,073	302,445	239	1,851		934,609	
23								
24	Calibration to 1307(f) Filing (b)							
25	Design Day Peak Demand Requirement in 2025 in 1307(f) Filing (c)						912,000	
26	Calibration Factor = Line 25 / Line 22 Total							0.98
27	Calibrated Design Day Peak Demand (Mcf) = Line 22 * Line 26	614,831	295,129	233	1,807		912,000	
28								
29	Transportation Service							
30	Transportation Firm in 2025 in 1307(f) Filing (Mcf) (d)					75,000	75,000	
31								
32	Design Day Peak Demand (Mcf) = Line 27 + Line 30	**614,831**	**295,129**	**233**	**1,807**	**75,000**	**987,000**	
33								
34	(a) Average system losses from 2019 to 2023							
35	(b) Purchased Gas Cost (PGC) filing under Section 1307(f) on April 30, 2023							
36	(c) Section 19 in PGC filing on April 30, 2023							
37	(d) Transportation Contract Quantity (TCQs) for TSF customers							

PECO Energy Company (Gas)
Cost of Service Study
Base Customer Charges

	Class	($000s)
1	Residential	327,766
2	GC	122,676
3	Large	184
4	Motor Vehicles- Firm	611
5	Motor Vehicles- Interr	4
6	Interruptible	75
7	Temperature	697
8	Transport- Firm	19,121
9	Transport- Interr	10,848
10	**Totals**	**481,982**

PECO Exhibit JD-7:

Gas Class Cost of Service Study for FPFTY Ended December 31, 2025 – Calculation of Costs to Serve NGS Customers

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	1	**SUMMARY AT PRESENT RATES**									
S	2										
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**									
S	4	**OPERATING REVENUE**									
S	5	Sales of Gas Revenue - Base	SCH RBC, LN 54	481,982	327,766	122,676	184	611	4	75	697
S	6	Other Operating Revenue	SCH RBC, LN 64	3,549	2,404	919	1	4	0	0	3
S	7	TOTAL OPERATING REVENUE		485,530	330,170	123,595	185	615	4	75	700
S	8										
S	9	**OPERATING EXPENSES**									
S	10	Operation and Maintenance Expense Excl Pur Gas	SCH E, LN 99	167,687	123,018	35,534	38	166	1	7	47
S	11	Depreciation and Amortization Expense	SCH D, LN 45	118,763	80,999	30,846	19	144	0	3	35
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 10	9,067	6,373	2,184	2	11	0	0	3
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 18	0	0	0	0	0	0	0	0
S	14	Income Taxes	SCH TI, LN 61	14,297	11,849	2,509	(21)	(0)	(0)	(14)	(134)
S	15	TOTAL OPERATING EXPENSES		281,220	198,541	66,056	80	321	1	25	220
S	16										
S	17	**OPERATING INCOME (RETURN)**		204,311	131,629	57,539	104	294	2	50	480
S	18										
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**									
S	20	Gas Plant in Service	SCH RBP, LN 65	4,630,050	3,126,806	1,225,457	726	5,495	17	127	1,352
S	21	Less: Accumulated Depreciation	SCH RBD, LN 37	1,022,690	699,138	266,349	150	1,142	4	25	316
S	22	Plus: Rate Base Additions Excl Purchased Gas	SCH RBO, LN 13	253,067	181,674	59,722	44	239	1	8	61
S	23	Less: Rate Base Deductions	SCH RBO, LN 26	346,452	229,908	97,612	59	409	1	10	104
S	24	TOTAL RATE BASE EXCL PURCHASED GAS	SCH RBO, LN 29	3,513,975	2,379,433	921,218	561	4,182	12	99	993
S	25										
S	26	RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		5.81%	5.53%	6.25%	18.59%	7.03%	17.52%	50.89%	48.30%
S	27	INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		1.00	0.95	1.07	3.20	1.21	3.01	8.75	8.31
S	28										
S	29										
S	30	**DEVELOPMENT OF PURCHASED GAS RETURN**									
S	31	Purchased Gas Revenues (PGC)	SCH RBC, LN 55	234,407	176,887	55,442	99	1,289	8	77	606
S	32	Other Sales of Gas Revenue (BSC)	SCH RBC, LN 56	26,508	17,003	9,245	8	194	1	6	50
S	33	Purchased Gas O&M Expense	SCH E, LN 98	260,932	193,902	64,692	107	1,483	9	84	656
S	34	Purchased Gas Income Taxes (Fed & State PP)		57	43	14	0	0	0	0	0
S	35	**PURCHASED GAS OPERATING INCOME (RETURN)**		40	31	9	0	0	0	0	0
S	36	RATE BASE - PURCHASED GAS CASH WORKING CAPITAL		10,032	7,570	2,373	4	55	0	3	26
S	37	PURCHASED GAS RATE OF RETURN (PRESENT)		0.40%	0.41%	0.37%	0.53%	0.52%	0.53%	0.53%	0.53%
S	38										
S	39										
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	41	Total Distribution Sales Revenue at Current Rates		742,897	521,656	187,363	291	2,094	12	158	1,353
S	42	Total Distribution Operating Revenues		746,445	524,060	188,282	292	2,098	12	159	1,356
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes		556,449	404,292	133,257	166	1,804	10	94	742
S	44	Plus: Total Federal & State Taxes		14,354	11,892	2,523	(21)	(0)	(0)	(14)	(134)
S	45	Total Operating Income (Return)		204,351	131,660	57,548	104	294	2	50	480
S	46	Total Rate Base		3,524,006	2,387,003	923,590	566	4,237	13	102	1,019
S	47										
S	48	COMPOSITE RATE OF RETURN (PRESENT)		5.80%	5.52%	6.23%	18.46%	6.94%	17.09%	49.26%	47.08%
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)		1.00	0.95	1.07	3.18	1.20	2.95	8.49	8.12
S	50										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TRANSP SERV FIRM	TRANSP SERV INTER	NEGOTIATED RATE	(n)	(o)	(p)	(q)	(r)
		(a)	(b)	(k)	(l)	(m)					
S	1	**SUMMARY AT PRESENT RATES**									
S	2										
S	3	**DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS**									
S	4	**OPERATING REVENUE**									
S	5	Sales of Gas Revenue - Base	SCH RBC, LN 54	18,136	10,351	1,482					
S	6	Other Operating Revenue	SCH RBC, LN 64	136	65	17					
S	7	TOTAL OPERATING REVENUE		18,272	10,416	1,499					
S	8										
S	9	**OPERATING EXPENSES**									
S	10	Operation and Maintenance Expense Excl Pur Gas	SCH E, LN 99	5,781	2,446	649					
S	11	Depreciation and Amortization Expense	SCH D, LN 45	4,129	1,853	735					
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 10	317	133	43					
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 18	0	0	0					
S	14	Income Taxes	SCH TI, LN 61	284	(530)	356					
S	15	TOTAL OPERATING EXPENSES		9,942	4,962	1,070					
S	16										
S	17	**OPERATING INCOME (RETURN)**		8,329	5,454	429					
S	18										
S	19	**DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS**									
S	20	Gas Plant in Service	SCH RBP, LN 65	170,133	72,475	27,463					
S	21	Less: Accumulated Depreciation	SCH RBD, LN 37	34,110	17,738	3,716					
S	22	Plus: Rate Base Additions Excl Purchased Gas	SCH RBO, LN 13	7,137	3,157	1,025					
S	23	Less: Rate Base Deductions	SCH RBO, LN 26	11,329	5,015	2,006					
S	24	TOTAL RATE BASE EXCL PURCHASED GAS	SCH RBO, LN 29	131,830	52,879	22,767					
S	25										
S	26	RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		6.32%	10.31%	1.88%					
S	27	INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)		1.09	1.77	0.32					
S	28										
S	29										
S	30	**DEVELOPMENT OF PURCHASED GAS RETURN**									
S	31	Purchased Gas Revenues (PGC)	SCH RBC, LN 55	0	0	0					
S	32	Other Sales of Gas Revenue (BSC)	SCH RBC, LN 56	0	0	0					
S	33	Purchased Gas O&M Expense	SCH E, LN 98	0	0	0					
S	34	Purchased Gas Income Taxes (Fed & State PP)		0	0	0					
S	35	**PURCHASED GAS OPERATING INCOME (RETURN)**		(0)	(0)	(0)					
S	36	RATE BASE - PURCHASED GAS CASH WORKING CAPITAL		0	0	0					
S	37	PURCHASED GAS RATE OF RETURN (PRESENT)		0.00%	0.00%	0.00%					
S	38										
S	39										
S	40	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	41	Total Distribution Sales Revenue at Current Rates		18,136	10,351	1,482					
S	42	Total Distribution Operating Revenues		18,272	10,416	1,499					
S	43	Total Distribution Operating Expenses Excl Federal & State Taxes		10,227	4,432	1,427					
S	44	Plus: Total Federal & State Taxes		284	(530)	356					
S	45	Total Operating Income (Return)		8,329	5,454	429					
S	46	Total Rate Base		131,830	52,879	22,767					
S	47										
S	48	COMPOSITE RATE OF RETURN (PRESENT)		6.32%	10.31%	1.88%					
S	49	COMPOSITE INDEX RATE OF RETURN (PRESENT)		1.09	1.78	0.32					
S	50										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	52										
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)**									
S	54										
S	55	Rate Base Excluding Purchased Gas	SCH S, LN 24	3,513,975	2,379,433	921,218	561	4,182	12	99	993
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		79,618	60,629	16,895	(59)	44	(1)	(42)	(399)
S	57			8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	58	**OPERATING REVENUES**									
S	59	**Change in Revenue (Change in Return * 1.383)**		110,103	83,843	23,364	(82)	61	(2)	(59)	(552)
S	60	Distribution Base Rate Revenue (Present Rates)	SCH S, LN 5	481,982	327,766	122,676	184	611	4	75	697
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	592,085	411,609	146,041	102	672	2	16	145
S	62										
S	63	Forfeited Discounts Revenues	CALCULATED	179	137	38	(0)	0	(0)	(0)	(1)
S	64	Other Operating Revenue (Present Rates)	SCH S, LN 6	3,549	2,404	919	1	4	0	0	3
S	65	**TOTAL OPERATING REVENUES**		595,813	414,150	146,997	103	676	2	16	147
S	66										
S	67	**OPERATING EXPENSES**									
S	68	Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 10	167,687	123,018	35,534	38	166	1	7	47
S	69	Depreciation and Amortization Expense	SCH S, LN 11	118,763	80,999	30,846	19	144	0	3	35
S	70	Additional Bad Debt Expense	CALCULATED	406	310	86	(0)	0	(0)	(0)	(2)
S	71	Additional PUC / OTS & SBA Fee Expense	CALCULATED	340	259	72	(0)	0	(0)	(0)	(2)
S	72	Taxes Other Than Income Taxes-General	SCH S, LN 12	9,067	6,373	2,184	2	11	0	0	3
S	73	Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 13	0	0	0	0	0	0	0	0
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**		296,263	210,959	68,723	58	321	1	10	82
S	75	State and Federal Income Taxes @ Effective Tax Rate	CALCULATED	(14,297)	(11,849)	(2,509)	21	0	0	14	134
S	76	State and Federal Income Taxes @ Statutory Rates	CALCULATED	29,917	22,781	6,348	(22)	17	(0)	(16)	(150)
S	77	**TOTAL OPERATING EXPENSES**		311,883	221,891	72,563	58	338	1	8	66
S	78										
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**		283,930	192,259	74,435	45	338	1	8	80
S	80										
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**		592,085	411,609	146,041	102	672	2	16	145
S	82										
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**		110,283	83,980	23,402	(82)	61	(2)	(59)	(553)
S	84	REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVENUES (%)		22.88%	25.62%	19.08%	-44.43%	9.97%	-45.26%	-78.66%	-79.36%
S	85										
S	86										
S	87										
S	88										
S	89										
S	90										
S	91										
S	92										
S	93										
S	94										
S	95										
S	96										
S	97										
S	98										
S	99										
S	100										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TRANSP SERV FIRM	TRANSP SERV INTER	NEGOTIATED RATE	(n)	(o)	(p)	(q)	(r)
		(a)	(b)	(k)	(l)	(m)					
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	52										
S	53	**DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)**									
S	54										
S	55	Rate Base Excluding Purchased Gas	SCH S, LN 24	131,830	52,879	22,767					
S	56	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		2,322	(1,181)	1,411					
S	57			8.08%	8.08%	8.08%					
S	58	**OPERATING REVENUES**									
S	59	**Change in Revenue (Change in Return * 1.383)**		3,212	(1,633)	1,951					
S	60	Distribution Base Rate Revenue (Present Rates)	SCH S, LN 5	18,136	10,351	1,482					
S	61	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	21,348	8,717	3,433					
S	62										
S	63	Forfeited Discounts Revenues	CALCULATED	5	(3)	3					
S	64	Other Operating Revenue (Present Rates)	SCH S, LN 6	136	65	17					
S	65	**TOTAL OPERATING REVENUES**		21,489	8,780	3,453					
S	66										
S	67	**OPERATING EXPENSES**									
S	68	Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 10	5,781	2,446	649					
S	69	Depreciation and Amortization Expense	SCH S, LN 11	4,129	1,853	735					
S	70	Additional Bad Debt Expense	CALCULATED	12	(6)	7					
S	71	Additional PUC / OTS & SBA Fee Expense	CALCULATED	10	(5)	6					
S	72	Taxes Other Than Income Taxes-General	SCH S, LN 12	317	133	43					
S	73	Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 13	0	0	0					
S	74	**TOTAL OPERATING EXPENSES BEFORE TAXES**		10,249	4,420	1,440					
S	75	State and Federal Income Taxes @ Effective Tax Rate	CALCULATED	(284)	530	(356)					
S	76	State and Federal Income Taxes @ Statutory Rates	CALCULATED	873	(444)	530					
S	77	**TOTAL OPERATING EXPENSES**		10,837	4,507	1,614					
S	78										
S	79	**NET OPERATING INCOME EXCL PURCHASED GAS**		10,652	4,273	1,840					
S	80										
S	81	**BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 8.08%**		21,348	8,717	3,433					
S	82										
S	83	**TOTAL REVENUE EXCL PUR GAS INCREASE/DECREASE**		3,217	(1,636)	1,954					
S	84	REVENUE INCREASE(DECREASE) TO RETAIL EXCL PUR GAS REVENUES (%)		17.74%	-15.81%	131.86%					
S	85										
S	86										
S	87										
S	88										
S	89										
S	90										
S	91										
S	92										
S	93										
S	94										
S	95										
S	96										
S	97										
S	98										
S	99										
S	100										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	102										
S	103	**DEVELOPMENT OF PURCHASED GAS RETURN (EQUALIZED RATE)**									
S	104										
S	105	Rate Base for Purchased Gas	SCH S, LN 36	10,032	7,570	2,373	4	55	0	3	26
S	106	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		770	581	183	0	4	0	0	2
S	107				8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	108	**OPERATING REVENUES**									
S	109	**Change in Revenue (Change in Return * 1.383)**		1,065	803	253	0	6	0	0	3
S	110	Distribution Base Rate Revenue (Present Rates)	CALCULATED	260,915	193,890	64,687	107	1,483	9	84	656
S	111	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	261,980	194,693	64,940	107	1,489	9	84	659
S	112										
S	113	**OPERATING EXPENSES**									
S	114	Purchased Gas O&M Expense	SCH S, LN 33	260,932	193,902	64,692	107	1,483	9	84	656
S	115	Additional Bad Debt Expense	CALCULATED	4	3	1	0	0	0	0	0
S	116	Additional PUC / OTS & SBA Fee Expense	CALCULATED	3	2	1	0	0	0	0	0
S	117	**TOTAL OPERATING EXPENSES BEFORE TAXES**		260,939	193,907	64,694	107	1,483	9	84	656
S	118	State and Federal Inc Taxes @ Effective Tax Rate	CALCULATED	(57)	(43)	(14)	(0)	(0)	(0)	(0)	(0)
S	119	State and Federal Income Taxes @ Statutory Rates	CALCULATED	289	218	69	0	2	0	0	1
S	120	**TOTAL OPERATING EXPENSES**		261,171	194,082	64,748	107	1,484	9	84	656
S	121										
S	122	**NET OPERATING INCOME FOR PURCHASED GAS**		809	611	191	0	4	0	0	2
S	123										
S	124	**EQUALS TOTAL PURCHASED GAS COST OF SERVICE @ ROR**		261,980	194,693	64,940	107	1,489	9	84	659
S	125										
S	126	**TOTAL SALES PURCH GAS INCREASE/DECREASE**		1,065	803	253	0	6	0	0	3
S	127	SALES REVENUE INCREASE TO RURCHASED GAS REVENUES (%)		0.45%	0.45%	0.46%	0.45%	0.45%	0.45%	0.45%	0.45%
S	128										
S	129										
S	130										
S	131										
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	133	**Total Composite Base Rate Sales Revenue Requirement**		854,065	606,302	210,980	210	2,160	11	100	803
S	134	**Other Operating Revenue**		3,728	2,541	957	1	4	0	0	2
S	135	**Total Revenue**		857,793	608,843	211,937	211	2,165	11	100	805
S	136	**Total Operating Expense before Income Taxes**		557,202	404,866	133,417	166	1,804	10	94	738
S	137	**OIBIT**		300,591	203,977	78,521	45	360	1	7	67
S	138	**Total Income Taxes**		15,851	11,107	3,894	(1)	18	(0)	(2)	(15)
S	139	**Net Operating Income**		284,739	192,870	74,626	46	342	1	8	82
S	140	**Total Increase (Decrease) Base Sales Required w/ Addt'l Forfeited Discount**		111,348	84,783	23,655	(81)	67	(2)	(58)	(551)
S	141	**TOTAL INCREASE (DECREASE) BASE SALES REQUIRED W/O ADDT'L FORFEITED DISCO**		111,168	84,646	23,617	(81)	67	(2)	(58)	(550)
S	142	**RATE OF RETURN (PROPOSED)**		8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	143										
S	144										
S	145										
S	146										
S	147										
S	148										
S	149										
S	150										

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 ($000'S)

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TRANSP SERV FIRM	TRANSP SERV INTER	NEGOTIATED RATE	(n)	(o)	(p)	(q)	(r)
		(a)	(b)	(k)	(l)	(m)					
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 8.08%**									
S	102										
S	103	**DEVELOPMENT OF PURCHASED GAS RETURN (EQUALIZED RATE)**									
S	104										
S	105	Rate Base for Purchased Gas	SCH S, LN 36	0	0	0					
S	106	**Change in Operating Income (Rate Base * (8.08% - ROR (Present)))**		0	0	0					
S	107			0.00%	0.00%	0.00%					
S	108	**OPERATING REVENUES**									
S	109	**Change in Revenue (Change in Return * 1.383)**		0	0	0					
S	110	Distribution Base Rate Revenue (Present Rates)	CALCULATED	0	0	0					
S	111	**Total Dist Base Rate Revenue (Proposed Rate)**	CALCULATED	0	0	0					
S	112										
S	113	**OPERATING EXPENSES**									
S	114	Purchased Gas O&M Expense	SCH S, LN 33	0	0	0					
S	115	Additional Bad Debt Expense	CALCULATED	0	0	0					
S	116	Additional PUC / OTS & SBA Fee Expense	CALCULATED	0	0	0					
S	117	**TOTAL OPERATING EXPENSES BEFORE TAXES**		0	0	0					
S	118	State and Federal Inc Taxes @ Effective Tax Rate	CALCULATED	(0)	(0)	(0)					
S	119	State and Federal Income Taxes @ Statutory Rates	CALCULATED	0	0	0					
S	120	**TOTAL OPERATING EXPENSES**		0	0	0					
S	121										
S	122	**NET OPERATING INCOME FOR PURCHASED GAS**		(0)	(0)	(0)					
S	123										
S	124	**EQUALS TOTAL PURCHASED GAS COST OF SERVICE @ ROR**		0	0	0					
S	125										
S	126	**TOTAL SALES PURCH GAS INCREASE/DECREASE**		0	0	0					
S	127	SALES REVENUE INCREASE TO RURCHASED GAS REVENUES (%)		0.00%	0.00%	0.00%					
S	128										
S	129										
S	130										
S	131										
S	132	**TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)**									
S	133	**Total Composite Base Rate Sales Revenue Requirement**		21,348	8,717	3,433					
S	134	**Other Operating Revenue**		141	63	20					
S	135	**Total Revenue**		21,489	8,780	3,453					
S	136	**Total Operating Expense before Income Taxes**		10,249	4,421	1,440					
S	137	**OIBIT**		11,240	4,359	2,014					
S	138	**Total Income Taxes**		588	87	174					
S	139	**Net Operating Income**		10,652	4,273	1,839					
S	140	**Total Increase (Decrease) Base Sales Required w/ Addt'l Forfeited Discount**		3,217	(1,636)	1,954					
S	141	**TOTAL INCREASE (DECREASE) BASE SALES REQUIRED W/O ADDT'L FORFEITED DISCO**		3,212	(1,633)	1,951					
S	142	**RATE OF RETURN (PROPOSED)**		8.08%	8.08%	8.08%					
S	143										
S	144										
S	145										
S	146										
S	147										
S	148										
S	149										
S	150										

PECO ENERGY COMPANY
STATEMENT NO. 6-R (Corrected Version)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: JIANG DING

SUBJECT: ALLOCATION OF MAINS, LARGE CUSTOMER ACCOUNT REPRESENTATIVES, ALLOCATION OF ACCOUNTS 908-916, RESIDENTIAL CUSTOMER CHARGE, DESIGN DAY DEMAND, AND ALLOCATORS FOR RATE CLASS TS-F CUSTOMERS

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
JIANG DING

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jiang Ding. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory & Rates Specialist. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony that is marked as PECO Statement No. 6. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to:

(1) Office of Consumer Advocate ("OCA") witness Clarence Johnson regarding the unbundled, fully allocated class cost-of-service study ("COSS") concerning allocation of distribution Mains, adjustments to large customer account representative cost allocations, allocation of Accounts 908-916, and residential customer-related costs; and

(2) Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte concerning design day demand for rate class TS-F and allocators separated between customers above and below 18,000 Mcf per year for rate class TS-F.

Some issues raised by other parties' witnesses may not be addressed in my rebuttal testimony. This should not be construed as the Company's assent to, or approval of, those other parties' positions.

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes, accompanying my rebuttal testimony are seven new exhibits labeled PECO Exhibit JD-8 through PECO Exhibit JD-14.

PECO Exhibit JD-8	PECO's Response to OCA-IV-10, Attachment OCA-IV-10 (a) (excerpt from American Gas Association's ("AGA") *Gas Rate Fundamentals* , 1987 Edition)
PECO Exhibit JD-9	OCA's Response to PECO-OCA-II-5
PECO Exhibit JD-10	PECO's Response to OCA-IV-4
PECO Exhibit JD-11	OCA's Response to PECO-OCA-II-10
PECO Exhibit JD-12	PECO's 1307 (f) Filing in 2022, Section 19
PECO Exhibit JD-13	PECO's 1307 (f) Filing in 2024, Section 15
PECO Exhibit JD-14	PECO's Response to OCA-III-7 in PECO's 2022 gas base rate case (Docket No. R-2022-3031113)

II. ALLOCATION OF MAINS

5. Q. Please summarize the objection of Mr. Johnson to the allocation of Mains in the COSS.

A. Mr. Johnson objects to PECO's use of the Average and Excess Demand ("A&E") method in the COSS for allocating the costs of Mains to customer classes. Mr. Johnson claims that most applications of the A&E formula fail to reflect average demand, leading to a potentially flawed methodology that does not accomplish PECO's intent to recognize average demand (OCA Statement No. 3, page 10).

Mr. Johnson also disagrees with the Company's 24.22% load factor used in the A&E formula (OCA Statement No. 3, page 11).

6. Q. Please summarize the methodology you used to allocate Mains in the COSS.

A. Excluding a small portion of Mains that was directly assigned, most of the Mains were classified and allocated using the A&E method. Under this method, the portion of Mains costs equal to the system average load factor is allocated among the rate classes based on their average daily deliveries. The balance of Mains costs is allocated based on excess demand. The excess demand is allocated among rate classes in proportion to each class's peak demand over its average demand. This method is recognized as an acceptable method by the AGA in *Gas Rate Fundamentals*, 1987 Edition.

7. Q. Has PECO used this method before?

A. Yes. As I explained in my direct testimony, PECO used the same A&E methodology in its 2022 gas base rate case (Docket No. R-2022-3031113) and the methodology was approved by the Commission in PECO's 2020 gas base rate case (Docket No. R-2020-3018929). PECO has also used this method in its 2010 gas base rate case (Docket No. R-2010-2161592). Moreover, PECO is aware of several other Pennsylvania natural gas distribution companies employing A&E as their cost allocation methodology (*see* PPL Gas Utilities Corporation, Docket No. R-00061398; UGI Utilities, Inc. - Gas Division, ("UGI"), Docket No. R-2021-3030218; UGI, Docket No. R-2018-3006814; Philadelphia Gas Works ("PGW"), Docket No. R-2023-3037933; PGW, Docket No. R-2020-3017206; PGW, Docket No. R-00061931).

8. Q. Please summarize Mr. Johnson's primary proposal for allocating Mains.

A. Mr. Johnson recommends that PECO adopt the peak and average ("P&A") method instead of the A&E method (OCA Statement No. 3, page 21).

9. Q. Do you agree with Mr. Johnson's proposal for allocating Mains for PECO?

A. No. First, the P&A method is flawed because it double counts average annual usage. That is, average annual usage is counted once in the annual component, and again in the peak component.

Second, Mr. Johnson incorrectly suggests that the Commission's final order in *Columbia Gas* was a conclusive determination that the P&A method was superior to the A&E method. To the contrary, in *Columbia Gas*, the Commission stated that the P&A method "is the most appropriate allocation methodology to use *in this proceeding*." (*Columbia Gas*, Docket No. R-2020-3018835, page 218, Order entered 7 February 19, 2021) (emphasis added). However, in that case, no party proposed the A&E method. Accordingly, the Commission did not disapprove of the A&E method nor did it approve the P&A method in all instances, as Mr. Johnson seems to suggest.

Third, *Columbia Gas* was not the Commission's most recent decision on the relative appropriateness of the A&E and P&A methods. The Commission has approved PECO's use of the A&E method in PECO's 2020 rate case, and PECO used the A&E method in its 2022 gas base rate case (Docket Nos. R-2020-3018929, R-2022-3031113).[1]

[1] *PECO Energy Company*, Docket Nos. R-2020-3018929 et al., pp. 228-229, Order entered June 22, 2021) ("We agree with the ALJ and PECO that the A&E methodology is reasonable and acceptable for an NGDC because it

Fourth, Mr. Johnson's proposal that PECO adopt the P&A method has already been considered and rejected by the Commission. In PECO's 2020 gas base rate case, the OCA proposed that PECO adopt the P&A method for allocating Mains on the same grounds that Mr. Johnson is proposing here (*see* Docket No. R-2020-3018929, OCA Statement No. 4, page 12).

Fifth, PECO designs its Mains to meet system peak demands on a design day such that all firm customers can be served. The cost of excess capacity (i.e., peak capacity minus average capacity) is the primary cost driver. It is inappropriate and in conflict with cost causation principles to treat the cost of excess capacity as an incremental cost instead of the primary cost driver.

Mr. Johnson overemphasizes the size of the pipe in determining the cost of Mains installation. There are actually several cost drivers, such as the material used for the construction, the type of restoration required to complete the job, and any environmental obstructions or concerns that need to be addressed during the construction of the pipeline. Specifically, proportional increases in both capacity and length result in a proportional and, many times, an even greater-than-proportional increase in expansion costs. Moreover, there is a point at which increasing demand necessitates material changes to the Main, such as a change in materials from plastic to steel. Once this occurs, the cost of the material and labor for that installation increases drastically. For example, large-size projects likely

aligns with cost causation principles and the design of PECO's distribution system. Indeed, despite the contentions raised against the Company's proposed methodology, the Commission has supported its use when it was presented in previous cases.").

require the utilization of steel instead of plastic Mains, trench shoring,[2] use of pipeline offsets[3] instead of rolling smaller diameter pipe around obstructions, and other factors that have direct cost effects.

10. Q. Do you agree with Mr. Johnson's alternative proposal that, if the Commission accepts the A&E method, PECO should be required to weight excess demand and average demand on a 50/50 basis?

A. No. Mr. Johnson's recommendation has no cost-causation basis and should be rejected. By equally weighting average and excess demand, Mr. Johnson's proposed allocation would fail to allocate costs equitably among the rate classes. By contrast, PECO's approach of assigning demand-related costs on the basis of load factors respects cost causation principles and is well recognized as an acceptable allocation methodology.

PECO plans for natural gas demand based on historical weather temperatures, natural gas load data, and multiple other variables. PECO annually projects natural gas capacity requirements by projecting for "design day requirements," which is approved through the Purchased Gas Cost Rates. As discussed above, PECO sizes its Mains to meet system peak demands on a design day such that all firm customers can be served. Accordingly, it is inappropriate and in conflict with cost causation principles to treat the cost of excess capacity (peak minus

[2] Shoring is the provision of a support system for trench faces used to prevent movement of soil, underground utilities, roadways, and foundations. Shoring or shielding is used when the location or depth of the cut makes sloping back to the maximum allowable slope impractical.

[3] When the joints in a pipe are not properly aligned and the ends of two pipe segments, called joints, are offset from each other so much that the pipe leaks at that junction, they are known as "offset joints." A rolling offset is a way to change the direction of a pipe by shifting it both vertically and horizontally.

average) as an incremental cost instead of the primary cost driver. Demand-related costs should be assigned on the basis of responsibility for peak demand, and PECO's Mains are designed to first meet peak demands. Thus, peak demands are appropriately the driver for Mains costs.

The Commission proceeding in Docket No. R-00061398 involving PPL Gas Utilities Corporation ("PPL") approved an allocation of all Mains costs using the A&E allocation method, using a 40%/60% weighting for average and excess demands, respectively. As noted on page 113 of Commission's February 8, 2007 Opinion and Order in Docket No. R-0061398: "PPL Gas stated that the 40% for commodity was based upon system average load factors for 2004 and 2005 of 39.1% and 39.8% respectively." Similarly, UGI relied on system load factors for firm services (*see* UGI, Docket Nos. R-2018-3006814, R-2021-3030218). Thus, PECO's reliance on load factors is consistent with industry practice, as noted in the AGA's *Gas Rate Fundamentals* on page 144 ("used capacity [average deliveries] costs are calculated by multiplying total capacity costs by the system load factor") (*see* PECO Exhibit JD-8).

11. Q. On pages 11-12 of his direct testimony, Mr. Johnson disagrees with PECO's 24.22% system load factor used in the Company's A&E formula and instead recommends a load factor of 33% based on average actual system use. Do you agree?

A. No. As defined in the AGA's *Gas Rate Fundamentals* on page 144, "[s]ystem load factor is the ratio, expressed as a percentage, of used capacity (Mcf sold) to total capacity." Used capacity is "numerically equal to the average deliveries"

(*see* PECO Exhibit JD-8). For cost allocation purposes, the Company's load factor of 24.22% is calculated by using average deliveries (236,211 Mcf) divided by total capacity (975,347 Mcf).[4] The Company's total capacity is designed to meet system peak demand on a design day, *i,e,* 975,347 Mcf on a design day in the fully projected future test year ("FPFTY"). The projected average deliveries are 236,211 Mcf in the FPFTY. The 33% actual load factor from 2019 to 2023 calculated by Mr. Johnson is based on average deliveries divided by average of maximum system send-out from 2019 to 2023 (*see* PECO Exhibit JD-9).[5] Actual maximum send-outs from 2019 through 2023 do not reflect the total capacity of the Company because the Company did not meet a design day during this period, and the Company's total capacity is designed to meet system peak demand on a design day. Therefore, applying the Company's system load factor of 24.22% is in conformance with the AGA's guidance, and is appropriate to use 24.22% in the A&E formula.

III. LARGE CUSTOMER ACCOUNT REPRESENTATIVES

12. Q. Please summarize Mr. Johnson's proposed adjustment to the assignment of large customer account representatives.

A. PECO's COSS directly assigns $561,000 of the total $800,000 cost of these employees to industrial customers. The remaining $240,000 is allocated on a general customer or payroll basis. Mr. Johnson claims that PECO's allocation of the cost to large customers is incomplete (OCA Statement No. 3, page 22). Mr.

[4] These figures are reflected in PECO Exhibit JD-6, p.5, which accompanied my direct testimony.

[5] I note that the maximum send-out of 682 Mmcf in 2020 in OCA's response to PECO-II-5 was incorrect. Instead, that amount should be 621,972 Mcf (*see* PECO Exhibit JD-10).

Johnson's proposed adjustment allocates the remaining $240,000 to the classes GC, L, MV, MV-I, TS-F, and TS-L. Mr. Johnson avers that the adjustment "completes the appropriate allocation of the large customer expense" (OCA Statement No. 3, page 22).

13. Q. Do you have any comments on Mr. Johnson's adjustment?

A. PECO's COSS produces a reasonable allocation of costs for large customer account representatives and is consistent with the practices applied in the Company's previous COSS. Trends in the direction of class revenues relative to costs of service can be discerned properly from case to case by applying the consistent allocation method. Moreover, Mr. Johnson's proposed adjustment produces an immaterial impact on class allocation in PECO's COSS (OCA Statement No. 3, page 4, line 1).[6]

IV. ALLOCATION OF ACCOUNTS 908-916

14. Q. Please summarize Mr. Johnson's recommendation with respect to customer service and sales expense under Accounts 908-916.

A. Mr. Johnson proposes a revision to the allocation factors applied to Accounts 908-916. These accounts include marketing and economic development costs (OCA Statement No. 3, pages 23-24). PECO allocates a portion (20%) of those costs using a general customer allocator based on number of customers, but Mr.

[6] On page 4 of his testimony, Mr. Johnson indicates that he used a "small adjustment." I have reviewed Mr. Johnson's analysis and I disagree with using 50% weighting factor in the A&E formula as a starting point to calculate the allocators for this adjustment (*see* PECO Exhibit JD-11, OCA's response to PECO-II-10). Based upon Mr. Johnson's method, the adjustment would result in a $236,000 decrease in revenue requirement for rate class GR (Residential), a $9,000 increase for rate class GC (General Service), a $3,000 increase for rate class L (Large High Load Factor), a $144,000 increase for rate class TS-F (Gas Transportation – Firm) and $79,000 for rate class TS-I (Gas Transportation – Interruptible). The above results are based on the revenue requirement in the Company's originally filed COSS by applying the Company's system load factor of 24.22%.

Johnson recommends using average daily demand as the basis for allocating those costs. Mr. Johnson avers that average daily demand is reasonable because it reflects the customer classes' usage of the distribution system (OCA Statement No. 3, page 24).

15. Q. Do you agree with Mr. Johnson's assertion?

A. No. The 20% balance of FERC Accounts 908-916 mainly includes costs of Information Technology ("IT") projects, internal labor and staff augmentation for business planning, budgeting, researching, energy and marketing service, information advertising and contracting. For example, IT projects included enhancements to an artificial intelligence "Chatbot" to reduce the need for customers to call the care center, integration of a cloud-based platform to gather customer feedback, and a revamp of the Company's website. Contracting included gaining customer insights for both residential and business communities. Projects and services are for all customers and not driven by customers' usage. Therefore, it is reasonable for the Company to use the number of customers as the allocator for this 20% balance of FERC Accounts 908-916.

V. RESIDENTIAL CUSTOMER CHARGE

16. Q. Please summarize Mr. Johnson's position on customer-related costs in PECO's COSS.

A. Mr. Johnson states that the customer charge should only recover costs which directly vary with the number of customers (OCA Statement No. 3, page 31). Mr. Johnson claims that the COSS's $33.00 target fixed charge would include administrative and general ("A&G") expenses in the customer charge, "even

though those expenses . . . are not directly related to any particular category of cost" (OCA Statement No. 3, page 31).

17. Q. Do you agree with Mr. Johnson's assertion?

A. No. The costs included in PECO's proposed customer charge are consistent with the Commission's guidance in a 2012 PPL proceeding and a 2004 Aqua Pennsylvania ("Aqua") proceeding, as well as subsequent cases in which the Commission relied on those proceedings.[7] Those cases support the recovery of both direct and certain indirect customer costs and reflect the Commission's current policy regarding customer charges. PECO's proposed customer charge is consistent with that guidance. For example, Mr. Johnson proposes to exclude A&G expenses, which he contends are not related to any particular category of cost. However, A&G costs include costs directly related to serving customers, such as labor costs for the Regulatory Performance group, which resolves customer complaints, and are therefore reasonable to include in a customer charge.

In contrast, Mr. Johnson's conclusions that limited the customer charge to a narrower subset of direct costs are based on the National Association of Regulatory Utility Commissioners ("NARUC") *Gas Distribution Utility Rate Design Manual* (1968) (*see* OCA Statement No. 3, footnote 43) instead of the

[7] *Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Opinion and Order entered Dec. 28, 2012) ("*PPL 2012*"); *Pa. P.U.C. v. Aqua Pa., Inc.*, Docket No. R-00038805 (Opinion and Order entered Aug. 5, 2004) ("*Aqua 2004*"); *see also Pa. P.U.C. v. UGI Utils., Inc. – Elec. Div.*, R-2017-2640058 (Opinion and Order entered Oct. 4, 2018), pp. 173-76 ("*UGI 2018*") (approving proposed increase in residential customer charge from $5.50 to $14.00 per month that was supported by a customer cost analysis consistent with the PUC's guidance in *PPL 2012* and *Aqua 2004*); *Pa. P.U.C. v. Aqua Pa., Inc.*, Docket No. R-2021-3027385 (Opinion and Order entered May 16, 2022), pp. 268-69 ("*Aqua 2022*").

Commission's established policy and final orders in the *Aqua 2022*, *UGI Electric 2018*, *PPL 2012* and *Aqua 2004* cases.

VI. DESIGN DAY DEMAND – RATE CLASS TS-F

18. Q. Please explain how PECO estimates peak design day demand for cost allocation purposes.

A. For non-transportation firm customers that do not have a designated contract quantity, PECO estimates class peak day demands based on the correlation, for each rate class, between customers' temperature-sensitive usage and heating degree days. The correlation is used to determine each rate class' share of the total demand estimated for the system "design day." The Company uses a design temperature of zero degrees Fahrenheit. This design temperature is the average of hourly temperatures over a twenty-four-hour period. The total demand for a "design day" reflects the highest system peak that is potentially achievable and, therefore, is not the same as the demand actually experienced in a particular historical period. PECO also uses the twenty-four hours of design day demand for gas supply capacity planning that, in turn, forms the basis for developing the commodity costs included for recovery in PECO's Purchased Gas Cost filings approved by the Commission. For firm transportation customers, the Company uses the aggregated Transportation Contract Quantity ("TCQ") of TS-F customers as design day demand.

19. Q. Please summarize Ms. LaConte's objection to the manner in which PECO calculates the design day peak demand for Rate Class TS-F.

A. PAIEUG witness LaConte argues that PECO overstated the cost of serving the

TS-F rate class by using TCQ as a proxy for this class's peak design day demand (PAIEUG Statement No. 1, pages 6-8). Ms. LaConte states that this approach is incorrect because the TCQ is neither a measure of TS-F actual demand coincident with the system peak design day nor is it representative of the class's actual peak demand, which has historically been lower than the TCQ.

20. Q. What does Ms. LaConte recommend?

A. Ms. LaConte recommends that PECO replace the TCQ with actual peak design day demand results from 2021, rounded up to 54,000 Mcf. Ms. LaConte concludes that, using that approach, the TS-F class should receive an increase that is below the system average increase or no increase, as the TS-F class is currently above its cost to serve (PAIEUG Statement No. 1, pages 8-9).

21. Q. Do you agree with Ms. LaConte's recommendation?

A. No. I do not. Ms. LaConte conflates design day peak demand and "actual" demand. While sharing some similarities, these concepts are distinct. Design day demand is a projection of the design day requirement, not a measure of actual usage. A design day forecast is a coincident peak forecast or, in other words, PECO's projection for what the potentially highest demand would be if the design day weather scenario were experienced. These forecasts influence how PECO designs and sizes its system. Specifically, PECO designs infrastructure, such as Mains, to meet total connected load and must ensure that the system can support a scenario in which each class is reaching its highest potentially achievable demand at the same time. That is why PECO's Mains are built to ensure that all firm customers' (including TS-F customers) peak demand can be served on a design

day. It would be inconsistent if costs were allocated to non-transportation firm customers using a projected design day demand and costs were allocated to transportation firm customers using actual usage.

22. Q. Why is the use of TCQ an appropriate proxy for design day demand for Rate Class TS-F customers?

A. PECO's Mains are designed to meet the aggregate TCQ requirement because the TCQ represents the highest potentially achievable peak design day demand for the TS-F class. Each customer has a "call" on PECO's distribution system capacity up to the TCQ, which customers can exercise at any time. This means PECO must reserve capacity up to the summation of the TCQ call on its capacity, which could potentially occur at any time, including on the design peak day. Therefore, the highest potentially achievable class demand, which corresponds to and is consistent with the highest potentially achievable demand captured by the system design day, is the summation of TCQs. While TS-F customers could, in theory, impose demands that exceed their TCQs, the summation of TCQs is a reasonable upper limit for the potentially achievable peak demand for the class because TS-F customers face stiff penalties if their demand goes beyond an allowable daily variation in TCQ. Non-transportation customers are not subject to those penalties and limits. Therefore, it is appropriate for PECO to use the summation of TCQs for the TS-F rate class's peak design day demand, and it is consistent with cost causation principle that costs are allocated to the TS-F rate class based on the summation of TCQs.

23. Q. Do you have other objections to Ms. LaConte's recommendation?

A. Yes. Ms. LaConte's suggestion to substitute actual demands as they contribute to actual system peaks will be inconsistent with PECO's approach to non-transportation customers in the COSS. Using the same comparison method[8] Ms. LaConte used in Table 1 referenced in her direct testimony (*see* PAIEUG Statement No. 1, page 7), I included actual demand and design day demand for non-transportation customer classes in Table A below. The exhibits supporting Table A are labeled as Exhibit JD-12 through Exhibit JD-14.

Table A
Design Day Demand Requirement vs. Peak Usage on a Non-Design Day (Mcf)

	A	B	C	D	E	F	G	H	I
		PAIEUG Table 1		PECO 1307(f) Filed					
		Usage	TCQ	TCQ	Usage				Design Day Demand
1	Year	TSF	Sum of TCQ	Sum of TCQ	R	GC	Others	Sum of R, GC &	Sum of R, GC & Others
2	2019	46,513	64,000	64,000	353,728	175,881	1,272	530,881	820,000
3	2020	51,174	75,000	75,000	390,951	186,003	1,387	578,341	834,815
4	2021	53,364	68,000	68,000	438,148	209,477	1,564	649,189	841,346
5	2022	47,922	69,000	69,000	453,564	226,971	1,795	682,330	859,000
6	2023	49,354	75,000	69,000	404,354	197,143	1,531	603,028	881,000

Notes:

1 Columns A-C, lines 2-6 from PAIEUG Direct Testimony of Billie LaConte, page 7, Table 1.

2 Column D, TCQ should be 69,000 in 2023. TCQ was incorrect in PAIEUG Table 1.
See PECO Exhibit JD-12, the Company's 1307(f) filing on April 29, 2022 (Docket No. R-2022-3032250, Section 19)

3 Columns E, F and G from the Company's 1307(f) filing on April 30, 2024 (Docket No. R-2024-3048767, Section 15 pages 2 and 3) *(See* PECO Exhibit JD-13)

4 Column I, 2019 to 2022 from the Company's response to OCA-III-7, Docket No. R-2022-3031113.
(*See* PECO Exhibit JD-14). See PECO Exhibit JD-12 for 2023 data.

As reflected in Table A, design day demand for non-transportation firm classes (column I) is significantly higher than actual usage (column H). The COSS uses

[8] I note that on page 7 of her testimony, Ms. LaConte's Table 1 showing "TS-F Peak Day Throughput and TCQ (Mcf)" uses projected TCQ from for the years 2019 through 2022 derived from PECO's Section 1307(f) filings, but actual TCQ for the year 2023.

design day peak demand (column I) for all non-transportation rate classes. Shifting the design day peak demand of the TS-F rate class from TCQs to actual demands will therefore produce inconsistent results among PECO's rate classes.

24. Q. At page 7 of her direct testimony, Ms. LaConte responded "No" to the question "Has the TS-F class actually used 100% of its daily contract quantity on the system peak design days?" (PAIEUG Statement No. 1, page 7, lines 1-3). Do you agree with that response?

A. No. Ms. LaConte's Table 1 at page 7 of her direct testimony shows actual usage for TS-F customers from 2019 to 2023. PECO did not meet a design day from 2019 to 2023.

25. Q. At page 8 of her direct testimony, Ms. LaConte recommends using the historical peak demand for purposes of applying the A&E method to the TS-F class, "just as PECO is using for the sales classes." Do you agree with that statement?

A. No. This statement is inaccurate. PECO did not use historical peak demand for its sales classes. Instead, PECO used a design day demand, which is a projection of the design day requirement, not a measure of actual usage, when applying the A&E method to its sales classes.

VII. ALLOCATORS FOR CUSTOMERS ABOVE AND BELOW 18,000 MCF PER YEAR – RATE CLASS TS-F

26. Q. At page 16 of her direct testimony, Ms. LaConte states PECO does not have the allocators for TS-F separated between customers above and below 18,000 Mcf per year. Do you have any comments on this?

A. PECO includes TS-F customers above and below 18,000 Mcf per year as a single customer class in its COSS and, therefore, does not have the allocators separated between customers above and below 18,000 Mcf per year. Firm Transportation customers with comparable service characteristics are grouped together in the TS-F rate class.

VIII. CONCLUSION

27. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

GAS RATE FUNDAMENTALS

Fourth Edition
1987

American Gas Association Rate Committee
1515 Wilson Boulevard, Arlington, VA 22209

PECO Exhibit JD-8

Attachment OCA-IV-10(a)

- It allocates costs to all groups of customers whether or not they create any demand at the time of the system peak. For this reason, the NCP method is inappropriate for incremental cost studies.
- It leads some analysts to contend that interruptible customers are charged for "too much" capacity because the capacity used by them is that "released" by others. Whether an interruptible customer should receive less than its proportional share of capacity costs or even no capacity costs depends on the *philosophy* of the cost analyst.

Average and Excess Demand Method (A&E)

Under the A&E method, also called "used and unused capacity," capacity costs are allocated by a two-part formula.[1] It recognizes both the average use of capacity and responsibility for the capacity required to meet the maximum system load. Used capacity costs are calculated by multiplying total capacity costs by the system load factor. These costs are allocated to the various classes in proportion to their respective use (Mcf sold). System load factor is the ratio, expressed as a percent, of used capacity (Mcf sold) to total capacity. The remainder of the capacity costs represent the costs associated with the unused portion of capacity (i.e., that portion above *average* requirements). These costs

TABLE 7-6
Cost Allocation by Non-Coincident Demand

Class of Service	Maximum Class Demand (Mcf/Day)	Ratio to Sum of Class Demands
Residential	4,500	0.375
Commercial	2,700	0.225
Industrial	4,000	0.333
Interruptible	800	0.067
Total (Non-Coincident)	12,000	1.000

[1] "Used capacity" is the minimum capacity needed to deliver the total gas used. Hence, it is numerically equal to the average deliveries. "Unused capacity" is the difference between average (used) capacity and peak capacity. Used, unused, or peak capacity may be expressed in terms of hours, days, year, or any other period. Peak capacity is usually expressed in terms of the peak hour or day.

PECO Exhibit JD-8 Attachment OCA-IV-10(a)

are allocated to the various classes in the ratio that the individual group demands, in *excess* of used demands, bear to the summation of such excess demands. A simplified example is shown in Table 7-7.

Use of the A & E method has the following effects:

- Shifts in the time of the system peak do not greatly affect the cost allocations.
- The allocation of unused capacity is similar to the non coincident demand method except that it is applied only to the excess of class demands above the average.
- The load factor of the various classes is recognized.

Two additional cost-allocation approaches deserve discussion: the Seaboard and United methods. While generally referred to as allocation methods, they are really cost classification methods. These two approaches have been used in FERC proceedings involving pipeline cost allocation studies. Recent FERC decisions, however, have moved towards a modified fixed-variable approach, which will be discussed later. Some analysts argue that such cost allocation methods are actually pricing mechanisms.

The Seaboard method assigns 50 percent of the fixed (demand) costs to the commodity classification and the other 50 percent to the demand classification. These costs are allocated to the various classes by the appropriate demand and commodity-allocation factors. The Seaboard method shifts capacity-related costs from classes with lower load factors (e.g., seasonal heating requirements) to classes with a more uniform or stable year-round (i.e., higher) load factor.

The United method (sometimes called the "Modified Seaboard" method) assigns 75 percent of the fixed costs to the commodity classification and the rest to the demand classification. Again, capacity-related costs are shifted from low to high load factor customers. Cost causation is not the rationale.

In recent FERC proceedings, the modified fixed-variable approach has been used. This allocation method permits all fixed costs to be classified in the demand component, except for return on equity and associated taxes. These are placed in the commodity component. Then the demand costs are allocated 50 percent on the basis of historical Average Peak Day and 50 percent on the customer's Annual Volume.

ALLOCATION OF SPECIAL COSTS

Taxes

Taxes are levied by federal, state, and local authorities. Taxes can be classified on the basis of assessment (i.e., income, revenue, property,

TABLE 7-7
Cost Allocation by Average and Excess Demand

Class of Service	Annual Use (Mcf)	System Peak (Mcf/Day)	Class Max Demand (Mcf/Day)
	(1)	(2)	(3)
Residential	365,000	N/A	3,000
Commercial	182,500	N/A	1,250
Industrial	146,000	N/A	1,100
Interruptible	219,000	N/A	3,000
Total	912,500	4,167	8,350

Class of Service	Class Max Demand (Mcf/Day)	Average Demand (Mcf/Day)	Process Demand Alloc. Basis (Mcf/Day)
	(4)	(5)	(6)
Residential	3,000	1,000	2,000
Commercial	1,250	500	750
Industrial	1,100	400	700
Interruptible	3,000	600	2,400
Total	8,350	2,500	5,850

Class of Service	Average Demand (Mcf/Day)	Excess Demand (Mcf/Day)	A & E Demand (Mcf/Day)
	(7)	(8)	(9)
Residential	1,000	570	1,570
Commercial	500	214	714
Industrial	400	199	599
Interruptible	600	684	1,284
Total	2,500	1,667	4,167

Column

1: Total annual consumption by class. This is equivalent to the commodity allocation factor.
2: Actual (estimated) peak day(s) demands of the system. The individual class values are not shown because they are not used in the calculation.
3: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
4: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
5: Calculated by dividing each element in Column 1 by 365 days.
6: Column 4 less Column 5.
7: Calculated by dividing each element in Column 1 by 365 days.
8: Calculated by multiplying the ratio of each to the total in Column 6 times the system excess demand. The system excess demand is defined as the system peak less the total system average demand. For example:

System excess demand would be

$$4{,}167 \text{ less } 2{,}500 = 1{,}667$$

Residential class excess demand would be

$$\frac{2{,}000}{5{,}850} \times 1{,}667 = 570$$

9: Sum of Column 7 and Column 8.

PECO Exhibit JD-9

Attachment to PECO 2-5 (OCA)

	Max Day OCA 10 -23		average day	load factor	OCA 13-1
2019	782		246	31.5%	
2020	682		225	33.0%	
2021	678		236	34.8%	
2022	750		248	33.1%	
2023	705		221	31.3%	
	719	Avg	235	32.7%	
	33%	LF	32.7%		

PECO Exhibit JD-10

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2024-3046932

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set IV

Response Date: May 02, 2024

OCA-IV-4

Please provide the gas distribution system's Max Day demand for each of the previous five years. Identify the day and system use on that day.

RESPONSE: **(Please do not delete or alter this section break. Enter your response in the space provided below and do not make any changes to the information above. If Changes must be made above this section break, please contact a Case Coordinator immediately. Please enter the name of your Responsible Witness at the bottom of the page.)**

Please see the table below:

Date	Sendout (MCF)
1/21/2019	782,361
1/20/2020	621,972
1/29/2021	677,652
12/24/2022	749,579
2/3/2023	704,703

Responsible Witness: Jiang Ding

PECO Energy Company, R-2024-3046932 (Gas)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-10. Refer to OCA Statement No. 3, Workpapers – Adjustment Workpaper 1 in Microsoft Excel format, on the tab labeled "LC Adj." Please provide the source data and calculations for cell F10, Line 21 and Line 23 (except cell D23). On the tab labeled "Load Factor," please provide the source data and calculation for cell D12 (i.e., the 33% value).

Response:

Tab LC Adj.: The Company's response to OCA IV 21 did not break down the $800,000 among accounts. The amount in cell F10 is an approximation for the portion attributed to account 926, assuming that the percentage is roughly 10% - 14%. The calculation at cells S3 – S5 is based on the ratio of A926 to total salaries and pensions and benefits in the Company's CCOSS. Line 23 is the "Cust_Ind" allocator percentage from Tab "Allocators" of Confidential Attachment to OCA 1-1 (Ding a.7). Line 21 is only utilized to develop the GC class percentage. Line 21 is based on the Company's confidential CCOSS model as adjusted only for the Average & Excess 50% weighting. Excel line 1721 of "Cost of Service" Tab for the confidential CCOSS model reflects the model's calculation of revenue requirement on a $/customer/month. (Attachment II-10.) Line 21 can be adjusted if a different CCOSS version is adopted.

Tab Load Factor: 33% is the rounded average load factor based on the average load factor for each year 2019 – 2023. The source data is based on the PECO responses to OCA 10-23 and 13-1. Attachment II-5 provided in response to PECO-OCA-II-5 provides the excel page with formulas intact.

Dated: July 1, 2024

Sponsored by: Clarence L. Johnson

Company Name: PECO Energy Company (Gas Services Group)
FORM-IRP-GAS-1B. PEAK DAY ENERGY DEMAND REQUIREMENTS

Millions of Cubic Feet (MMCF)

		Historical Data		Current Year	Three Year Forecast		
	Index Year	**-2**	**-1**	**0**	**1**	**2**	**3**
	Actual Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
	FIRM REQUIREMENTS						
01	Retail Residential	296	334	**377**	555	549	558
02	Retail Commercial	159	164	**204**	325	321	326
03	Retail Industrial	0	0	**0**	0	0	0
04	Electric Power Generation	0	0	**0**	0	0	0
05	Exchange w/other utilities	0	0	**0**	0	0	0
06	Unaccounted for	0	0	**0**	0	0	0
07	Company use	1	1	**1**	1	1	1
08	Other	0	0	**0**	0	0	0
09	**Subtotal Firm**	**456**	**499**	**582**	**881**	**871**	**885**
	INTERRUPTIBLE REQUIREMENTS						
10	Retail	0	0	0	0	0	0
11	Electric Power Generation	0	0	0	0	0	0
12	Company own plant	0	0	0	0	0	0
13	**Subtotal Interruptible**	**0**	**0**	**0**	**0**	**0**	**0**
14	**Subtotal Firm & Interruptible**	**456**	**499**	**582**	**881**	**871**	**885**
	TRANSPORTATION SERVICE						
15	Firm	167	170	165	69	69	69
16	Interruptible	0	0	0	0	0	0
17	Electric Power Generation	0	0	0	0	0	0
18	**Subtotal Transportation**	**167**	**170**	**165**	**69**	**69**	**69**
19	**Total Gas Requirements**	**623**	**669**	**747**	**950**	**940**	**954**

PECO Energy Company (Gas Division)
PUC 1307 (F) Filing

Section 15

Data for the consecutive three-day peak periods over the last five send out years are shown below. PECO's send out year begins September 1 and ends August 31 of the following year. "Int" means the rate was interrupted for some portion or all of the day. "Avail" means the rate was available for use the entire day.

Date	Mcf	Avg. Tem	Max. Tem	Min. Tem	Status Rate TSI	Status Rate IS	Status Rate TCS	Status Rate CGS*
12/18/2019	610,969	28	39	19	Avail	Avail	Avail	Avail
12/19/2019	633,077	26	29	22	Avail	Avail	Avail	Avail
12/20/2019	569,245	29	36	22	Avail	Avail	Avail	Avail
TOTAL	**1,813,291**							
1/28/2021	635,344	27	33	23	Avail	Avail	Avail	Avail
1/29/2021	677,652	24	29	19	Avail	Avail	Avail	Avail
1/30/2021	570,260	30	35	25	Avail	Avail	Avail	Avail
TOTAL	**1,883,256**							
1/29/2022	748,912	17	24	12	Avail	Int	Avail	N/A
1/30/2022	667,611	23	27	19	Avail	Int	Avail	N/A
1/31/2022	629,552	28	35	24	Avail	Int	Avail	N/A
TOTAL	**2,046,075**							
12/23/2022	728,437	17	47	8	Avail	Int	Avail	N/A
12/24/2022	761,932	18	22	10	Avail	Int	Avail	N/A
12/25/2022	657,876	23	28	17	Avail	Int	Avail	N/A
TOTAL	**2,148,245**							
1/15/2024	605,525	27	28	26	Avail	Avail	Avail	N/A
1/16/2024	687,045	23	30	14	Avail	Avail	Avail	N/A
1/17/2024	698,763	23	26	18	Avail	Avail	Avail	N/A
TOTAL	**1,991,333**							

*Rate CGS was removed effective 7/1/2021 in Gas Rate Case Docket #R-2020-3018929.

Only partial information is available by rate class for the three-day peaks since some rate classes are not metered on a daily basis. A tabulation by rate class is shown below.

Rate Class	Description	Frequency of Meter Reading
TSI & IS	Interruptible transportation & sales	Daily
TSF & L	Firm transportation & sales	Daily
TCS	Interruptible by temperature	Daily
CGS	City Gate Sales	Daily
GC	Commercial firm sales	Monthly
GR	Residential firm sales	Monthly
MV-F	Motor vehicle-firm sales	Monthly
MV-I	Motor vehicle-interruptible sales	Monthly
OL	Outdoor lighting	Monthly

The usage by rate class for the three-day peaks for the last five send out years appears below. All figures are in Mcf.

Date	TSI/IS	TSF/L	TCS	GC	GR	Others*	Total Mcf
12/18/2019	53,823	45,249	1,379	169,119	340,127	1,272	610,969
12/19/2019	54,249	46,513	1,434	175,881	353,728	1,272	633,077
12/20/2019	50,678	45,266	1,274	156,336	314,419	1,272	569,245
1/28/2021	46,076	50,749	634	172,960	363,538	1,387	635,344
1/29/2021	47,456	51,174	681	186,003	390,951	1,387	677,652
1/30/2021	48,221	50,235	555	151,478	318,384	1,387	570,260
1/29/2022	45,850	53,364	509	209,477	438,148	1,564	748,912
1/30/2022	46,332	52,836	446	183,215	383,218	1,564	667,611
1/31/2022	46,649	53,025	415	170,751	357,148	1,564	629,552
12/23/2022	47,128	47,922	87	210,619	420,886	1,795	728,437
12/24/2022	37,096	42,413	94	226,971	453,564	1,795	761,932
12/25/2022	41,035	45,944	78	189,780	379,244	1,795	657,876

Date	TSI/IS	TSF/L	TCS	GC	GR	Others**	Total Mcf
1/15/2024	40,847	46,634	300	169,191	347,022	1,531	605,525
1/16/2024	41,156	48,258	346	195,261	400,493	1,531	687,045
1/17/2024	46,031	49,354	349	197,143	404,354	1,531	698,763

** Rates MV-F, MV-I, OL, CGS, L, IS, Interdepartmental

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2022-3031113

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set III

Response Date: May 20, 2022

OCA-III-7

Please refer to the Direct Testimony of Jiang Ding (Statement No. 6), page 13, line 20 to page 14, line2. Please provide PECO's system design day peak demand for each of the years 2017 – 2022.

RESPONSE:

PECO did not experience design day demand during the years 2017 through 2022. The table below provides PECO's projected design day demand for those years.

		Peak Day Demand Requirements (MMcf)	
Year PGC Filed	Year Forecast	Non-Transportation	Transportation
2021	2022	859	69
2020	2021	841	68
2019	2020	835	75
2018	2019	820	64
2017	2018	811	64
2016	2017	803	64

Responsible Witness: Jiang Ding

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. 2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Jiang Ding, hereby state that I am a Principal Regulatory & 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 statements and exhibits listed below 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.

- PECO Statement No. 6
- PECO Exhibit JD-1
- PECO Exhibit JD-2
- PECO Exhibit JD-3
- PECO Exhibit JD-4
- PECO Exhibit JD-5
- PECO Exhibit JD-6
- PECO Exhibit JD-7

- PECO Statement No. 6-R Corrected Version
- PECO Exhibit JD-8
- PECO Exhibit JD-9
- PECO Exhibit JD-10
- PECO Exhibit JD-11
- PECO Exhibit JD-12
- PECO Exhibit JD-13
- PECO Exhibit JD-14

Dated: August 5, 2024

Jiang Ding

Jiang Ding

PECO Statement No. 7:

Direct Testimony of Joseph A. Bisti

PECO ENERGY COMPANY
STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: REVENUE ALLOCATION; RATE DESIGN; DEVELOPMENT OF PROPOSED NEW RATES; AND NEGOTIATED GAS CONTRACTS

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Joseph A. Bisti. 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 Manager of Rate Analysts. I am responsible for retail tariff administration, project management and regulatory affairs relating to PECO's gas and electric operations.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph's University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned a certification as a Project Management Institute Professional in Business Analysis. In September of 2022, I was promoted to my current position. My professional experience includes various roles involving business analysis, project leadership, and regulatory compliance within PECO's Retail Rates, Energy Acquisition, and Information Technology departments.

4. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe: (1) how PECO proposes to allocate

its claimed revenue increase among rate classes and the principles that guided PECO in developing its proposed revenue allocation; and (2) the changes PECO is proposing in the rate design for certain rate classes, why PECO is proposing these changes, and how the proposed new rates were developed. In addition, I will also describe the Company's negotiated gas rate customers that have all had their competitive alternatives verified within five years of the filing date of this proceeding in accordance with Commission requirements.[1]

5. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit JAB-1	Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return under Proposed Rates
Exhibit JAB-2	Relevant Gas Service Tariff Pages (Blacklined to Show Changes)
Exhibit JAB-3	Comparison of Residential Customer Charges for Pennsylvania Natural Gas Distribution Utilities
Exhibit JAB-4	Proof of Revenues at Present and Proposed Rates
Exhibit JAB-5	Calculation Methodology for Differentiated Rate GC Customer Charges By Tier
Exhibit JAB-6	Modified Base Rate Recovery of CAP Revenues in USFC

[1] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021) ("2020 Gas Rate Case Order"), p. 297.

II. REVENUE ALLOCATION

6. Q. Please state the principles that guided PECO in developing its proposed revenue allocation.

A. The proposed revenue allocation reflects a reasonable balance of accepted principles for designing utility rates. Specifically, PECO considered the following four principles in developing its proposed revenue allocation:

1. The results of the class cost-of-service study ("COSS") prepared by Company witness Jiang Ding and discussed in PECO Statement No. 6 should be used as a guide in allocating the proposed revenue increase among rate classes;

2. The overall proposed revenue allocation should produce reasonable movement toward the cost of service indicated by the COSS; and

3. Customer impacts should be considered, and PECO should attempt to avoid increases in revenue for major rate classes that, on a percentage basis, exceed two times the proposed system average increase.

7. Q. Has an exhibit been prepared showing the cost of service by rate class?

A. Yes, a summary of class cost-of-service data is provided in PECO Exhibit JD-1, sponsored by Ms. Ding, and accompanies her direct testimony (PECO Statement No. 6). PECO Exhibit JD-1 shows, at page 1, line 26, the overall and class rates of return produced by the Company's current gas distribution base rates based on its supporting data for the twelve months ending December 31, 2025, which is the Fully Projected Future Test Year ("FPFTY") in this case. PECO Exhibit JD-1 also shows, at page 2, lines 83-84, the increase or decrease (in dollars and as a percentage of class gas distribution revenues under current rates, respectively) that each rate class would have to receive for its revenues to equal its indicated class cost of service. As indicated by the guiding principles I summarized above,

while the results of the Company's COSS are an important guide in evaluating its proposed revenue allocation, they are not the only factor that must be considered.

8. Q. Please discuss the principle of gradualism and how it influenced PECO's proposed revenue allocation.

A. The ratemaking principle of gradualism, as traditionally applied in Pennsylvania, guides utilities to avoid abruptly increasing rates in favor of slower adjustments that incrementally move rates toward the actual cost of service over time. PECO's proposed revenue allocation in this case attempts to balance gradualism and other ratemaking principles, and at the same time, also more closely align the class rates of return with the proposed system average rate of return while recognizing the degree to which rates for other classes diverge from their indicated cost of service. Under PECO's proposed revenue allocation and rate structure, the maximum increase for any rate class is 2.0 times the system average to prevent rate shock.

9. Q. What is the revenue allocation that PECO determined to be appropriate in this case?

A. PECO's proposed revenue allocation is presented in PECO Exhibit JAB-1.

10. Q. Why is the proposed revenue allocation reasonable?

A. The proposed revenue allocation in PECO Exhibit JAB-1 is reasonable because it appropriately reflects the principles discussed previously:

1. The COSS prepared by Ms. Ding guided its development;

2. It produces reasonable movement of rate classes closer to their indicated cost of service; and

3. It moderates the impact on each major rate class and supports the principle of gradualism by avoiding rate increases exceeding two times the

proposed system average increase.

The class rates of return and relative rates of return[2] at present and proposed rates in PECO Exhibit JAB-1 are provided in Table 1 below.

Table 1, Relative Rates of Return Under Company's Proposal

Rate Class	Under Present Rates	Under Proposed Rates
GR	0.95	0.98
GC & OL	1.07	1.04
L	3.20	2.28
MV-F	1.21	1.04
MV-I	3.01	2.20
IS	8.75	6.09
TCS	8.31	5.83
TS-I	1.53	1.10
TS-F	1.03	1.00

11. Q. Please explain the significance of the relative rates of return shown in PECO Exhibit JAB-1 to which you previously referred.

A. The relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return. Relative rates of return are commonly used to test whether a proposed revenue allocation moves each rate class closer to, or at least no further from, the system average rate of return. A relative rate of return of 1.00 would mean the class rate of return equals the system average rate of return and, therefore, class revenues equal the class cost of service. Conversely, relative rates of return that depart from 1.00 indicate that the class rates of return are higher or lower than the system average rate of return and, therefore, the classes

[2] A relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return.

are providing revenues higher or lower than their indicated cost of service.

III. RATE DESIGN

12. Q. Explain in general how PECO proposes to change the charges within each rate schedule to recover the revenue allocated to each rate class.

A. PECO proposes to increase or decrease each of the charges within each rate schedule in proportion to the revenue increase or decrease allocated to that rate class, subject to certain rate design changes, discussed below. PECO Exhibit JAB-2 is a copy of the Company's Tariff Gas-Pa. P.U.C. No. 6 ("Tariff No. 6") that shows, by strike-out and blacklining, the proposed rate changes I discuss below, as well as the proposed changes in rules, regulations, rate schedules and riders discussed by Ms. Megan A. McDevitt in PECO Statement No. 8. Tariff No. 6 is being filed with the Secretary of the Pennsylvania Public Utility Commission ("PUC" or the "Commission") as part of PECO's base rate filing.

Currently, service is provided under the Company's Tariff Gas-Pa. P.U.C. No. 5 ("Tariff No. 5") and associated supplements. It is anticipated that Tariff No. 6, which was filed as part of this case on 60 days' notice, will be suspended by operation of Section 1308(d) of the Public Utility Code pending an investigation by the Commission. Because it is possible and, in fact, likely, that changes will be made, via subsequently filed supplements, to Tariff No. 5 during the period Tariff No. 6 is suspended, any provisions of the current tariff that will continue beyond the end of the suspension period and have not already been incorporated in Tariff No. 6 will be merged into the tariff that will be filed as part of PECO's compliance filing at the conclusion of this proceeding.

13. Q. Why is PECO proposing to increase customer charges for several rate classes by a greater percentage than the proposed overall revenue increase for those classes?

A. PECO is proposing to increase customer charges in this manner to reduce the disparity between its current customer charges and the customer-related costs that should properly be recovered by those customer charges as reflected by Ms. Ding in PECO Exhibit JD-4 at page 4, line 25.

A summary of the proposed customer charge increases is shown in Table 2 below. These changes are intended to align customer charges more closely with the Company's customer-classified costs. In most cases, the proposed modified customer charges will be closer to, but still less than, the customer charges warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4.

Table 2, Proposed Customer Charge Increases

Rate Class	Present Customer Charge	Cost-Of-Service, $/Month/Customer (PECO Exhibit JD-4)	Proposed Customer Charge	Proposed % Increase
GR	$14.25	$33.00	$19.38	36%
GC	$29.86	$85.59	$36.38[3]	22%
L	$260.00	$297.01	$297.01	14.2%
MV-F	$49.84	$346.27	$67.80	36%
MV-I	$49.84	$84.16	$58.50	17%
IS	$217.89	$297.41	$297.41	36.5%
TCS	$125.00	$180.17	$170.00	36%
TS-I, >=18,000 Mcf	$383.88	$678.04	$574.65	50%
TS-I, <18,000 Mcf	$322.66		$385.67	20%
TS-F >=18,000 Mcf	$336.62	$504.83	$504.83	50%
TS-F <18,000 Mcf	$280.17		$381.03	36%

14. Q. Why is it important to increase customer charges so those charges are closer to customer-classified costs?

A. Customer-classified costs are, by definition, costs that vary based on the number of customers, not usage. Such costs include, principally, but not exclusively, the cost of meters, customer service lines, billing, and meter reading. Consequently, customer-classified costs are, on average, the same amount for each customer within a rate class. Accordingly, customer-classified costs are appropriately recovered in the customer charge, which is the same for each customer served under a given rate schedule. A utility should, to the extent practicable, avoid including customer-classified costs in variable distribution charges because to do

[3] As discussed later in my testimony, a single Rate GC customer charge is proposed for 2025 only, and differentiated Rate GC customer charges will be implemented as of January 1, 2026.

so would make the recovery of customer-related costs a function of customers' usage, which they are not. More accurate price signals also offer greater transparency to customers about the fixed costs incurred to connect them to the Company's system.

Misplacing customer costs in variable distribution charges has adverse consequences. First, it can create inappropriate intra-class subsidies because some customers will pay more than their share of customer-classified costs and others less, based on their relative levels of usage each month. Second, because customer costs, which are a fixed amount per customer, would be recovered in a charge that applies to usage, which varies, the Company could recover either too little or too much of its customer-related costs as a consequence of variations in customer usage.

In summary, putting customer costs in the wrong element of a rate can be unfair to both customers and the utility. For these reasons, among others, customer-related costs in a utility's cost of service should be charged to customers in a manner that appropriately reflects the nature of the costs incurred subject to consideration of the principle of gradualism.

15. Q. What residential rate change is PECO proposing?

A. PECO is proposing a residential customer charge of $19.38 per month. This customer charge will be closer to, but still less than, the customer charge warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4. The revenue to be recovered from this customer charge was deducted from the total revenue target for the residential class to determine the revenue to be

recovered in the variable distribution service charge. The variable distribution service charge was changed to recover the balance of the residential class revenue not recovered by the customer charge.

16. Q. Please summarize PECO's proposed changes to Rate Schedule GC – General Service - Commercial and Industrial ("Rate GC") in the context of PECO's related 2022 gas rate case settlement commitment.

A. In the settlement of its 2022 gas base rate case at Docket No. R-2022-3031113 ("2022 rate case settlement"), the Company agreed to present a cost analysis and rate design proposal for Rate GC in its next base rate case that would evaluate (a) the potential for differentiated customer charges and (b) the cost basis for any declining block commodity charge differentials proposed.

PECO's proposal for the Rate GC customer charge in this case is intended to justify differentiated customer charges for small and large customers, while also eliminating the declining block structure for the variable distribution charge.

17. Q. Please describe PECO's customer charge proposal for Rate GC.

A. PECO's customer charge proposal is intended to more reasonably allocate the recovery of meter-related customer costs to smaller and larger GC customers, given that many smaller Rate GC customers have the same meter-related costs as an average residential customer and therefore must not unreasonably subsidize similar costs for larger Rate GC customers.

Effective January 1, 2026, PECO proposes to implement two customer charges for Rate GC that will collectively recover the same amount of revenue as a single

customer charge in a revenue-neutral manner as illustrated in PECO Exhibit JAB-5. PECO proposes to place Rate GC customers into one of two GC tiers, "Small" or "Large", based on the size of their gas meter. The customer charge will vary by tier. According to PECO's COSS in this proceeding, "Small Diaphragm" meters are the most common for PECO's residential customers, representing over 89% of the meters in the residential class. These meter sizes are less common for Rate GC customers but still represent 34% of Rate GC meters. PECO therefore proposes to assign any Rate GC customer with a single Small Diaphragm meter to the "Small" GC tier. Consequently, PECO proposes to assign any Rate GC customer with a gas meter of any other size meter to the "Large" GC tier. Since customers with more than one gas meter impose higher customer-related costs, PECO also proposes to assign any customer with more than one gas meter – regardless of meter sizes – to the "Large" GC tier.

To allow sufficient time for PECO to implement this proposal, PECO suggests maintaining a single Rate GC customer charge of $36.38 per month for all Rate GC customers in 2025. This single customer charge, as well as the differentiated customer charges effective in 2026, will be closer to, but still less than, the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4. During 2025, PECO would implement the necessary billing system enhancements, assign existing Rate GC customers to the appropriate tier, and notify Rate GC customers of both their tier and the modified customer charge prior to January 1, 2026.

Using the proposed customer charge for 2025 as a starting point, PECO will base the resulting "Small" and "Large" tiered customer charge calculations for 2026 on

the average meter-related cost per customer for each tier. The proof of revenues for Rate GC in Exhibit JAB-4 displays both the single customer charge proposed for the FPFTY as well as the proposed differentiated customer charges for each tier, demonstrating that PECO intends to collect the same amount of customer-related revenue in each case. PECO Exhibit JAB-5 describes the methodology used to calculate the differentiated customer charges effective for 2026 in more detail, citing relevant supporting COSS data submitted by Ms. Ding.

18. Q. Please describe PECO's variable distribution charge proposal for Rate GC.

A. PECO proposes to eliminate the current declining block structure for the Rate GC variable distribution charge and implement a single variable distribution charge with no declining block charge differentials or thresholds. This single charge would apply to all Rate GC distribution customers regardless of their proposed GC tier assignment. The revenue to be recovered from the customer charge during the FPFTY, or alternatively from the differentiated customer charges after the FPFTY, was deducted from the total revenue target for the Rate GC class to determine the revenue to be recovered by this single variable distribution service charge.

Eliminating the declining block structure for Rate GC requires PECO to modify related terms in flexible rate classes MV-I – Motor Vehicle Interruptible – and TCS – Temperature-Controlled Service. The current MV-I and TCS tariffs cap the maximum variable distribution charge per month based on calculations that include the current end block of the Rate GC variable distribution charge. PECO therefore is proposing to modify the terms of both the MV-I and TCS tariffs by

replacing the use of the end block with the use of the proposed single variable distribution charge for Rate GC.

19. Q. Please explain the proposed volumetric rate differentials for the TS-F and TS-I rate classes in the context of PECO's related 2022 rate case settlement commitment.

A. In the 2022 rate case settlement, the Company agreed to undertake the load factor analysis for TS-F customers originally performed by the Pennsylvania Office of Small Business Advocate ("OSBA") during that proceeding as part of the Company's next gas base rate case. Load factor is the ratio of average demand to peak day demand. The OSBA's stated intent of its analysis at that time was to evaluate whether the differentials between the Company's proposed variable distribution charges for Rate TS-F customers with annual usage above and below 18,000 Mcf yield correlations between load factor and customer size, reasoning that demand-related costs for customers with higher load factors should be lower on a per-mcf basis. The OSBA also suggested that this load factor analysis is not relevant to the Company's existing volumetric rate differentials for Rate TS-I customers because, as explained by Company witness Ms. Ding in her testimony, the Company's Cost Of Service Study assigns demand-related costs to the Rate TS-I class based entirely on average volumes rather than peak demand.

A summary of PECO's load factor analysis results for Rate TS-F customers is presented in Tables 3 and 4 below, based on Rate TS-F customer gas data from November of 2022 through October of 2023. To ensure that this analysis aligns with the OSBA's prior methodology, the data reflects the averages considering all

available data for this period, as well as recalculated averages which exclude outlying customers for whom the data provides load factors under 5% and above 100%.

Table 3, TS-F Load Factor Analysis (Outliers Included)			
Simple Average of Load Factor		<18,000 Mcf	44.1%
		>=18,000 Mcf	54.6%
		Differential	1.24
Weighted Average of Load Factor:			
	TSF Usage (Mcf)	**Sum of Average TSF TCQ (Mcf)**	
<18,000 Mcf	1,850,970	15,287	33.2%
>=18,000 Mcf	12,452,360	60,823	56.1%
		Differential	1.69

Table 4, TS-F Load Factor Analysis (Outliers Excluded)			
Simple Average of Load Factor		**<18,000 Mcf**	43.4%
		>=18,000 Mcf	54.2%
		Differential	1.25
Weighted Average of Load Factor:			
	TSF Usage Mcf)	**Sum of Average TSF TCQ (Mcf)**	
<18,000 Mcf	1,804,777	13,162	38%
>=18,000 Mcf	12,408,963	60,714	56%
		Differential	1.49

The differential ranges above represent the ratios of load factors for large TS-F customers over 18,000 Mcf/year) to those of smaller TS-F customers (under 18,000 mcf/year), using both a simple average (the lower end of the range) and a weighted average (the upper end). The load factors for the larger customers were higher than those of the smaller customers below 18,000 Mcf, though not to a level that supports the existing Rate TS-F volumetric rate differential of over two

to one. The Company's proposed volumetric rates for TS-F in PECO Exhibit JAB-4 are therefore designed to reduce this differential to a level consistent with these results by setting the differential to the ratio of 1.49 shown above in Table 4.

Given that the above analysis is not relevant for Rate TS-I customers, the Company proposes to phase out the Rate TS-I volumetric rate differentials over multiple proceedings, beginning with this proceeding. As shown in PECO Exhibit JAB-4, the Company is proposing to maintain the existing TS-I variable base rate for customers below 18,000 Mcf annually while increasing the TS-I variable base rate to the extent necessary to maintain the desired level of TS-I rate revenues. Doing so initially reduces the TS-I volumetric rate differential from 1.88 to 1.67.

IV. CUSTOMER ASSISTANCE PROGRAM ("CAP") COST RECOVERY

20. Q. Mr. Bisti, please provide an overview of PECO's existing Universal Service Fund Charge ("USFC").

A. The USFC is PECO's Commission-approved rate mechanism for recovery of the costs of PECO's universal service programs that are not included in base rates. The USFC is an automatically adjusted surcharge created pursuant to Section 1307(a) of the Pennsylvania Public Utility Code.

USFC costs are reconciled on an annual basis using actual costs for a historic twelve-month period ("E-Factor") and projected costs for a future twelve month period ("C-Factor"). Interest accrues from the month in which over/under

collection of USFC costs occurs to the midpoint of the collection period, the sum of which results in a credit or charge to customers if costs are over- or under-collected, respectively. The cumulative amount (either positive or negative) at the end of the reconciliation period determines the E-Factor to be included in calculation of the next USFC for the subsequent period. PECO normally files its USFC reconciliation and annual rate adjustment in September of each year, with the new USFC rate becoming effective on the following December 1.

21. Q. Please describe the CAP "shortfall".

A. As explained by Company witness Jacqueline F. Golden in PECO Statement No. 10, PECO's CAP uses a percentage-of-income-based approach to provide bill credits to qualifying low-income residential customers. A portion of the cost of the aggregate benefits provided through PECO's gas CAP rider is recovered through base rates paid by residential distribution service customers.

As explained by Ms. Golden, the CAP "shortfall" refers to the amount of aggregate bill credits (in dollars) provided to CAP customers each year that is not included in base rates. This shortfall is recovered from or refunded to PECO's residential customers on an ongoing basis through the USFC, with annual reconciliation of any over/under collections as described above. The USFC is currently adjusted so that residential customers pay 73% of the total CAP shortfall amount. The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to bad debt expense and working capital.

22. Q. Is PECO proposing to increase the amount of gas CAP bill credits included in its base rates in this proceeding?

A. Yes. As explained by Ms. Golden, PECO is proposing to increase the aggregate value of bill credits provided to gas CAP customer currently included in its base rates from $11 million to $13.7 million and to change the offset factor applied to reconcilable CAP costs reflected in the USFC formula from 27% to 10.5%. PECO Exhibit JAB-6 illustrates the impact of these changes on the C-Factor and E-Factor calculations for PECO's USFC.

V. REVENUE EFFECT BY RATE SCHEDULE, PROOF OF REVENUES, AND SCALE-BACK

23. Q. Have you prepared a summary of distribution revenues at present and proposed rates for each rate class?

A. Yes. PECO Exhibit JAB-1 shows revenue at both present rates and proposed rates as well as the percentage increases each class will receive on an overall basis.

24. Q. Have you prepared proofs of revenue with respect to PECO's present and proposed rates?

A. Yes. PECO Exhibit JAB-4 is a proof of revenue with respect to PECO's present and proposed rates, based on pro forma billing determinants for the FPFTY. This exhibit is tied to the portion of PECO Exhibit JAB-1 that addresses the increased revenue that would be required.

25. Q. Please explain the adjustment made to the proof of revenues at present rates for the Company's Distribution System Improvement Charge ("DSIC").

A. The DSIC is a rate adjustment mechanism that permits PECO to recover the fixed costs of DSIC-eligible property between base rate cases through a separate, reconcilable charge established pursuant to Section 1353 of the Public Utility Code. The Commission approved PECO's establishment of a DSIC by its final order entered October 22, 2015, at Docket No. P-2015-2471423. PECO began to charge a DSIC effective with bills rendered on or after July 1 of 2018.

As required by the terms of the DSIC and Section 1358(b) of the Public Utility Code, PECO is currently charging a DSIC of 0.0%, having reset the DSIC to zero as of January 1, 2023 – the effective date of new base rates established by the Commission's Final Order in PECO's 2022 rate case at Docket R-2022-3031113. PECO has filed a DSIC charge of 0.07% effective with bills rendered on or after April 1, 2024 and intends to reset its DSIC charge at zero on the effective date of new rates established through this proceeding. (PECO may file a DSIC charge to be effective January 1, 2025 or later for the sole of reconciling residual over and under-collections experienced before the end of 2024.) The fixed costs of DSIC-eligible property that PECO will continue to recover through the effective date of its new base rates have been included in the Company's claimed rate base and reflected in the revenue requirement used to establish its proposed rates. Consequently, to properly compare PECO's revenues at present rates to revenues

at its proposed base rates, PECO's proof of revenue at present rates has been adjusted by customer class to include the revenues billed under its DSIC.

26. Q. How does PECO propose to scale-back the proposed rates if it is granted less than the revenue increase it requested?

A. In the event PECO is granted less than its requested increase, PECO proposes that:

(1) the revenue increases proposed for all rate classes will be reduced in proportion to the proposed increase for each class; and

(2) the customer charges for all rate classes remain as proposed, and all other rates and charges for all rate schedules be reduced proportionately to produce the revenue target for each rate class.

VI. NEGOTIATED GAS CONTRACTS

27. Q. Please describe PECO's Negotiated Gas Service ("NGS") rate.

A. The Commission approved the addition of Rate NGS to the Company's tariff in 2001 under the consolidated Docket Nos. of R-00016200 and R-00016366. Rate NGS permits the Company to offer negotiated, or discounted, gas service to customers who: (1) either have a history of at least 18,000 Mcf of annual billed gas usage or, if a new customer, establish that the facilities to be served are likely to consume at least 18,000 Mcf of annual gas usage; (2) document a viable, currently available competitive alternative to service under rates GC, L, TS-F, or TS-I; and (3) execute an NGS agreement that agrees with all provisions set forth in rate NGS.

The Company requires customers to document their competitive alternative when customers seek service under Rate NGS. A customer's competitive alternative

could be an alternative fuel source, a direct connection to a pipeline or producer that bypasses the Company's distribution system, relocation of customer facilities outside of PECO's service territory, or a shutdown of customer facilities. PECO and its customers generally evaluate the potential benefits of a Rate NGS service agreement over a period that is long enough to adequately analyze the impact of the economic conditions that drive the competitive alternative, which can be ten years or more in the case of bypass or facility relocation alternatives.

In the Company's 2020 Gas Rate Case Order, the Commission directed PECO to update the competitive alternative analysis for negotiated gas contracts that have not had their competitive alternative verified for a period of five years or more upon PECO's filing of a new base rate case.

28. Q. How many customers currently receive service under negotiated rates?

A. Three customers currently receive service under negotiated rate contracts, and PECO has verified the competitive alternative for each of those customers within the last five years.[4] Consistent with its commitments in the Company's 2022 base rate case proceeding, on April 1, 2023, PECO entered into a new contract with one of these customers under the terms of PECO's Rate NGS at a reduced discount, allowing Customer 1's variable distribution rate to remain lower than PECO's full standard tariff rates.

[4] Two of those customers are served pursuant to negotiated rate contracts that were executed under Tariff Rule 4.6, Special Contracts. The third is served under Rate NGS.

VII. CONCLUSION

29. Q. Please summarize your conclusions.

A. PECO's proposed rates reflect a reasonable allocation of the Company's proposed revenue increase and a reasonable rate design for each rate schedule. The proposed rate design changes are consistent with relevant terms of the 2022 rate case settlement, the results of the COSS identified by Ms. Ding, and applicable principles of rate structure and rate design, including gradualism.

30. Q. Does this conclude your direct testimony?

A. Yes, it does.

PECO Exhibit JAB-1:

Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return Under Proposed Rates

PECO Energy Company (Gas)
Proposed Revenue Allocation and Rates of Return by Rate Class

Rate	(1) Current Distribution Revenue	(2) Proposed Distribution Revenue	(3) *(2) - (1)* Distribution Revenue Ask	(4) *(3) / (1)* % Increase	(5) Increase vs. System Avg
Residential (GR)	$ 326,681,235	$ 405,304,235	$ 78,623,000	24.1%	1.04
General Service (GC)	$ 122,650,416	$ 150,901,344	$ 28,250,928	23.0%	1.00
Outdoor Lighting (OL)	$ 313	$ 385	$ 72	23.0%	0.99
Large High Load Factor (L)	$ 139,317	$ 139,317	$ -	0.0%	0.00
Motor Vehicle Service - Firm (MV-F)	$ 612,691	$ 698,691	$ 86,000	14.0%	0.61
Motor Vehicle Service - Interruptible (MV-I)	$ 3,597	$ 3,597	$ -	0.0%	0.00
Interruptible Service (IS)	$ 65,812	$ 65,812	$ -	0.0%	0.00
Temperature-Controlled Service (TCS)	$ 697,247	$ 697,247	$ -	0.0%	0.00
Gas Transportation - Interruptible (TS-I)	$ 10,848,053	$ 10,848,053	$ -	0.0%	0.00
Gas Transportation - Firm (TS-F)	$ 19,120,685	$ 23,328,685	$ 4,208,000	22.0%	0.95
Total	$ 480,819,366	$ 591,987,366	$ 111,168,000	23.1%	

Rate	(7) Present Rate of Return	(8) *(8) / Average of (8)* Present Relative Rate of Return	(9) Proposed Rate of Return	(10) *(9) / Average of (9)* Proposed Relative Rate of Return
Residential (GR)	5.53%	0.95	7.90%	0.98
General Service (GC)	6.25%	1.07	8.44%	1.04
Outdoor Lighting (OL)	6.25%	1.07	8.44%	1.04
Large High Load Factor (L)	18.59%	3.20	18.42%	2.28
Motor Vehicle Service - Firm (MV-F)	7.03%	1.21	8.40%	1.04
Motor Vehicle Service - Interruptible (MV-I)	17.52%	3.01	17.78%	2.20
Interruptible Service (IS)	50.89%	8.75	49.21%	6.09
Temperature-Controlled Service (TCS)	48.30%	8.31	47.11%	5.83
Gas Transportation - Interruptible (TS-I)	8.88%	1.53	8.88%	1.10
Gas Transportation - Firm (TS-F)	5.99%	1.03	8.08%	1.00
Total	5.81%		8.08%	

PECO Exhibit JAB-2:

Relevant Gas Service Tariff Pages (Redline to Show Changes)

Exhibit JAB-2

Gas-Pa. P.U.C. No. 6

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SUPERCEDES GAS PA P.U.C. NO. 5 AND ALL SUPPLEMENTS THERETO

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued March 28, 2024

Effective May 27, 2024

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ISSUED BY: M. A. Innocenzo - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 1

LIST OF CHANGES MADE BY THIS SUPPLEMENT

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS – Original Page No. 6 - Holidays updated.

TCJA VOLUNTARY SURCHARGE – page deleted.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 41 - Revised the USFC formula to remove the "F" Correction Factor. Revise the "L" and "I" Factors and update the offset factor in the Reconcilable Customer Assistance Program Costs and annual spend amount.

SALES SERVICE COSTS (SSC) – Original Page No. 42 – The Commodity Charges are decreased.

GAS PROCUREMENT CHARGE – Original Page No. 45 – The Gas Procurement Charge is decreased.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – Original Page No. 46 and Original Page No. 47 – The Merchant Function Charges and Write-Off Factors are changed. The Prices to Compare are decreased.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE - Original Page No. 51 – reset the DSIC to 0%.

RATE GR - GENERAL SERVICE RESIDENTIAL - Original Page No. 57 – Distribution prices updated. TCJA language removed.

RATE GC - GENERAL SERVICE COMMERCIAL AND INDUSTRIAL Original Page No. 58 – Distribution prices updated. TCJA language removed. Revise to show only one Variable Distribution Charge for all GC customers. Added effective through December 31, 2025.

Rate GC – GENERAL SERVICE COMMERCIAL AND INDUSTRIAL Original Page No. 58a – Replaced single Fixed Distribution Charge with multiple Fixed Distribution Charges based on gas meter size, effective as of January 1, 2026.

RATE OL- OUTDOOR LIGHTING Original Page No. 59 – Distribution prices updated. TCJA language removed.

RATE L – LARGE HIGH LOAD FACTOR SERVICE Original Page No. 60 – Distribution prices updated. TCJA language removed.

RATE MV-F MOTOR VEHICLE SERVICE - FIRM - Original Page No. 62 – Distribution prices updated. TCJA language removed.

RATE MV-I MOTOR VEHICLE SERVICE - INTERRUPTIBLE Original Page No. 63 – Distribution prices updated. Remove language referencing end block. TCJA language removed.

RATE IS – INTERRUPTIBLE SERVICE Original Page No. 65 – Distribution prices updated. Summer period language revised from November to October for consistency. TCJA language removed.

RATE TCS - TEMPERATURE CONTROLLED SERVICE Original Page No. 67 – Distribution prices updated. Remove language referencing end block. TCJA language removed.

RATE TS-I GAS TRANSPORTATION SERVICE - INTERRUPTIBLE Original Page No. 74 – Distribution prices updated. TCJA and Voluntary Surcharge language removed.

RATE TS-F GAS TRANSPORTATION SERVICE FIRM Original Page No. 75 – Distribution prices updated. TCJA language removed.

Applicability Index of Riders Original Page No. 78 – page numbers updated.

NEIGHBORHOOD GAS PILOT RIDER (NGPR) Original Page No. 80– Rider revised to reflect extension of the pilot program by an additional five years from 01/01/2025 to 12/31/2029. Also reflect change to total investment amount.

WEATHER NORMALIZED ADJUSTMENT (WNA) Original Page No. 84 –The new WNA will adjust certain customers' bills to reflect normalized weather conditions.

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The Commodity Charges are increased. The Gas Cost Adjustment is increased.¶
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MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 6th Revised Page No. 47 and 6th Revised Page No. 48¶
The Merchant Function Charges are increased. The Prices to Compare are increased.¶
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BALANCING SERVICE COSTS (BSC) – 6th Revised Page No. 49¶
The Balancing Service Cost is decreased.¶
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LIST OF COMMUNITIES SERVED

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

FIRST-CLASS TOWNSHIP: Bristol.

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

CHESTER COUNTY:
CITY: Coatesville.

BOROUGHS: Atglen, Avondale, Downingtown, Elverson, Honey Brook, 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, Easttown, East Vincent, East Whiteland, Elk, Franklin, Highland, Honey Brook, 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 Uwchlan, Uwchlan, 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.

DELAWARE COUNTY:
CITY: Chester.

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

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

SECOND-CLASS TOWNSHIPS: Bethel, Chadds Ford, Chester, Concord, Edgmont, Haverford, Middletown, Newtown, Radnor, Thornbury, Upper Providence,

LANCASTER COUNTY:
BOROUGH: Christiana

SECOND-CLASS TOWNSHIPS: Sadsbury, Salisbury.

MONTGOMERY COUNTY:
BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Hatfield, Jenkintown, Lansdale, Narbeth, 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, Marlborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Hanover, Upper Merion, Upper Providence, Upper Salford, Whitemarsh, Whitpain, Worcester.

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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 is to supersede, 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.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

Aggregation Services Fee - A charge of 1¢/mcf applicable to all Low Volume Sales and Transportation Customers to be added to such Customers' Variable Distribution Service Charge effective January 1, 2001.

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 Customer's location is such that this service can be supplied from existing facilities of the Company.

Bad credit (for deposit purposes) - 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.

Balancing Service Cost or ("BSC") – Charge to all Low Volume Customers, both Sales and Transportation, included in Variable Distribution Charges, for fixed and variable storage costs for each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff, or the successors thereto.

British thermal unit (Btu) - The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours

Ccf – 100 cubic feet. This is a measure of gas usage.

Chapter 56 – The PUC regulations that govern metering, billing and collections for residential gas and electricity service.

Commodity Charge ("CC") – The "C" factor component of the Sales Service Cost representing the charge to Low Volume Sales Customers for purchased gas costs for each McF of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff, or the successors thereto.

Commission or PAPUC– The Pennsylvania Public Utility Commission.

Company – PECO Energy Company

Competition Act - the Natural Gas Choice and Competition Act, 66 Pa.C.S. §2201, et seq.

Competitive Natural Gas Supply - firm natural gas provided by an NGS to Low Volume Transportation Customers under the Company's Gas Choice program.

Consolidated NGDC Billing – Billing provided by the Company that contains both the Company's charges for its services and the NGS's separate charges for gas supply services.

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.

cu. ft. - Cubic foot.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules or Regulations, an NGS may act as an agent for a Customer upon written authorization to PECO Energy, which authorization may be included in the notice of NGS selection.

Daily quantity - The quantity of gas used in a 24-hour period beginning at 10:00 a.m., Eastern Standard Time or Daylight Savings Time, whichever is in common use.

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Delivery point - That point at which the Customer's facilities are connected to the Company's facilities which is typically the first fitting after the outlet side of the meter connection. or in certain cases the first fitting after the outlet side of the regulator or relief valve if located downstream of the meter.

Firm Service - Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

Fixed Distribution Service Charge – A charge to recover costs caused by the presence of the Low Volume Customer on the system, other than the costs associated with the Customer's usage.

Gas Choice – Program under which Suppliers provide Competitive Natural Gas Supply to Low Volume Transportation Customers.

Gas Cost Adjustment ("GCA") Charge – The "E" factor component of the Sales Service Cost representing the net overcollection or undercollection of purchased gas costs, charged to Low Volume Sales Customers for each Mcf of Sales Service gas supplied under Rate Schedules GR, GC, CAP, OL L, and MV-F or the successors thereto.

High Volume Transportation (HVT) - PECO Energy's Gas program as administered by this tariff for Suppliers providing Competitive Natural Gas Supply to High Volume Transportation Customers.

High Volume Transportation Customers - Customers who purchase natural gas from an alternative Supplier under Rates Schedules TS-F, TS-I and/or the successors thereto, and not under the Company's Gas Choice program.

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, and Sundays

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Initial Contract Term - The Customer's initial contract term, or in the case of transportation service, any renegotiation of an existing contract, for a service location shall be the Customer's first term of contract for service as specified under a given tariff rate or contract agreement to a location and shall also be the first term of contract after the Customer changes service at a location to a different rate, or in case of transportation service, any renegotiation of an existing contract.

Low Volume Customers – Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F or successors thereto.

Low Volume Sales Customer – Low Volume Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F who purchase their gas from the Company.

Low Volume Transportation Customers ("LVT Customers") - Low Volume Customers who purchase Competitive Natural Gas Supply from a Supplier pursuant to the Company's Gas Choice program, under Rates Schedules GR, GC, OL, MV-F or the successors thereto, and not under Rate Schedules CAP, L, TCS, IS, MV-I, TS-F, TS-I, and/or the successors thereto.

Master Meter System - a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter (i.e., Master Meter) or by other means, such as by rents.

Mcf – 1,000 cubic feet. This is a measure of gas usage.

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

Natural Gas Distribution Company ("NGDC") - a public utility that owns natural gas distribution facilities, used at times in this Tariff to refer to the role of the Company as the distributor of Competitive Natural Gas Supply pursuant to the Competition Act.

Natural Gas Supplier ("Supplier" or "NGS") - A natural gas supplier as defined in 66 Pa.C.S. § 2202, that has been licensed by the Pennsylvania Public Utility Commission to sell Competitive Natural Gas Supply to Low Volume Transportation Customers on the Company's system under the Company's Gas Choice program, to sell natural gas to Customers under Rates TCS, IS and/or MV-I or to sell natural gas to High Volume Transportation Customers under Rate Schedules TS-F, TS-I, and/or any other entity that takes title to gas as defined in 52 Pa. Code § 62.101

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Natural Gas Supplier Coordination Tariff – The Tariff, setting forth the basic requirements for interactions and coordination between the Company, as the natural gas distribution company, and Suppliers necessary for maintaining the delivery of Competitive Natural Gas Supply from Suppliers to their Low Volume Transportation Customers under the Company's Gas Choice program.

Principal Office - The Company's Main Office Building 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.

Sales Service Cost ("SSC") - Cost of commodity and non-storage interstate pipeline firm transportation capacity to delivery such commodity to the city gate for Low Volume Sales Customers.

Rate - The rates are CAP, GR, GC, OL, L, MV-F, MV-I, IS, TCS, TS-I, TS-F, and NGS or the successors thereto.

Separate NGS Billing ("Dual Billing") – Separate Billing by an NGS of its charges for gas supply service.

Service - The distribution of gas for use by the Customer, including all things done by the Company in connection with such distribution.

Service-Supply Pipe - The pipe extending from the Company's supply main to a metered delivery point or, in the case of installations comprised exclusively of outdoor gas lights, to the first such light.

Summary Billing Accounts - An aggregate bill prepared at the option of the Company for Customers with multiple accounts that are related within the same partnership, association, corporation or governmental agency.

Supplier of Last Resort Service ("SLR Service" or "Sales Service") - Natural gas supply service provided by the Company as supplier-of-last-resort to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order ("SMO") – operational directive issued by the Company in its sole discretion to protect the operational integrity of its systems in terms of line pressure and adequacy of supply, which orders directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer's natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company's system.

Tariff – This Gas Service Tariff comprising the rates, rules and regulations that apply to the distribution of natural gas, including all things done by the Company in connection with such distribution and/or the supply of natural gas under Supplier of Last Resort (Sales) Service.

Transportation Service – Natural gas supply service provided to HVT Customers, by an alternative Natural Gas Supplier as further detailed in Rule 1.1 of the Gas Transportation Service General Terms and Conditions Section of this Tariff.

Variable Distribution Service Charge – The variable charges on a Mcf basis for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

Volume Adjustment - the current adjustable factor applied to all rate classes to account for: a) reduction for system losses of 3.0% and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot.

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RULES AND REGULATIONS

1. THE GAS SERVICE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and SLR (Sales) Service will be supplied to its Customers by PECO Energy Company, is on file with the Pennsylvania Public Utility Commission and is posted and open to inspection at the Principal Office of the Company. A copy of this Tariff also is available on the Company's website at: 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 receipt of service shall constitute the receiver a Customer of the Company as the term is used herein, whether service is based upon contract, agreement, accepted signed application, or otherwise. A Customer will receive service under this Tariff effective with their first scheduled billing cycle beginning after July 1, 2000.

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 provision and will be adjusted for application to service provided during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as a 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 provision. 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 provision of service under a particular rate may be modified or amended only by the application of standard riders, filed as part of this Tariff.

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.

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RULES AND REGULATIONS - Continued

2. SERVICE SPECIFICATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of natural gas, or its equivalent. Supply pressures will be limited in accordance with Company specifications.

2.2 SINGLE-POINT DELIVERY. The rates named in this Tariff are based upon the Company's distribution and/or supply through a single delivery point. Separate distribution and/or supply for the same Customer at other points of delivery shall be billed separately unless otherwise specifically provided for under a rate or rider statement.

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.

c. The distribution and other 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 buildings 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 distribution and other 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 buildings or units supplied or by the tenants of such operator whose use of gas 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 rate or rider under which service is supplied.

2.5 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Prior to furnishing permanent residential service for heating or cooling purposes to new residential buildings, a copy of the Compliance Certification from the Pennsylvania Department of Community Affairs indicating proof of compliance with, or exemption from, the insulation standards set forth in the Building Energy Conservation Act and the regulations promulgated thereunder, will be required for residential buildings located in municipalities that have not elected to administer the Act.

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RULES AND REGULATIONS - Continued

3. CUSTOMER'S INSTALLATION

3.1 INFORMATION FROM APPLICANT FOR SERVICE. The Company should be advised by the applicant for service in writing, preferably on a form supplied by the Company, of premises to be equipped for gas, giving exact location, and details of all gas appliances to be installed.

The applicant for service shall supply the Company information regarding potential or actual contamination, waste or other materials or other adverse environmental conditions on the Customer's premises on or near where the Company facilities are to be located. The Customer has a continuing obligation to provide the Company with copies of any environmental assessment relating to the premises. The Company also has a continuing right to inspect the Customer's premises for the purposes of performing an environmental assessment.

3.2 DELIVERY POINT. The Company will designate in writing, upon request, a satisfactory point at which the Customer shall terminate the Customer's piping for connection to the facilities of the Company. The failure to request and obtain such information may result in refusal of service pending rearrangement of Customer's facilities, but the designation of a termination point 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 other materials or other adverse environmental conditions.

The Company may waive this right upon agreement from 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 (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 this Agreement and the termination of the business relationship of the parties hereto.

3.3 METER LOCATION. There shall be provided, free of expense to the Company, at a location outdoors, unless otherwise designated by the Company, which the Company will designate in writing upon request, a suitable place for the regulator or regulators, meter or meters, and any other supply, protective or control equipment of the Company which may be required in the delivery of gas service. Meters and regulators must be located outside and above ground in accordance with 52 Pa. Code § 59.18. However, meters and service regulators cannot be installed in locations specified in 52 Pa. Code § 59.18(a)(8)(i-vi). Inside meter and service regulator locations shall be considered by the Company, but only in accordance with the exceptions contained in 52 Pa. Code §59.18(d). The Company may also consider other meter or regulator locations (such as a specially constructed cabinet recessed in the building wall, sealed from inside the building and vented to and accessible from outside the building) per 52 PA Code §59.18(e). The customer shall provide access (see Rule 10.5) 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, contactors 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 also shall be situated so that the meter(s) are not concealed, but shall be situated in a manner acceptable to the Company.

3.4 NONSTANDARD SERVICE. The Customer shall pay the cost of any special installation necessary to meet any peculiar requirements for service.

The Customer shall pay all costs to the Company of performing environmental assessments, including consultant costs and the costs of removal and disposal of hazardous materials associated with either the initial installation of service, modifications to the service or repair and maintenance of service.

3.5 REVERSE FLOW. The Customer may be required to install check-valves, or other devices, to prevent compressed air or other gases from entering the Company's mains.

3.6 EXCESS FLOW VALVES ("EFVs"). For new and replaced service line installations, the Company will install an Excess Flow Valve (EFV) at its own expense pursuant to 49 C.F.R. § 192.383, (defined in § 192.383(a), as required in (b) with exceptions in (c)). Eligible customers who request installation of an EFV on existing service lines (per § 192.383(d)), must pay the installation costs before any work begins.

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RULES AND REGULATIONS - Continued

4. APPLICATION FOR SERVICE

4.1 PLACE OF APPLICATION. Applications for service may be made at any commercial office of the Company 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 gas, and shall abide by these Rules and Regulations and the standard requirements of the Company.

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, or which might affect the supply of service to other Customers, or to be delivered at a location which 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. Customer can be denied SLR (Sales) Service or new service for failure to pay an NGS'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 contaminated waste or materials or other adverse environmental conditions.

4.5 ACCEPTANCE. When an application is accepted, or when service is supplied according thereto either without modification or with supplemental agreement, it constitutes the contract between the Customer and the Company, subject to the Rules and Regulations.

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.

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's service-supply facilities, and/or unauthorized use of utility service, may be terminated by the Company without notice. Unauthorized use of utility service means unreasonable interference or diversion of service, including meter tampering any-act which affects the proper registration of service through a meter, by-passing (unmetered service that flows through a device connected between a service line and Customer-owned facilities), and unauthorized service restoral. In cases of tampering or by-passing, the use of service without notifying the Company and enabling it to read its meter will render the user liable for any amount due for service supplied 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 BY NON-RESIDENTIAL CUSTOMERS. In the event the Customer or potential Customer withdraws, in whole or in part, 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 supplying the new or modified service where such costs were described by the Company to the Customer at or before the time application was made. This provision does not apply to individual residential service applicants.

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RULES AND REGULATIONS - Continued

5. CREDIT

5.1 PAYMENT OBLIGATION. The provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff as applicable to the location and the character of service.

5.2 PRIOR DEBTS. Service will not be furnished to applicants or 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. The Company may, at its discretion, determine liability for prior debts or past due balances by: (1) the use of company records that contain information provided to the Company; (2) information contained on a valid mortgage, lease, deed or renter's license; (3) the use of commercially available public records databases; (4) Government and property ownership records. 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 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 customers 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. Deposits required by the Company for Tariff regulated charges shall not be based on unpaid supplier charges.

. 5.5 RETURN OF DEPOSIT Deposits secured from a residential Customer shall be returned with accrued interest, in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations In cases of discontinuance of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Effective July 1, 2011, PECO will return the deposit on a non-residential account if the account was assessed fewer than two late payments in the previous 24 months. The first annual review of the customer's payment status will occur 24 months after the initial deposit date. Any residential or commercial customer having secured the return of a 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:

(1) with respect to residential accounts:
- (a) interest accrued prior to December 14, 2004, at an annual rate determined by the average of the 1-Year Treasury Bills for September, October and November of the previous year ("Interest Index");
- (b) interest accrued on or after December 14, 2004, at an annual rate determined by the legal rate of interest pursuant to 66 Pa. C.S.A. § 1404(C)(6);

(2) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent; provided that interest accrued prior to April 14, 1995 shall be calculated at 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 NGDC Billing or Separate NGDC 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 or through in-person identification; (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.

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RULES AND REGULATIONS - Continued

6. SERVICE-SUPPLY FACILITIES

6.1 COMPANY'S SERVICE-SUPPLY PIPE. The Company will install, own and maintain the required service-supply pipe with Company participation in the cost of installation determined by the Company in accordance with Section 7 Extensions.

6.2 SERVICE-SUPPLY ALTERATIONS. Changes in location of service-supply pipe, or meter and connections, for the accommodation of the Customer, shall be at the expense of the Customer. A customer or building owner requesting that a meter or regulator be moved shall pay the costs associated with relocation when the meter and regulator are currently situated in a suitable location under State and Federal regulations per PA 52 Code § 59.18(a)(11).

6.3 STUB-SERVICE PIPE. When supply mains are in place, service-supply pipe to a point beyond the curb line may be installed, at the option of the Company, ahead of paving, providing the owners of the abutting property shall request and pay for such stub-service pipe. The cost of any such stub-service pipe may be refunded to the Customer over a term of years, upon such basis or condition as may be determined by the Company and specified in the contract for service.

6.4 METERS AND REGULATORS. The Company will provide, own and maintain any meter or meters, regulator or regulators, required in the supply of service.

7. EXTENSIONS

7.1 SUPPLY MAIN CONSTRUCTION. The Company will install, own and maintain gas supply mains located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general supply system.

7.2 OBLIGATION TO EXTEND. Subject to the terms set forth herein, the Company will extend its facilities to a new point of delivery without charge to a potential customer making a valid request for natural gas service. For additional details see Section 7.3, Service Pipe and Main Extension Policy.

7.3 SERVICE PIPE AND MAIN EXTENSION POLICY. When gas is available for sale to new customers under one of the Company's firm sales or transportation rate schedules, main and service facilities will be extended to an applicant in accordance with the following provisions:

A. General Economic Test. For firm service customers the Company will make a capital investment in the total cost of new main and service facilities to serve the customer (including, but not limited to, allocated overheads and related system modifications) when the net present value (NPV) from a proposed project is greater than or equal to zero. Net present value shall be calculated based on the capital investment, exclusive of the costs of meter and meter installation, required to serve the applicant(s) and the estimated base annual revenues (EBAR) generated from the applicant(s). The "EBAR" shall be calculated by multiplying the applicable Variable Distribution Charge rate (excluding any applicable gross receipts tax or certain fixed TCS costs) times the estimated annual consumption, plus the portion of annualized Fixed Distribution Charge attributable to service line capital costs. In calculating the NPV, the following assumptions will be made: 1) a 40 year evaluation period, 2) the discount rate shall be the Company's after–tax cost of capital, 3) revenue shall be assumed to be collected throughout the year, and 4) capital is assumed to be invested at the beginning of the year. If the proposed project has a negative NPV, the Customer shall make a payment to bring the net present value to a zero value. This will enable the proposed project to support a reasonable rate of return to the Company.

B. Developments. Payments shall be required in advance for all lot developments. If a payment is required, the amount of payment shall be based on the General Economic Test set forth in Section 7.3A and shall incorporate known gas applications in buildings under construction or buildings not yet under construction but which are expected to be fully constructed within a five year period from the date of the original contract signing. This requirement may alternatively be satisfied by payment of at least 35 percent of the required contribution upon execution of the service agreement with the remainder subject to payment bond and interest (at prime rate) and is due no later than 6 months after PECO certifies, in writing, that service is available to the development. At the time of execution of the service agreement, the developer shall also post a letter of credit, surety bond, or other security, satisfactory to the Company equal to 50% of the value of the revenue stream as calculated by the Company under Section 7.3A. If the developer does not fully develop the lots within five years, including, but not limited to, installing all required appliances and flowing natural gas to them, the Company reserves the right to use the security as payment for the contract amount. Lot developments are defined as tracts subdivided for sale as individual lots or groups of lots to more than one builder or buyer.

C. Interruptible Service Installations. The Company will make a capital investment in the total cost of new main, service facilities and dual fuel installations, (including, but not limited to allocated overheads and related system modifications) to serve Customers with interruptible service installations, up to an amount equal to three times the additional Estimated Base Annual Revenue (EBAR) attributable to the Customer. The Customer shall pay the cost, if any, in excess of the above limit exclusive of the costs of the meter and, meter installation.

D. After-tax cost of capital (discount rate) shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

7.4 EXTENSION REFUNDS. Upon receipt of a written request by a Customer or developer made no earlier than the end of the third year following the date of an agreement for new gas service, PECO will: (a) review its records to determine if a refund is due the customer or the developer for additional customers beyond those used to calculate the projected revenue stream as determined in the General Economic Test above that attached to the facilities paid for by the customer or the developer within three (3) years after the execution date of the agreement for new gas service, and (b) within sixty (60) days of receipt of such request, (i) make payment to the customer or developer of any refund due and (ii) provide the customer or developer with documentation substantiating the refund calculations and identifying the attached loads for which the developer was credited. Customer or developer contributions may be refunded if, within three years of the date of the service agreement, new loads are added to facilities paid for by the contributing Customer or developer. Revenue and cost computations shall simulate that the original and new loads were installed at the same time. Refunds will be paid only to the contributing Customer or developer, and the original contribution shall be the maximum refund.

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7.5 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.

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RULES AND REGULATIONS - Continued

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 the permit or agreement covering the location and the maintenance of service equipment, and the Customer shall reimburse Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

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 the costs incident thereto.

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 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any later time, and reserves the right to reject any piping 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, piping, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the Customer.

9.2 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.

9.3 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.

9.4 INITIAL SERVICE. In all cases gas shall be introduced to the Customer's installation by, or under the supervision of, a representative of the Company.

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RULES AND REGULATIONS - Continued

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 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 Customer's premises, and shall not permit any person, except a Company employee having a standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter, service-supply pipe or other equipment 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.

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 disconnecting service, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. See 52 Pa. Code § 59.24.

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 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 compensate the Company for 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 those costs caused by the Owner's request. Such relocation costs are not part of the capital investment toward supplying service and are, therefore, not included in the revenue test with which the line extension contribution is calculated.

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.

10.8 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.

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RULES AND REGULATIONS - Continued

11. TARIFF OPTIONS ON APPLICATIONS FOR SERVICE

11.1 CHOICE OF RATE. Where the classes of service-supply or conditions of use are such that two or more rates are available, an applicant shall select the rate or rates to be applied to the applicant's service.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist an applicant in selecting the most advantageous rate or rate application.

11.3 RATE CHANGES. A Customer may not change rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above. At any other time, a Customer may change to a rate for which the Customer qualifies upon 30 days' notice to the Company. The new rate will be effective the next meter reading date after Company approval.

The Company will not make any rate change retroactive, unless the Company failed to adequately respond to a Customer's request for assistance or modification at the time of such request.

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RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY

12.1 REGULARITY OF SUPPLY. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service.

12.2 CURTAILMENT OF SERVICE.

a. Authority to Curtail. In the event of a natural gas emergency, the Company may curtail the availability of natural gas service to its Customers in accordance with this Rule 12.2.

b. Priority of Service. Following are the service priority categories listed in descending order of priority (highest to lowest):

Priority 1

(1) Residential and firm critical commercial essential human needs.

Priority 2

(2) Firm small commercial requirements, excluding critical essential human needs requirements in Category 1, and firm large commercial and industrial requirements for plant protection.

(3) Firm small industrial requirements.

(4) Firm large critical commercial and industrial requirements, excluding firm critical commercial essential human needs requirements in Category 1.

(5) Firm large non-critical commercial and industrial requirements other than requirements for boiler fuel use.

(6) Firm large non-critical commercial and industrial requirements for boiler fuel use.

Priority 3

(7) Contractually interruptible use.

c. Definitions Applicable. The definition for terms used in the Curtailment of Service Rule are as follows:

(1) Alternate Fuel Capability. The installed and operable ability to use any fuel other than natural gas on a time sensitive basis. For purposes of this definition, alternate fuel means any fuel other than natural gas or its equivalent.

(2) Commercial Use. Gas usage by Customers engaged primarily in the sale of goods or services including, but not limited to, consumption by office buildings, institutions and governmental agencies and shall include Customers in Standard Industrial Classification Codes 01 through 09, 15 through 19, and 49 through 99. Commercial use shall not include use of gas for manufacturing or electric power generation.

(3) Critical Use. Gas usage where natural gas, or its equivalent, is the only feasible form of energy due to its combustion characteristics, controllability or chemical properties.

(4) Essential Human Needs Use. Gas usage in any building where persons normally dwell, including residences, apartment houses, dormitories, hotels, hospitals, and nursing homes, where the Customer does not have alternate fuel capability.

(5) Firm Service. Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

(6) Industrial Use. Gas usage by Customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power and shall include Customers in Standard Industrial Classification Codes 10 through 14 and 20 through 39.

(7) Interruptible Service. Natural gas services that can be temporarily discontinued under terms and conditions specified by tariff or contract.

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RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(8) Large Customer. A customer with annual usage of at least 18,000 Mcf during the prior calendar year.

(9) Natural Gas Emergency. Whenever the aggregate demand of firm service customers on the Company's system or portion of the Company's system, for any reason, exceeds or threatens to exceed the gas supply or capacity that is actually and lawfully available to the Company to meet the demands, and the actual or threatened excess creates an immediate threat to the Company's system operating integrity or the ability of the Company to satisfy the demand requirements of its Priority 1 Customers (including when continued delivery of gas to Customers would prevent the Company to arrange for the injection of gas into underground storage pools necessary for the protection of winter season supply requirements).

(10) Non-Critical Use. Gas usage where natural gas is not the only feasible form of energy; i.e., where the Customer has alternate fuel capability.

(11) Small Customer. A customer with annual usage of less than 18,000 Mcf during the prior calendar year.

(12) System Maintenance Order ("SMO") – as defined in the definitions section of the tariff.

(13) Plant Protection Use. Minimum usage of natural gas required to prevent physical harm to an industrial or commercial customer's facility, or danger to personnel at the facility, when the protection cannot be afforded through the use of an alternative fuel. Plant protection requirements includes usage necessary for the protection of the material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

(14) Residential Use. Gas usage in a residential dwelling or unit for space heating, air conditioning, cooking, water heating, or other domestic purposes.

d. Curtailment Process.

(1) Reservation of Company Right to Curtail. The Company reserves the right to reduce or eliminate the availability of firm natural gas service to Customers during a natural gas emergency, on a system-wide or localized basis ("curtailment"), when, in the Company's sole judgment, curtailment of natural gas service is necessary to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets. When necessary, the Company may curtail service to Priority 1 customers.

(2) Pre-Curtailment Procedures. To avoid curtailment of service, the Company will use reasonable business and operational efforts to interrupt all Priority 3 services; issue appropriate system maintenance orders (SMO) to HVT and LVT Customers, their Natural Gas Suppliers or other agents; and/or request customers to institute voluntary usage reductions.

(3) Curtailment Directive. In the event that Pre-Curtailment Procedures are not practicable or fail to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets, the Company may issue a curtailment directive. The curtailment directive should be reasonably well-tailored by the Company to require Customers of lower priority services to reduce usage by an amount calculated by the Company, as necessary to minimize the potential threat to public health and safety and to minimize the effect of a natural gas emergency on the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets but may be issued without regard to priorities of service. During the period specified by the curtailment directive, Customers directed to curtail usage must comply with the directive or face physical shut-off by the Company and/or the assessment of penalties elsewhere set forth in this Rule 12.

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RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(4) Curtailment Sequence. Curtailment of a customer class of a higher priority shall not be initiated until all Customers falling into the lower classifications have been completely curtailed. Where only partial curtailment of any one classification is required, customer usage should be reduced pro rata to the extent reasonably possible. As applied to High Volume Transportation Customers served under Rate TS-F, pro rata reductions will be based on a percentage of the Customer's Transportation Contract Quantity unless the Customer has alternative fuel capability.
If the Customer has alternative fuel capability, a pro rata reduction shall be based on a percentage of the Customer's Transportation Contract Quantity less the daily alternative fuel capability. The Company shall restore service as soon as practicable to any gas-fired generation facility that is deemed critical to electric system reliability by the applicable electrical system's control area operator.

(5) Customer Notification. The Company shall provide maximum notice possible of a curtailment directive or of a change in curtailment amount or priority level set forth in a curtailment directive. In the curtailment directive, the Company shall specify the authorized consumption for a specified period or until further notice. The Company reserves the right to provide notice by any reasonable means, including by telephone, pager, e-mail, facsimile or personal contact. If such notice is by telephone, then it will be followed by a written notice to the Customer, specifying the Customer's curtailment percentage and resulting peak day, daily, monthly, seasonal or annual authorized entitlement, as the case may be. An emergency curtailment may be made after oral notice to the Customer, effective when so given, but such oral notice will be confirmed in writing within 48 hours.

(6) Commission Notification. The Company shall notify the Commission as soon as practicable after the issuance of a curtailment directive.

(7) Curtailment Directive Exceeding 5 Days. The Company must obtain Commission authorization before it may extend a curtailment directive beyond a maximum duration of 5 business days. Business days shall be all days except Saturdays, Sundays, and federal holidays.

(8) Natural Gas Emergency Plan. This Rule 12 is supplemented by Company procedures referenced in the Company's Natural Gas Emergency Plan filed by the Company in compliance with Commission Regulations, 52 Pa. Code § 59.63 and 59.71 et seq., and such procedures may be modified from time to time.

e. Unauthorized Use.

(1) Penalties. A Customer determined to have used natural gas in violation of a SMO issued pursuant to Rule 12.2.d(3) or a curtailment directive issued by the Company ("unauthorized use") shall pay the Company a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Also, included will be the actual, additional cost incurred by the Company as a result of such unauthorized gas usage, as reasonably determined by the Company.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-Non NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

(2) Disposition of Penalties. As of December 31, of each year, the Company shall subtract the total of all penalties paid that year to the Company's suppliers from penalties collected that year from Customers. The Company will then distribute all remaining penalties collected by the Company to its curtailed Customers who did not incur penalties under e(i) above.

(3) To determine the amount of reimbursement due a Customer, the total amount to be redistributed shall be divided by the total volume of sales during the twelve-month period to all Customers eligible for reimbursement. This quotient shall represent the factor, which when multiplied by an eligible Customer's total purchase volume during the twelve-month period will equal the amount to be credited to that Customer. However, no reimbursement shall be made to Customers who have terminated service during the year.

(4) The Company will make periodic reports to the Commission containing itemized statements, status of penalty accounts and the extent and nature of disbursements from such accounts made during that period.

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RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY - Continued

12.3 LIMITATION OF LIABILITY. Should the supply of service be curtailed or interrupted by the Company because of gas shortage, or 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 should the supply of service be interrupted, curtailed or fail, by reason of accident, weather, strike, legal process, state or municipal interference, or any cause whatsoever the Company shall not be liable for damages, direct or consequential, resulting from such interruption or failure unless such interruption or failure resulted from the Company's wanton or willful misconduct. If the supply of service to a firm service Customer is interrupted for more than seven consecutive days as a result of the Company's wanton or willful misconduct, the Customer's bill will be prorated for the month during which this interruption occurs.

In all other circumstances, including but not limited to failure to furnish a sufficient supply of gas or failure to transport the customer's gas to the customer, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to equipment and appliances, loss of business, or loss of production caused by any interruption or variation in supply or pressure, or any other failure in the supply of natural gas 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 or variation in supply or pressure, or any other failure in the supply of natural gas occurs.

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.

12.4 ADDITIONAL LIMITATIONS OF LIABILITY IN CONNECTION WITH CUSTOMER CHOICE. Other than its duty to deliver natural gas, the Company shall have no other duty or liability to a Customer receiving Competitive Natural Gas Supply arising out of or relating to a contract or other relationship between such Customer and an NGS. The Company shall implement Low Volume Customer selection of an NGS consistent with applicable rules of the Commission and shall have no liability to a Low Volume Customer receiving Competitive Natural Gas Supply arising out of or relating to switching NGSs unless the Company is negligent in switching or failing to switch a Customer. The Company shall have no duty or liability with respect to natural gas before it is delivered by an NGS to a point of delivery on the Company's distribution system. After its receipt of natural gas at the point of delivery the Company shall have the same duty and liability for distribution service to Customers receiving Competitive Natural Gas Supply as to those purchasing natural gas from the Company.

12.5 NOTICE OF TROUBLE. The Customer must immediately notify the Company if there is any defect, leak, trouble or accident affecting the supply of gas.

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RULES AND REGULATIONS - Continued

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. As of January 5, 1980, the resale of gas and/or service provided by the Company is prohibited for Customers who receive gas service from the Company through a master meter and resell it to individual dwelling units by the use of submeters. Customers receiving service prior to January 5, 1980, may resell gas purchased from the Company through a single master meter in accordance with 66 Pa.C.S. § 1313 if the purchased gas is: (1) for the total requirements of the premises served and (2) the use of the resold gas conforms to the availability requirements of this tariff for the Customer's own account.

13.2 FLUCTUATIONS. Gas and/or 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 ADDITIONAL LOAD. Any additional loads, either connected to existing equipment or new equipment, will not be allowed except by consent of the Company.

13.4 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 regulator, meters, or other equipment of the Company, caused by the additional or changed installation.

14. MEASUREMENT

14.1 SUPPLY OF METERS. The measurement of gas usage shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment, 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.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments, on the premises of any Customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the Customer's load.

14.3 METER READING INTERVALS. The Company will read its meters at scheduled regular intervals of one or more months and will render standard bills for the recorded gas usage based upon the time interval between meter readings. Only those bills which cover a period of service of less than 27 days or more than 34 days will be prorated.

14.4 ESTIMATED USAGE. The Company may estimate the amount of gas usage at the premises where access to the meter is not available, or to installations at remote locations, for such number of months as the type of installation, normal regularity of usage, or other circumstances may warrant, and 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.

14.5 CORRECTION TO STANDARD CONDITIONS. The quantities of gas used may be corrected to standard conditions, namely 60 degrees Fahrenheit temperature and 30 inches of mercury barometric pressure. All methods employed in correcting measurements of gas volume to said standard conditions shall be in accordance with established industry standards.

14.6 TELEMETRY AND TELEPHONE EQUIPMENT

(a) Customer shall permit PECO to install and operate telemetering equipment to remotely read PECO's meter.

(b) Customer shall provide and pay for telephone service required for the operation of PECO's equipment and/or the transmittal of data from PECO's meter, as directed by PECO. Customer must maintain either a dedicated non-digital telephone line or telephone equipment that converts the digital signal to analog. Customer shall provide telephone service for this purpose at least fifteen (15) working days prior to the commencement of service under this agreement.

(c) Service will not be provided prior to the date on which Customer installs the required telephone service. Customer is responsible to maintain the telephone service in working order at all times.

(d) PECO will read the meter on the last day of the month if a reading is not transmitted. If PECO determines that the phone line is not functioning, Customer will be notified that the phone line must be repaired within thirty (30) days.

(e) If more than thirty (30) days elapse and the telephone service is not restored to working order to PECO's satisfaction, then the following steps will be taken:

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(1) If PECO has sufficient capacity in its gas supply system to supply Customer, then Customer's Account will be served as firm service on PECO's Rate GC-General Service–Commercial and Industrial, for a minimum of twelve (12) months.

(2) If PECO does not have sufficient capacity in its gas supply system to supply Customer, then PECO will disconnect Customer's facility from the PECO gas supply system for a minimum of twelve (12) months. During any such period of disconnection, Customer will use an alternate fuel to meet its heating and process needs.

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RULES AND REGULATIONS - Continued

15. TESTS

15.1 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. See 52 Pa. Code § 59.21.

15.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a Customer, or an NGS providing Competitive Natural Gas Supply to a Customer, but reserves the right to charge the Customer or NGS, as applicable, any Commission-approved charge as provided in the Commission's Gas Regulations.

15.3 ADJUSTMENT FOR ERROR. Should any meter become defective or fail to register correctly, the quantity of gas consumed shall be determined by a test of the meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount of gas used for the nearest meter reading period preceding and the meter reading period immediately following the date when the meter was found not be to registering, taking into consideration the character of use by the Customer.

15.4 RESIDENTIAL METER ERRORS. Meter errors in residential 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.

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

15.6 TESTING SERVICE. The Company will, upon request by the Customer, make tests 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.

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RULES AND REGULATIONS - Continued

16. PAYMENT TERMS

16.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its supply. Rate values stated for direct application to monthly periods will be adjusted when the time elapsed between readings is substantially greater or less than a month.

16.2 BILLING OPTIONS. A Low Volume Customer may select one of the following two billing options as communicated to PECO by the customers' supplier: (1) Consolidated NGDC Billing; or (2) Separate NGS Billing.

16.3 PAYMENT PERIOD. Bills are payable upon presentation, and payment may be made at any commercial office of the Company or at any authorized payment agency. Payment for service received must be made on or before the due date shown on the bill, which shall be not less than 20 days from the date of transmittal of the bill for Rate GR, GC and OL (excluding Summary Billing Accounts); not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts, with the exception of accounts (including Summary Billing Accounts) with the United States of America or the Commonwealth of Pennsylvania or any of their departments or institutions for which 30 days will be allowed. If a normal due date should fall on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not open to the general public, 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.

16.4 FINANCE CHARGE. If payment may be made at a Company office or authorized payment agency after the due date shown on the bill, a finance charge will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the finance charge will be added if the payment is received by the Company more than 5 days after the due date shown on the bill. For Rates GR, GC and OL, this finance charge will be 1-1/2% per month; for all other rates the finance charge will be 2% per month.

16.5 BUDGET BILLING

(a) At the option of a Customer receiving service under Rates GR, GC, and OL, 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 twelfth 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 16.4. Any such late fee will be calculated based on the lesser of budget billing arrears and arrears from actual charges.

(b) When the Company provides Consolidated NGDC Billing, the NGSs charges will be included in the Customer's Budget Billing Plan.

16.6 CALCULATION OF FINANCE CHARGE. Where a finance charge is applicable, the amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid finance charges, by the appropriate finance charge rate. Finance charges shall be applied to all charges when the Company is providing Supplier of Last Resort service and to the Fixed Distribution Service Charges, Variable Distribution Service Charges and any applicable service charges when the Customer has selected an NGS. The Company will apply finance charges to NGS charges at the NGS's electronic request when the Company is performing billing services for the NGS.

16.7 APPLICATION OF PAYMENT. When the Company provides Consolidated NGDC Billing or SLR (Sales) Service and a Low Volume 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 NGS 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 NGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

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16.8 RETURNED CHECK CHARGE. If a check received in payment of a Customer's account is returned to the Company unpaid by the Customer's bank and cannot be redeposited by the Company for payment on the second attempt, a $20.00 charge for the returned check will be added to the Customer's account.

16.9 BILLING ERRORS. When the Company provides Consolidated NGDC Billing, the Company shall not be responsible for billing errors resulting from incorrect information received from an NGS.

16.10 PAYMENT TERMS. The Company will negotiate payment arrangements with Sales Service Customers The Company will also negotiate payment arrangements for customers served under Consolidated NDGC Billing which includes NGS charges. If the NGS is providing Separate NGS Billing ("dual billing"), the Company will not negotiate agreements on behalf of those NGS charges.

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RULES AND REGULATIONS - Continued

17. TERMINATION BY THE COMPANY

17.1 NON-PAYMENT SHUT-OFF. On reasonable notice, 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 service and/or gas commodity. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered "reasonable hereunder". Consistent with 52 PA Code §56.100, the Company will accept the following most current and valid documents as proof of household income: (1) income tax returns; (2) pay stubs; (3) benefit letters and governmental agency verification; (4) other forms to be accepted at the Company's discretion. The customer must provide this information within 10 days of the Company's request. This information may also be used by the company to determine deposit requirements, payment arrangements, and any other income specific program.

17.2 SHUT-OFF FOR CAUSE. The Company may terminate on reasonable notice if entry to its 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/or applicable Commission rules in accordance with the Pennsylvania Public Utility Code or the Commission's regulations.

17.3 SAFETY SHUT-OFF. The Company may terminate without notice if the Customer's installation has become hazardous or defective.

17.4 DEFECTIVE EQUIPMENT SHUT-OFF. 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.

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

17.6 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.

	Reconnect Fees For Non-Payment
Gas Reconnect at Meter	$80.00
Gas Reconnect at Curb	$70.00

17.7 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 17.6.

	Theft Investigation Fees
Gas Theft at Meter	$400.00

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18. UNFULFILLED CONTRACTS

18.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service prior to the expiration of a contract term will not relieve a Customer from any minimum, or guaranteed, payment under any contract or rate.

18.2 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 supplying 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 contract term shall become due and payable immediately as liquidated damages in lieu of the anticipated returns from the said contract. These liquidated damages may, at the option of the Company, be offset by any estimated revenues from a succeeding Customer at the same location if such exists.

18.3 TEMPORARY SUSPENSION OF SERVICE. A residential or commercial Customer may elect to have service temporarily disconnected at the start of a period of suspension and then reconnected at the end of the period by paying a charge of $115.00. During the period of suspension, the Customer will be relieved of the payment of minimum bills.

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RULES AND REGULATIONS - Continued

19. CANCELLATION BY CUSTOMER

19.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service must give at least 7 days' notice to that effect, unless otherwise provided for in a rate schedule or service agreement.

19.2 FINAL BILL. The Customer is liable for service taken after notice to terminate the contract until the meter is read and gas shut off. The final bill for service is then due and payable within 20 days from the date of transmittal of the bill for residential customers and 15 days for non-residential customers.

19.3 EXIT FEES. A Customer, other than a Low Volume Customer, taking firm sales service that transfers to an interruptible service or to firm Transportation Service without firm standby sales service will be required to continue payment of the firm gas supply demand costs allocable to Customer's firm sales service until the Company is able to reduce its contract demand level or otherwise utilize the contract demand allocable to Customer's firm sales service.

20. GENERAL

20.1 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 Main Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

20.2 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.

20.3 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.

20.4 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 check is made.

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

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

20.7 OTHER CHARGES. Except as where otherwise provided in this tariff the Company may where feasible, provide and charge for services requested by the Customer or his agent. 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.

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21. **GAS CHOICE PROGRAM ENROLLMENT AND SWITCHING**

In accordance with all applicable final Commission Orders:

21.1 All LVT Customers will be eligible to obtain Competitive Natural Gas Supply starting with their first regularly scheduled meter reading after July 1, 2000.

21.2 The Company will send Gas Choice Release of Information packets to all new LVT Customers, 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-2012-2324075, PECO will re-solicit its entire customer base for the purpose of opting out of disclosing information.

21.3 Customers may select a Supplier, as often as monthly, in accordance with Commission Orders and the procedures contained in this Tariff and in the Supplier Coordination Tariff.

21.4 If a Customer, or agent authorized to act on the Customer's behalf, contacts the Company via telephone to select a Supplier, the Company will advise the Customer or agent to contact the selected Supplier to submit the required electronic enrollment file.

21.5 For a Customer's enrollment to become effective on the Customer's next regularly scheduled meter read date, the Supplier must submit the required electronic file at least eleven (11) days prior to said meter read date.

21.6 If, in any month, a Customer selects more than one Supplier, the Supplier that submitted to the Company, before the end of the applicable Supplier selection period, the Supplier enrollment file with the latest valid Supplier contract will become the Customer's Supplier of record.

21.7 The Company will send a confirmation notice to all Customers who have made a Supplier selection by the next business day after receiving the Customer's enrollment file from the Supplier. This confirmation shall include notification of a five (5) day waiting period in which the Customer may cancel its selection of a Supplier. The waiting period shall begin on the date the Company confirmation is mailed to the Customer. If the five (5)-day waiting period expires, and the Customer has not contacted the Company to cancel the Supplier selection, the Supplier will become the Customer's Supplier of record.

21.8 If the Customer elects to cancel its Supplier selection, the Company will notify the rejected Supplier electronically via an approved EDI transaction. In the event the Customer cancels its Supplier selection after the five (5) day waiting period, the Customer will be required to remain with the selected Supplier for a minimum of one billing cycle.

21.9 If at least eleven (11) days prior to the Customer's next regularly scheduled meter read date, a Customer contacts the Company to request a switch from a Supplier to the Company's (SLR) Sales Service, the request will be effective as of that meter read date and the Company as the supplier of-last resort will become the Supplier of record for delivery.

21.10 In the event the Customer requests a switch less than eleven (11) days before the Customer's next regularly scheduled meter read date, the switch will be effective as of the next following meter read date.

21.11 If, other than at the end of a billing cycle, and because of an NGS's default, an NGS terminates sales to a Customer prior to the end of the Customer's contract with the NGS, for gas supply provided through the end of the relevant billing cycle, said Customer will pay the NGS's contract rate in accordance with information filed by the NGS with the Commission.

22. USAGE DATA

At the request of the Customer, or at the request the Customer's designated Supplier or authorized agent, the Company will supply twelve (12) individual months of historical usage data for no charge. Any additional historical information requested will be provided, if available, for a fee of ninety-two dollars ($92.00) per provision.

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23. AFFILIATED MARKETER STANDARDS OF CONDUCT

PECO Energy and its affiliated natural gas supplier shall comply with the following requirements:

(1) A natural gas distribution company shall apply its tariffs in a nondiscriminatory manner to its affiliated natural gas supplier and any nonaffiliated natural gas supplier.

(2) A natural gas distribution company shall not apply a tariff provision in any manner that would give its affiliated natural gas supplier an unreasonable preference over other natural gas suppliers with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, or non-delivery, and all other services provided to its affiliated natural gas supplier.

(3) Mandatory tariff provisions shall not be waived by a natural gas distribution company for any natural gas suppliers absent prior approval of the Commission.

(4) If a tariff provision is not mandatory or provides for waivers, a natural gas distribution company shall grant the waivers without preference to its affiliated natural gas supplier or non-affiliated natural gas supplier.

(5) A natural gas distribution company shall maintain a chronological log of tariff provisions for which it has granted waivers. Entries shall include the name of the party receiving the waiver, the date and time of the request, the specific tariff provision waived and the reason for the waiver. The chronological log shall be open for public inspection during normal business hours.

(6) A natural gas distribution company shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period. A natural gas distribution company shall maintain a chronological log showing the processing of requests for transportation services. The chronological log shall be open for public inspection during normal business hours.

(7) If a natural gas distribution company provides a distribution service discount, fee waiver or rebate to its favored customers, or to the favored customers of its affiliated natural gas supplier, the natural gas distribution company shall offer the same distribution service discount, fee waiver or rebate to other similarly situated customers. Offers shall not be tied to any unrelated service, incentive or offer on behalf of either the natural gas distribution company or its affiliated natural gas supplier. A chronological log shall be maintained showing the date, party, time and rationale for the action. The chronological log shall be open for public inspection during normal business hours.

(8) Subject to customer privacy or confidentiality constraints, a natural gas distribution company shall not disclose, directly or indirectly, any customer proprietary information to its affiliated natural gas supplier unless authorized by the customer. To the extent that a natural gas distribution company does disclose customer information without customer authorization, it shall contemporaneously provide this same information to other similarly situated natural gas suppliers in a similar fashion so as not to selectively disclose, delay disclosure, or give itself or its affiliated natural gas supplier any advantage related to the disclosure. A chronological log shall be maintained showing the date, time and rationale for the disclosure. The chronological log shall be open for public inspection during normal business hours.

(9) A natural gas distribution company shall justly and reasonably allocate to its affiliated natural gas supplier the costs or expenses for general administration or support services provided to its affiliated natural gas supplier.

(10) Natural gas distribution companies shall not condition or tie the provision of any product, service or price agreement by the natural gas distribution company (including release of interstate pipeline capacity) to the provision of any product or service by its affiliated natural gas supplier.

(11) A natural gas distribution company shall not give its affiliated natural gas supplier preference over a non-affiliated natural gas supplier in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. Natural gas distribution companies shall provide comparable treatment in its provision of such goods and services without regard to a customer's chosen natural gas supplier.

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(12) A natural gas distribution company and its affiliated natural gas supplier shall maintain separate books and records. Further, transactions between the natural gas distribution company and its affiliated natural gas supplier shall not involve cross-subsidies. Any shared facilities shall be fully and transparently allocated between the natural gas distribution company function and the affiliated natural gas supplier function. The natural gas distribution company accounts and records shall be maintained such that the costs incurred on behalf of an affiliated natural gas supplier may be clearly identified.

(13) Natural gas distribution company employees who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, shall not be shared with an affiliated natural gas supplier, and their offices shall be physically separated from the office(s) used by those working for the affiliated natural gas supplier. Such natural gas distribution company employees may transfer to an affiliated natural gas supplier provided such transfer is not used as a means to circumvent these interim standards of conduct.

(14) Neither the natural gas distribution company nor its affiliated natural gas supplier shall directly or by implication, falsely and unfairly represent to any customer, natural gas supplier or third party that an advantage may accrue to any party through use of the natural gas distribution company's affiliates or subsidiary, such as:

- That the Commission regulated services provided by the natural gas distribution company are of a superior quality when services is purchased from its affiliated natural gas supplier; or
- That the merchant services (for natural gas) are being provided by the natural gas distribution company when they are in fact being provided by an affiliated natural gas supplier;
- That the natural gas purchased from a non-affiliated natural gas supplier may not be reliably delivered;
- That natural gas must be purchased from an affiliated natural gas supplier to receive Commission regulated services.

(15) When affiliated natural gas supplier market or communicate to the public using the natural gas distribution company name or logo, it shall include a legible disclaimer that states:

- That the affiliated natural gas supplier is not the same company as the natural gas distribution company;
- That the prices of the affiliated natural gas supplier are not regulated by the Pa PUC; and
- That a customer does not have to buy natural gas or other products from the affiliated natural gas supplier in order to receive the same quality service from the natural gas distribution company.

When an affiliated natural gas supplier advertises or communicates verbally through radio or television to the public using the natural gas distribution company name or logo, the affiliated natural gas supplier shall include at the conclusion of any such communication a legible disclaimer that includes all of the disclaimers listed in this paragraph.

(16) Except in competitive bid situations a natural gas distribution company shall not (a) jointly market or jointly package its Commission regulated services with the services of an affiliated natural gas supplier or (b) offer or provide to its affiliated natural gas supplier products or services, including bill inserts in its natural gas distribution company bills promoting an affiliated natural gas supplier's services or a link from the natural gas distribution company's web-site, unless the natural gas distribution company offers or provides the products or service to all non-affiliated natural gas supplier on the same terms and conditions.

(17) A natural gas distribution company shall not offer or sell natural gas commodity or capacity to its affiliated natural gas supplier without simultaneously posting the offering electronically on a source generally available to the market or otherwise

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making a sufficient offer to the market. The natural gas distribution company shall maintain a chronological log of these public disseminations. The chronological log shall be open for public inspection during normal business hours.

(18) Natural gas distribution companies shall establish and file with the Commission a complaint procedure for dealing with any alleged violations of any of the standards of conduct, with the exception of paragraph (9), which are exclusively under the purview of the Commission. These procedures shall be developed in consultation with interested parties during consideration of any tariff guided by this section and §69.191 (relating to general). The Commission may grant an exception to these requirements if warranted by the facts or circumstances.

(19) A natural gas distribution company shall keep a chronological log of any complaints, excepting paragraph (9), regarding discriminatory treatment of natural gas suppliers. This chronological log shall include the date and nature of the complaint and the resolution of the complaint. The chronological log shall be open for inspection during normal business hours.

(20) Dispute Resolution Procedures: In addition to the procedure set forth in paragraph 18:

- Any dispute between a natural gas supplier, and/or an affiliated natural gas supplier, and a non-affiliated natural gas supplier alleging a violation of any of these Standards of Conduct provisions, the natural gas supplier must provide the natural gas distribution company and/or affiliated natural gas supplier, as applicable, a written Notice of Dispute that includes the names of the Parties and Customer(s), if any, involved and a brief description of the matters in dispute.

- Within five (5) days of a natural gas distribution company's and/or affiliated natural gas supplier's receipt of a Notice of Dispute, a designated senior representative of each of the Parties shall attempt to resolve the dispute on an informal basis.

- In the event the designated representatives are unable to resolve the dispute by mutual agreement within thirty (30) days of said referral, the dispute shall be referred for mediation through the Commission's Office of Administrative Law Judge. A party may request mediation prior to that time if it appears that informal resolution is not productive.

- If mediation is not successful, then the matter shall be converted to a formal proceeding before a Commission Administrative Law Judge.

- Any Party may file a complaint concerning the dispute with the Commission under relevant provisions of the Public Utility Code.

- Parties alleging violations of these standards may pursue their allegations through the Commission's established complaint procedures. A complainant bears the burden of proof consistent with 66 Pa. C.S. §332 (relating to Public Utility Code) in regard to the allegations and may impose penalties for such violations pursuant to 66 Pa.C.S.§ 3301.

(21) A natural gas distribution company shall file a compliance filing within sixty (60) days of the entry of an order approving or modifying a restructuring plan, which sets forth a detailed plan for compliance with this Standard of Conduct as well as the Commission separation and cost allocation requirements already ordered.

(22) Every natural gas distribution company and its affiliated natural gas supplier shall formally adopt and implement these provisions as company policy and shall take appropriate steps to train and instruct its employees in their content and application.

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RULES AND REGULATIONS – Continued

24 REQUESTS FOR ENERGY EFFICIENCY INFORMATION

Upon request of a Customer for energy efficiency information, the Company will provide a copy of its then current residential or commercial energy efficiency guide, as applicable.

25. CREDITWORTHINESS OF A NATURAL GAS SUPPLIER (NGS) SERVING HIGH VOLUME TRANSPORTATION CUSTOMERS

(a) Unless a mutual agreement is reached between the Company and a NGS, or other applicable entity as specified in 52 Pa. Code § 62.101 the amount and form of security shall be based on the criteria established in 52 Pa. Code §62.111. In accordance with §62.111, a NGS seeking to deliver natural gas supplies to the Company for the account of one or more of the Company's non-exempt HVT Customers must satisfy at least one of the following financial criteria:

(1) The NGS has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, or a rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps; or

(2) The NGS has furnished the Company with an irrevocable and binding form of security (e.g., surety bond, letter of credit, security interest in collateral acceptable to the Company, a corporate guaranty, or a written affirmation of financial support by a parent or affiliated company) issued by an obligor that has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, a minimum bond rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps, or, for an insurance company, an A.M. Best credit rating of no less than A-and in which the obligor designates the Company as the sole beneficiary and which otherwise is in a form and amount acceptable to the Company; or

(3) The NGS provides the Company with a cash deposit and/or a cash escrow arrangement in an amount and form acceptable to the Company, and agrees, in a writing furnished to the Company, to be responsible, as between the Company and the Supplier, for the payment of all deficient and excess delivery charges assessed in accordance with the Company's Gas Transportation Service – General Terms and Conditions that are caused by the NGS' excess or deficient deliveries. Such responsibility on the part of the NGS would not relieve the HVT Customer of its responsibility for the payment of the same charges in accordance with the Gas Transportation General Terms and Conditions. If the NGS is determined to have been responsible for the excess/deficient delivery and if the NGS pays the related charges to the Company, then the HVT customer would be relieved of such responsibility.

For the purposes of this subsection (a), the "amount acceptable to the Company" shall be a dollar amount ($US) equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

(4) The NGS has furnished the Company with an acceptable amount of Security in the form of an escrow account or nets any gas supply sales that the NGS has made to the Company and for which the Company owes payment to the NGS against the amount of Security required. The amount of Security contained in either situation must be in an amount equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

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(b) The Company shall have the right to assess each NGS' creditworthiness on an annual basis. As such, the Supplier is required to furnish annual audited financial statements to the Company. In the event the Company does not receive any annual audited financial statements, unaudited financial statements may be acceptable. The Company also may perform more than one financial analysis for any Supplier during the course of the year when the Company reviews financial information of a Supplier and determines, in the Company's judgment that the Supplier's creditworthiness has materially changed.

(c) Unless a mutual agreement is reached, the amount of Security required may be modified based on one or more of the following criteria:

1. The NGS's past operating history on all other NGDC systems, including the duration that the NGS operated on each system, the number of customers served on each system and any supply reliability problems that occurred on each system.
2. An NGS's credit reports.
3. The number and class of customers being served.
4. Information that materially affects a NGS's creditworthiness such as:

a) a change in the NGS's recent operating history on the Company's system or on other NGDC systems that has materially affected NGDC system operation or reliability. Such a change may occur when a Supplier fails to deliver natural gas supply to meet its customers' needs or fails to comply with NGDC operational flow orders as defined at 52 Pa. Code § 69.11;

b) a change in the NGS's credit reports that materially affects its creditworthiness. Creditworthiness could be materially affected when 2 of the following credit rating companies change the Supplier's credit rating:
1. Dun & Bradstreet
2. Standard & Poor's Rating Services Inc.
3. Transunion LLC
4. Equifax Inc.
5. Experian Information Solutions, Inc;

c) a significant change, defined as a 25% change over a 30-day period, in the number and class of customers served, the volume of gas delivered or the average unit price of natural gas;

d) a change in operational or financial circumstances that materially affects a NGS's creditworthiness. This can occur when 2 of the following investment rating companies change the NGS's rating of its issued securities from an investment grade or good rating to a speculative or moderate credit risk rating and vice versa:
1. Standard & Poor's Rating Services Inc.
2. Moody's Investment Service, Inc.
3. Fitch, Inc.
4. A.M. Best Company, Inc.
5. DBRS, Inc.;

e) a change in the NGS's demonstrated capability to provide the necessary volume of natural gas to meet its customers' needs that materially affects the Company's system operation or reliability. Such a change may occur when the NGS fails to deliver natural gas supply sufficient to meet its customers' needs on 5 separate occasions within a 30-day period or fails to comply with the Company's operational flow orders.

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5. The NGS's demonstrated capability to provide the volume of natural gas necessary to meet its customers' needs.

(d) After it is reasonably determined by the Company that an adjustment to the amount of Security provided by the Supplier is required, the Company will adjust the Security amount in accordance with subsection (a)(3).

(e) The NGS shall have the affirmative obligation to inform the Company in writing of any material change in its financial condition in a timely manner.

(f) Notwithstanding anything to the contrary stated in this Rule 25, an NGS shall not be creditworthy if, for any reason, it owes a past due amount to the Company that is not subject to a good faith billing dispute and the payment has not been received by the Company within two business days after the Company has provided a past due notice, or if so determined by order of the Pennsylvania Public Utility Commission.

(g) When the Company determines that a Security adjustment is required, it will provide written notice to the NGS. The NGS shall comply with the Company's determination within 5 business days after the NGS is served with such notice. If the NGS disagrees with the Company's determination, it shall file a dispute in accordance with subsection (h). However, the NGS is still required to post the full amount of adjusted Security requested by the Company within 5 business days after the NGS is served with the Company's notice.
An NGS also may request, in writing, that the Company adjust its Security amount according to the criteria set forth in subsection (c). The Company will provide a written response to the NGS within 5 business days after receipt of the written request from the NGS. In the event that the Company agrees with the NGS's request, the NGS shall post the Security adjustment within 5 business days after the NGS is served with the Company's determination. In the event that the NGS disagrees with the Company's determination, it may file a dispute in accordance with subsection (h). However, if the Company requires an adjustment of Security, the NGS is still required to post the full amount of adjusted Security within 5 business days after the NGS is served with the Company's notice.

(h) An applicant, licensee or NGS shall notify the Company in writing of any dispute(s) it may have regarding the form and amount of Security or the adjustment of Security requested by the Company. If a resolution cannot be reached within 30 days after the Company receives the written notice, the applicant, licensee or NGS may do any of the following:

1. Request that the Secretary of the PUC initiate an informal mediation and resolution process. If the NGS is dissatisfied with the PUC's decision at the informal level, it may petition to appeal the decision or file a Formal Complaint.
2. File a Formal Complaint at the Commission.
3. File a Petition challenging the criteria used by the Company to determine the form and amount of Security requested or the Security adjustment amount.

If a NGS initiates a dispute or files a complaint related to an adjustment in Security by the Company, the following requirements exist during the pendency of the dispute:

1. The NGS is required to provide and maintain the full adjusted Security amount to the Company until the dispute is resolved.
2. The NGS must continue to operate in accordance with the Company's system operations and business rules and practices.
3. The NGS must continue to deliver natural gas volumes necessary to fulfill customer needs and provide customer support services.
4. The Company shall allow the NGS to continue to operate on the Company's system.

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RULES AND REGULATIONS – Continued

26. GAS QUALITY STANDARDS: Quality of Gas Delivered to the Company

A. Terms Defined. The following definitions shall apply throughout the Gas Quality Standards sections of this Tariff.

Biogas is a mixture of naturally produced gases resulting from the decomposition of organic matter under anaerobic conditions (in an oxygen-free environment). The principal constituents are methane and carbon dioxide.

Interconnect or interconnection is the physical connection between the Company's natural gas system and the physical equipment of another natural gas system associated with the interconnection point, which may include the interconnection metering, pressure control, filtration and odorization equipment.

Renewable Natural Gas (RNG) is a term used to describe Biogas that has been upgraded for use in place of fossil natural gas. The Biogas used to produce RNG may come from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities (wastewater treatment plants), livestock farms, food production facilities, and organic waste management operations.

RNG Counterparty is any individual, entity, Customer, or otherwise-described party that executes a Renewable Natural Gas agreement with the Company for purposes of injecting, transporting, using, or otherwise introducing or causing RNG to be introduced into the Company's natural gas system. This definition includes RNG producers and/or production facilities.

B. Quality of Gas at Point(s) of Receipt with an Interstate Pipeline.

Natural gas delivered by or caused to be delivered on behalf of Customer to the Company at point(s) of receipt with an interstate pipeline shall conform to the quality specifications of the pipeline(s) used to transport natural gas.

C. For Quality of Gas at Point(s) of Receipt for Renewable Natural Gas.

Gas Quality Standards are specifications meant to ensure that the RNG entering the Company's natural gas system will be interchangeable with the natural gas that the Company currently distributes and will not damage the Company's or the Company's customers' equipment. RNG being injected into the Company's natural gas system shall conform to the following quality specifications at the time of receipt at the interconnection point. With advance notice from RNG Counterparty in writing, the Company may allow deviations from these standards on a case-by-case basis at its sole discretion. With notice to RNG Counterparty in writing, the Company may require adherence to additional specifications, for good cause as determined by the Company on a case-by-case basis at its sole discretion.

C.1 General Specifications:

(a) The Company's interconnection equipment will have automatic and remote shut-off capabilities to ensure the following constituents and standards can be adequately monitored at the point of interconnection and the safety and reliability of the Company's natural gas system protected. The Company may temporarily discontinue the receipt of RNG without notice if it does not conform to the following specifications.

The following constituents and values will be monitored by the Company via chromatograph or other such measurement device as the Company may employ and will be monitored on a regular basis as the Company may determine from time to time (i.e., hourly):

(i) **Heating Value**: The following minimum and maximum heating values apply, both measured on a dry basis at a temperature of sixty degrees Fahrenheit (60^{O} F) and a pressure of 14.73 pounds per square inch absolute (PSIA)—the minimum heating value is 970 Btu (gross) per standard cubic foot (SCF) and the maximum heating value is 1070 Btu (gross) per SCF.

(ii) **Delivery Temperature**: The RNG delivery temperature is not to be below fifty degrees Fahrenheit (50^{O} F) or above one hundred and twenty degrees Fahrenheit (120^{O} F).

(iii) **Methane:** The gas shall contain a minimum of 95% Methane.

(iv) **Propane**: The gas shall contain a maximum of 20% Propane.

(v) **Hydrogen Sulfide:** The gas shall contain no more than 0.5 grains per 100 SCF.

(vi) **Total Sulfur**: The gas shall contain no more than 5 grains per 100 SCF total sulfur. This includes Carbonyl Sulfide (COS) and Carbon Disulfide (CS_2), hydrogen sulfide, mercaptans, and mono, di- and poly-sulfides.

(vii) **Carbon Dioxide and Nitrogen**: The gas shall contain no more than 2% by volume of carbon dioxide (CO_2), not more than 3% by volume of nitrogen (N_2), and shall contain no more than 5% by volume of combined nonhydrocarbon gases including, but not limited to, CO2, N2, and O_2.

(viii) **Hydrogen:** The gas shall contain no more than 0.1% by volume of hydrogen.

(ix) **Oxygen:** The gas shall not contain in excess of 0.3% by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

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RULES AND REGULATIONS – Continued

(x) **Hydrocarbons:** The RNG hydrocarbon dew point is not to exceed forty-five degrees Fahrenheit (45^{O} F) at the delivery pressure.

(xi) **Water Vapor:** The gas shall not contain in excess seven (7) pounds (lbs.) of water vapor/1mcf.

C.2 RNG Constituents:

(a) RNG Counterparty shall complete laboratory testing, as described in Section C.3, for the trace constituents listed in the following table. If testing results do not meet the standards listed in the table below, the Company may temporarily interrupt RNG service as outlined in Section C.4.

Parameter	Symbol	Level (max unless noted otherwise)	Units
Siloxanes	Si	5	Mg Si/m³
Hydrogen	H_2	0.1	% vol
Ammonia	NH_3	0.00%	Mol%
Mercury	Hg	0.08	mg/m³
Arsenic	As	0.19	mg/m³
Copper	Cu	0.6	mg/m³
Oxygen	O_2	0.3	% vol
Propane	C_3H_8	20	% vol
Nitrogen	N_2	3	% vol
Methane	CH_4	95	% vol
Hydrogen Sulfide	H_2S	0.5	Grains per 100 SCF
Carbon Dioxide	CO_2	2	% vol
Carbon Monoxide	CO	0.1	% vol
Volatile Organic Compounds	VOCs	5	PPM
Moisture or Water Content	H_2O	7	Pounds per million cu ft
Total Sulfur	S	5	Grains per 100 SCF

(b) Additional Quality Requirements:

(i) **Wobbe Index**: The RNG shall have a minimum Wobbe Number of 1255 Btu/ft^3 and shall not have a maximum Wobbe Number greater than 1375 Btu/ft^3.

(ii) **Dust, Gums, etc.**: The gas shall be free of objectionable odors, dust, gum, dirt, impurities and other solid or liquid or hazardous matter which might interfere with proper operation of the facilities, lines, regulators, meters or other appliances through which it flows. Filters shall be installed on the RNG Counterparty's equipment (i.e., the supply side) to catch any debris.

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RULES AND REGULATIONS – Continued

(iii) **Bacteria:** The gas and any associated liquids shall not contain any active bacteria or bacterial agent capable of contributing to or causing operational problems.

C.3 Testing Requirements:

(a) To ensure adherence to the Gas Quality Standards, testing required under this section will be performed by RNG Counterparty using independent, certified third-party laboratories. The Company shall be notified at least five (5) calendar days in advance of the RNG sampling and tests and have the option to observe the samples being taken. Test results will be shared with the Company within five (5) calendar days of the test results being received by RNG Counterparty. Unless otherwise noted herein, the costs associated with the required testing shall be paid by RNG Counterparty.

In its discretion, the Company may, at its own cost and expense, collect samples for testing at the utility meter at the point of interconnection. Re-testing shall be allowed to verify and validate the results of any test. The cost of retesting shall be paid by the entity requesting the retest.

(b) **RNG Pre-Interconnection Testing:** Prior to the injection of RNG into the Company's natural gas system, RNG Counterparty shall conduct two (2) tests over a two (2)-to four (4)-week period for the Gas Quality Standards. If during pre-injection testing, the RNG is found to be non-compliant with the Gas Quality Standards, RNG Counterparty shall make necessary modifications to reduce constituent levels and restart pre-interconnection testing. Connection to the Company's natural gas system is subject to successfully passing these two (2) tests.

(i) **RNG Periodic Testing:** The Company will require RNG Counterparty to conduct periodic testing for the Gas Quality Standards on a quarterly basis (at least once in every three-month period).

C.4 Temporary Discontinuance of Gas Receipt:

(a) **Temporary Discontinuance:** The Company reserves the right to temporarily discontinue the receipt of gas on an immediate basis whenever the RNG is non-compliant with any of the specifications as detailed in the Gas Quality Standards and, as applicable, an RNG agreement, whenever there is an imminent safety risk (including any risk stemming from either Company or RNG Counterparty-owned facilities or equipment), or whenever Company reasonably determines it is necessary to maintain system integrity.

(i) The Company may temporarily disconnect RNG equipment from the Company's natural gas system in the event of an emergency condition as determined by the Company, for scheduled maintenance, construction or repair, or if it is reasonably determined to be necessary in order to maintain the safety and reliability of its system.

(ii) The Company shall notify RNG Counterparty promptly when it becomes aware of an emergency condition or any other condition that that may reasonably be expected to affect RNG Counterparty's operation of its RNG production facility. RNG Counterparty shall notify the Company promptly when it becomes aware of an emergency condition or any other condition that may reasonably be expected to affect the Company's natural gas system. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both parties' facilities and operations, its anticipated duration, and the necessary corrective action.

(iii) In the event the Company temporarily discontinues the receipt of RNG for any reason, RNG Counterparty is responsible for ceasing production or diverting RNG from the point of interconnection, as applicable.

(iv) The Company and the RNG Counterparty shall provide five (5) business days' notice prior to temporarily interrupting service for scheduled maintenance, construction, or repair. The Company shall use reasonable efforts to coordinate such temporary disconnection with RNG Counterparty.

(v) The Company and RNG Counterparty shall cooperate with each other to restore any production facility, interconnection facilities, and the Company's natural gas system to their normal operating state as soon as reasonably practicable following any disconnection pursuant to this section, as long as the safety and reliability of the Company's natural gas system is ensured, including ensuring that all Gas Quality Standards are met. During a temporary discontinuance of service, RNG Counterparty shall still be charged the Customer Charge.

(vi) The Company shall not be liable, under any circumstances or in any respect, to RNG Counterparties or any other person or entity for damages arising either directly or indirectly from temporary discontinuance of service.

(b) **Restart Procedures:**
(i) To restart RNG injection following a temporary discontinuance, RNG Counterparty will complete a minimum of one (1) test of the RNG in accordance with the testing requirements specified above. Injection may then resume if the test indicates the RNG complies with the Gas Quality Standards. This test must be reviewed and approved by both the Company and RNG Counterparty.

(ii) To restart RNG injection following a shut-off resulting from above concerns, RNG Counterparty shall notify the Company and may begin injections only once the Company has given approval.

(iii) When the Company's crews are required on-site to restart the RNG injection, including but not limited to on-site testing, the Company has the right to require the associated RNG Counterparty to bear all costs required for such activities, including but not limited to materials, transportation, labor, and overhead.

(iv) The Company and RNG Counterparty may agree to modify the restart procedures identified in this Section on a case-by-case basis, upon written agreement between each party.

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RULES AND REGULATIONS – Continued

C.5 Changes Impacting Gas Quality:

The Company must be notified as soon as possible of any substantive expected change to the feedstock, raw gas quality or conversion process that has the potential to impact RNG quality, so that the Company can review whether any action is required including, but not limited to, additional testing, new or revised Gas Quality Standards or a suspension of the receipt of RNG into the Company's natural gas system.

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STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this Tariff, a value of 0.00% will apply to all service on and after January 1, 2024.

Whenever any of the tax rates used in the calculation of the surcharge are changed, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the tax rates 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, the Company will thereafter file each year on December 21 annual updates 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 as the effect of the change in tax rates has been included in base rate.

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PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for gas service in Residential Rate Schedule GR of this Tariff shall include a charge of **$0.2419** per Mcf (1,000 cubic feet) for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below. The USFC rate for gas 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 Mcf ($x.xxxx), shall be computed in accordance with the formula set forth below:

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

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

In computing the USFC, per Mcf, 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 10.5% offset factor.

USFC – Universal Service Fund Charge determined to the nearest one-hundredth cent (0.01¢) to be included in the rate for each Mcf of Variable Distribution Service Charge calculated under Rate Schedule GR, to recover or refund Reconcilable CAP Costs and other items as addressed in the "E" factor.

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

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 up to $900,000 of LIURP expenditures above the $2.25 million threshold included in base rates. Also included in the "E" Factor will be any rate credit due customers to the extent PECO expends less than $3,077,500 annually in its Energy Efficiency Plan effective January 1, 2025.

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 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 period such overcollection is refunded or undercollection is recouped. The interest calculation will not apply to the LIURP amounts.

"

S - projected Mcf of gas service to be billed under Rate GR (exclusive of CAP Rider) during the projected period when rates will be in effect. Mcf's shall be consistent with the projected residential throughput used in the applicable Purchased Gas Cost filing.

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 December 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.

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To implement the effects of the Tax Cuts and Jobs Act (TCJA), on March 15, 2018 the Pennsylvania Public Utility Commission (Commission) issued a Temporary Rates Order at Docket No. M-2018-2641242 directing PECO to file its current base rates and riders as temporary rates, pursuant to Section 1310(d) of the Public Utility Code. 66 Pa. C.S. § 1310(d). Subsequently, on May 17, 2018, the Commission entered an Order at Docket R-2018-3000512 superseding the March 15, 2018 Temporary Rates Order directing PECO to establish a surcharge effective July 1, 2018 to provide the benefits of the TCJA to customers.¶
¶
A surcharge of 0.00% will apply to intrastate service to all customer bills rendered on and after March 1, 2023. This **(C)** surcharge will be distributed equally among the utility's various customer classes and will be provided through a separate mechanism showing a line item on customer bills (e.g., Federal Tax Adjustment Credit – "FTAC"). ¶
¶
PECO will file revised surcharges (or FTAC) as required at least thirty (30) days prior to the effective date of January 1st of each year reflecting an estimate of the savings for the TCJA from January 1 through December 31 exclusive of STAS and non-distribution automatic adjustment clause revenues. ¶
¶
This surcharge or FTAC will be reconciled at the end of each calendar year and will remain in place until PECO files and the Commission approves new base rates for PECO pursuant to Section 1308(d) that include the effects of the TCJA tax rate changes. Interest on the over or under collection shall be computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.). The reconciliation shall be submitted by April 30th of each calendar year and shall be subject for review and audit by the Commission's Bureau of Audits. ¶
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The Company may file an interim rate adjustment in order to eliminate any over or under recovery of the surcharge outside of the annual filing period. Such adjustment would be filed on at least 10 days' notice. ¶
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A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.¶
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SALES SERVICE COSTS (SSC) - Section 1307(f)

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **$4.4199** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$4.4062** per Mcf for Rate Schedules GC and **$4.3996** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **a credit of $0.0468** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales Service gas shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of gas costs related to Sales Service.

COMPUTATION OF CC AND GCA PER MCF.

The CC and GCA, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formulas set forth below:

$$CC = \frac{(C)}{(S)} \times \frac{1}{(1 - T)} + GPC + MFC \quad ; \text{and}$$

$$GCA = \frac{(E)}{(S)} \times \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, CC is revised to:

$$CC = (CC1 + \frac{O}{S1} + \frac{C1)}{S2} \times \frac{1}{(1-T)} + GPC + MFC$$

The CC and GCA so computed, shall be applicable to Customers receiving Sales Service pursuant to the rate schedules identified above. The CC and GCA, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Charges, per Mcf, pursuant to the formulas above, the following definitions shall apply:

"CC" - Purchased Gas Costs determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: (a) for all types of purchased gas, project the commodity and all non-storage interstate pipeline costs for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect; plus (b) the cost of gas provided from storage and LNG facilities, less (c) the new monthly cash-out result determined pursuant to Rule 10.11.3, or the successor thereto, of the Gas Choice Supplier Coordination Tariff .

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1" – defined as the Commodity Charge rate effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by Commodity Charge revenues less associated gas costs, from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

GCA - the "E" factor component of the CC, representing the net overcollection or undercollection of Purchased Gas Costs. Applicable to Sales Service and determined to the nearest one-hundredth cent (0.01¢) for service provided under Rate Schedules GR, GC, CAP, OL, L, and MV-F of this Tariff.

"E" - the net (overcollection) or undercollection of Purchased Gas Costs applicable to the CC.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

Supplier refunds received after July 1, 2001 associated with Commodity Charges will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) beginning with the month such refund is received by the Company.

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"GPC" – Gas Procurement Charge determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

"MFC" – Merchant Function Charge determined to the nearest one hundredth cent (0.01¢) to be charged for each Mcf of Sales Services gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

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 1307(f) GCA.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle

"S" projected Mcf of gas to be billed to Customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L & and MV-F during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve month mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F.

"S2" – defined as mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F and for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"Purchased Gas Costs" - Include the direct costs paid by the Company for the purchase and delivery of natural gas (which also includes liquefied natural gas, synthetic natural gas, and natural gas substitutes, excluding propane, the cost of which is included in the Balancing Service Costs) to its system to supply its Customers (plus such portion of the Company's used and unaccounted for gas as the Commission permits), including costs paid under agreements to purchase natural gas from sellers; costs paid for transporting natural gas to its system; all charges, fees, taxes and rates paid in connection with such purchases, pipeline gathering, and transportation; and costs paid for employing futures, options and other risk management tools.

QUARTERLY UPDATES

The Company's rates for recovery of gas costs related to Sales Service are also subject to quarterly adjustments under procedures set forth in Section 1307 (f) of the Public Utility Code and in the Commission's regulations. Such updates shall reflect, adjustments for under or overcollections and, adjustments to the projected cost of gas related to Sales Service based upon more current versions of the same sources of data and using the same methods to project the gas costs related to Sales Service approved by the Commission in the Company's most recent annual proceeding for recovery of gas costs related to Sales Service under section 1307 (f).

OFF-SYSTEM SALES SHARING MECHANISM

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first $3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over $3.5 million. Subsequently, effective March 31, 2008 through November 30, 2026 and thereafter, until terminated or otherwise revised by Final Order of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

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SALES SERVICE COSTS (SSC) - Section 1307 (f) - Continued

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

The Company shall notify the Commission of any change in the price of purchased gas from any supplier, which change would cause an increase or decrease of more than one per cent (1%) in the "C" factor, defined above. Such notification will be given within thirty (30) days after the effective date of such change in price, or as soon as reasonably practical thereafter.

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GAS PROCUREMENT CHARGE

PROVISIONS FOR RECOVERY OF GAS PROCUREMENT CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Gas Procurement Charge ("GPC") at **$0.0360** per Mcf (1,000 cubic feet) for recovery of gas procurement costs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Orders at Docket No. P-2012-2328614 and Docket No. R-2024-3046932.

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The GPC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC").

COMPUTATION OF GAS PROCUREMENT CHARGE

The GPC shall include gas procurement costs incurred by the Company on behalf of its Sales Service customers. The GPC shall include the following costs:

1. Natural gas supply service, acquisition and management costs, including natural gas supply bidding, contracting, hedging, credit, risk management costs and working capital.
2. Administrative, legal, regulatory and general expenses related to those natural gas procurement activities, excluding those related to the administration of firm storage and transportation capacity.

The GPC shall be computed as follows:

GPC = GPCC/S x 1/(1-T)

"GPCC" – applicable gas procurement costs as defined in Items 1 and 2 above.

"S" – defined as twelve months of Mcf sales billed to customers receiving Sales Service under Rate Schedules GR CAP, GC, OL, L, and MV-F.

"T" – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The costs for the GPC shall remain in effect until reviewed and updated in each base rate case filed by the Company. The calculation of the GPC shall be updated in conjunction with updates in costs for the GPC. The GPC shall not be subject to reconciliation for any prior period over or under collections.

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MERCHANT FUNCTION CHARGE

PROVISIONS FOR RECOVERY OF MERCHANT FUNCTION CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP GC, OL, L and MV-F shall include the Merchant Function Charge ("MFC") at **$0.0207** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0070** per Mcf for Rate Schedule GC and at **$0.0004** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2024-3046932. The MFC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC") and shall be updated quarterly in conjunction with the calculation of the CC.

COMPUTATION OF MERCHANT FUNCTION CHARGE

The MFC shall include uncollectible charge-offs incurred by the Company on behalf of its Sales Service customers and calculated for Rate Schedules GR, CAP, GC, OL, L and MV-F. The MFC shall be computed as follows:

MFC = Write-Off Factor x CCEMFC x 1 / (1 – T)

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP **(0.47%),** Rate Schedule GC **(0.16%)** and Rate Schedules OL, L and MV-F **(0.01%)** as determined at Docket No R-2024-3046932, the Company's 2024 gas base rate case. The write-off factors shall be updated as part of future base rate cases.

"CCEMFC" – the applicable quarterly CC including the GPC and excluding the MFC.

"T" – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The calculation of the MFC shall be updated in conjunction with changes in the CC including the GPC and excluding the MFC and updates in the write-off factors. The MFC shall not be subject to reconciliation for any prior period over or under collections.

PRICE TO COMPARE

The Price to Compare ("PTC") is comprised of the Commodity Charge ("CC"), the Gas Cost Adjustment ("GCA"), the Gas Procurement Charge ("GPC") and the Merchant Function Charge ("MFC"). The Commodity Charge includes the Gas Procurement Charge and the Merchant Function Charge. The PTC will change whenever any components of the PTC change. The current PTC's are detailed below:

COMPONENT	RATES GR and CAP
Commodity Charge excluding GPC and MFC	$4.3632 per Mcf
Gas Cost Adjustment	($0.0468) per Mcf
Gas Procurement Charge	$0.0360 per Mcf
Merchant Function Charge	$0.0207 per Mcf
Price to Compare	$4.3731 per Mcf

COMPONENT	RATES GC
Commodity Charge excluding GPC and MFC	$4.3632 per Mcf
Gas Cost Adjustment	($0.0468) per Mcf
Gas Procurement Charge	$0.0360 per Mcf
Merchant Function Charge	$0.0070 per Mcf
Price to Compare	$4.3594 per Mcf

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COMPONENT	RATES OL, L and MV-F
Commodity Charge excluding GPC and MFC	$4.3632 per Mcf
Gas Cost Adjustment	($0.0468) per Mcf
Gas Procurement Charge	$0.0360 per Mcf
Merchant Function Charge	$0.0004 per Mcf
Price to Compare	$4.3528 per Mcf

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BALANCING SERVICE COSTS (BSC)- Section 1307(f)

PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at **$0.3843** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs.

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COMPUTATION OF BALANCING SERVICE COSTS PER MCF

Balancing Service Costs, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formula set forth below:

$$BSC = \frac{(C - E)}{(S)} \times \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, the BSC is revised to:

$$BSC = (CC1 + \frac{O}{S1} + \frac{C1}{S2} - \frac{E}{S1}) \times \frac{1}{(1 - T)}$$

Projected Balancing Service Costs, so computed, shall be charged to Customers for all gas delivered pursuant to the rate schedules identified above. The amount of those costs, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Balancing Service Costs, per Mcf, pursuant to the formula above, the following definitions shall apply:

"BSC" - Balancing Service Costs determined to the nearest one-hundredth cent (0.01¢) to be charged to each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: for all types of storage and related services, project the cost for the projected period when rates will be in effect.

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1"- defined as the rate associated with "C" effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by storage and related services revenues less associated storage and related services costs from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

"E" - the net overcollection or undercollection of Balancing Service Costs.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

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 Balancing Service Costs Rate.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle.

As otherwise described in the Sales Service Costs section "Off-System Sales Sharing Mechanisms", the portion of margin revenue attributable to certain balancing assets shall be included in the calculation of "E".

Supplier refunds received prior to July 1, 2001 will be included in the calculation of "E" with interest added at the annual rate of six per cent (6%) beginning with the month such refund is received by the Company.

"S" - projected Mcf of gas to be delivered to Customers during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve months of mcf of gas to be delivered to customers.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"S2" – defined as mcf sales delivered to customers for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

Balancing Service Costs - fixed and variable storage costs and the cost of propane to be charged to all customers served under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

QUARTERLY UPDATES

The Company's rates for recovery of Balancing Service Costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code 53.64 (1) (5). Such updates shall reflect adjustments for under or over collections and adjustments to the projected cost of Balancing Services based upon more current versions of the same sources of data and using the same methods to project the Balancing Service Costs approved by the Commission in the Company's most annual proceeding for recovery of Balancing Service Costs under section 1307 (f) of the Public Utility Code.

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FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

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Consumer Education Charge (CEC)

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS

Purpose - The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's approved gas consumer education costs.

Applicability - The surcharge shall be charge calculated to the nearest one-hundredth cent (0.01¢), which shall be added to the Variable Distribution rates for all Low Volume Customers for recovery of Consumer Education Costs associated with Gas Choice. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is $0.0012 per Mcf for Rates GR and CAP, Class 2 is $0.0000 per Mcf for Rate GC and for Class 3 is $0.0000 per Mcf for Rates L and MV-F.

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COMPUTATION OF CEC
The CEC per MCF shall be calculated on an annual basis using the following formula:

$$CEC(n) = \frac{(C+E+I)}{S(n)}$$

In computing the CEC, pursuant to the formula above, the following definitions shall apply:

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

Consumer Education Cost: Costs attributable to the Company's payment of the Commission's Statewide Education Assessment and all incremental external and incremental internal costs of the Company's own local customer choice education program. Such program costs may include outreach programs, paid media, direct mail, company call center, grass roots outreach and other costs as approved by the Commission.

CEC(n) - consumer education costs for Low Volume Customers in rate 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 – rate class where 1 = residential (Rate GR) 2 = small C&I (Rate GC) 3 = large C&I (Rate L).

S – projected MCF of gas, as included in the Balancing Service Costs (BSC) provided in the Company's most recent Commission approved annual 1307(f) Purchase Gas Cost (PGC) filing.

Filing Schedule:
The estimated surcharge shall be filed with the Commission by January 1 of each year to be effective on the following March 1. The application period shall be the 12 months that start the March 1 effective date of the surcharge. The CEC mechanism is subject to annual audit review by the Bureau of Audits.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply consistent with the Commission Order dated September 3, 2015 at Docket No. P-2013-2347340, approving the DSIC.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (CONTINUED)

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 included for recovery in the DSIC.

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

Piping (account 376);
Couplings (account 376);
Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
Valves (account 376);
Excess flow valves (account 376);
Risers (account 376);
Meter bars (account 382);
Meters (account 381);
Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective October 1, 2015.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective October 1, 2015, 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 June 1, 2015 and August 31, 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.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

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:

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

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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.
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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 that a utility may elect to include STFT calculation in the PTRR component).

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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.

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

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Revenue shall be based on one-fourth of the projected annual revenues.

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[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.]

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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 Commission's 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 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. An explanatory bill insert shall also be included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who are paying flexed or discounted rates and customers having negotiated contracts with the Company, if it is reasonably necessary to do so.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

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 GR - GENERAL SERVICE -RESIDENTIAL

AVAILABILITY.

Service in the entire service 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 domestic requirements of its members when such service is supplied through one meter. Resale of gas and/or service provided by the Company under this rate is only allowed for those locations being served through a single meter prior to January 6, 1980.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $19.38 per month
VARIABLE DISTRIBUTION CHARGE: $7.0866 per Mcf

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge. The Universal Service Fund Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial term for any contract shall be at least one year.

PAYMENT TERMS.
Standard.

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RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective through December 31, 2025)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $36.38 per month

VARIABLE DISTRIBUTION CHARGE: $5.4413 per Mcf

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
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RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective as of January 1, 2026)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE:
$29.36 for service provided through a single small diaphragm meter
$40.61 for all other service

VARIABLE DISTRIBUTION CHARGE: $5.4413 per Mcf

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
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RATE OL - OUTDOOR LIGHTING SERVICE

AVAILABILITY.
Service for outdoor lighting by Company-approved lighting devices of the sizes hereinafter specified, where the consumption is not registered on a meter.

MONTHLY RATE TABLE.

Manufacturer's Rated Input to Lighting Devices	Nominal Mcf Rating Per Month	Distribution Charges: When Not in Conjunction With Service Under Other Gas Rates	Distribution Charges: When in Conjunction With Service Under Other Gas Rates
1,999 Btu/Hr.or less	1.5 Mcf	$10.0878	$5.0204
2,000 Btu/Hr.to 2,499 Btu/Hr.	1.7 Mcf	$11.7355	$6.7059
2,500 Btu/Hr.to 2,999 Btu/Hr.	2.1 Mcf	$13.1731	$8.1247
3,000 Btu/Hr.to 3,499 Btu/Hr.	2.4 Mcf	$14.7064	$9.6764

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), and BALANCING SERVICE COST ("BSC") apply to this rate.

INSTALLATIONS.
The Customer shall install, own and maintain the lighting devices and all tubing from the Company's service-supply pipe to the lighting devices.

FINAL CONNECTION.
The final connection of any lighting devices or tubing to the supply system shall be made by or under the supervision of a representative of the Company and the costs of such connections shall be borne by the Customer.

BUDGET BILLING.
At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
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RATE L - LARGE HIGH LOAD FACTOR SERVICE

AVAILABILITY.

Large volume high load factor service for use in commercial and/or industrial applications, with the right reserved to restrict its use as a boiler fuel and for other non-critical use. This service shall be under a contract specifying in Mcf, the maximum daily quantity (MDQ) of natural gas to be supplied on a seasonal basis. The winter period MDQ may not exceed the summer period MDQ. Deliveries shall be as nearly as practicable at uniform hourly rates of flow.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $297.01 per month
VARIABLE DISTRIBUTION CHARGE: $8.0858 per Mcf for the first 50% of all usage.
$2.4560 per Mcf for the additional use.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), and BALANCING SERVICE COST ("BSC"), apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Charge.

MEASUREMENT.

The quantities of gas used shall be determined from the Company's meters, corrected to standard conditions, namely 60° Fahrenheit temperature and 30 inches of mercury barometric pressure.

UNAUTHORIZED OVERRUN.

Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract for this service shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily Weighted prices for a particular calendar month are summed and the result is equal to the MWP.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

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MDQ DETERMINATION.

Each Customer shall review the contract annually and shall supply the Company written notification by August 1 of the Customer's requested MDQ(s) for the coming contract year. The MDQ requested shall be subject to reduction by the Company for either or both of the seasonal periods in light of available gas supplies, winter deliverability constraints, or for other good reason before the contract becomes effective. Any reduction made by the Company below the prior year's MDQ(s) shall be limited to the Customer's boiler fuel and other non-critical use.

The Company may, with the consent of the Customer, increase the existing winter MDQ up to the level of the contracted summer MDQ at such time during the winter period when, in the judgment of the Company, sufficient quantities of gas are available for the balance of the contract year.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

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RATE MV-F MOTOR VEHICLE SERVICE-FIRM

AVAILABILITY.
Firm motor vehicle service is available to Customers using natural gas exclusively as fuel for motor vehicles.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $67.80 per month.

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ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE: $1.3649 per Mcf

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ADDITIONAL VARIABLE DISTRIBUTION CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.66 per Mcf added for each Mcf of gas supplied.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), BALANCING SERVICE COST ("BSC"), and any applicable fuel taxes apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

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RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
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RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE

AVAILABILITY.
Interruptible motor vehicle service is available to Customers using natural gas for the sole purpose of a fuel for motor vehicles which have installed dual-fuel capability.

QUALITY OF SERVICE.
Upon notification by the Company, the Customer is required to transfer load to an alternate fuel. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. The Customer shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate schedule are subordinate to all firm sales or firm transportation service provided by the Company.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION CHARGE: $58.50 per month

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ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE AND COMMODITY CHARGES:
Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the allocated monthly cost of gas plus three cents, plus the applicable gross receipts tax factor.

The total of the Variable Distribution Charge and the Commodity Charge shall not exceed the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and the Gas Cost Adjustment Charge ("GCA") of Rate GC.

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The Company will provide the Pennsylvania Public Utility Commission with written notification of the Rate MV-I prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, the price will remain in effect from month to month unless changed by the above notification procedure.

ADDITIONAL COMMODITY CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.65 per Mcf added for each Mcf of gas supplied.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), and any applicable fuel taxes apply to this rate.

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OTHER CONDITIONS.
1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate. It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

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RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE - Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent unleaded gasoline dealer tank wagon price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate MV-I revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes.
The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

5. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

6. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

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RATE IS - INTERRUPTIBLE SERVICE

AVAILABILITY.

Interruptible sales service is available to individual Customers who have dual-fuel capability or are willing to accept interruption of gas service. The Customer must have an estimated gas consumption of at least 3,000 Mcf per month during each summer month. The summer period includes the months of April through October. For a Customer that also receives service under Rates L, TS-I, or TS-F, the 3,000 Mcf per month use requirement does not apply.

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Rate GC or other firm sales services may not be used as a backup supply during periods of interruption under this rate schedule. Rate GC service may be provided through separate metering where firm service is required. Piping connections between the firm and interruptible fuel line systems are prohibited.

The Customer will be required to execute a contract specifying the maximum daily quantity (MDQ) of gas that the Company's service and metering facilities are designed to supply. The maximum hourly capacity that the Company's facilities are designed to supply shall not be more than 6.5% of the MDQ.

QUALITY OF SERVICE.

Service under this rate is made available to Customers for purposes of balancing the Company's gas demands and optimizing its daily use of pipeline supplies and is strictly within the discretion of the Company. When the available quantity of gas is inadequate to serve the needs of all Customers under this rate, the Company will impose limitations, as necessary, endeavoring to provide each Customer with the opportunity to take gas from time to time. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Interruptible sales are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $297.41 per month.

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VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels the Customer has the economic capability of consuming. The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the applicable commodity cost of gas for the current month plus three cents, increased by the applicable gross receipts tax factor and shall be no higher than the applicable delivered price, on an equivalent BTU basis of alternate fuel.

The Company will provide the Pennsylvania Public Utility Commission with written notification of each of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, prices will remain in effect from month to month unless changed in accordance with the above notification procedure. If there is a major change in competitive fuel prices during the month, the Company may change the Commodity Charge prices within the same upper and lower limits on notice of five working days to the Commission.

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

METERING SEQUENCE.

Service under this rate may be supplied in combination with Rates L, TS-F or TS-I at a single point and through a single metering installation, in which case the MDQ for each rate schedule shall be specified in the contract. The Company will assume for billing purposes that metered volumes first reflect deliveries of the Contract Maximum Daily Quantity of Rate L gas, next the Firm Transportation Contract Quantity of Rate TS-F, next the Contract Quantity of Interruptible Transportation under Rate TS-I, and finally the Interruptible Gas under this rate schedule. Determination of Rate IS deliveries will be made at the end of the billing period. The number of Mcf billed under Rate L shall never be less than the number of Mcf resulting from 15 days' use of the Rate L billing demand.

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

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RATE IS - INTERRUPTIBLE SERVICE - Continued

OTHER CONDITIONS.

1. Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the applicable commodity cost used to establish the current Rate IS Commodity Charge for the Customer and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate schedule.

The revenue received for Customer emergency service which is in excess of the normal Rate IS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

EXTENSION OF MAIN - INSTALLATION OF SERVICE.

Each Customer shall prepay the total cost of any main extension, service installation, meter installation, or enlargement or rearrangement of existing facilities required for service under this rate schedule.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial contract term shall be at least 1 year.

PAYMENT TERMS.

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RATE TCS - TEMPERATURE CONTROLLED SERVICE

AVAILABILITY

Temperature controlled service is available to individual Customers that have dual-fuel equipment with a rated input of more than 2,100,000 Btu per hour and an estimated fuel use which totals 5,000 Mcf or more during the billing months of December, January, February and March and are willing to accept interruption of service at the cut-off temperature specified by the Company.

QUALITY OF SERVICE.

Upon notification by the Company, the Customer is required to transfer load to an alternate fuel whenever the outdoor temperature is below the cut-off limit specified by the Company. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. During August of each year the Company will notify each Customer of the cut-off temperature limit to be effective during the twelve-month period beginning September 1. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $170.00 per month.

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VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

Monthly prices shall not exceed the Variable Distribution Charge of Rate GC, the monthly projected weighted average commodity cost of gas (WACCOG) and the Fixed Cost Credit determined in the most recent annual 1307(f) proceeding. Monthly prices shall be no less than monthly projected WACCOG and the 1307(f) Fixed Cost Credit, plus three cents. The Company will provide the Pennsylvania Public Utility Commission with written notification of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. If there is a significant change in WACCOG during a month, the Company may change the commodity charge prices within the same upper and lower limits on notice of five working days to the Commission.

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"Fixed Cost Credit" means the result derived by dividing the Company's annual projected interstate pipeline transportation and storage demand charges by its projected annual firm sales throughput as determined by reference to the Company's Section 1307(f) filing made immediately prior to the period in which the Fixed Cost Credit shall apply.

"Commodity cost of gas" shall include all purchased gas costs charged by the Company's natural gas and interstate pipeline suppliers on a volumetric or commodity basis (including but not limited to interstate pipeline fuel and the Company's company use and unaccounted for gas) and shall exclude all costs used in determining the Fixed Cost Credit.

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

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

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OTHER CONDITIONS.

1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate.
It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

The Company may, in its sole discretion, permit minimal volumes of gas which would otherwise be supplied under Rate GC to flow through the Rate TCS metering where, in the Company's judgment, the cost of installing separate metering is uneconomical.

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RATE TCS - TEMPERATURE CONTROLLED SERVICE – Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate TCS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Upon notification to the Customer by the Company that an emergency condition exists, the Company may change the threshold outdoor ambient temperature at which service is provided, for the duration of the emergency.

5. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price.(In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and
the result is equal to the MWP.

6. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

7. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least 1 year.

PAYMENT TERMS.
Standard.

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GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and Rate TS-F Gas Transportation Service-Firm.)

1. TRANSPORTATION SERVICE

1.1 GENERAL. Transportation service shall consist of: the receipt of gas on behalf of a Customer; the transportation of gas through the Company's distribution facilities, and the delivery of equivalent quantities of gas to the Customer, adjusted for thermal correction and system losses where applicable.

Transportation service may also include Standby Sales Service to permit purchases of gas under one of the Company's retail sales rate schedules.

1.2 TERMS DEFINED. The following definitions shall apply throughout the transportation portion of this tariff:

RECEIVED/RECEIPT shall refer to gas tendered to the Company for the Customer's account at one or more of the interconnections between the Company and its interstate pipeline suppliers, or other specified location. The normal unit of measurement is the dekatherm or mmBtu.

DELIVERED/DELIVERY shall refer to gas tendered to the Customer by the Company at the Customer's specified location. The normal unit of measurement is the Mcf.

USE/USAGE shall refer to gas actually consumed by the Customer at the specified location as measured by the Company's meter in Mcf.

DEFICIENT DELIVERIES shall refer to occurrences in which the Customer uses more gas than the quantity of transportation gas tendered by the Company for delivery.

EXCESS DELIVERIES shall refer to occurrences in which the Customer uses less than the quantity of gas tendered by the Company for delivery.

1.3 VOLUME ADJUSTMENT. The quantity of transportation gas received into the Company's distribution system for the Customer's account shall be: (a) reduced by 3.0% for system losses; and (b) adjusted for thermal correction determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. Where the transported gas can be delivered directly to the Customer without commingling with other system supplies, no reduction for system losses shall be made, and the thermal correction shall be based on the daily average Btu content of the pipeline to which the Customer is directly connected.

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1.4 SUPPLY COST ADJUSTMENT. If the Company incurs any added gas supply cost in order to provide transportation service by displacement, or for other reasons, such additional cost will be charged to the Customer. Displacement occurs when a Customer, who is directly connected to one of the Company's pipeline suppliers, arranges for receipt of transportation gas on another pipeline to which the Customer is not directly connected. Revenues received by the Company in payment for added gas supply cost will be credited to firm sales Customers through the annual Sales Service Costs reconciliation (Section 1307[f]).

1.5 SERVICE AGREEMENT. The Customer will be required to execute a Transportation Service Agreement which will specify an initial Transportation Contract Quantity (TCQ) to be the maximum daily volume of gas, expressed in Mcf net of system losses where applicable, to be transported and delivered to the Customer. The agreement will also specify delivery locations, the election of Standby Sales Service, the commodity charge to be in effect for the term of the agreement, and any special provisions for service. The standard term for a Transportation Service Agreement shall be twelve months, unless the Company and the Customer agree to a shorter or longer term.

The TCQ shall not exceed the lower of (a) the capacity of the Company's metering and regulating equipment at the Customer's location; or (b) 110% of the maximum daily usage of the Customer during the twelve-month period prior to the execution of the Transportation Service Agreement, unless full documentation of new or additional gas usage capability is provided by the Customer. If a Customer chooses to designate an Agent to act on the Customer's behalf for scheduling, dispatching, billing and other administrative aspects of transportation service, such designation shall be made in the Transportation Service Agreement. The designation of an Agent shall not relieve the Customer of ultimate responsibility for payment for service or other obligations incurred under this tariff.

Every November 1 following execution of the Transportation Service Agreement, the Customer's TCQ shall be automatically adjusted by the Company to be 110% of the maximum daily usage of the Customer during the prior twelve-month period if such adjustment would raise or lower the customer TCQ by the higher of either 10 mcf or 10%. The TCQ may also be adjusted by mutual agreement of the Customer and the Company.

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GAS TRANSPORTATION SERVICE GENERAL TERMS AND CONDITIONS – Continued
(Applicable to: Rate TS-I Gas Transportation Service Interruptible and Rate TS F Gas Transportation Service Firm.)

1.6 BUYER GROUP/LEAD CUSTOMER. A Buyer Group generally consists of up to ten individual Customers who voluntarily join together to obtain either firm or interruptible transportation service. The Company, at its discretion, may require all members of the Buyer Group to execute the same Transportation Service Agreement and make the same elections as to Standby Sales Service. One member of the Buyer Group may be designated by the Company as the Lead Customer who shall be responsible for the timely payment of all bills rendered to the Buyer Group, as well as all day to day dispatch scheduling coordination and administrative communication between the Company and all members of the Buyer Group. A member of one Buyer Group may not be a member of another Buyer Group. Eleven or more individual Customers may form a Buyer Group only upon specific agreement by the Company. Unless otherwise described, the term "Customer" as used throughout these general terms and conditions shall refer to an individual Customer or to a Buyer Group. The Company, at its discretion, may set the maximum Commodity Charge for a Buyer Group at the maximum which any member would be individually required to pay.
1.7 MINIMUM SIZE. The minimum total gas consumption capability required to be eligible for transportation service shall be less than or equal to 5,000 Mcf per year. This minimum shall apply to an individual Customer or to a Buyer Group which, in the aggregate, uses less than or equal to 5,000 Mcf of gas annually.

2. BALANCING PROVISIONS

2.1 GENERAL. Transportation balancing is provided to adjust for the unavoidable minor variations between Customer usage and scheduled deliveries, and is not intended to function as a storage service or a standby sales service. Each Customer shall use best efforts to balance deliveries and usage at all times.
2.2 INTERRUPTED RECEIPTS. On days when no transportation gas is received for the Customer's account, all gas used by the Customer shall be billed as a purchase from the Company. For Customers which have elected Standby Sales Service, the usage shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the usage shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and, the Gas Cost Adjustment Charge ("GCA") of Rate GC and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Excess deliveries already being held for the Customer at the time of interruption will be tendered for delivery when transportation receipts resume. If the interruption of receipts continues for more than thirty days, the Company will tender excess deliveries as soon as practicable subject to operating and gas procurement considerations.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, non-NY

North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.3 BALANCING CHARGE. A **$0.0247** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. The Balancing Charge shall be reviewed and adjusted annually, as necessary, effective December 1 subject to approval of the new charge in the Company's annual purchased gas cost filing under 66 Pa. C.S. § 1307(f)
2.4 ALLOWABLE DAILY VARIATION. In order to minimize the effect of transportation imbalances on the operation of the system, the allowable daily variation between delivered quantities and Customer usage is ten percent of the TCQ.
If a Customer exceeds these limits, the Company shall: (a) in the case of excess deliveries, impose a $0.25 per Mcf penalty charge on that portion of daily excess deliveries greater than the allowable daily variation and have the right to limit the receipt of Gas Transportation if a customer has excess deliveries greater than the allowable daily variation (b) in the case of deficient deliveries, have the right to bill such deficiency as a purchase from the Company. For Customers which have elected Standby Sales Service, the deficiency shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the deficiency shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and, the Gas Cost Adjustment Charge ("GCA") of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, Non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

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GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

2.5 MONTHLY BALANCING FOR DEFICIENT DELIVERIES. If in any billing month a Customer has deficient deliveries, the volumes shall be billed at the applicable rate for those customers that have elected Standby Sales Service. For Customers which have not elected Standby Sales Service, the volumes shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and Gas Cost Adjustment Charge ("GCA") of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 Non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.6 MONTHLY BANKING SERVICE FOR EXCESS DELIVERIES. The Customer is permitted to carry over or bank a positive imbalance each month at the following monthly charges:

(a) where the monthly excess does not exceed the TCQ - $0.00 per Mcf;
(b) for the monthly excess greater than the TCQ and less than twice the TCQ - $1.00 per Mcf;
(c) for the monthly excess greater than twice the TCQ and less than three times the TCQ - $5.00 per Mcf;
(d) for the monthly excess greater than three times the TCQ - $10.00 per Mcf.

3. STANDBY SALES SERVICE

3.1 GENERAL. Standby Sales Service permits the Customer to purchase gas under one of the Company's retail sales rate schedules when:
(a) no transportation gas is received for the Customer;
(b) transportation deliveries are deficient with respect to the Customer's usage;
(c) a Customer elects to purchase gas from the Company in lieu of transportation service.

Transportation service under Rate TS-I automatically provides Standby Sales Service as described in Section 3.2 below. A Customer purchasing transportation service under Rate TS-F shall indicate in the Transportation Service Agreement if the Customer elects to have Standby Sales Service. If the Customer elects Standby Sales Service, the Customer shall specify the election in the Transportation Service Agreement as well as the Standby Sales Quantity (SSQ) which is the maximum daily quantity of gas expressed in Mcf that the Customer may purchase. A penalty charge based on the following will be imposed on volumes taken in excess of the SSQ: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

The Company maintains no current or future duty to provide retail sales service to a Customer who declines to elect Standby Sales Service. Availability of Standby Sales Service for new gas loads not previously served under a retail firm sales rate schedule is contingent upon the Company's ability to arrange the required supply contracts.

3.2 INTERRUPTIBLE SERVICE. Interruptible Standby Sales Service under Rate IS is automatically provided to the Customer in conjunction with Rate TS-I. The billing and all other conditions of service shall be as stated under the Rate IS tariff, except that the Customer Charge shall be waived.

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GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

3.3 FIRM SERVICE. All Rate TS-F Customers may elect Standby Sales Service under:
(a) Rate L, for Customers with an SSQ of at least 100 Mcf per day and gas consumption capability of at least 18,000 Mcf per year;

(b) Rate GC, for Customers with an SSQ of less than 100 Mcf per day or gas consumption capability of less than 18,000 Mcf per year except that the Standby Sales Service rate schedule applicable to a Buyer Group may, at the Company's discretion, be set at the highest priced rate schedule under which any member would be individually required to pay. The billing and all other conditions of service shall be as stated in the applicable rate schedule and prorated for actual days of use, except that the Customer Charge shall be waived. In addition, the Customer shall pay a monthly demand charge per Mcf of SSQ which is based on 110% of the average monthly demand charges paid for the Company's firm supply. The monthly demand charge, prorated on an Mcf-per-day basis, will be credited to all volumes purchased. Following the end of the Company's supply contract year (October 31), the Customer shall also be assessed those minimum bill, take-or-pay, supply inventory, or other similar charges actually paid by the Company, which are attributable to the annual volume reserved but not taken under this provision. Customers that request to terminate Standby Sales Service after one or more years will be required to continue payment of the monthly demand charge until the Company is able to reduce its purchase obligations or otherwise utilize the released supplies.

4. OTHER PROVISIONS

4.1 METERING SEQUENCE. Where gas is used by the Customer under more than one of the Company's rate schedules through the same meter location, the Company will assume for billing purposes that metered volumes reflect deliveries in the following sequence where applicable:

(a) Rate L, up to maximum daily quantity.
(b) Rate TS-F, up to transportation contract quantity.
(c) Rate TS-I, up to transportation contract quantity, or actual delivered quantity, whichever is lower.
(d) Rate IS.

4.2 GAS SUPPLY SHORTAGE. The Company shall have the right to appropriate natural gas supplies to be delivered by or on behalf of a Customer in the event of a natural gas emergency (as defined in Rule 12 of the Rules and Regulations). In the event of a natural gas emergency, the Customer or its Natural Gas Supplier (NGS) shall continue to deliver all available natural gas supplies to the Company for which the Customer is contracted to purchase from the NGS. As compensation, the Company shall pay a price not in excess of the greater of the city gate cost of the appropriated natural gas, including transportation charges up to the Company's city gate, or the reasonable cost actually paid by the customer for delivered substitute energy, as documented by the Customer. The Company may also provide compensation in kind at the discretion of the affected customer or NGS. Upon request, the Customer shall demonstrate its cost of natural gas by making a copy and invoice of the contract with the natural gas supplier available to the Company upon request.

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4.3 LIABILITY.

(a) The Company shall not be liable for curtailment of service under this rate schedule or loss of gas of the Customer as a result of any steps taken to comply with any law, regulation, or order of any governmental agency with jurisdiction to regulate, allocate, or control gas supplies or the rendering of service hereunder, and regardless of any defect in such law, regulation, or order.

(b) Gas shall be and remain the property of the Customer while transported and delivered by the Company. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during, and after receipt by the Company.

(c) The Company shall not be liable for any loss to the Customer arising from or out of service under this rate schedule, including loss of gas in the possession of the Company or any other cause. The Company reserves the right to commingle gas of the Customer with other supplies.

(d) The Company shall not be liable, under any circumstances or in any respect, to a Customer, to a gas producer or natural gas supplier, or to any other person or entity for damages arising either directly or indirectly from interruption, curtailment, or termination of transportation service.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

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RATE TS-I GAS TRANSPORTATION SERVICE-INTERRUPTIBLE
(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.
Interruptible transportation service (Rate TS-I) is available to an individual Customer, or a Buyer Group, who may have dual fuel capability or is willing to accept interruption of gas service.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate, as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.
Upgrading and/or installation of mains and services required to provide adequate delivery capacity for interruptible transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.
Interruptible transportation service will be provided on a best efforts basis by the Company and may be restricted or interrupted from time to time due to operating and capacity limitations. Under normal operating conditions a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day.

BILLING.
A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
1. FIXED DISTRIBUTION CHARGE.
$504.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
2. VARIABLE DISTRIBUTION CHARGE.
The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $0.9561 per Mcf.
B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
1. FIXED DISTRIBUTION CHARGE.
$381.03 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
2. VARIABLE DISTRIBUTION CHARGE.
The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual customer. The maximum Variable Distribution Charge shall be $1.6002 per Mcf.
C. The State Tax Adjustment Clause does not apply to this rate.
D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.
The monthly minimum charge shall be the Customer Charge.
SEPARATION OF SERVICE.
Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

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RATE TS-F GAS TRANSPORTATION SERVICE-FIRM

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Firm transportation service (Rate TS-F) is available to an individual Customer or a Buyer Group, who desires uninterrupted transportation service. Firm transportation service is not available with Rate GC through the same meter, except as provided under Standby Sales Service of the General Terms and Conditions.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for firm transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Transportation service under this rate schedule is firm and shall be interrupted only in cases of operating emergencies experienced by the Company or in the case of a natural gas shortage when the supply of gas is insufficient to meet the requirements of Priority 1 Customers.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE
      $504.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $ 1.5529 per Mcf.
B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $381.03 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $2.3138 per Mcf.
C. The State Tax Adjustment Clause does not apply to this rate.
D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge plus 15 days' use of the TCQ at the Customer's applicable commodity charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

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RATE NGS - Negotiated Gas Service

AVAILABILITY. Service under this rate is available only to customers that satisfy the following criteria:

1. The customer either must have a history of at least 18,000 Mcf of annual natural gas usage billed by the Company. Alternatively, if a new customer, the customer must establish that the facilities to be served are likely to consume at least 18,000 Mcf of annual natural gas usage.

2. The customer must document a viable, currently available competitive alternative to service under the Rates GC, L, TS-F, or TS-I including any applicable riders. Documentation must include a written description of the competitive alternative and any further information necessary to establish the cost and demonstrate the viability of the customer's competitive alternative with reasonable certainty. The Company shall have sole discretion over whether the customer is eligible for a rate negotiated pursuant to this rate based on the information provided by the customer. If the customer already has in place a competitive alternative, the Company may require such written proof of the existence, nature, and working condition of such alternative, as the Company deems appropriate and necessary.

3. The customer executes an NGS agreement that comports with all other provisions of this rate.

4. As per Commission Order at Docket No. R-2020-3018929 (Order Entered June 22, 2021), the Company is required to provide an updated competitive alternative analysis to the Commission for any customer that has not had their alternative fuel source verified for a period of five years or more at the point when the Company files a base rate case.

QUALITY OF SERVICE. Service quality shall be negotiated and specified in each service agreement. Service quality may be firm, interruptible or a hybrid thereof. Priority 1 customers, however, shall be required to take firm standby service as a component of service provided under this rate schedule unless the customer demonstrates to the Company's reasonable satisfaction that it has an installed, operable backup system. Unless expressly stated in the service agreement, an interruptible customer shall bear the entire risk for any and all damages associated with an interruption.

NATURE OF SERVICE. The nature of service shall be negotiated and specified in each service agreement. Service may involve any one or more of the following services: supply; transportation; storage; upgrade or installation of mains, services, and appurtenant facilities; and such other natural gas management services the customer may require from time to time. The service agreement shall include all essential terms and conditions of the negotiated service. Where a term is not defined expressly in the service agreement, it shall have the meaning specified in the Tariff or, if the Tariff does not provide a definition, the meaning generally understood within the natural gas industry.

TERM LENGTH/NOTICE OF TERMINATION. The primary term length of a service agreement shall be no less than one year in length. Either the customer or the Company may terminate the agreement at the end of the primary term by giving written notice of termination at least one hundred-eighty (180) days before primary term ending date unless otherwise stated in the service agreement. If neither party gives such notice, then the agreement shall continue for consecutive one year terms until terminated by either party giving written notice of termination at least one hundred-eighty (180) days before the end of the continued term. Terms and conditions applicable to any continued term shall be stated in the service agreement.

RATES, CHARGES, BILLING.

1. Rates for service shall be negotiated and specified in the applicable service agreement. Rates negotiated for this service shall be presumed to have been designed to recover a fair rate of return on the incremental investment in facilities needed to provide service to the customer.

2. Rates will be, in the Company's sole judgment, competitive but the Company shall not be obligated to agree to charges that match the customer's costs under the customer's viable, currently available competitive alternative.

3. Unless otherwise stated in the service agreement, no charge of otherwise general applicability (e.g., State Tax Adjustment Clause) shall apply to service under this rate.

4. Unless otherwise stated in the service agreement, no charge applicable to other sales or transportation services offered under the Company's tariff (e.g., Rates GC, L, TS-I, TS-F) shall apply to service under this rate.

PAYMENT TERMS. Payment terms may be negotiated and specified in the service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 16. Standard Payment Terms of the Rules and Regulations of the Tariff shall apply.

RULES AND REGULATIONS. The Company's Rules and Regulations in effect from time to time, where not inconsistent with any provision hereof or the terms and conditions of the applicable service agreement, shall apply to a service agreement negotiated under this rate.

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RATE NGS - Negotiated Gas Service - Continued

CREDITWORTHINESS

1. Prior to commencement of performance, or at any time during the term of service under this rate, Customer must provide financial information reasonably requested by the Company to ascertain Customer's ability to discharge its payment or other obligations under this rate. The Company shall be permitted to conduct financial evaluations during the term of the service agreement when information received by the Company indicates that the effective Credit Assurance has become unsatisfactory. The Company may charge $100.00 for each evaluation up to two evaluations per calendar year.

2. Based on the Company's initial or subsequent credit evaluation, the Company may refuse, suspend or terminate service under this rate if the Customer fails to deliver the requested credit information or assurance of its ability to pay within ten (10) business days of such request. Credit Assurance may include (i) the required posting of an irrevocable letter of credit acceptable to the Company, (ii) a cash prepayment in an amount acceptable to the Company, (iii) a corporate guaranty or (iv) other security acceptable to the Company.

3. Upon five days prior written notice ("Notice Period") to an NGS customer, the Company may suspend or terminate service to the customer upon the occurrence of a Default Event. A Default Event shall mean (i) the failure by the customer to make, when due, any payment or perform any obligation required under the service agreement, (ii) any representation or warranty made by the customer shall prove to have been false or misleading in any material respect when made, (iii) the customer is subject to a Bankruptcy Proceeding, or (iv) the customer fails to post satisfactory Credit Assurance. If the customer cures the Default Event within the Notice Period, service will be continued by the Company pursuant to the terms of the service agreement.

CONFIDENTIALITY/PENALTY FOR DISCLOSURE.

1. The terms and conditions of a service agreement executed pursuant to this rate shall be considered "Highly Confidential and Privileged" by the parties and by the Commission.

2. "Highly Confidential and Privileged" shall mean that disclosure to any third party, non-governmental entity is likely to cause the non-disclosing party pecuniary and competitive damage not easily susceptible to quantification.

3. Unless disclosure is otherwise permitted, each party to a service agreement under this rate must agree not to oppose a legal action by a party that is designed to enjoin or otherwise prevent the other party from disclosing the terms and conditions of such service agreement to a third party.

4. Service agreements may be disclosed to a third party only: a) upon prior written authorization by the parties to the agreement; b) as necessary for the parties to administer and enforce the agreement; c) to an agent, attorney or consultant of either party which has executed an agreement in which it acknowledges the "Highly Confidential and Privileged" nature of the service agreement and agrees to be subject to these Confidentiality/Penalty for Disclosure provisions set forth herein; or d) pursuant to the order of a court of agency having appropriate jurisdiction. Disclosure under b) or d) shall be permitted only after the parties to the service agreement have been provided adequate prior notice and opportunity to prevent such disclosure or to seek an appropriate protective order.

5. Any disclosure by the customer in violation of this provision shall result in a penalty equal to 10% of the otherwise applicable rate for the remaining term of the agreement, or as otherwise set forth in the service agreement.

EXCLUSION OF RATE NGS PURCHASED GAS COSTS FROM SECTION 1307(f) CLAIM

Purchased gas commodity and interstate pipeline demand costs, and associated quantities of natural gas purchased to provide service to customers served under Rate NGS, shall be excluded from the Company's annual purchased gas cost filing under 66 Pa. C.S. § 1307(f), in accordance with Exhibit RAF-1 submitted by the Company at Docket No. R-00016366.

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APPLICABILITY INDEX OF RIDERS INTRODUCTORY STATEMENT

Customers under the 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 rate under which they are supplied. 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.

RIDERS	PAGE NUMBERS	RATES TO WHICH RIDERS APPLY						
		GR	GC	OL	L	IS	TSI	TSF
Casualty	79	X	X	X	X	X	X	X
Construction	79	-	X	-	X	X	X	X
Neighborhood Gas	80	X	-	-	-	-	-	-
Receivership	82	X	X	X	X	X	X	X
Temporary Service	82	X	X	-	X	-	-	-
Customer Assistance Program	83	X	-	-	-	-	-	-

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CASUALTY RIDER

APPLICABILITY. To service delivered 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.

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.

GUARANTEES WAIVED. Guarantees of revenue under the Customer's contract shall be suspended during the period of the interruption, but shall be restored when the cause of interruption shall cease, be removed or remedied.

BILLS PRORATED. Bills for service supplied shall be prorated, based upon the actual level of operation during the period of suspension of guarantees.

RETURN TO NORMAL USE. The Customer shall use reasonable diligence in resuming the use of service provided in the Customer's contract.

TERM. The contract term shall be extended for a period equal to the period of suspension so that the Company shall secure a working term at full connected load equal to the term of the contract.

CONSTRUCTION RIDER

APPLICABILITY. To service supplied during a preliminary operating or construction period while the load is being built up to normal level or during a receding load period after the expiration of a standard contract term while a business is in process of dissolution.

GUARANTEE WAIVED. The guarantee minimum of a contract will be waived 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 a contract term.

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 two successive renewals of the rider term on major construction projects. Its application subsequent to the completion of a contract term shall be for not more than one year.

CONTRACT TERM. The termination date of a contract for service to permanent installations to which this rider is applied shall be extended for a period corresponding to the total time of the rider application during start up, construction or extension of the Customer's plant so that the Company will be assured the business represented by service to the total connected load for the term provided in the contract.

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NEIGHBORHOOD GAS PILOT RIDER (NGPR)

AVAILABILITY

The Neighborhood Gas Pilot Rider (NGPR) is available to any existing residential neighborhood that: (1) applies for natural gas service within the Company's service territory under Rate Schedules GR or CAP; (2) would be required to pay the portion of the main extension and service line project costs that exceed the Company's capital investment under Rule No. 7 – Extensions of the Company's gas service tariff ("Rule No. 7") for an extension of the Company's distribution facilities needed to furnish natural gas service to a neighborhood; and (3) meets the Program Criteria set forth below.

The NGPR will close for new main extension projects on December 31, 2029 unless the Company decides to extend this program and the extension is approved by the Commission. The Company reserves the right to suspend the pilot program if, in its sole judgment, critical safety or reliability related issues require that the resources that would be used to implement the NGPR are needed to maintain safe and reliable natural gas service to its existing customers. The Company shall be the sole judge in establishing what constitutes a neighborhood when determining the availability under this pilot program.

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NATURE OF THE NGPR

The NGPR provides customers in a neighborhood an alternative method of making the payment required by Rule No. 7 when the extension of distribution facilities needed to serve eligible new customers is not economically justified based on the anticipated revenues from natural gas distribution service that would be provided to customers served by such extension. The NGPR provides for a fixed charge (NGPR Charge) to be added to the customer's bill or an option to pay via a lump sum payment. The NGPR Charge shall be calculated separately for each main extension project and shall be based on the cost of that particular project in the manner described below for each customer served from such main extension project.

PROGRAM CRITERIA

For a main extension project to qualify for the NGPR, the neighborhood must consist of 2 or more existing residences, and the cost for such project must equal or exceed $15,000 and must meet the following additional criteria:

(1) A minimum of twenty percent (20%) of the existing residences located along the new main extension must commit to receive natural gas service by signing an agreement prior to the start of construction.

(2) The Company must have adequate system capacity to serve the customers that are eligible to receive natural gas service from the main extension; and

(3) The Company's total investment under this pilot program is limited to no more than $40,000,000 over five (5) years. The five-year extension period that this pilot program is in effect shall commence on January 1, 2025 and, as set forth above, shall close on December 31, 2029.

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CALCULATION OF THE NGPR CHARGE

A Net Present Value (NPV) economic test (based on 40 years of revenue for each customer) shall be used to determine the payment required by Rule No. 7.

Pursuant to Rule No. 7, if the NPV of the capital investment (excluding 40 feet gas main allotment per existing residence) and the associated estimated revenues is less than zero, a customer is required to make a payment to the Company in an amount that would produce an NPV of zero, exclusive of any tax on the NGPR For purposes of this NGPR, however, in calculating the NPV, the anticipated revenues from natural gas service shall consist of: (1) the revenues from 20% (or greater) of eligible customers signing a contract prior to the start of construction to take natural gas service in the first year, which is one of the Program Criteria that must be satisfied for a project to be eligible for the NGPR; and (2) additional revenues will be applied in the first year based on the assumption a minimum of 66% of the eligible customers within the project area will sign a contract for natural gas service within 20 years of the completion of the project.

Capital investment shall include the total cost of new main(s) (excluding 40 feet gas main allotment per existing residence) and service facilities installed under the NGPR, excluding the costs of meters and meter installations, to serve eligible customers.

Estimated revenues shall be based on the applicable variable distribution charge rate set forth in the Company's gas service tariff, the estimated annual consumption and the portion of the fixed distribution charge that is attributable to the capital costs of a service line.

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NEIGHBORHOOD GAS PILOT RIDER (NGPR) - Continued

Because the NGPR permits payment over time, rather than a lump-sum payment prior to the start of construction of main extension projects, as Rule No. 7 requires, the NGPR Charge will recover a reasonable return on the Company's capital investment in new facilities installed pursuant to the NGPR. For purposes of the NGPR calculation, the discount rate shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

The NGPR shall be calculated to enable the project to have an NPV of zero based upon the above cost of capital. The resulting charge shall be increased by 1% by dividing the calculated rate by 0.99 to reflect an adjustment for uncollectible accounts expense.

BILLING

The NGPR Charge shall appear as a fixed monthly charge on the customer's bill.

The NGPR Charge calculated for a specific main extension will apply to all customers taking service from that main extension including any future customers that connect after the first year of the project.

For CAP customers, the NGPR charge will not be subject to the CAP discount.

If a customer fails to pay the full amount of any bill, a late payment charge of one and one-half percent (1.5%) per month will accrue on the portion of the bill that is unpaid on the due date.

PAYMENT TERMS

NGPR Charges shall be calculated based on input data specific to each project undertaken pursuant to the NGPR and shall be in effect for 20 years for each customer taking gas service from the main installed under this pilot within 20 years after the project has been completed.

The customer shall retain the right to pay the present value of the remaining monthly payments at any point in time during the 20 year period. Payments shall be present valued using PECO's after-tax cost of capital which shall be based on the sources as described above.

Service shall not be terminated for non-payment of this charge during the pilot program.

The STATE TAX ADJUSTMENT CLAUSE applies to this rider.

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RECEIVERSHIP RIDER

APPLICABILITY. To service supplied a Receiver-Trustee for the continued operation of a property formerly under contract for its gas 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 gas service under which the Company has been supplying gas.

ACCEPTANCE. The Receiver-Trustee shall accept and adopt for the continuation of the supply of gas service the contract therefore in effect, including all of its provisions, and agree to pay the Company for all service furnished hereunder 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, the commodity charge will be determined on a monthly basis and multiplied by 14/30ths (0.4667).
(c) The monthly rate per lighting device for Rate OL will be multiplied by 0.4667.
(d) 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.
(e) A discount of 0.4% will be applied to the total bill.
(f) 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.

CONTRACT TERM. 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 supply under the standard terms of this Tariff.

TEMPORARY SERVICE RIDER

APPLICABILITY. To the supply of service for a temporary period.

AVAILABILITY. Temporary service will be supplied only when the Company has available unsold capacity from which to furnish it and its supply will not in any way interfere with service to other Customers.

INVESTMENT IN SUPPLY FACILITIES. The cost of the connection and disconnection of the service supply and of any equipment and extension 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 shall not, for billing purposes, be considered to be for a period of less than one month.

CONTRACT TERM. Short term arrangements as agreed upon.

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Customer Assistance Program (CAP) Rider

AVAILABILITY:

To payment-troubled customers who are currently served under or otherwise qualify for Rate GR (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 and will not be eligible to obtain Competitive Natural Gas Supply or participate in budget billing.

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Based on the applicable level of income and number of household members, CAP customers will receive a 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.

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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 energy reduction 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.

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MINIMUM CHARGE.

The minimum charge per month will be $20.

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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.

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WEATHER NORMALIZATION ADJUSTMENT (WNA)

APPLICABILITY AND PURPOSE

A Weather Normalization Adjustment ("WNA") for natural gas service shall be included in monthly bills under Rate Schedules GR and GC for any bills rendered during the heating season (October through May). The WNA shall commence with bills rendered on and after January 1, 2025.

Calculated WNA amounts shall be subject to the State Tax Adjustment Surcharge (STAS) and the Distribution System Improvement Charge (DSIC).

COMPUTATION OF WNA

The WNA is a dollar value that will be included in billing periods from October through May. The Company shall calculate the WNA for each Rate GR and GC customer on an account-specific monthly basis using the formulas below:

WNBC = BLMC + [((NHDD +/- (NHDD * 1%)) / AHDD) x (AMC-BLMC)]

WNAC = WNBC – AMC

WNA = WNAC x VDC(n)

In computing the WNA, pursuant to the formulas above, the following definitions shall apply:

- **WNBC** - Weather Normalized Billing Ccfs as defined in the formula above.

- **BLMC** – Base Load Monthly Ccfs.

  The Company shall establish a BLMC for each customer annually using the customer's actual average daily consumption history, measured in Ccfs, from the two billing periods from the prior summer with starting meter read dates of June 15th, multiplied by the number of days in the billing period.

  If less than two billing periods of actual consumption history from the prior summer is available for a customer, the Company shall establish the BLMC for that customer using the average daily consumption per customer for all customers taking service under the applicable rate schedule.

- **NHDD** – Normal Heating Degree Days ("NHDD") shall reflect heating degree days associated with "normal" weather during the billing period for the customer based on a 3-year average.

- **AHDD** – Actual Heating Degree Days ("AHDD") shall be the actual experienced heating degree days during the billing period for the customer.
  If AHDD are unavailable for any day(s) during a billing period, the Company will also exclude the respective NHDD for the same day(s) from the calculation, thereby excluding any day(s) missing AHDD from the WNBC calculation for that billing period.

- **1% (Deadband) –** A threshold governing when the WNA is applied for a particular billing period.

  The Company shall apply a deadband of 1%. The WNA will apply for a given billing period only if the AHDD for that period are either lower than 99%, or higher than 101%, of the NHDD for that period.

  When the weather is colder than normal (i.e., AHDD>NHDD), the deadband percentage shall be multiplied by, and then added to, the NHDD for that period.

  When the weather is warmer than normal (i.e., AHDD<NHDD), the deadband percentage shall be multiplied by, and then subtracted from, the NHDD for that period.

- **AMC** – Actual Monthly Ccfs ("AMC"). The Company will measure this for each customer's billing period. The WNA for a billing period will only apply if the customer's AMC for that period are greater than their BLMC.

- **WNAC** – Weather Normalized Adjustment Ccfs ("WNAC"). The Company will calculate the WNAC by subtracting the customer's AMC for the billing period from their WNBC.

WEATHER NORMALIZATION ADJUSTMENT (WNA) (continued)

- **VDC(n)** – Applicable Customer Variable Distribution Charge

- **WNA** – Weather Normalization Adjustment amount charged or credited to each customer served under the GR and GC rate schedules for the billing period.

The Company will calculate the WNA amount for that period based on service rendered by multiplying the WNAC by the applicable rate schedule's Variable Distribution Charge, including all applicable surcharges.

If the Company cancels and rebills a customer's bill for a given billing period, the Company will recalculate the WNA for that period using the most recently available data for that period. This may result in a different WNA calculation for the billing period. Bills requiring manual processing shall not have WNA applied.

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PECO Exhibit JAB-3:

Comparison of Residential Customer Charges for Pennsylvania Natural Gas Distribution Utilities

Comparison of Residential Customer Charges for Pennsylvania Natural Gas Distribution Utilities

Company	**Current Residential Customer Charge**
Columbia Gas of Pennsylvania[1]	$16.75
National Fuel	$14.00
Peoples Natural Gas[2]	$14.50
Philadelphia Gas Works	$16.25
UGI	$15.00
PECO Current	**$14.25**
PECO Proposed	**$19.45**

1 Columbia Gas of Pennsylvania filed a proposed customer charge per month of $26.00 on March 15, 2024 (Docket No. R-2024-3046519).

2 Peoples Gas filed a proposed customer charge per meter per month of $21.50 on December 29, 2023 (Docket No. R-2023-3044549).

PECO Exhibit JAB-4:

Proof of Revenues at Present and Proposed Rates

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Residential (GR)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	6,151,911	$ 14.25	$ 87,664,732	$ 19.38	$ 119,224,035
3						
4	**Total Customer Charge Revenue**			$ 87,664,732		$ 119,224,035
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate	43,867,240	$ 5.4651	$ 239,738,853	$ 6.8435	$ 300,204,298
8	CAP Credits - Distribution			$ (6,943,356)		$ (8,694,566)
9	CAP Credits - Non-Distribution			$ (6,900,338)		$ (6,900,338)
10	CAP Shortfall			$ 1,819,092		$ -
11	Distribution System Improvement Charge (DSIC)			$ 10,116,761		$ -
12						
13	**Total Variable Distribution Revenue**			$ 237,831,012		$ 284,609,394
14						
15	Annualization			$ 1,185,491		$ 1,470,806
16						
17	**Adjusted Total Distribution Revenue**			$ 326,681,235		$ 405,304,235

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - General Service Commercial & Industrial (GC)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate, 2025	547,071	$ 29.86	$ 16,335,540	$ 36.38	$ 19,902,443
3						
4	Proposed Base Rate as of 1/1/2026					
5	Small	*205,656*			*$ 29.36*	*$ 6,038,060*
6	Large	*341,415*			*$ 40.61*	*$ 13,864,383*
7						
8	**Total Customer Charge Revenue**			$ 16,335,540		$ 19,902,443
9						
10	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
11	Base Rate - First 200 mcf	17,650,825	$ 4.4248	$ 78,101,369	$ -	$ -
12	Base Rate - Over 200 mcf	6,201,691	$ 3.5201	$ 21,830,574	$ -	$ -
13						
14	Base Rate - All Usage	23,852,516			$ 5.4413	$ 129,788,370
15						
16	Distribution System Improvement Charge (DSIC)			$ 5,399,031		$ -
17						
18	**Total Variable Distribution Charge Revenue**			$ 105,330,974		$ 129,788,370
19						
20	Annualization			$ 983,902		$ 1,210,531
21						
22	**Adjusted Total Distribution Revenue**			$ 122,650,416		$ 150,901,344

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Outdoor Lighting (OL)

Line			PRESENT RATES		PROPOSED RATES	
1	**Manufacturer-Rated Input to Lighting Devices (lamp-based)**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	When NOT in Conjunction With Service Under Other Gas Rates					
3	Up to 1,999 Btu/Hr	24	$ 7.8994	$ 190	$ 10.0878	$ 242
4	2,000-2,499 Btu/Hr	12	$ 9.1897	$ 110	$ 11.7355	$ 141
5	2,500-2,999 Btu/Hr	-	$ 10.3154	$ -	$ 13.1731	$ -
6	3,000-3,499 Btu/Hr	-	$ 11.5161	$ -	$ 14.7064	$ -
7				$ 300		$ 383
8	When in Conjunction With Service Under Other Gas Rates					
9	Up to 1,999 Btu/Hr	-	$ 3.9313	$ -	$ 5.0204	$ -
10	2,000-2,499 Btu/Hr	-	$ 5.2512	$ -	$ 6.7059	$ -
11	2,500-2,999 Btu/Hr	-	$ 6.3622	$ -	$ 8.1247	$ -
12	3,000-3,499 Btu/Hr	-	$ 7.5773	$ -	$ 9.6764	$ -
13				$ -		$ -
14						
15	Distribution System Improvement Charge (DSIC)			$ 11		$ -
16						
17	**Total Lamp-Based Distribution Revenue**			$ 311		$ 383
18						
19	Annualization			$ 2		$ 2
20						
21	**Adjusted Total Distribution Revenue**			$ 313		$ 385

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Large Load Factor (L)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	96	$ 260.00	$ 24,960	$297.01	$ 28,513
3						
4	**Total Customer Charge Revenue**			$ 24,960		$ 28,513
5						
6	**Variable Distribution Charges (mcf-based)**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate - First 50% of usage	10,500	$ 7.3127	$ 76,783	$ 8.0858	$ 84,901
8	Base Rate - Additional usage	10,500	$ 2.2212	$ 23,323	$ 2.4560	$ 25,788
9						
10	Distribution System Improvement Charge (DSIC)			$ 14,136		$ -
11						
12	**Total Variable Distribution Charge Revenue**			$ 114,242		$ 110,689
13						
14	Annualization			$ 115		$ 115
15						
16	**Adjusted Total Distribution Revenue**			$ 139,317		$ 139,317

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Motor Vehicles - Firm (MV-F)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	180	$ 49.84	$ 8,971	$ 67.80	$ 12,204
3						
4	**Total Customer Charge Revenue**			$ 8,971		$ 12,204
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate	502,606	$ 1.1005	$ 553,118	$ 1.3649	$ 686,025
8						
9	Distribution System Improvement Charge (DSIC)			$ 50,197		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 603,315		$ 686,025
12						
13	Annualization			$ 405		$ 462
14						
15	**Adjusted Total Distribution Revenue**			$ 612,691		$ 698,691

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Motor Vehicles - Interruptible (MV-I)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	12	$ 49.84	$ 598	$ 58.50	$ 702
3						
4	**Total Customer Charge Revenue**			$ 598		$ 702
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	1,064	$ 2.7186	$ 2,892	$ 2.7203	$ 2,894
8						
9	Distribution System Improvement Charge (DSIC)			$ 106		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 2,998		$ 2,894
12						
13	Annualization			$ 1		$ 1
14						
15	**Adjusted Total Distribution Revenue**			$ 3,597		$ 3,597
16						
17	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Interruptible Service (IS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	12	$ 217.89	$ 2,615	$ 297.41	$ 3,569
3						
4	**Total Customer Charge Revenue**			$ 2,615		$ 3,569
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	16,440	$ 3.5201	$ 57,870	$ 3.7861	$ 62,243
8						
9	Distribution System Improvement Charge (DSIC)			$ 5,327		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 63,197		$ 62,243
12						
13	**Total Distribution Revenue**			$ 65,812		$ 65,812
14						
15	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Temperature Controlled Service (TCS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	237	$ 125.00	$ 29,625	$ 170.00	$ 40,290
3						
4	**Total Customer Charge Revenue**			$ 29,625		$ 40,290
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	129,260	$ 5.0639	$ 654,560	$ 5.2873	$ 683,431
8						
9	Distribution System Improvement Charge (DSIC)			$ 39,536		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 694,096		$ 683,431
12						
13	Annualization			$ (26,474)		$ (26,474)
14						
15	**Adjusted Total Distribution Revenue**			$ 697,247		$ 697,247
16						
17	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Interruptible (TS-I)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	No backup					
3	>= 18,000 mcf annually	1,020	$ 383.88	$ 391,558	$ 504.83	$ 514,927
4	< 18,000 mcf annually	1,116	$ 322.66	$ 360,089	$ 381.03	$ 425,231
5						
6	Rate L backup					
7	>= 18,000 mcf annually	264				
8	TS-I Base Rate		$ 383.88	$ 101,344	$ 504.83	$ 133,275
9	TS-F Duel Fuel		$ 161.00	$ 42,504	$ 161.00	$ 42,504
10	< 18,000 mcf annually	-				
11	TS-I Base Rate		$ 322.66	$ -	$ 381.03	$ -
12	TS-F Duel Fuel		$ 161.00	$ -	$ 161.00	$ -
13						
14	Rate GC backup					
15	>= 18,000 mcf annually	60				
16	TS-I Base Rate		$ 383.88	$ 23,033	$ 504.83	$ 30,290
17	TS-F Duel Fuel		$ 161.00	$ 9,660	$ 161.00	$ 9,660
18	< 18,000 mcf annually	216				
19	TS-I Base Rate		$ 322.66	$ 69,695	$ 381.03	$ 82,303
20	TS-F Duel Fuel		$ 161.00	$ 34,776	$ 161.00	$ 34,776
21						
22	**Total Customer Charge Revenue**			$ 1,032,659		$ 1,272,966
23						
24	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
25	No Backup					
26	>= 18,000 mcf annually	6,246,637	$ 0.8522	$ 5,323,384	$ 0.9561	$ 5,972,495
27	< 18,000 mcf annually	658,263	$ 1.6002	$ 1,053,352	$ 1.6002	$ 1,053,352
28	Negotiated Gas Sales	4,900,376	Negotiated	$ 488,306	Negotiated	$ 488,306
29						
30	Rate L Backup					
31	>= 18,000 mcf annually					
32	Commodity TSI Mcf	854,235	$ 0.8522	$ 727,979	$ 0.9561	$ 816,746
33	Commodity TSF Mcf	441,722	$ 1.0776	$ 476,000	$ 1.5529	$ 685,955
34	Additional Commodity (15 days TCQ)	97,807	$ 1.0776	$ 105,396	$ 1.5529	$ 151,885
35	< 18,000 mcf annually					
36	Commodity TSI Mcf	-	$ 1.6002	$ -	$ 1.6002	$ -
37	Commodity TSF Mcf	-	$ 2.2578	$ -	$ 2.3138	$ -
38	Additional Commodity (15 days TCQ)	-	$ 2.2578	$ -	$ 2.3138	$ -

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Interruptible (TS-I)

Line			PRESENT RATES		PROPOSED RATES	
39		**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
40	Rate GC Backup					
41	>= 18,000 mcf annually					
42	Commodity TSI Mcf	42,349	$ 0.8522	$ 36,090	$ 0.9561	$ 40,490
43	Commodity TSF Mcf	24,949	$ 1.0776	$ 26,885	$ 1.5529	$ 38,744
44	Additional Commodity (15 days TCQ)	5,539	$ 1.0776	$ 5,969	$ 1.5529	$ 8,602
45	< 18,000 mcf annually					
46	Commodity TSI Mcf	124,365	$ 1.6002	$ 199,009	$ 1.6002	$ 199,009
47	Commodity TSF Mcf	45,240	$ 2.2578	$ 102,143	$ 2.3138	$ 104,678
48	Additional Commodity (15 days TCQ)	6,407	$ 2.2578	$ 14,466	$ 2.3138	$ 14,825
49						
50						
51	Distribution System Improvement Charge (DSIC)			$ 1,256,415		$ -
52						
53	**Total Variable Distribution Charge Revenue**			$ 9,815,394		$ 9,575,087
54						
55	**Adjusted Total Distribution Revenue**			$ 10,848,053		$ 10,848,053

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Firm (TS-F)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	>= 18,000 mcf annually	1,656	$ 336.62	$ 557,443	$ 504.83	$ 835,998
3	< 18,000 mcf annually	3,144	$ 280.17	$ 880,854	$ 381.03	$ 1,197,962
4						
5	**Total Customer Charge Revenue**			$ 1,438,297		$ 2,033,960
6						
7	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	>= 18,000 mcf annually					
9	Negotiated Gas Sales	2,650,270	Negotiated	$ 980,600	Negotiated	$ 980,600
10	Commodity TSF Mcf	7,597,193	$ 1.0776	$ 8,186,735	$ 1.5529	$ 11,797,766
11	Additional Commodity (15 days TCQ)	2,087,112	$ 1.0776	$ 2,249,072	$ 1.5529	$ 3,241,099
12	< 18,000 mcf annually					
13	Commodity TSF Mcf	1,626,344	$ 2.2578	$ 3,671,960	$ 2.3138	$ 3,763,096
14	Additional Commodity (15 days TCQ)	653,531	$ 2.2578	$ 1,475,542	$ 2.3138	$ 1,512,164
15						
16	Distribution System Improvement Charge (DSIC)			$ 1,118,479		$ -
17						
18	**Total Variable Distribution Charge Revenue**			$ 17,682,388		$ 21,294,725
19						
20	**Adjusted Total Distribution Revenue**			$ 19,120,685		$ 23,328,685

PECO Exhibit JAB-5:

Calculation Methodology for Differentiated Rate GC Customer Charge by Tier

Calculation Methodology for Differentiated Rate GC Customer Charge by Tier

This exhibit describes the methodology used by PECO to calculate the proposed differentiated customer charges for Gas Rate GC customers, proposed to be effective as of January 1st, 2026.

The "Small" Rate GC tier includes all Rate GC customers with exactly one Company-owned "Small Diaphragm" gas meter at their premises. Meter sizes considered "Small Diaphragm" include Sizes 6, 11, 12, 13, 14, 15, 16, 17, 18, 19, and 33.

The "Large" Rate GC tier includes all Rate GC customers with a meter of any other size and all Rate GC customers with more than one gas meter at their premises, regardless of gas meter size. (For example, a customer served by two Small Diaphragm gas meters is considered "Large".)

1. Gather Rate GC customers' gas meter size and cost data based on Company records as of October 2023, as used in PECO's most recent Cost Of Service Study ("COSS").

Meter Size (Rate GC)	Meter Count	% of Total GC Meter Count	Meter Cost	% of Total GC Meter Cost
Small Diaphragm	17,069	34.0%	$5,585,318	8.7%
All Other Sizes	33,118	66.0%	$58,694,001	91.3%

2. Determine the number of Rate GC accounts qualifying for each tier based on the size of the gas meter(s) at their premises.

GC Tier	Number of GC Accounts	% of GC Accounts	Adjusted Number of Bills*
Small	17,754	37.6%	205,656
Large	29,474	62.4%	341,415

** Based on estimated Rate GC total of 547,071 bills to be issued in Fully Projected Future Test Year (FPFTY)*

3. Calculate the average cost per meter per customer for each tier, as follows:
   Rate GC Meter Investment (Exhibit JAD-4, Page 3, Line 16)
   times
   % of Total GC Meter Cost by Tier (8.7% for Small, 91.3% for Large)
   divided by
   Adjusted Number of FPFTY Bills by Tier (205,656 for Small, 341,415 for Large)

GC Tier	GC Meter Investment	% of Total GC Meter Cost	Adjusted Number of Bills*	Resulting Average Cost Per Meter Per Customer
Small	$11,748,210	8.7%	205,656	**$4.96**
Large		91.3%	341,415	**$31.42**

4. Simulate PECO COSS customer-related cost for Rate GC for each GC tier, using the average costs per meter above.

$ / MONTH / CUSTOMER	Overall GC	Small GC Tier	Large GC Tier
CUSTOMER COMPONENTS	$85.59	$69.07	$95.53
CUSTOMER SERVICE INVESTMENT	$57.52	$57.52	$57.52
CUSTOMER METERS, REGUL & INSTALL INVESTMENT	$21.47	**$4.96**	**$31.42**
CUSTOMER INSTALLATION EXPENSE	$2.52	$2.52	$2.52
CUSTOMER SERVICE & SALES EXPENSE	$0.28	$0.28	$0.28
CUSTOMER ACCOUNTS EXPENSE	$3.79	$3.79	$3.79

5. Determine the "Small GC Tier" customer charge by reducing PECO's proposed "single" customer charge based on the ratio of the "Small GC Tier" to "Overall GC" customer-based costs.

   Proposed "Single" Customer Charge: $36.38

   Resulting Proposed Small GC Tier Customer Charge:
   $36.38 * $69.07/85.59 = **$29.36**

6. Calculate the "Large GC Tier" customer charge so that it recovers the remaining customer-related revenues. Collectively, the rate design goal is to set both tiered customer charges at levels designed to recover the same amount of revenue that the originally proposed single customer charge would have recovered from all Rate GC customers.

   As shown on Page 2 of PECO Exhibit JAB-4:

   Proposed "Single" Customer Charge Revenue:
   $36.38 Cust Charge * 547,071 Bills = $19,902,443 (Total GC Cust Rev)

   Resulting Proposed GC Tier Customer Charge Revenues:
   $29.36 Small GC Cust Charge * 205,656 Small GC Bills = $6,038,060 (Small GC Cust Rev)

   $19,902,443 GC Cust Rev - $6,038,060 Small GC Cust Rev = $13,864,383 (Large GC Cust Rev)

   $13,864,383 Large GC Cust Rev / 341,415 Large GC Bills = **$40.61** (Large GC Cust Charge)

PECO Exhibit JAB-6:

Modified Base Rate Recovery of CAP Revenues in Gas USFC

C-Factor Period	Estimated CAP Credits ($)	Estimated GR Sales (a) (MCF)	Estimated Shortfall Recovered in Base Rates (b)	Shortfall o/(u) Base Recovery	Shortfall o/(u) Base Recovery (c)
			(3) = (2) * $0.2656 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024
	(1)	(2)	(3) = (2) * $0.3123 as of 1/1/2025	(4) = (1) - (3)	(5) = (4) * 0.895 as of 1/1/2025
Dec-24					
Jan-25					
Feb-25					
Mar-25					
Apr-25					
May-25					
Jun-25					
Jul-25					
Aug-25					
Sep-25					
Oct-25					
Nov-25					
	$ -	-	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Non-CAP MCFs.
(b) Current factor is per settlement approved at Docket No. R-2010-2161592.
PECO is proposing to update this factor effective January 1, 2025.

Projected FPFTY 2025 CAP Credits:	$	13,700,000
Projected Res Non-CAP Sales for FPFTY 2025 (MCF):		43,865,478
Resulting Base Rate Recovery per MCF:	$	0.3123

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.5%

-0.1398

E-Factor Period	Total CAP Credits ($)	GR Sales (b) (MCF)	CAP Revenues Recovered in Base Rates (c)	Base Recovery o/(u) Actual	Base Recovery o/(u) Actual (d)	C-Factor Revenue	C-Factor Over/(Under) Recovery
			(3) = (2) * $0.2656 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024		
	(1)	(2)	(3) = (2) * $0.3123 as of 1/1/2025	(4) = (3) - (1)	(5) = (4) * 0.895 as of 1/1/2025	(6) = (2) * (.1398)	(7) = (5) + (6)
Dec-23							
Jan-24							
Feb-24							
Mar-24							
Apr-24							
May-24							
Jun-24							
Jul-24							
Aug-24							
Sept-24 (a)							
Oct-24 (a)							
Nov-24 (a)							
	$ -	-	$ -	$ -	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (c-d) for PECO's proposed change.

(a) Actual 1307 filing uses estimates since a hearing date may be on or after September 1 of each year.
(b) Residential Non-CAP MCFs.
(b) Current factor is per settlement approved at Docket No. R-2010-2161592.
PECO is proposing to update this factor effective January 1, 2025.

Projected FPFTY 2025 CAP Credits:	$	13,700,000
Projected Res Non-CAP Sales for FPFTY 2025 (MCF):		43865477.5
Resulting Base Rate Recovery per MCF:	$	0.3123

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.5%

PECO ENERGY COMPANY
STATEMENT NO. 7-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: RESPONDING TO OPPOSING PARTIES' TESTIMONY REGARDING PECO ENERGY COMPANY'S REVENUE ALLOCATION; SCALE BACK OF RATES; CUSTOMER CHARGES; AND NON-RESIDENTIAL RATE DESIGN

DATED: JULY 16, 2024

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VI. CONCLUSION 17

REBUTTAL TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Joseph A. Bisti. I am employed by PECO Energy Company ("PECO" or the "Company") as a Manager of Rate Analysts. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 7. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to: (1) Office of Consumer Advocate ("OCA") witness Clarence Johnson, Bureau of Investigation and Enforcement ("I&E") witness Ethan H. Cline, Office of Small Business Advocate ("OSBA") witness Mark D. Ewen, Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte, and Walmart, Inc. ("Walmart") witness Lisa V. Perry regarding the proposed revenue allocation I prepared on behalf of PECO Energy Company ("PECO" or the "Company") and which was attached to my direct testimony as Exhibit JAB-1; (2) OCA witness Johnson, OCA witness Roger D. Colton, Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") witness Elizabeth R. Marx, and OSBA witness Ewen regarding PECO's proposed customer charges; and

(3) the direct testimony of OSBA witness Ewen and PAIEUG witness LaConte concerning rate design for non-residential customers.

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes, I have prepared the following exhibits:

PECO Exhibit JAB-1 Revised	Revised Proposed Revenue Allocation and Rates of Return by Rate Class
PECO Exhibit JAB-2 Revised	Gas Service Tariff (Revised Pages Only)
PECO Exhibit JAB-3 Revised	Corrected Comparison of Residential Customer Charges for Pennsylvania Natural Gas Distribution Utilities
PECO Exhibit JAB-4 Revised	Revised Proof of Revenue at Present and Proposed Rates
PECO Exhibit JAB-6 Revised	Revised Modified Base Rate Recovery of CAP Revenues in Universal Service Fund Charge
PECO Exhibit JAB-7	Response to Interrogatory PECO OCA-II-12
PECO Exhibit JAB-8	Response to Interrogatory PECO OCA-II-13
PECO Exhibit JAB-9	Response to Interrogatory PECO OSBA-II-2

5. Q. Do you have any revisions to your exhibits accompanying your direct testimony?

A. Yes. During the discovery process, the Company determined that PECO Exhibit JAB-3 listed its proposed residential customer charge as $19.45 instead of $19.38 in the comparison of customer charges among Pennsylvania natural gas distribution companies. I have corrected this error in Exhibit JAB-3 Revised.

In addition, PECO is revising its recommended change to the offset factor applied to reconcilable Customer Assistance Program ("CAP") costs recovered through PECO's Universal Service Fund Charge ("USFC") as discussed in the rebuttal

testimony of Company witnesses Michael J. Trzaska (PECO Statement No. 3-R) and Jacqueline F. Golden (PECO Statement No. 10-R). PECO Exhibits JAB-2 Revised and JAB-5 Revised reflect PECO's updated proposal for the USFC offset factor (12.1%), which represents a 1.6% increase from PECO's initial filing.

Finally, PECO Exhibits JAB-1 Revised and JAB-4 Revised incorporate the revisions summarized below.

II. REVENUE ALLOCATION

6. Q. Is the Company proposing any changes to its initial proposed revenue allocation presented in PECO Exhibit JAB-1?

A. Yes. PECO's revised revenue allocation is presented with my rebuttal testimony as PECO Exhibit JAB-1 Revised, along with a revised proof of revenues at present and proposed rates as PECO Exhibit JAB-4 Revised. These exhibits incorporate modifications to the Company's revenue requirement submitted by Company witness Michael J. Trzaska and revisions to the Company's gas cost of service study ("COSS") discussed by Company witness Jiang Ding in her rebuttal testimony (PECO Statement No. 6-R). The Company has incorporated the necessary changes without making any substantive modifications to its revenue allocation or relative rates of return.

7. Q. Please summarize the other parties' alternative revenue allocation proposals.

A. OCA witness Johnson, OSBA witness Ewen and PAIEUG witness LaConte offer alternative proposed revenue allocations and expressed concerns with PECO's original proposal. The OSBA's proposed revenue allocation was based on the Company's COSS and the use of an alternative revenue allocation methodology

in lieu of indexed rates of return, while the OCA's and PAIEUG's proposals were based on their proposed modifications to PECO's COSS. Table 1 below shows the differences in the relative rates of return by rate class from PECO's revised allocation of revenues that would result from each opposing party's proposed revenue allocation.

Table 1: Proposed Relative Rates of Return by Class (rounded to 0.XX)

Rate Class	PECO Present Rates	PECO Original Proposal	PECO Revised Proposal	OCA[1]	OSBA[2]	PAIEUG
Residential ("GR")	0.95	0.98	0.98	0.95	0.98	0.99
General Service ("GC")	1.07	1.04	1.04	1.03	1.04	1.00
Outdoor Lighting ("OL")	1.07	1.04	1.04	1.03	1.04	1.00
Large High Load Factor ("L")	3.20	2.28	2.28	2.62	2.29	2.25
Motor Vehicle Service- Firm ("MV-F")	1.21	1.04	1.04	1.30	1.04	0.89
Motor Vehicle Service- Interruptible ("MV-I")	3.01	2.20	2.20	2.00	2.00	2.17
Interruptible Service ("IS")	8.75	6.09	6.09	6.88	6.08	6.30
Temperature Controlled Service ("TCS")	8.31	5.83	5.83	6.53	5.83	5.97
Gas Transportation – Interruptible ("TS-I")	1.53	1.10	1.10	1.64	1.10	1.10
Gas Transportation – Firm ("TS-F")	1.03	1.00	1.00	1.14	1.00	1.17

OCA witness Johnson contends that the Company should allocate the cost of mains using the Peak and Average ("P&A") approach instead of the Average and Excess Demand ("A&E") method. Due to the reallocation of gas main costs in the OCA's alternative COSS, Mr. Johnson proposes to assign more revenue responsibility to the L, MV-F, MV-I, TCS, TS-I and TS-F classes than PECO and

[1] The Company calculated relative rates of return for the OCA's proposal based on the OCA's proposed revenue increases by class and the Company's originally proposed COSS.

[2] The Company calculated relative rates of return for the OSBA's proposal by applying the OSBA's proposed revenue increases by class within the Company's originally proposed indexed rate of return methodology.

the other parties.

PECO witness Ding addresses this issue in her rebuttal testimony. She explains why the P&A approach Mr. Johnson proposes is inconsistent with cost causation principles. The Company's COSS therefore retains the A&E method, which continues to be reflected in the revised revenue allocation proposed in PECO Exhibit JAB-1 Revised.

PAIEUG witness LaConte agrees with PECO's use of the A&E methodology but asserts that the Company overstated the allocation of demand-related costs to the TS-F class because the Company used the Transportation Contract Quantity ("TCQ") instead of actual peak design day demand. This recommendation was incorporated into PAIEUG's proposed revenue allocation and is reflected in PAIEUG's proposed relative rates of return shown in Table 1.

As Ms. Ding testifies, it is appropriate for PECO to use the TCQ as a reasonable upper limit for this purpose because the Company's mains are designed to meet the highest potentially achievable peak design day demand for the TS-F class, which is represented by the TCQ and subjects TS-F customers to penalties and limits that do not apply to non-transportation customers. The Company's COSS therefore retains the use of the TCQ to allocate demand-related costs, which continues to be reflected in the revised revenue allocation proposed in PECO Exhibit JAB-1 Revised.

OSBA witness Ewen recommends the alternative revenue allocation shown in Table 1 that uses the revenue-cost ratio instead of the indexed rate of return. However, based on prior Commission guidance leveraging relative rates of return

to model movement of class-based rates toward unity,[3] the Company continues to apply the indexed rate of return methodology in the revised revenue allocation proposed in PECO Exhibit JAB-1 Revised.

8. Q. What is your general assessment of the opposing parties' recommendations?

A. There are many ways to allocate the increase that purport to give due consideration to valid cost of service indications and the principle of gradualism, as illustrated by the various proposals advanced in this case. Apart from the OCA's and PAIEUG's starting point with an alternative COSS and the OSBA's use of an alternate revenue allocation methodology, the other parties' proposed revenue allocations, while differing from each other and from PECO's original and revised allocations, generally used cost of service as the starting point and, as shown in Table 1, limited the percentage increases to most rate schedules to no more than 2.0 times the system average increase. Nonetheless, PECO believes that its revised revenue allocation continues to provide an appropriate balance of the competing interests of all customer classes, producing reasonable movement toward the cost of service and system average rate of return indicated by the Company's revised COSS while also still reflecting the principle of gradualism.

[3] *See 2018 Pennsylvania Guide to Ratemaking*, available at https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf, pp. 146-48.

9. Q. Mr. Johnson explains that he adjusted PECO's proposed rates so that no class receives an increase greater than 1.5 times the system average increase. Do you agree?

A. In part. As stated in my direct testimony, I agree that gradualism is an accepted ratemaking principle that should be considered and applied in developing a utility's rate structure and revenue allocation. However, the gradualism considerations that I originally proposed and continue to support would allow for individual rate class increases of up to 2.0 times the system average increase, as opposed to 1.5 times that increase. As shown in PECO Exhibit JAB-7, Mr. Johnson himself has cited two prior Orders in which the Commission has previously acknowledged and accepted the use of a range of 1.5 times to 2.0 times the system average in prior utility rate proceedings in the absence of definitive rules for determining the level of rate increase that would violate this principle.[4] Mr. Johnson has therefore elected to limit this Commission-sanctioned range to the minimum without providing evidence of that limit as being "frequently used" in Pennsylvania. I continue to support allowing flexibility up to the maximum of the Commission's range to support more effectively balancing gradualism with other ratemaking considerations.

[4] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021), p. 249.

10. Q. Mr. Johnson also recommends applying a 50% system average increase "floor" to the class revenue allocation. Do you agree with that proposal?

A. No. Mr. Johnson claims that his 50% "floor" suggestion is "cost-based" but defends it primarily based on equity, arguing that "the most equitable approach is to spread the increase across all classes" and apply a minimum class percent increase to each class. This implies that Mr. Johnson considers equity of greater importance to ratemaking than cost of service in this instance and that all customer classes should always receive a revenue increase regardless of whether COSS results indicate that an increase for that class is financially warranted. As shown in Exhibit JAB-8, he describes this design as assigning substantially below-average revenue increases to classes paying in excess of their cost of service for this reason and, as a result, creating a generally "more accepting" view of the overall rate increase through sharing of "pain." This is antithetical to cost causation principles. Equity considerations, along with gradualism and others, are certainly valid concerns in balanced ratemaking, but I do not believe they should have priority over cost of service.

III. SCALE BACK

11. Q. Have any of the parties proposed methods of scaling back PECO's proposed increases if the Commission grants less than the Company's requested revenue increase?

A. Yes. I&E witness Cline proposes that the Company's proposed GR and GC customer charge increases should be included in any proportional scale back of rates. PAIEUG witness LaConte recommends a proportional scale back of rates

based on her proposed alternative revenue allocation and a proportional decrease in rates for classes that Ms. LaConte's COSS indicates should receive a reduction to move toward cost of service. Walmart witness Perry recommends that the Commission apply 50% of the overall revenue reduction to those rate classes with relative rates of return above 1.0, with the remaining 50% distributed evenly among all rate classes.

12. Q. If the Commission grants less than the Company's requested revenue increase, what do you think is the appropriate scale back methodology?

A. I support a proportional scale back of revenues relative to the approved increase but oppose inclusion of PECO's proposed customer charge increases in that scale back. As I explained in my direct testimony, the proposed monthly customer charges are supported by the Company's customer cost analysis. Mr. Cline points to the Commission's 2018 order in a UGI Utilities, Inc. ("UGI") electric distribution rate case as precedent for inclusion of the GR and GC customer charges in the scale back. However, in that proceeding, UGI was proposing to increase its residential customer charge from $5.50 to $14.00 based on its COSS, an increase of over 250%. That proposal varies significantly from the Company's proposal in this proceeding to increase its residential customer charge by just 36%, from $10.50 to $14.28, and therefore does not provide a reasonable apples-to-apples comparison for use as Commission precedent.

I also support limiting a scale back to classes that will receive an increase (rather than providing proportional decreases as Ms. LaConte proposes), consistent with the Commission's decision in the Company's 2020 gas base rate case.

13. Q. Please respond to the scale back methodology proposal of Walmart witness Perry.

A. By design, Ms. Perry's approach does not scale back the proposed increases uniformly relative to the Company's proposed increase. It solely favors additional movement toward cost-based allocations. The Company supports a proportional scale back because it more equitably treats all customer classes based directly on the amount of any reduction along with the cost-based allocations and gradualism concerns determined to be reasonable prior to the reduction granted through a scale back.

IV. CUSTOMER CHARGES

14. Q. Witnesses on behalf of the OCA and CAUSE-PA have opposed PECO's proposed increase in its residential customer charge because they contend it will harm low-income customers. Do you agree?

A. No. If PECO's residential customer charge remains at its current level or is only increased by 10% as the OCA recommends, more of the rate increase would have to be recovered through a volumetric (mcf) charge. PECO analyzed the impact on its low-income gas customers of increasing the residential charge from $14.50 to $19.38 as PECO proposes and to $15.70 as the OCA proposes. Table 2 below presents the results of the Company's analysis using average monthly 2023 sales data (for Customer Assistance Program ("CAP") customers and non-CAP confirmed low-income customers) and rates in effect as of July 1, 2024.

Table 2: Rate Design Impact on PECO Low-Income Customers (OCA Proposed Increase)

	Federal Poverty Level ("FPL")	2023 Monthly Average Usage (mcf)	Proposed PECO Rate GR, $19.38 Cust Charge Plus $6.8279/Mcf	Proposed OCA Rate GR, $15.70 Cust Charge, Plus $7.3594/Mcf	$ Diff	% Diff
CAP	0-25%	5.9	$89.17	$88.62	($0.545)	-0.6%
	25-50%	6.4	$92.70	$92.43	($0.28)	-0.3%
	51-100%	5.4	$85.63	$84.82	($0.81)	-0.9%
	101-150%	5.4	$85.63	$84.82	($0.81)	-0.9%
	151-200%	6.1	$90.58	$90.15	($0.43)	-0.5%
	Unknown	5.7	$87.75	$87.10	($0.66)	-0.8%
Non-CAP Confirmed Low-Income	0-25%	6.3	$92.00	$91.67	($0.33)	-0.4%
	25-50%	6.7	$94.83	$94.71	($0.12)	-0.1%
	51-100%	6.4	$92.70	$92.43	($0.28)	-0.3%
	101-150%	6.5	$93.41	$93.19	($0.22)	-0.2%
	151-200%	5.6	$87.05	$86.34	($0.71)	-0.8%
	Unknown	5.6	$87.05	$86.34	($0.71)	-0.8%

The data presented in Table 2 demonstrates that the cost impact of PECO's proposed change in the residential customer charge vs. the OCA's proposed lower residential customer charge is not material (between 0.1% and 0.9%).

15. Q. Please respond to assertions that PECO's proposed residential charge will negatively impact energy efficiency and undermine Low-Income Usage Reduction Program ("LIURP") goals.

A. PECO considered the impact that an increase in the residential customer charge could have on both lower-usage and higher-usage residential customers in developing all elements of its rate structure and rate design, consistent with prior Commission precedent that the customer charge should be considered in the context of the entire increase for a rate class. Any division of costs between fixed

and volumetric rate components within a rate class will have relative winners and losers. PECO believes that its proposal to provide a relative benefit to higher-usage low-income customers, who are more likely to experience high monthly bills and therefore would benefit more from lessening the impact of the overall rate increase, is reasonable. PECO witness Jacqueline F. Golden addresses bill affordability for low-income customers.

OCA witnesses Colton and Johnson support an increase in PECO's residential customer charge, but not to the degree that PECO has proposed. They appear to favor equitable treatment of lower-usage, low-income customers, based on their contention that low-income customers residing in PECO's service area are more likely to be lower-usage customers than higher-usage customers. However, as shown in Table 2 above, the increase in PECO's residential customer charge will not have a material adverse impact on low-income customers.

In addition, Mr. Colton does not support his assertions that the Company's proposed increase to the residential customer charge will impair efficiency efforts or will undermine the Company's LIURP. He presents no evidence backing his claims that a customer charge increase will directly lead to low-income customers either reducing efforts to pursue usage-reduction measures or, conversely, to those customers pursuing "more dangerous" measures. Finally, Mr. Colton's comparisons in the charge to the Low Income Home Energy Assistance Program ("LIHEAP") are irrelevant. LIHEAP is a federal program, and PECO is not involved in the establishment of LIHEAP funding levels.

16. Q. OCA witness Johnson recommends a 10% increase in PECO's current residential customer charge. Why is the Company's proposed 36% increase residential customer charge appropriate?

A. The $19.38 residential customer charge proposed by the Company will be closer to, but still less than, the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4. PECO's proposal to increase the residential customer charge will also provide a relative benefit to high-usage, low-income customers by lessening the impact of the overall rate increase on customers that are more likely to experience high monthly bills. PECO therefore continues to consider its proposed increase to the residential customer charge as both well-supported and reasonable.

17. Q. Please address Mr. Ewen's testimony concerning the Company's proposal to implement two Rate GC customer charges based on meter size.

A. Mr. Ewen supports PECO's proposal but requests additional detail about how the Company will proceed with system changes and customer education to implement the modified customer charges during the interim one-year period after new rates go into effect.

Assuming that the Company's proposal is approved, the Company will implement its modified interim Rate GC customer charge for all Rate GC customers on the effective date of Tariff No. 6, in conjunction with all other approved rate changes. Later in 2025, as described in my direct testimony, the Company will implement the necessary billing system enhancements, assign existing Rate GC customers to the appropriate tier, and notify Rate GC customers of both their tier and the modified customer charge prior to January 1, 2026. The Company will also

propose specific tariff changes to reflect the new Rate GC customer charges in a compliance filing in 2025.

Billing system enhancements require creating processes for automated tier assignment of Rate GC customers. These processes must be configured to accommodate actions that trigger initial assignments and changes to the customer's tier based on gas meter size and the number of gas meters, and by extension to the customer charge assessed. Scenarios to accommodate will include changes in meter size, changes in the number of gas customer meters, connects of new Rate GC customers, and customer rate changes to Rate GC from another PECO gas rate schedule. If and when the Company invests in additional gas meter sizes in the future, those must be classified as "Small" or "Large" and configured within these processes accordingly. Enhancements will also include configuring the system to bill the correct Rate GC customer charge to customers based on their GC tier, which will begin with bills rendered in January of 2026.

The Company will solidify detailed customer education plans and related timelines in 2025. Customer communications may include mailed correspondence to all Rate GC customers as well as direct outreach to managed Rate GC accounts by Company account managers and/or external affairs managers as appropriate for each Rate GC customer. The Company will inform these customers that their Rate GC customer charge will change as of January 1, 2026 based on the size of their gas meter. Company bill inserts for January of 2026 will also incorporate the total bill impacts of the modified customer charges.

In addition, PECO will file a related compliance tariff in the fourth quarter of 2025 to update Rate GC customer charge pricing and related language.

V. RATE DESIGN FOR NON-RESIDENTIAL CUSTOMERS

18. Q. Please summarize and comment on Mr. Ewen's recommendations regarding the Rate GC rate design.

A. Mr. Ewen supports PECO's proposal to eliminate block charge differential entirely but offers an alternative of reducing the differential by 50% from $0.90 to $0.45 to reduce the impact on Rate GC customers with usage of at least 1,000 mcf per month. PECO accepts this alternative, as indicated in the revised Rate GC rate structure under PECO Exhibit JAB-4 Revised, as it reduces the overall bill impacts of the revenue increase on larger Rate GC customers in lieu of the Company's original proposal. The proposed volumetric rates are slightly lower than those calculated by Mr. Ewen because, given the same relative rate of return and level of customer charge revenue as in the Company's original proposal, the revenue required from the variable distribution charges is slightly lower than originally proposed. As shown in PECO Exhibit JAB-9, the OSBA acknowledges and accepts that this change also results in slightly larger bill impacts on smaller Rate GC customers than under the Company's original proposal, assuming that it represents an initial step toward an eventual complete phaseout of the second GC rate block.

19. Q. Did any parties oppose PECO's proposed modification to the rate differentials for its transportation service classes?

A. Yes. PAIEUG witness LaConte argues that PECO's current rate differentials should be maintained because (1) increasing the volumetric rate for large TS-F customers by 44% based on load factors rather than actual costs incurred to serve those customers would result in rate shock and (2) large TS-I customers would receive a 12% increase in volumetric rates under PECO's proposed phase-out of volumetric differentials, despite the fact that the class as a whole is significantly above cost and should receive a decrease.

20. Q. Do you agree with Ms. LaConte's recommendation?

No. As explained in my direct testimony, PECO's proposal to reduce the Rate TS-F differentials is based on its commitment to revise those differentials based on a load factor analysis as part of the Commission-approved settlement of PECO's 2022 gas base rate case. PAIEUG is a party to that settlement. Ms. LaConte's proposals to maintain the existing differentials as-is or to spread the increase evenly across larger and smaller customers are no more or less cost-based than changing them. Moreover, the latter option could result in an *increase* to the volumetric rate differential between larger and smaller TS-F customers rather than a reduction as sought, which would also not be a cost-based outcome. Ms. Ding supports the continued combination of TS-F customers above and below annual usage of 18 mmcf within the Company's COSS in her rebuttal testimony, which continues to underpin PECO's revised rate design. Additionally, the Company's resulting proposed revenue increase for large TS-F

customers of nearly 2.0 times the system average is consistent with the commonly accepted range for gradualism that I described previously.

Regarding the Company's proposed TS-I rate design, the proposed volumetric rate increase for TS-I customers is primarily a result of rolling current Distribution System Improvement Charge revenues into base volumetric rates while holding TS-I revenues at their current levels, as the Company has done in prior proceedings and for other rate classes for which its COSS has not warranted a rate increase. Ms. LaConte does not acknowledge this in arguing to maintain the current TS-I rate differentials or to spread any TS-I rate increase evenly across larger and smaller TS-I customers.

VI. CONCLUSION

21. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

Revised "Gas Proposed Revenue Increase by Class" Matrix (based on COS Study results)

Supports Exhibit JAB-1 (Revenue Allocation)

Sys Average Rate of Return (RRM A-1): 8.08%

Gross Revenue Conversion Factor (RRM A-1): 1.3829

	($000's) Rate Base (COS)	($000's) Initial COS Increase at Sys Average ROR (COS)	Proposed Relative ROR (Input)	Proposed Rate of Return	ROR Variance from Sys Avg ROR	COS Adjustment	($000's) at Proposed Relative ROR (COS)	($000's) Net Revenue Ask at Proposed Relative ROR	($000's) Current Adjusted Distribution Revenue (Proof of Revenues)	($000's) Proposed Adjusted Distribution Revenue (Proof of Revenues)
GR	$ 2,379,330	$ 83,962	0.98	7.90%	0.18%	0.25%	$ 6,003	$ 77,959	$ 326,684	$ 404,643
GC & OL	$ 920,153	$ 23,179	1.04	8.44%	-0.36%	-0.50%	$ (4,616)	$ 27,796	$ 122,651	$ 150,447
L	$ 566	$ (81)	2.28	18.42%	-10.34%	-14.30%	$ (81)	$ -	$ 139	$ 139.317
MV-F	$ 4,234	$ 66	1.04	8.40%	-0.32%	-0.45%	$ (19)	$ 85	$ 613	$ 698
MV-I	$ 13	$ (2)	2.20	17.78%	-9.70%	-13.41%	$ (2)	$ -	$ 4	$ 3.597
IS	$ 102	$ (58)	6.09	49.21%	-41.13%	-56.87%	$ (58)	$ -	$ 66	$ 66
TCS	$ 1,019	$ (550)	5.83	47.11%	-39.03%	-53.97%	$ (550)	$ -	$ 697	$ 697
TS-I	$ 61,482	$ (692)	1.10	8.89%	-0.81%	-1.13%	$ (692)	$ -	$ 10,848	$ 10,848
TS-F	$ 145,803	$ 4,192	1.00	8.07%	0.01%	0.01%	$ 15	$ 4,176	$ 19,121	$ 23,297
Summary	$ 3,512,701	$ 110,016					$ 1	$ 110,016	$ 480,822	$ 590,838

PECO Energy Company (Gas)
Revised Revenue Allocation and Rates of Return by Rate Class

Rate	(1) Current Distribution Revenue	(2) Proposed Distribution Revenue	(3) *(2) - (1)* Distribution Revenue Ask	(4) *(3) / (1)* % Increase	(5) Increase vs. System Avg
Residential (GR)	$ 326,684,253	$ 404,643,253	$ 77,959,000	23.9%	1.04
General Service (GC)	$ 122,650,416	$ 150,446,345	$ 27,795,929	22.7%	0.99
Outdoor Lighting (OL)	$ 313	$ 384	$ 71	22.7%	0.99
Large High Load Factor (L)	$ 139,317	$ 139,317	$ -	0.0%	0.00
Motor Vehicle Service - Firm (MV-F)	$ 612,691	$ 697,691	$ 85,000	13.9%	0.61
Motor Vehicle Service - Interruptible (MV-I)	$ 3,597	$ 3,597	$ -	0.0%	0.00
Interruptible Service (IS)	$ 65,812	$ 65,812	$ -	0.0%	0.00
Temperature-Controlled Service (TCS)	$ 697,247	$ 697,247	$ -	0.0%	0.00
Gas Transportation - Interruptible (TS-I)	$ 10,848,053	$ 10,848,053	$ -	0.0%	0.00
Gas Transportation - Firm (TS-F)	$ 19,120,685	$ 23,296,685	$ 4,176,000	21.8%	0.95
Total	$ 480,822,384	$ 590,838,384	$ 110,016,000	22.9%	

Rate	(7) Present Rate of Return	(8) *(8) / Average of (8)* Present Relative Rate of Return	(9) Proposed Rate of Return	(10) *(9) / Average of (9)* Proposed Relative Rate of Return
Residential (GR)	5.54%	0.95	7.90%	0.98
General Service (GC)	6.27%	1.08	8.44%	1.04
Outdoor Lighting (OL)	6.27%	1.08	8.44%	1.04
Large High Load Factor (L)	18.58%	3.19	18.42%	2.28
Motor Vehicle Service - Firm (MV-F)	7.04%	1.21	8.40%	1.04
Motor Vehicle Service - Interruptible (MV-I)	17.53%	3.01	17.78%	2.20
Interruptible Service (IS)	50.89%	8.73	49.21%	6.09
Temperature-Controlled Service (TCS)	48.31%	8.28	47.11%	5.83
Gas Transportation - Interruptible (TS-I)	8.89%	1.53	8.89%	1.10
Gas Transportation - Firm (TS-F)	6.00%	1.03	8.07%	1.00
Total	5.83%		8.08%	

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 1

LIST OF CHANGES MADE BY THIS SUPPLEMENT

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS – Original Page No. 6 - Holidays updated.

TCJA VOLUNTARY SURCHARGE – page deleted.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 41 - Revised the USFC formula to remove the "F" Correction Factor. Revise the "L" and "I" Factors and update the offset factor in the Reconcilable Customer Assistance Program Costs and annual spend amount.

SALES SERVICE COSTS (SSC) – Original Page No. 42 – The Commodity Charges are decreased.

GAS PROCUREMENT CHARGE – Original Page No. 45 – The Gas Procurement Charge is decreased.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – Original Page No. 46 and Original Page No. 47 – The Merchant Function Charges and Write-Off Factors are changed. The Prices to Compare are decreased.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE - Original Page No. 51 – reset the DSIC to 0%.

RATE GR - GENERAL SERVICE RESIDENTIAL - Original Page No. 57 – Distribution prices updated. TCJA language removed.

RATE GC - GENERAL SERVICE COMMERCIAL AND INDUSTRIAL Original Page No. 58 – Distribution prices updated. TCJA language removed. Added effective through December 31, 2025.

Rate GC – GENERAL SERVICE COMMERCIAL AND INDUSTRIAL Original Page No. 58a – Replaced single Fixed Distribution Charge with multiple Fixed Distribution Charges based on gas meter size, effective as of January 1, 2026.

RATE OL- OUTDOOR LIGHTING Original Page No. 59 – Distribution prices updated. TCJA language removed.

RATE L – LARGE HIGH LOAD FACTOR SERVICE Original Page No. 60 – Distribution prices updated. TCJA language removed.

RATE MV-F MOTOR VEHICLE SERVICE - FIRM - Original Page No. 62 – Distribution prices updated. TCJA language removed.

RATE MV-I MOTOR VEHICLE SERVICE - INTERRUPTIBLE Original Page No. 63 – Distribution prices updated. Remove language referencing end block. TCJA language removed.

RATE IS – INTERRUPTIBLE SERVICE Original Page No. 65 – Distribution prices updated. Summer period language revised from November to October for consistency. TCJA language removed.

RATE TCS - TEMPERATURE CONTROLLED SERVICE Original Page No. 67 – Distribution prices updated. Remove language referencing end block. TCJA language removed.

RATE TS-I GAS TRANSPORTATION SERVICE - INTERRUPTIBLE Original Page No. 74 – Distribution prices updated. TCJA and Voluntary Surcharge language removed.

RATE TS-F GAS TRANSPORTATION SERVICE FIRM Original Page No. 75 – Distribution prices updated. TCJA language removed.

Applicability Index of Riders Original Page No. 78 – page numbers updated.

NEIGHBORHOOD GAS PILOT RIDER (NGPR) Original Page No. 80– Rider revised to reflect extension of the pilot program by an additional five years from 01/01/2025 to 12/31/2029. Also reflect change to total investment amount.

WEATHER NORMALIZED ADJUSTMENT (WNA) Original Page No. 84 –The new WNA will adjust certain customers' bills to reflect normalized weather conditions.

Issued March 28, 2024

Effective May 27, 2024

Deleted: Supplement No. 13 to¶

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Deleted: Twelfth Revised Page No. 1¶

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Deleted: SALES SERVICE COSTS (SSC) – 6th Revised Page No. 43¶
The Commodity Charges are increased. The Gas Cost Adjustment is increased.¶
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MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 6th Revised Page No. 47 and 6th Revised Page No. 48¶
The Merchant Function Charges are increased. The Prices to Compare are increased.¶
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BALANCING SERVICE COSTS (BSC) – 6th Revised Page No. 49¶
The Balancing Service Cost is decreased.¶
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PECO Energy Company — **Gas-Pa. P.U.C. No. 6**
Original Page No. 41

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for gas service in Residential Rate Schedule GR of this Tariff shall include a charge of **$0.2419** per Mcf (1,000 cubic feet) for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below. The USFC rate for gas 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 Mcf ($x.xxxx), shall be computed in accordance with the formula set forth below:

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

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

In computing the USFC, per Mcf, 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 12.1% offset factor.

USFC – Universal Service Fund Charge determined to the nearest one-hundredth cent (0.01¢) to be included in the rate for each Mcf of Variable Distribution Service Charge calculated under Rate Schedule GR, to recover or refund Reconcilable CAP Costs and other items as addressed in the "E" factor.

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

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 up to $900,000 of LIURP expenditures above the $2.25 million threshold included in base rates. Also included in the "E" Factor will be any rate credit due customers to the extent PECO expends less than $3,077,500 annually in its Energy Efficiency Plan effective January 1, 2025.

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 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 period such overcollection is refunded or undercollection is recouped. The interest calculation will not apply to the LIURP amounts.
"

S - projected Mcf of gas service to be billed under Rate GR (exclusive of CAP Rider) during the projected period when rates will be in effect. Mcf's shall be consistent with the projected residential throughput used in the applicable Purchased Gas Cost filing.

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 December 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.

Deleted: Supplement No. 3 to¶
Gas-Pa. P.U.C. No. 5¶
First Revised Page No. 41¶
PECO Energy Company — Supersedes
Original Page No. 41¶

Deleted: TCJA VOLUNTARY SURCHARGE ¶
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To implement the effects of the Tax Cuts and Jobs Act (TCJA), on March 15, 2018 the Pennsylvania Public Utility Commission (Commission) issued a Temporary Rates Order at Docket No. M-2018-2641242 directing PECO to file its current base rates and riders as temporary rates, pursuant to Section 1310(d) of the Public Utility Code. 66 Pa. C.S. § 1310(d). Subsequently, on May 17, 2018, the Commission entered an Order at Docket R-2018-3000512 superseding the March 15, 2018 Temporary Rates Order directing PECO to establish a surcharge effective July 1, 2018 to provide the benefits of the TCJA to customers.¶
¶
A surcharge of 0.00% will apply to intrastate service to all customer bills rendered on and after March 1, 2023. This **(C)** surcharge will be distributed equally among the utility's various customer classes and will be provided through a separate mechanism showing a line item on customer bills (e.g., Federal Tax Adjustment Credit – "FTAC"). ¶
¶
PECO will file revised surcharges (or FTAC) as required at least thirty (30) days prior to the effective date of January 1st of each year reflecting an estimate of the savings for the TCJA from January 1 through December 31 exclusive of STAS and non-distribution automatic adjustment clause revenues. ¶
¶
This surcharge or FTAC will be reconciled at the end of each calendar year and will remain in place until PECO files and the Commission approves new base rates for PECO pursuant to Section 1308(d) that include the effects of the TCJA tax rate changes. Interest on the over or under collection shall be computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.). The reconciliation shall be submitted by April 30th of each calendar year and shall be subject for review and audit by the Commission's Bureau of Audits. ¶
¶
The Company may file an interim rate adjustment in order to eliminate any over or under recovery of the surcharge outside of the annual filing period. Such adjustment would be filed on at least 10 days' notice. ¶
¶
A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.¶ ... [1]

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PECO Energy Company **Gas-Pa. P.U.C. No. 6**
Original Page No. 57

RATE GR - GENERAL SERVICE -RESIDENTIAL

AVAILABILITY.

Service in the entire service 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 domestic requirements of its members when such service is supplied through one meter. Resale of gas and/or service provided by the Company under this rate is only allowed for those locations being served through a single meter prior to January 6, 1980.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $19.38 per month
VARIABLE DISTRIBUTION CHARGE: $7.0710 per Mcf

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge. The Universal Service Fund Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial term for any contract shall be at least one year.

PAYMENT TERMS.
Standard.

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RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective through December 31, 2025)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $36.38 per month

VARIABLE DISTRIBUTION CHARGE: $5.5394 per Mcf for all or any part of the first 200 Mcf
$5.0894 per Mcf for the additional use

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

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RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective as of January 1, 2026)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE:
$29.36 for service provided through a single small diaphragm meter
$40.61 for all other service

VARIABLE DISTRIBUTION CHARGE: $5.5394 per Mcf for all or any part of the first 200 Mcf
$5.0894 per Mcf for the additional use

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), MERCHANT FUNCTION CHARGE ("MFC"), and BALANCING SERVICE COST ("BSC") apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 59

RATE OL - OUTDOOR LIGHTING SERVICE

AVAILABILITY.
Service for outdoor lighting by Company-approved lighting devices of the sizes hereinafter specified, where the consumption is not registered on a meter.

MONTHLY RATE TABLE.

Manufacturer's Rated Input to Lighting Devices	Nominal Mcf Rating Per Month	Distribution Charges: When Not in Conjunction With Service Under Other Gas Rates	Distribution Charges: When in Conjunction With Service Under Other Gas Rates
1,999 Btu/Hr.or less	1.5 Mcf	$10.0625	$5.0078
2,000 Btu/Hr.to 2,499 Btu/Hr.	1.7 Mcf	$11.7062	$6.6892
2,500 Btu/Hr.to 2,999 Btu/Hr.	2.1 Mcf	$13.1401	$8.1044
3,000 Btu/Hr.to 3,499 Btu/Hr.	2.4 Mcf	$14.6696	$9.6522

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), and BALANCING SERVICE COST ("BSC") apply to this rate.

INSTALLATIONS.
The Customer shall install, own and maintain the lighting devices and all tubing from the Company's service-supply pipe to the lighting devices.

FINAL CONNECTION.
The final connection of any lighting devices or tubing to the supply system shall be made by or under the supervision of a representative of the Company and the costs of such connections shall be borne by the Customer.

BUDGET BILLING.
At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 62

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RATE MV-F MOTOR VEHICLE SERVICE-FIRM

AVAILABILITY.
Firm motor vehicle service is available to Customers using natural gas exclusively as fuel for motor vehicles.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $67.80 per month.

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ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE: $1.3629 per Mcf

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ADDITIONAL VARIABLE DISTRIBUTION CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.66 per Mcf added for each Mcf of gas supplied.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE ("CC") (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE ("GCA"), GAS PROCUREMENT CHARGE ("GPC"), BALANCING SERVICE COST ("BSC"), and any applicable fuel taxes apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

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RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

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PECO Energy Company

Gas-Pa. P.U.C. No. 6
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RATE TS-I GAS TRANSPORTATION SERVICE-INTERRUPTIBLE
(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.
Interruptible transportation service (Rate TS-I) is available to an individual Customer, or a Buyer Group, who may have dual fuel capability or is willing to accept interruption of gas service.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate, as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.
Upgrading and/or installation of mains and services required to provide adequate delivery capacity for interruptible transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.
Interruptible transportation service will be provided on a best efforts basis by the Company and may be restricted or interrupted from time to time due to operating and capacity limitations. Under normal operating conditions a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day.

BILLING.
A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
1. FIXED DISTRIBUTION CHARGE.
$504.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
2. VARIABLE DISTRIBUTION CHARGE.
The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $0.9563 per Mcf.
B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
1. FIXED DISTRIBUTION CHARGE.
$381.03 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
2. VARIABLE DISTRIBUTION CHARGE.
The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual customer. The maximum Variable Distribution Charge shall be $1.6002 per Mcf.
C. The State Tax Adjustment Clause does not apply to this rate.
D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

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MINIMUM CHARGE.
The monthly minimum charge shall be the Customer Charge.
SEPARATION OF SERVICE.
Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.
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PECO Energy Company **Gas-Pa. P.U.C. No. 6**
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RATE TS-F GAS TRANSPORTATION SERVICE-FIRM

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Firm transportation service (Rate TS-F) is available to an individual Customer or a Buyer Group, who desires uninterrupted transportation service. Firm transportation service is not available with Rate GC through the same meter, except as provided under Standby Sales Service of the General Terms and Conditions.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for firm transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Transportation service under this rate schedule is firm and shall be interrupted only in cases of operating emergencies experienced by the Company or in the case of a natural gas shortage when the supply of gas is insufficient to meet the requirements of Priority 1 Customers.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE
      $504.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $ 1.5505 per Mcf.
B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $381.03 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $161.00.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $2.3102 per Mcf.
C. The State Tax Adjustment Clause does not apply to this rate.
D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

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MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge plus 15 days' use of the TCQ at the Customer's applicable commodity charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.

Standard.

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Comparison of Residential Customer Charges for Pennsylvania Natural Gas Distribution Utilities

Company	**Current Residential Customer Charge**
Columbia Gas of Pennsylvania[1]	$16.75
National Fuel	$14.00
Peoples Natural Gas[2]	$14.50
Philadelphia Gas Works	$16.25
UGI	$15.00
PECO Current	**$14.25**
PECO Proposed	**$19.38**

[1] Columbia Gas of Pennsylvania filed a proposed customer charge per month of $26.00 on March 15, 2024 (Docket No. R-2024-3046519).

[2] Peoples Gas filed a proposed customer charge per meter per month of $21.50 on December 29, 2023 (Docket No. R-2023-3044549).

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Residential (GR)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	6,151,911	$ 14.25	$ 87,664,732	$ 19.38	$ 119,224,035
3						
4	**Total Customer Charge Revenue**			$ 87,664,732		$ 119,224,035
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate	43,867,240	$ 5.4651	$ 239,738,853	$ 6.8279	$ 299,522,589
8	CAP Credits - Distribution			$ (6,941,842)		$ (8,672,931)
9	CAP Credits - Non-Distribution			$ (6,898,834)		$ (6,898,834)
10	CAP Shortfall			$ 1,819,092		$ -
11	Distribution System Improvement Charge (DSIC)			$ 10,116,761		$ -
12						
13	**Total Variable Distribution Revenue**			$ 237,834,030		$ 283,950,824
14						
15	Annualization			$ 1,185,491		$ 1,468,394
16						
17	**Adjusted Total Distribution Revenue**			$ 326,684,253		$ 404,643,253

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - General Service Commercial & Industrial (GC)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate, 2025	547,071	$ 29.86	$ 16,335,540	$ 36.38	$ 19,902,443
3						
4	Proposed Base Rate as of 1/1/2026					
5	Small	*205,656*			*$ 29.36*	*$ 6,038,060*
6	Large	*341,415*			*$ 40.61*	*$ 13,864,383*
7						
8	**Total Customer Charge Revenue**			$ 16,335,540		$ 19,902,443
9						
10	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
11	Base Rate - First 200 mcf	17,650,825	$ 4.4248	$ 78,101,369	$ 5.5394	$ 97,774,352
12	Base Rate - Over 200 mcf	6,201,691	$ 3.5201	$ 21,830,574	$ 5.0894	$ 31,562,669
13						
14	Base Rate - All Usage	23,852,516			$ 5.4413	$ 129,788,370
15						
16	Distribution System Improvement Charge (DSIC)			$ 5,399,031		$ -
17						
18	**Total Variable Distribution Charge Revenue**			$ 105,330,974		$ 129,337,021
19						
20	Annualization			$ 983,902		$ 1,206,881
21						
22	**Adjusted Total Distribution Revenue**			$ 122,650,416		$ 150,446,345

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Outdoor Lighting (OL)

Line			PRESENT RATES		PROPOSED RATES	
1	**Manufacturer-Rated Input to Lighting Devices (lamp-based)**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	When NOT in Conjunction With Service Under Other Gas Rates					
3	Up to 1,999 Btu/Hr	24	$ 7.8994	$ 190	$ 10.0625	$ 242
4	2,000-2,499 Btu/Hr	12	$ 9.1897	$ 110	$ 11.7062	$ 140
5	2,500-2,999 Btu/Hr	-	$ 10.3154	$ -	$ 13.1401	$ -
6	3,000-3,499 Btu/Hr	-	$ 11.5161	$ -	$ 14.6696	$ -
7				$ 300		$ 382
8	When in Conjunction With Service Under Other Gas Rates					
9	Up to 1,999 Btu/Hr	-	$ 3.9313	$ -	$ 5.0078	$ -
10	2,000-2,499 Btu/Hr	-	$ 5.2512	$ -	$ 6.6892	$ -
11	2,500-2,999 Btu/Hr	-	$ 6.3622	$ -	$ 8.1044	$ -
12	3,000-3,499 Btu/Hr	-	$ 7.5773	$ -	$ 9.6522	$ -
13				$ -		$ -
14						
15	Distribution System Improvement Charge (DSIC)			$ 11		$ -
16						
17	**Total Lamp-Based Distribution Revenue**			$ 311		$ 382
18						
19	Annualization			$ 2		$ 2
20						
21	**Adjusted Total Distribution Revenue**			$ 313		$ 384

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Large Load Factor (L)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	96	$ 260.00	$ 24,960	$297.01	$ 28,513
3						
4	**Total Customer Charge Revenue**			$ 24,960		$ 28,513
5						
6	**Variable Distribution Charges (mcf-based)**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate - First 50% of usage	10,500	$ 7.3127	$ 76,783	$ 8.0858	$ 84,901
8	Base Rate - Additional usage	10,500	$ 2.2212	$ 23,323	$ 2.4560	$ 25,788
9						
10	Distribution System Improvement Charge (DSIC)			$ 14,136		$ -
11						
12	**Total Variable Distribution Charge Revenue**			$ 114,242		$ 110,689
13						
14	Annualization			$ 115		$ 115
15						
16	**Adjusted Total Distribution Revenue**			$ 139,317		$ 139,317

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Motor Vehicles - Firm (MV-F)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	180	$ 49.84	$ 8,971	$ 67.80	$ 12,204
3						
4	**Total Customer Charge Revenue**			$ 8,971		$ 12,204
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate	502,606	$ 1.1005	$ 553,118	$ 1.3629	$ 685,026
8						
9	Distribution System Improvement Charge (DSIC)			$ 50,197		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 603,315		$ 685,026
12						
13	Annualization			$ 405		$ 461
14						
15	**Adjusted Total Distribution Revenue**			$ 612,691		$ 697,691

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Motor Vehicles - Interruptible (MV-I)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	12	$ 49.84	$ 598	$ 58.50	$ 702
3						
4	**Total Customer Charge Revenue**			$ 598		$ 702
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	1,064	$ 2.7186	$ 2,892	$ 2.7203	$ 2,894
8						
9	Distribution System Improvement Charge (DSIC)			$ 106		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 2,998		$ 2,894
12						
13	Annualization			$ 1		$ 1
14						
15	**Adjusted Total Distribution Revenue**			$ 3,597		$ 3,597
16						
17	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Interruptible Service (IS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	12	$ 217.89	$ 2,615	$ 297.41	$ 3,569
3						
4	**Total Customer Charge Revenue**			$ 2,615		$ 3,569
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	16,440	$ 3.5201	$ 57,870	$ 3.7861	$ 62,243
8						
9	Distribution System Improvement Charge (DSIC)			$ 5,327		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 63,197		$ 62,243
12						
13	**Total Distribution Revenue**			$ 65,812		$ 65,812
14						
15	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Temperature Controlled Service (TCS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	237	$ 125.00	$ 29,625	$ 170.00	$ 40,290
3						
4	**Total Customer Charge Revenue**			$ 29,625		$ 40,290
5						
6	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Flex Rate*	129,260	$ 5.0639	$ 654,560	$ 5.2873	$ 683,431
8						
9	Distribution System Improvement Charge (DSIC)			$ 39,536		$ -
10						
11	**Total Variable Distribution Charge Revenue**			$ 694,096		$ 683,431
12						
13	Annualization			$ (26,474)		$ (26,474)
14						
15	**Adjusted Total Distribution Revenue**			$ 697,247		$ 697,247
16						
17	**Flex Rate fluctuates month-to-month based on the cost of alternative fuels*					

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Interruptible (TS-I)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	No backup					
3	>= 18,000 mcf annually	1,020	$ 383.88	$ 391,558	$ 504.83	$ 514,927
4	< 18,000 mcf annually	1,116	$ 322.66	$ 360,089	$ 381.03	$ 425,231
5						
6	Rate L backup					
7	>= 18,000 mcf annually	264				
8	TS-I Base Rate		$ 383.88	$ 101,344	$ 504.83	$ 133,275
9	TS-F Duel Fuel		$ 161.00	$ 42,504	$ 161.00	$ 42,504
10	< 18,000 mcf annually	-				
11	TS-I Base Rate		$ 322.66	$ -	$ 381.03	$ -
12	TS-F Duel Fuel		$ 161.00	$ -	$ 161.00	$ -
13						
14	Rate GC backup					
15	>= 18,000 mcf annually	60				
16	TS-I Base Rate		$ 383.88	$ 23,033	$ 504.83	$ 30,290
17	TS-F Duel Fuel		$ 161.00	$ 9,660	$ 161.00	$ 9,660
18	< 18,000 mcf annually	216				
19	TS-I Base Rate		$ 322.66	$ 69,695	$ 381.03	$ 82,303
20	TS-F Duel Fuel		$ 161.00	$ 34,776	$ 161.00	$ 34,776
21						
22	**Total Customer Charge Revenue**			$ 1,032,659		$ 1,272,966
23						
24	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
25	No Backup					
26	>= 18,000 mcf annually	6,246,637	$ 0.8522	$ 5,323,384	$ 0.9563	$ 5,973,878
27	< 18,000 mcf annually	658,263	$ 1.6002	$ 1,053,352	$ 1.6002	$ 1,053,352
28	Negotiated Gas Sales	4,900,376	Negotiated	$ 488,306	Negotiated	$ 488,306
29						
30	Rate L Backup					
31	>= 18,000 mcf annually					
32	Commodity TSI Mcf	854,235	$ 0.8522	$ 727,979	$ 0.9563	$ 816,935
33	Commodity TSF Mcf	441,722	$ 1.0776	$ 476,000	$ 1.5505	$ 684,874
34	Additional Commodity (15 days TCQ)	97,807	$ 1.0776	$ 105,396	$ 1.5505	$ 151,646
35	< 18,000 mcf annually					
36	Commodity TSI Mcf	-	$ 1.6002	$ -	$ 1.6002	$ -
37	Commodity TSF Mcf	-	$ 2.2578	$ -	$ 2.3102	$ -

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Interruptible (TS-I)

Line			PRESENT RATES		PROPOSED RATES	
38	Additional Commodity (15 days TCQ)	-	$ 2.2578	$ -	$ 2.3102	$ -

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Interruptible (TS-I)

Line			PRESENT RATES		PROPOSED RATES	
39		mcf	Rate	Revenue	Rate	Revenue
40	Rate GC Backup					
41	>= 18,000 mcf annually					
42	Commodity TSI Mcf	42,349	$ 0.8522	$ 36,090	$ 0.9563	$ 40,500
43	Commodity TSF Mcf	24,949	$ 1.0776	$ 26,885	$ 1.5505	$ 38,683
44	Additional Commodity (15 days TCQ)	5,539	$ 1.0776	$ 5,969	$ 1.5505	$ 8,589
45	< 18,000 mcf annually					
46	Commodity TSI Mcf	124,365	$ 1.6002	$ 199,009	$ 1.6002	$ 199,009
47	Commodity TSF Mcf	45,240	$ 2.2578	$ 102,143	$ 2.3102	$ 104,513
48	Additional Commodity (15 days TCQ)	6,407	$ 2.2578	$ 14,466	$ 2.3102	$ 14,802
49						
50						
51	Distribution System Improvement Charge (DSIC)			$ 1,256,415		$ -
52						
53	**Total Variable Distribution Charge Revenue**			$ 9,815,394		$ 9,575,087
54						
55	**Adjusted Total Distribution Revenue**			$ 10,848,053		$ 10,848,053

PECO Energy Company (Gas)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Gas Transportation Service - Firm (TS-F)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	>= 18,000 mcf annually	1,656	$ 336.62	$ 557,443	$ 504.83	$ 835,998
3	< 18,000 mcf annually	3,144	$ 280.17	$ 880,854	$ 381.03	$ 1,197,962
4						
5	**Total Customer Charge Revenue**			$ 1,438,297		$ 2,033,960
6						
7	**Variable Distribution Charges**	**mcf**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	>= 18,000 mcf annually					
9	Negotiated Gas Sales	2,650,270	Negotiated	$ 980,600	Negotiated	$ 980,600
10	Commodity TSF Mcf	7,597,193	$ 1.0776	$ 8,186,735	$ 1.5505	$ 11,779,181
11	Additional Commodity (15 days TCQ)	2,087,112	$ 1.0776	$ 2,249,072	$ 1.5505	$ 3,235,994
12	< 18,000 mcf annually					
13	Commodity TSF Mcf	1,626,344	$ 2.2578	$ 3,671,960	$ 2.3102	$ 3,757,168
14	Additional Commodity (15 days TCQ)	653,531	$ 2.2578	$ 1,475,542	$ 2.3102	$ 1,509,782
15						
16	Distribution System Improvement Charge (DSIC)			$ 1,118,479		$ -
17						
18	**Total Variable Distribution Charge Revenue**			$ 17,682,388		$ 21,262,725
19						
20	**Adjusted Total Distribution Revenue**			$ 19,120,685		$ 23,296,685

C-Factor Period	Estimated CAP Credits ($)	Estimated GR Sales (a) (MCF)	Estimated Shortfall Recovered in Base Rates (b)	Shortfall o/(u) Base Recovery	Shortfall o/(u) Base Recovery (c)
			(3) = (2) * $0.2656 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024
	(1)	(2)	(3) = (2) * $0.3123 as of 1/1/2025	(4) = (1) - (3)	(5) = (4) * 0.893 as of 1/1/2025
Dec-24					
Jan-25					
Feb-25					
Mar-25					
Apr-25					
May-25					
Jun-25					
Jul-25					
Aug-25					
Sep-25					
Oct-25					
Nov-25					
	$ -	-	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Non-CAP MCFs.
(b) Current factor is per settlement approved at Docket No. R-2010-2161592.
PECO is proposing to update this factor effective January 1, 2025.

Projected FPFTY 2025 CAP Credits:	$	13,700,000
Projected Res Non-CAP Sales for FPFTY 2025 (MCF):		43,865,478
Resulting Base Rate Recovery per MCF:	$	0.3123

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.3%

-0.1398

E-Factor Period	Total CAP Credits ($)	GR Sales (b) (MCF)	CAP Revenues Recovered in Base Rates (c)	Base Recovery o/(u) Actual	Base Recovery o/(u) Actual (d)	C-Factor Revenue	C-Factor Over/(Under) Recovery
			(3) = (2) * $0.2656 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024		
	(1)	(2)	(3) = (2) * $0.3123 as of 1/1/2025	(4) = (3) - (1)	(5) = (4) * 0.893 as of 1/1/2025	(6) = (2) * (.1398)	(7) = (5) + (6)
Dec-23							
Jan-24							
Feb-24							
Mar-24							
Apr-24							
May-24							
Jun-24							
Jul-24							
Aug-24							
Sept-24 (a)							
Oct-24 (a)							
Nov-24 (a)							
	$ -	-	$ -	$ -	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (c-d) for PECO's proposed change.

(a) Actual 1307 filing uses estimates since a hearing date may be on or after September 1 of each year.
(b) Residential Non-CAP MCFs.
(b) Current factor is per settlement approved at Docket No. R-2010-2161592.
PECO is proposing to update this factor effective January 1, 2025.

Projected FPFTY 2025 CAP Credits:	$	13,700,000
Projected Res Non-CAP Sales for FPFTY 2025 (MCF):		43865477.5
Resulting Base Rate Recovery per MCF:	$	0.3123

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.3%

Proj CAP-Specific GR Mcf, 2025	1,763
Proj Total GR Mcf Sales, 2025 (from Exhibit JAB-4)	43,867,240
Proj Non-CAP GR Mcf Sales, 2025	43,865,478

PECO Energy Company, R-2024-3046932 (Gas)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-12. Refer to OCA Statement No. 3, p. 26, lines 19-20. Please provide a citation to all Commission precedent or other Pennsylvania authority supporting your assertions that:

a. Gradualism is a "subjective consideration", and;

b. The Commission has the potential to "favor different degrees of moderation."

Response:

I am not a legal expert. Therefore, I cannot claim with certainty that the below-cited Pennsylvania Commission precedent is an exhaustive list of all Pennsylvania Commission decisions which may support the assertions that gradualism is a subjective consideration and/or that the Commission has the potential to favor different degrees of moderation. However, I am aware of the below cited Commission decisions related to this subject.

a. Gradualism is a "subjective consideration"
   1. *Pa. PUC v. PECO Energy Company - Gas Division*, Docket No. R-2020-3018929 (Order entered June 22, 2021). https://www.puc.pa.gov/pcdocs/1708475.docx

   2. *Pa. PUC v. UGI Utilities, Inc. - Electric Division*, Docket No. R-2017-2640058 (Order entered Oct. 25, 2018) at 174. https://www.puc.pa.gov/pcdocs/1591254.docx

   3. *Pa. PUC v. Phila. Gas Works*, Docket No. R-2023-3037933 (Order entered Nov. 9, 2023). https://www.puc.pa.gov/pcdocs/1804829.pdf

   4. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc*., R-2020-3018835 (Order entered Feb. 19, 2021). https://www.puc.pa.gov/pcdocs/1693880.docx

b. The Commission has the potential to "favor different degrees of moderation."
   1. *Pa. PUC v. PECO Energy Company - Gas Division*, Docket No. R-2020-3018929 (Order entered June 22, 2021). https://www.puc.pa.gov/pcdocs/1708475.docx

   2. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc*., R-2020-3018835 (Order entered Feb. 19, 2021). https://www.puc.pa.gov/pcdocs/1693880.docx

Dated: July 1, 2024

Sponsored by: Clarence L. Johnson

PECO Energy Company, R-2024-3046932 (Gas)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-13. Refer to OCA Statement No. 3, p. 27, lines 3-7.

a. Please provide cost-based justification for the following position: "In my view, under circumstances in which most customers will face a substantial rate increase, the most equitable approach to spread the increase across all classes and apply a 50% of system average floor as the minimum class percent increase." If a cost-based justification is not applicable, please explain why it is not applicable.

b. Please set forth the factual basis, including all studies, analyses, citations to all Commission precedent, and copies of any supporting documentation, that support implementation of the recommended 50% of system average increase "floor", highlighting all references from each supporting factor to both cost-based evidence and to 50% as the appropriate threshold.

Response:

a. Mr. Johnson's recommendation is a "cost-based" approach warranted in certain cases which involve a proposed overall increase in revenues simultaneous with a revenue reduction for specified classes. The 50% floor guarantees that these specified classes which pay revenues in excess of class cost of service will receive a base revenue increase which is substantially below the system average percent increase. If the 50% percent floor is applied as part of an overall gradualism proposal, the constraint recognizes cost-based considerations by limiting the revenue increase applied to the above-cost class(es) while also providing support for symmetric gradualism ceilings which can be applied to below-cost classes.

[response continued on next page]

PECO Energy Company, R-2024-3046932 (Gas)

PECO Interrogatories to the Office of Consumer Advocate
Set II

b. A number of factors may be relevant when evaluating a gradualism constraint such as the 50% floor. These factors include: (a) magnitude of the overall increase in revenues; (b) impact on an overall proposal for moderating class revenue changes; and (c) recognizing Bonbright's criteria for a sound rate structure. In Mr. Johnson's experience, customers and the public in general are more accepting of significant percentage revenue increases if there is some sharing of the "pain" by all classes. I am not a legal expert with respect to Commission precedent. Therefore, I have not conducted an exhaustive survey of Pennsylvania Commission precedent which may support constraints on class revenue decreases. However, in the Order in the following proceeding asserts that a class should not experience a revenue decrease when other classes experience a revenue increase: *Pa. PUC v. PECO Energy Company - Gas Division*, Docket No. R-2020-3018929 (Order entered June 22, 2021). https://www.puc.pa.gov/pcdocs/1708475.docx

Dated: July 1, 2024

Sponsored by: Clarence L. Johnson

Witness: Mark D. Ewen

The Office of Small Business Advocate
Responses to PECO Gas Energy Company – Gas Division
Set II Interrogatories Dated June 21, 2024
Docket No. R-2024-3046932

PECO-OSBA-II-1. Refer to OSBA Statement No. 1, page 27, line 3. Please explain how Mr. Ewen determined that 100 Heating Degree Days is an appropriate limitation for application of PECO's proposed Weather Normalization Adjustment.

OSBA Response. Mr. Ewen determined that 100 Heating Degree Days ("HDDs") is an appropriate limitation based on his review of other gas utilities' Weather Normalization Adjustment ("WNA") mechanisms. For example, as referenced in Mr. Ewen's direct testimony, application of the Philadelphia Gas Works ("PGW") WNA mechanism in May 2022 produced anomalous and unintended rate shocks for ratepayers due to unseasonably warm weather. See *Pennsylvania Public Utility Commission v. Philadelphia Gas Works*, Docket No. R-2022-3034229 and P-2022-3034264, Order entered September 21, 2023. The 100 HDD limit is intended to avoid extreme multipliers (driven by the difference between actual HDDs and normal HDDs) that may be produced by the Company's WNA mechanism as proposed. This recommended limit is based on Mr. Ewen's professional experience and is consistent with other gas utilities' WNA mechanisms. For example, Liberty Utilities sets the WNA for its New Hampshire gas utility to zero in any month where the actual HDD is below 100 (see OSBA-II-Attachment 1 at page 63). The OSBA is open to alternative limits to 100 if the Company can provide evidence that application of the WNA will not produce large multipliers and bills for ratepayers.

PECO-OSBA-II-2. Refer to OSBA Statement No. 1, p. 21, lines 1-13, and Exhibit IEc-2, Electronic Workpaper IEc WP1, IEc Table 4 regarding the OSBA's "halfway differential phaseout alternative" for the Rate GC block differentials. Is the Company understanding correctly that the OSBA is unopposed to the increased bill impacts that its proposal could create for smaller GC customers with monthly volumes of less than 250 Mcf relative to the Company's original proposal?

OSBA Response. Yes. OSBA prepared the "halfway differential phaseout alternative" consistent with the principle of rate gradualism for GC customers of all sizes. OSBA does not support the rate differential in the "halfway differential phaseout alternative" as a permanent solution and expects additional progress toward cost-based rates in the Company's next base rates filing.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2024-3046932**
	:	
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Joseph A. Bisti, hereby state that I am a Manager of Rate Analysts for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below 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.

- PECO Statement No. 7
- PECO Exhibit JAB-1
- PECO Exhibit JAB-2
- PECO Exhibit JAB-3
- PECO Exhibit JAB-4
- PECO Exhibit JAB-5
- PECO Exhibit JAB-6

- PECO Statement No. 7-R
- PECO Exhibit JAB-1 Revised
- PECO Exhibit JAB-2 Revised
- PECO Exhibit JAB-3 Revised
- PECO Exhibit JAB-4 Revised
- PECO Exhibit JAB-6 Revised
- PECO Exhibit JAB-7
- PECO Exhibit JAB-8
- PECO Exhibit JAB-9

Dated: August 5, 2024

Joseph A. Bisti

PECO Statement No. 8:

Direct Testimony of
Megan A. McDevitt

PECO ENERGY COMPANY
STATEMENT NO. 8

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: MEGAN A. MCDEVITT

SUBJECT: PROPOSED CHANGES TO PECO ENERGY COMPANY'S GAS DIVISION TARIFF

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
MEGAN A. MCDEVITT

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Megan A. McDevitt. 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 Senior Manager, Retail Rates. In that capacity, I am responsible for the management and oversight of PECO's electric and gas retail and supplier service tariffs and oversee numerous filings with the Pennsylvania Public Utility Commission (the "Commission").

3. Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Accounting from DeSales University in 2001. In 2006, I became a Certified Public Accountant in Pennsylvania. In March of 2022, I was promoted to my current position in PECO's Regulatory Policy and Strategy department, following roles of increasing responsibility within Accounting, Finance, Energy Acquisition, and Gas Supply and Transportation since joining PECO in September of 2004.

4. Q. What is the purpose of your testimony?

A. My testimony will explain proposed revisions to PECO's Tariff Gas – Pa. P.U.C. No. 5 that have been incorporated in the Company's proposed Tariff Gas – Pa. P.U.C. No. 6 ("Gas Tariff No. 6") filed in this case. My testimony divides the

proposed changes into the following categories: (1) tariff rates and riders; (2) Section 1307 surcharges; and (3) various miscellaneous provisions.

5. Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following PECO Exhibits:

PECO Exhibit MAM-1	Calculation of the Gas Procurement Charge ("GPC")
PECO Exhibit MAM-2	Components and Calculation of the Write-Off Rates and the Merchant Function Charge ("MFC")
PECO Exhibit MAM-3	Purchase of Receivables ("POR") Discount Rates from Gas Supplier Coordination Tariff

In addition, as explained by Company witness Joseph A. Bisti in PECO Statement No. 7, the various retail tariff changes that I am discussing are reflected in PECO Exhibit JAB-2, the Company's proposed Gas Tariff No. 6 in blackline format. Accordingly, I will refer to PECO Exhibit JAB-2 at certain points in my testimony.

II. TARIFF RATES AND RIDERS

6. Q. Is PECO proposing any changes to Rate GC – General Service Commercial and Industrial ("Rate GC")?

A. Yes. As explained by Mr. Bisti in PECO Statement No. 7, the Company is proposing revisions to Rate GC to provide two different customer charges based on the Rate GC customer's gas meter size and to eliminate the current declining block structure for the Rate GC variable distribution charge.

7. Q. Please describe the revisions that PECO is proposing to the Neighborhood Gas Pilot Rider ("NGPR").

A. As explained by Company witness Doreen L. Masalta in PECO Statement No. 9, the Company is proposing to continue the gas main extension pilot program for an additional five years (January 1, 2025 to December 31, 2029). During the five-year pilot extension, the Company's total investment would not exceed $40 million.

III. SECTION 1307 SURCHARGES

8. Q. What is a Section 1307 surcharge mechanism?

A. Section 1307 of the Public Utility Code, 66 Pa.C.S. § 1307, authorizes utilities to establish automatic adjustment clauses that allow them to recover, outside of a base rate proceeding, specific, designated categories of costs. Cost recovery is subject to annual review and reconciliation, such that over- or under-recoveries of actual costs are refunded to customers or recouped, as applicable. The operation of Section 1307 clauses is also subject to annual public hearings and periodic audits by the Commission.

9. Q. Is PECO proposing changes to any of its existing Section 1307 surcharge mechanisms?

A. Yes, the Company is proposing to revise its Universal Service Fund Charge ("USFC"), GPC, MFC and Distribution System Improvement Charge ("DSIC").

10. Q. Please describe the changes PECO is proposing to the USFC.

A. The USFC, among other things, is a mechanism by which the Company reflects the aggregate bill credits (in dollars) provided to low-income customers through

PECO's gas Customer Assistance Program ("CAP") rider each year that are not included in base rates (the "CAP shortfall"). The USFC also returns funds to customers for the cost of energy efficiency programs that were collected in base rates but were not expended.

With respect to CAP costs, the current USFC is adjusted so that non-CAP residential customers pay 73% of the total CAP shortfall amount. The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to bad debt expense and cash working capital arising from incremental changes to the level of CAP bill credits reflected in base rates. In this proceeding, as explained by Company witness Jacqueline F. Golden in PECO Statement No. 10, the Company is proposing to increase the aggregate value of bill credits provided to electric CAP customers included in its base rates and to change the offset factor applied to reconcilable CAP costs in the USFC formula from 27% to 10.5%.

With regard to residential natural gas energy efficiency and conservation ("EE&C") programs, PECO currently collects $2,727,500 through base rates each year.[1] If the Company expends less than that amount annually, a credit is provided to residential customers through the USFC. As explained by Ms. Masalta in PECO Statement No. 9, the Company also proposes changes to its residential natural gas EE&C programs and to increase its annual expenditures by $350,000 to $3,077,500. To implement these proposals, the gas USFC must be

[1] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021) ("2020 Gas Rate Case Order"), p. 115.

revised to reflect the change to the offset factor for CAP costs and the new energy efficiency spending level.

11. Q. Please describe the update that PECO is proposing to the GPC.

A. The GPC is comprised of non-fuel gas procurement costs incurred by the Company on behalf of its Sales Service (default) customers supplied under Rate Schedules GR, CAP, GC, OL, L, and MV-F. The current GPC ($0.0386 per Mcf) was established in PECO's 2022 gas rate case and has been effective since January 2023. PECO is proposing to update the GPC in this proceeding based on projected costs.

12. Q. What is the relationship between the costs included in the GPC and distribution base rates?

A. Consistent with current Commission-approved practice, non-fuel gas procurement costs will be included in the GPC and eliminated from distribution base rates.

13. Q. What procurement costs have been identified?

A. PECO has identified and quantified the following non-fuel natural gas procurement cost categories for inclusion in the GPC: Labor and Benefits, Outside Legal Costs, IT-Related Gas Procurement Costs and Cash Working Capital ("CWC"). In this case, PECO is proposing to continue to exclude these costs from distribution base rates and to recover them through a separate GPC charge, in the same manner approved by the Commission at Docket No. P-2012-2328614 and at Docket No. R-2022-3031113.

14. Q. What are the total annual gas procurement costs PECO has included for recovery in the Company's proposed GPC?

A. As summarized on PECO Exhibit MAM-1, p. 1, the total annual non-fuel procurement costs included in the Company's GPC are $1,742,000 for labor and benefits, outside legal costs, GasStar costs and CWC costs. These annual non-fuel procurement costs are also eliminated from distribution costs in PECO Exhibit MJT-1, Schedule D-15 by an associated reduction in distribution revenue requirement.

15. Q. How did you determine the GPC and the associated reduction in distribution base revenue requirement?

A. The revised GPC was calculated by dividing the non-fuel procurement costs of $1,742,000 by the projected default service volumes of 48,351,926 Mcf for the fully projected future test year ending December 31, 2025 ("FPFTY") for Rate Schedules GR, CAP, GC, OL, L and MV-F (PECO Exhibit MAM-1, p. 1). The resulting GPC rate is $0.0360 per Mcf. Consistent with the Commission regulation and current practice, the GPC rate will be included in the Company's PGC rate (PECO Exhibit JAB-2) and will remain constant until PECO's next gas distribution base rate proceeding. The updated tariff page reflecting this GPC is in PECO Exhibit JAB-2, p. 45.

The purpose of the distribution revenue requirement reduction is to eliminate from distribution rates the procurement-related costs included in the GPC rate. The associated distribution base rate reduction of $0.0255 per Mcf for non-fuel procurement costs was determined by dividing the annual gas procurement costs

of $1,742,000 by the projected distribution sales volumes of 68,243,939 Mcf for FPFTY, as shown on PECO Exhibit MAM-1, p. 1. The resulting distribution rate reduction of $0.0255 per Mcf is shown on PECO MAM-1, p. 1.

The annual distribution revenue requirement reduction is determined by applying the distribution base rate reduction of $0.0255 per Mcf to the associated projected distribution service volumes for the applicable classes of service. As noted above, the overall reduction is $1,742,000, as applied to the classes of service shown in PECO Exhibit MAM-1, p. 7. This reduction in annual distribution revenue requirement is factored into PECO Exhibit MJT-1, Schedule D-15, page 69 and discussed by Company witness Michael J. Trzaska in PECO Statement No. 3.

16. Q. Please describe the update PECO is proposing to the MFC.

A. The MFC recovers charge-offs of uncollectible PGC commodity charge revenues billed to sales service (default) customers. The MFC is calculated separately for three groups of customers consisting of: (1) Rate Schedules GR and CAP; (2) Rate Schedule GC; and (3) Rate Schedules L, OL and MV-F. The current write-off factors used to calculate the quarterly MFC rates were determined in PECO's 2022 gas base rate case (0.42% for Rate Schedule GR including CAP; 0.13% for Rate Schedule GC; and 0.04% for Rate Schedules L, OL and MV-F). PECO is proposing to update the write-off factors in this proceeding based on current costs and use those factors to calculate the update to the MFC, as it did in its previous 2022 gas distribution base rate case.

17. Q. What are the updated write-off factors from this proceeding that are used to calculate the proposed MFC and the natural gas suppliers' Purchase of Receivables ("POR") discount rates?

A. The updated write-off factors are 0.47% for Rate Schedule GR including CAP; 0.16% for Rate Schedule GC; and 0.01% for Rate Schedules L, OL and MV-F. These factors are based on a three-year weighted average of charge-offs (2021-2023) expressed as a percentage of billed revenues. Refer to PECO Exhibit MAM-2, p. 1, for the derivation of these factors. These factors will remain constant until the Company's next gas distribution base rate proceeding.

18. Q. How is the MFC determined?

A. Write-off factors for each of the applicable groups of rate schedules are multiplied by the Commodity Charge portion of the Company's projected PGC rate to determine the MFC. Upon completion of this proceeding, the approved write-off factors will be applied to the then-existing applicable Commodity Charge portion of the PGC rate, including the updated GPC from this proceeding, to determine the MFC. Thereafter, the MFC will be updated quarterly as the Commodity Charge rate portion of the PGC rate changes, while the approved write-off factors and GPC will remain constant until the Company's next gas distribution base rate proceeding.

19. Q. What is the relationship between the costs for charge-offs of uncollectible accounts included in the MFC and the POR discount rates and the expense for uncollectible accounts included for recovery in PECO's gas distribution base rates?

A. In accordance with existing practices, the costs for uncollectible charge-offs for sales service (default) customers reflected in the MFC will be included in the PGC rate as part of the Commodity Charge portion of the PGC. In addition, the costs for uncollectible charge-offs for natural gas suppliers are included as part of the POR discount rates. Therefore, these costs will not be included in PECO's gas distribution base rates.

20. Q. What is the MFC PECO proposes in this proceeding?

A. As shown in PECO Exhibit MAM-2, p. 2, the proposed MFC for Rate Schedule GR including CAP is $0.0227 per Mcf; for Rate Schedule GC is $0.0077 per Mcf; and for Rate Schedules L, OL and MV-F is $0.0005 per Mcf. These rates are based on data included in the distribution base rate case from PECO Exhibit MJT-1. As previously discussed, once the write-off factors from this proceeding are approved, they will be applied to the applicable commodity charge portion of the PGC rate in effect, including the updated GPC from this proceeding to determine applicable MFC values. Using the current PGC No. 40 Q1 effective March 1, 2024, the updated MFC values with the updated write-off factors and GPC from this proceeding are shown in PECO Exhibit JAB-2, p. 46.

21. Q. How is the Company's distribution base rate revenue adjusted to account for costs recovered in the MFC?

A. PECO Exhibit MAM-2, p. 3, shows the reduction to the overall distribution revenue requirement to reflect costs recovered in the MFC for sales service (default) customers. The applicable MFC annual revenue requirement of $919,000 will be deducted from the overall distribution revenue requirement for each of Rate Schedule GR including CAP; Rate Schedule GC; and Rate Schedules L, OL and MV-F, as included in PECO Exhibit MJT-1, Schedule D-15, page 69 and discussed by Mr. Trzaska in PECO Statement No. 3.

22. Q. What is the effect of the updated write-off factors on the POR discount rates for natural gas suppliers?

A. The current POR discount rates will be revised to reflect the updated write-off factors. Specifically, the POR discount rates will be equal to the updated write-off factors at this time. PECO's Gas Choice Supplier Coordination Tariff ("Gas Supplier Tariff"), Section 11.11.2.2, Consolidated NGDC Billing with Purchase of Receivables, item h, reflects the updated POR discount rates. *See* PECO Exhibit MAM-3, Gas Supplier Tariff, p. 43.

23. Q. How is the distribution base rate revenue adjusted to account for costs associated with uncollectible charge-offs recovered through the POR discount rates from natural gas suppliers for customers who shop for their natural gas?

A. PECO Exhibit MAM-2, p. 3, shows the reduction to overall distribution revenue requirements associated with the POR discount rates for shopping customers. These rates, which are equal to the write-off factors at this time, are applied to natural gas supplier revenues to determine the reduction in distribution revenue requirement as a result of costs recovered through the POR discount rate. The associated annual revenue requirement that will be deducted from the overall distribution revenue requirement is $281,000, as shown in PECO Exhibit MAM-2, p. 3 and included in PECO Exhibit MJT-1, Schedule D-15, page 69 and discussed by Mr. Trzaska in PECO Statement No. 3. The MFC reduction, when combined with the annual revenue requirement of $919,000, results in a total MFC and POR reduction in distribution annual revenue requirement of $1,200,000.

24. Q. Please describe the revision that PECO is proposing to its DSIC in conjunction with this gas distribution rate case.

A. In accordance with the "New Base Rate" section of PECO's DSIC, which was approved by the Commission's Order at Docket No. P-2015-2471423 entered on October 22, 2015, PECO is required to reset the DSIC to 0% upon the effective date of Commission-approved base rates. PECO's DSIC charge will be set to

zero effective January 1, 2025, as shown in the proposed DSIC. *See* PECO Exhibit JAB-2.

25. Q. Are there any other matters relating to Section 1307 mechanisms in PECO's Gas Tariff that you wish to address?

A. Yes, I would like to address PECO's temporary Tax Cuts and Jobs Act ("TCJA") Voluntary Surcharge, which is a rate adjustment mechanism to refund the estimated TCJA savings to customers. The TCJA Voluntary Surcharge became effective on July 1, 2018 pursuant to the Commission's Order entered on May 17, 2018 at Docket R-2018-3000512 (the "2018 Order").

From 2018 through 2023, PECO made several additional TCJA Voluntary Surcharge filings to continue to reconcile the final balances for residential, small commercial, large commercial and industrial customers, eventually resetting the TCJA to 0% for all rate classes effective March 1, 2023. The remaining balance as of May 31, 2023 is an undercollection of $62,667. As explained by Mr. Trzaska in PECO Statement No. 3, PECO proposes to collect the small under-recovery from customers through a distribution revenue requirement addition. Accordingly, PECO has fully satisfied the requirement of the 2018 Order.

IV. MISCELLANEOUS REVISIONS

26. Q. What miscellaneous revisions are being proposed by PECO and reflected in the proposed tariff?

A. PECO is proposing two miscellaneous revisions. First, PECO is proposing to revise the definition of "Holidays" to remove the term "Company" to align

language with PECO's electric service tariff and add the new Federal holiday of Juneteenth to the list of holidays.

Second, PECO is proposing to revise the Availability section of Rate IS – Interruptible Service to reflect the summer months of April through October. This change will align the summer months with other sections of the tariff.

V. CONCLUSION

27. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit MAM-1:

Calculation of the Gas Procurement Charge ("GPC")

PECO-Gas Operations

Annual Gas Procurement Charge (GPC) Calculation

Effective January 1, 2025
(Thousand$)

LABOR AND BENEFITS	**Costs**		**Source**
Gas Supply	$665		PECO Exhibit MAM-1, Page 2
Financial and Accounting Support	$22		PECO Exhibit MAM-1, Page 2
Internal Legal Support	$16		PECO Exhibit MAM-1, Page 2
Regulatory Support	$55		PECO Exhibit MAM-1, Page 2
Enterprise Credit	$8		PECO Exhibit MAM-1, Page 2
Management Support	$82		PECO Exhibit MAM-1, Page 2
Total Labor and Benefits	$848		PECO Exhibit MAM-1, Page 2
Outside Legal Costs	$60		PECO Exhibit MAM-1, Page 4
GasStar Related Costs	$62		PECO Exhibit MAM-1, Page 5
Working Capital	$772		PECO Exhibit MAM-1, Page 6
TOTAL COSTS	$1,742		
Distribution Base Rate Case Mcf Sales Volumes	68,243,939	Mcf	Projected Distribution Sales Volume
Distribution Charge Rate Reduction	$0.0255	$ per Mcf	
Default Customers' Mcf Supply Sales Service Volumes	48,351,926	Mcf	Projected Sales Service (Default) Volumes
GPC Rate	$0.0360	$ per Mcf	

PECO-Gas Operations

Annual Procurement Labor and Benefits Costs

January 1, 2025 through December 31, 2025

(Thousand$)

	Procurement Hours	Rate $/Hour (a)	Cost
Gas Supply	6,333.6	$105.01	$665
Financial and Accounting Support	210.0	$105.01	$22
Internal Legal Support	150.0	$105.01	$16
Regulatory Support	528.0	$105.01	$55
Enterprise Credit	80.0	$105.01	$8
Management Support	778.8	$105.01	$82
Total Labor and Benefits Costs	8,080.4		$848

Note (a) Per PECO Exhibit MAM-1, Page 3

PECO-Gas Operations
Annual Procurement Labor and Benefit Costs
January 1, 2025 through December 31, 2025

	Costs (Thousand$)	$/Hour (a)
Total Base Salaries & Wages	$42,599	$62.81
Total Other Payroll	$8,187	$12.07
Total Base and Other Payroll	$50,786	$74.88
Stock/Incentive Compensation	$5,585	$8.24
Total Base/Other Payroll Incl. Stock/Incentive Comp	$56,371	$83.12
Taxes Other Than Income, Employment Taxes (FICA, FUTA and SUTA)	$4,319	$6.37
Proforma Salaries and Wage Adjustment	$1,695	$2.50
Employment Taxes Adjustment	$144	$0.21
Total Wages and Employment Taxes	$62,529	$92.20
Employee Pensions and Benefits	$7,676	$11.32
Pension and Benefits Adjustment	$1,008	$1.49
Total Employee Pensions and Benefits	$8,684	$12.81
Total Wages, Employment Taxes and Pensions and Benefits	$71,213	$105.01
Hours in a Year	2,088	
Total O&M Full Time Equivalents (FTE)	401.07	
Paid Time-Off Factor (b)	1.2350	
Adjusted Hours in a Year	1,691	

Note (a) Total dollars divided by FTE divided by adjusted hours in a year
Note (b) Reflects adjustment to hours based on factors including vacation, holidays and sick time.

PECO-Gas Operations
Annual Outside Legal Expenses
January 1, 2025 through December 31, 2025
(Thousand$)

	Costs	Source
Outside Legal Expenses	$60	Company Records

PECO-Gas Operations
Annual Expenses for GasStar
January 1, 2025 through December 31, 2025
(Thousand$)

	Costs	Source
Annual Expenses	$92	Company Records
Allocated Commodity Portion	67.41%	PGC No. 40 Compliance Filing, Docket No. R-2023-3040285 Filed November 28, 2023, Effective December 1, 2023, Attachment D
Allocated to GPC	$62	

PECO-Gas Operations
Annual Cash Working Capital
January 1, 2025 through December 31, 2025
(Thousand$)

			Source
Revenue Lag	48.86	days	PECO Exhibit MJT-1, Schedule C-4, Page 23
Purchased Gas Costs Lag	33.24	days	PECO Exhibit MJT-1, Schedule C-4, Page 23
Net Lag Days	15.62	days	
Commodity and Capacity Fuel Costs	$233,721		Based on PECO Exhibit MJT-1, Schedule C-4, Page 23
Commodity Portion	74.81%		PGC No. 40 Compliance Filing, Docket No. R-2023-3040285 Filed November 28, 2023 Effective December 1, 2023, Attachment D
Applicable Fuel Costs	$174,847		
Average Cost per Day	$479		
Net Lag Days	15.62	days	
Commodity and GCA Related Cash Working Capital Requirement	$7,482		
Cash Working Capital Requirement	**$7,482**		
Pre-Tax Weighted Overall Rate of Return	10.32%	(a)	PECO Exhibit MJT-1, Schedule B-7, Page 13
Cash Working Capital Revenue Requirement	**$772**		

Note (a)

	Capital Structure	Return	Weighted Return	After-Tax Return
Debt	46.60%	4.58%	2.13%	1.55%
Common	53.40%	11.15%	5.95%	5.95%
	100.00%		8.08%	7.50%
Composite Federal and State Income Tax Rate	27.312%			
Gross Revenue Conversion Factor	1.37574			
Pre-Tax Weighted Overall Rate of Return				10.32%

PECO-Gas Operations

Annual Distribution Revenue Reduction from the GPC

January 1, 2025 through December 31, 2025

(Thousand$)

Rate Schedule	Distribution Mcf Sales	Distribution Charge Rate Reduction $ per Mcf (a)	Distribution Revenue Reduction
GR Incl CAP	43,867,240	0.0255	$1,119
GC	23,852,516	0.0255	$609
L	21,000	0.0255	$1
OL	-	0.0255	$0
MVF	503,183	0.0255	$13
Total	68,243,939		$1,742 (b)

Note (a) From PECO Exhibit MAM-1, Page 1
Note (b) From PECO Exhibit MAM-1, Page 1, Revenue Reduction Associated with the GPC

PECO Exhibit MAM-2:

Components and Calculation of the Merchant Function Charge ("MFC")

Gas Charge-Off Factors
Three-Year Weighted Average
Years 2021 through 2023 (a)
Percentages

Residential	12 months ended December 31, 2021 Charge-Off Analysis	12 months ended December 31, 2022 Charge-Off Analysis	12 months ended December 31, 2023 Charge-Off Analysis	Total
Charge offs	1,808,833	2,461,407	2,765,617	7,035,857
Billed Revenue	411,847,492	545,584,328	541,931,062	1,499,362,881
Charge offs %	0.44%	0.45%	0.51%	0.47%

GC	2021	2022	2023	Total
Charge offs	222,758	363,956	324,531	911,245
Billed Revenue	159,461,939	208,806,775	209,194,720	577,463,434
Charge offs %	0.14%	0.17%	0.16%	0.16%

L, OL and MVF	2021	2022	2023	Total
Charge offs	4,667	875	1,043	6,584
Billed Revenue	24,224,923	25,717,014	27,607,313	77,549,250
Charge offs %	0.02%	0.00%	0.00%	0.01%

Total	2021	2022	2023	Total
Charge offs	2,036,257	2,826,238	3,091,191	7,953,686
Billed Revenue	595,534,353	780,108,116	778,733,096	2,154,375,565
Charge offs %	0.34%	0.36%	0.40%	0.37%

Note (a) Per PECO Exhibit MJT-1, Schedule D-10, Page 64

PECO-Gas Operations

Determination of the Merchant Function Charge (MFC)

Effective January 1, 2025

Dollars per Mcf

Rate Schedules	Updated Write-Off Factor (a)	FPFTY Commodity Charge Portion of PGC Rate $ per Mcf	Updated MFC $ per Mcf
Rates GR and CAP	0.47%	$4.8380	$0.0227
Rate GC	0.16%	$4.8227	$0.0077
Rate L	0.01%	$4.7104	$0.0005
Rate OL	0.01%	$4.7343	$0.0005
Rate MVF	0.01%	$4.7343	$0.0005

Note (a) From PECO Exhibit MAM-2, Page 1

PECO-Gas Operations

Annual Reduction in Distribution Revenue Requirement from the MFC and the POR

Effective January 1, 2025

(Thousand$)

	Default Customers					Shopping Customers			Total
Rate Schedules	Updated Write-Off Factor (a)	FPFTY Commodity Charge Portion of PGC Rate $ per Mcf	Updated MFC $ per Mcf	Default Mcf Sales	Reduction in Distribution Revenue Requirement	Updated Write-Off Factor (a)	Shoppers Supply Revenues (b)	Reduction in Distribution Revenue Requirement	Reduction in Distribution Revenue Requirement
Rates GR and CAP	0.47%	$4.8380	$0.0227	36,561,612	$830	0.47%	$48,229	$227	$1,057
Rate GC	0.16%	$4.8227	$0.0077	11,496,008	$89	0.16%	$33,624	$54	$143
Rate L	0.01%	$4.7104	$0.0005	21,000	$0	0.01%	$0	$0	$0
Rate OL	0.01%	$4.7343	$0.0005	-	$0	0.01%	$0	$0	$0
Rate MVF	0.01%	$4.7343	$0.0005	273,306	$0	0.01%	$626	$0	$0
Total				48,351,926	$919		$82,479	$281	$1,200

Note (a) From PECO Exhibit MAM-2, Page 1
Note (b) From PECO Exhibit MJT-1, Schedule D-10, Page 64

PECO Exhibit MAM-3:

Purchase of Receivables ("POR") Discount Rates from Gas Supplier Coordination Tariff

Supplement No x to
Tariff Gas PaPUC No. 2S

PECO Energy Company

GAS CHOICE SUPPLIER COORDINATION TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

Issued: March 28, 2024

Effective: May 27, 2024

ISSUED BY:
Michael A. Innocenzo, President & CEO
PECO Energy Distribution Company
2301 Market Street
Philadelphia, PA. 19103

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Section 11.11.2.2, Consolidated NGDC Billing with Purchase of Receivables, item h, x Revised Page No. 43 -
Revise the Purchase of Receivables discount rates to reflect the write-off factors from the gas distribution base rate case at Docket No. R-2024-3046932.

Billing Service Options / Purchase of Receivables Program (continued)

f. Any transaction with Supplier Charges sent to the Company after the time period, in accordance with Attachment A - Data Transfer Schedule or not in the format, specified in Paragraph c. above, will be rejected and the LVT Customers' bill for the current billing period will state that the Supplier Charges for the current billing period are not available. The Supplier must resubmit the data the following month as required along with the then current month charges. Upon such resubmission, the Company will place the Supplier Charges into the that billing cycle and the delayed Supplier Charges will appear on the LVT Customer's bill for the then current month.

g. The Company will collect and process LVT Customer's payments in accordance with Section 2205 (c)(5) of the Competition Act and the Commission's applicable payment priority requirements.

h. The Company will purchase each LVT Customer's accounts receivable, without recourse and without discount, provided, however, as a result of the final order at Docket No. R-2024-3046932, that PECO shall discount the payment by 0.47% for Rates GR and CAP, 0.16% for Rate GC and 0.01% for Rates OL, L and MV-F consistent with the methodology approved in the partial settlement agreement and the Commission's final order in Docket No. P-2009-2143588 and the final order in Docket No. P-2012-2328614. PECO will pay the Supplier for amounts owed for all undisputed Supplier charges for basic gas supply services, regardless of whether the customer has paid the Company. Subject to the provisions of the partial settlement agreement and the Commission's final order in Docket No. P-2009-2143588, an amount is deemed disputed if the customer contacts the Company questioning the charges on the bill and he/she does not agree with the position of the Company or the Supplier regarding the amount due for Supplier charges. If the Supplier charges are not in dispute, the Company will remit all applicable monies due the Supplier, even if the Company's portion of the bill is disputed. A customer's claim of the inability to pay shall not constitute a dispute for purposes of the Company's obligation to pay the Supplier its undisputed charges. The ownership of each LVT Customer's accounts receivable will transfer from the Supplier to the Company upon payment to the Supplier for the receivable. **(C)**

i. The Company will pay the Supplier in accordance with the following schedule:

- The Company will send the Supplier the amount of its undisputed Supplier Charges within 40 calendar days from the date of the electronic transmission of the Supplier Charges. If the 40th day falls on a weekend, a PECO holiday, or a bank holiday, the Supplier payment will occur on the next business day.
- Payment will not be made to the Supplier when Supplier Charges are not received by the Company within the specified time period, as explained in paragraph (d) above. Payment for these charges will be made according to the applicable schedule in the following month, if they are received within the appropriate time period along with the current month charges.

(C) Denotes Change

Supplement No x to
Tariff Gas PaPUC No. 2S

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PECO Energy Company

GAS CHOICE SUPPLIER COORDINATION TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

Issued: March 28, 2024

Effective: May 27, 2024

Deleted: February 19,

Deleted: February

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ISSUED BY:
Michael A. Innocenzo, President & CEO
PECO Energy Distribution Company
2301 Market Street
Philadelphia, PA. 19103

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NOTICE.

Supplement No. x To
Tariff Gas PaPUC No. 2S
x Revised Page No. 1

PECO Energy Company

Supersedes x Revised Page No. 1

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Section 11.11.2.2, Consolidated NGDC Billing with Purchase of Receivables, item h, x Revised Page No. 43 - Revise the Purchase of Receivables discount rates to reflect the write-off factors from the gas distribution base rate case at Docket No. R-2024-3046932.

Issued March 28, 2024

Effective May 27, 2024

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Deleted: **6.1 – Provision of Customer Release of Information List – 2nd Revised Page No. 17**¶
Modified to indicate that the list shall include monthly gas usage data at the "Gas Choice ID" level, rather than at the account level. **6.2 – Data Exchange –**Changed Account Number" to "Gas Choice ID" and removed Billing Route reference.¶
¶
6.2.b Data Exchange and 6.3.1.c – NGS Selection Procedures –2nd Revised Page No. 18¶
Replaced Company Account Number with Gas Choice ID.¶
¶
6.3.1.f – NGS Selection Procedures – 2nd Revised Page No. 19¶
Replaced Company Account Number with Gas Choice ID.¶
¶
6.3.3.b – NGS Selection Procedures – 2nd Revised Page No. 20¶
Changed the number of scheduled meter reading dates referenced from "four" to "five".¶
¶
7.11.1 – Record Retention – 2nd Revised Page No. 23¶
Replaced NGDC Account Number with Gas Choice ID.¶
¶
7.14.b – Record Retention – 2nd Revised Page No. 24¶
Replaced PECO Energy Account Number with Gas Choice ID.¶

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Billing Service Options / Purchase of Receivables Program (continued)

f. Any transaction with Supplier Charges sent to the Company after the time period, in accordance with Attachment A - Data Transfer Schedule or not in the format, specified in Paragraph c. above, will be rejected and the LVT Customers' bill for the current billing period will state that the Supplier Charges for the current billing period are not available. The Supplier must resubmit the data the following month as required along with the then current month charges. Upon such resubmission, the Company will place the Supplier Charges into the that billing cycle and the delayed Supplier Charges will appear on the LVT Customer's bill for the the then current month.

g. The Company will collect and process LVT Customer's payments in accordance with Section 2205 (c)(5) of the Competition Act and the Commission's applicable payment priority requirements.

h. The Company will purchase each LVT Customer's accounts receivable, without recourse and without discount, provided, however, as a result of the final order at Docket No. R-2024-3046932, that PECO shall discount the payment by 0.47% for Rates GR and CAP, 0.16% for Rate GC and 0.01% for Rates OL, L and MV-F consistent with the methodology approved in the partial settlement agreement and the Commission's final order in Docket No. P-2009-2143588 and the final order in Docket No. P-2012-2328614. PECO will pay the Supplier for amounts owed for all undisputed Supplier charges for basic gas supply services, regardless of whether the customer has paid the Company. Subject to the provisions of the partial settlement agreement and the Commission's final order in Docket No. P-2009-2143588, an amount is deemed disputed if the customer contacts the Company questioning the charges on the bill and he/she does not agree with the position of the Company or the Supplier regarding the amount due for Supplier charges. If the Supplier charges are not in dispute, the Company will remit all applicable monies due the Supplier, even if the Company's portion of the bill is disputed. A customer's claim of the inability to pay shall not constitute a dispute for purposes of the Company's obligation to pay the Supplier its undisputed charges. The ownership of each LVT Customer's accounts receivable will transfer from the Supplier to the Company upon payment to the Supplier for the receivable. (C)

i. The Company will pay the Supplier in accordance with the following schedule:

- The Company will send the Supplier the amount of its undisputed Supplier Charges within 40 calendar days from the date of the electronic transmission of the Supplier Charges. If the 40th day falls on a weekend, a PECO holiday, or a bank holiday, the Supplier payment will occur on the next business day.
- Payment will not be made to the Supplier when Supplier Charges are not received by the Company within the specified time period, as explained in paragraph (d) above. Payment for these charges will be made according to the applicable schedule in the following month, if they are received within the appropriate time period along with the current month charges.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046932**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Megan A. McDevitt, hereby state that I am the Senior Manager, Retail Rates for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below 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.

- PECO Statement No. 8
- PECO Exhibit MAM-1
- PECO Exhibit MAM-2
- PECO Exhibit MAM-3

Dated: August 5, 2024

Megan A. McDevitt

PECO Statement No. 9:

Direct Testimony of
Doreen L. Masalta

PECO ENERGY COMPANY
STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: DOREEN L. MASALTA

SUBJECT: PROPOSED CHANGES TO PECO'S RESIDENTIAL NATURAL GAS ENERGY EFFICIENCY AND CONSERVATION PROGRAMS AND NEIGHBORHOOD GAS PILOT

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
DOREEN L. MASALTA

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Doreen L. Masalta. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 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 Director of Energy and Marketing Services. In that capacity, I have responsibility for the suite of energy efficiency programs offered by PECO to the Company's residential, commercial, and industrial customers. My team provides the marketing and promotions for these programs to encourage all customers to reduce their energy usage and save money on their bills.

3. Q. Please describe your educational background.

A. I have a Bachelor of Arts in Organizational Dynamics from Immaculata University.

4. Q. Please describe your professional experience.

A. I began my career owning and operating Arbor Tree Specialist, a private tree contracting business out of Pittsburgh, Pennsylvania. I then moved into the utility line clearance industry in 1994 with Asplundh Tree Expert Company where I held various positions including climber, foreperson, estimator, and emergent work coordinator. I joined PECO in 1998 as a project lead in the Vegetation

Management Department and transitioned to program manager in 2000. Beginning in 2002, I had responsibility for the Vegetation Management Programs at both PECO and one of the Company's utility affiliates, Commonwealth Edison Company. In 2007, I was named Director of PECO's Project, Contract & Vegetation Management Department. In late 2009, I became the Director of Operations in the Bucks & Montgomery County Regions and then transitioned in 2013 to the City of Philadelphia and PECO Underground. Finally, in 2019, I was promoted to my current position of Director of Energy and Marketing Services.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) describe PECO's existing residential natural gas energy efficiency and conservation ("EE&C") programs and the Company's proposals to enhance residential natural gas EE&C offerings and add flexibility to the administration of the Safe and Efficient Heating Program ("SEHP") for income-eligible customers; and (2) describe PECO's neighborhood gas pilot and the Company's proposal to extend the pilot with a programmatic change based on implementation experience.

6. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring PECO Exhibits DLM-1 and DLM-2 which relate to the Company's natural gas EE&C programs. In addition, I will refer to certain tariff changes contained in PECO Exhibit JAB-2 (sponsored by Company witness Joseph A. Bisti in PECO Statement No. 7).

II. PECO'S RESIDENTIAL NATURAL GAS EE&C PROGRAMS

A. Current Programs

7. Q. Please describe PECO's existing residential natural gas EE&C programs.

A. PECO currently offers its residential customers a mix of rebates to encourage them to upgrade to high-efficiency furnaces, boilers and water heaters, direct install measures, as well as discounts on smart thermostats purchased through PECO's online marketplace. In addition, SEHP provides qualifying low-income customers no-cost direct installation measures through the Low-Income Usage Reduction Program ("LIURP") and as part of free home energy assessments to improve the efficiency and safety of natural gas heating and water heating in their homes. SEHP also provides program recipients education on maintenance and energy efficiency tips at no cost. The Company has a total Pennsylvania Public Utility Commission ("Commission") approved residential natural gas EE&C budget of $2.727 million and has allocated $719,000 of that budget to the SEHP.[1]

8. Q. What natural gas equipment rebates are currently offered to PECO's residential customers?

A. As shown in the Table 1 below, PECO offers residential customers the following rebates for ENERGY STAR® high efficiency natural gas appliances:

[1] The Company's overall residential natural gas EE&C budget was approved by the Commission in PECO's 2020 gas distribution base rate proceeding. *See Pa PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929 (Order entered June 17, 2021), pp. 115-116. ("2020 Gas Order").

Table 1

Rebate Type	Rebate Amount ($)	Rebate Requirements
ENERGY STAR®+ Natural Gas Furnace	$600	Product must be ENERGY STAR® certified with an efficiency rating of ≥ 97% annual fuel utilization efficiency ("AFUE") and ≤ 2% air leakage and equipped with an electronically commutated fan motor ("ECM").
ENERGY STAR® Natural Gas Furnace	$350	Product must be ENERGY STAR® certified with an efficiency rating of 95-96.9% AFUE and ≤ 2% air leakage and equipped with an ECM. Natural gas furnace rebates cannot be combined.
ENERGY STAR® + Natural Gas Combi Boiler	$1,000	Qualifying combination boilers must be the primary system for both space heating and domestic water heating. Units must be ENERGY STAR® certified with ≥94% AFUE and fueled by PECO's natural gas distribution system
ENERGY STAR® Natural Gas Boiler	$350	Product must be ENERGY STAR® certified
*ENERGY STAR® Natural Gas Tankless Water Heater	$400	Product must be ENERGY STAR® certified
ENERGY STAR® Natural Gas Storage Tank Water Heater	$125	Product must be ENERGY STAR® certified
ENERGY STAR® Natural Gas Clothes Dryer	$15	Product must be ENERGY STAR® certified

*New measure to be implemented in Q2 of 2024.

9. Q. What direct install measures does PECO offer to residential natural gas customers?

A. For PECO natural gas residential customers who use natural gas to heat their water, PECO offers low flow showerheads, insulation/wrap for hot water pipes, thermostatic shower restriction valves and low-flow faucet aerators at no cost to the customer. In the second quarter of 2024, PECO will add two new direct installation home weatherization measures — outlet gaskets and weatherstripping — for customers who heat their homes with natural gas from PECO's distribution system. All installations are funded through PECO's natural gas EE&C programs and performed as part of the Energy Assessment Program included in PECO's Phase IV Act 129 EE&C Plan ("Phase IV Plan"). The SEHP, which is discussed later in my testimony, also offers certain direct install measures to income-eligible customers.

10. Q. How does PECO offer natural gas customers discounts on smart thermostats?

A. Eligible natural gas customers can purchase discounted smart thermostats using PECO's online marketplace.[2] Eligibility is determined by the customer's heating and cooling source that will be connected to the smart thermostat.[3]

11. Q. How has PECO informed its customers about these rebates?

A. PECO has used several channels to promote customer rebate opportunities,

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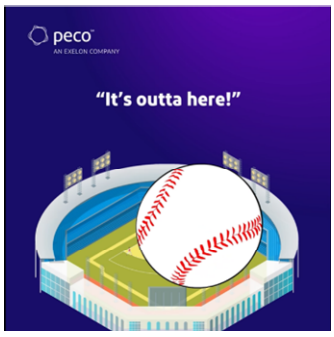
[2] https://www.pecomarketplace.com/peco. Residential customers who heat their homes with natural gas from PECO's distribution system can receive between $25-$50 in discounts.

[3] Smart thermostat eligibility requirements can be found at https://www.pecomarketplace.com/peco/peco-customers.

including the Company's website, trade-ally networks, newsletters, and bill inserts. In addition, PECO has utilized targeted digital promotions to build residential customer awareness of the Company's natural gas energy efficiency offerings. Below are examples of the Company's digital efforts to promote natural gas energy efficiency awareness.

Social Media Campaigns. Digital ads, such as those shown below, are designed to reach PECO customers on social media platforms to deliver brief, relatable animations around the importance of Energy Efficiency. The ads provide a direct link for customers to learn about PECO's programs online, including how to apply. In addition to the digital ads, PECO often sends corresponding emails using similar messaging and imagery.





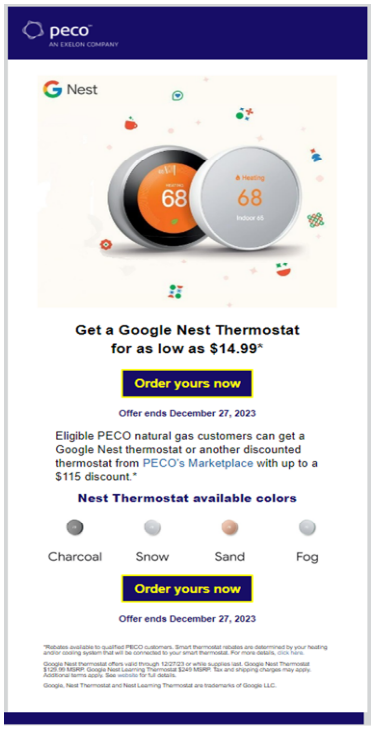
The above-referenced social media and email campaign ran in November 2023. During this time, PECO saw an average of over 600 unique visitors per day to the Gas Energy Efficiency webpage[4] versus an average of 30 unique visitors per day during months when there were no campaigns. In the month following the campaign (December of 2023), PECO saw a 55% increase in rebates issued

[4] https://www.peco.com/naturalgashomerebates.

versus the average since 2018.[5]

Email Campaigns. Email campaigns are often used to reach customers who have provided email addresses to the Company. Below are examples of emails sent to natural gas customers about PECO's Natural Gas Energy Efficiency Rebates and smart thermostat discounts. These email campaigns ran in March 2023 and November to December 2023, respectively. During the months the email campaigns ran, the Company saw an average of 219 unique visitors to the Gas Energy Efficiency website as well as a 27% increase in rebates paid versus the average during the same months since 2018.[6]





[5] Since 2018, PECO averaged 378 rebates during the months of December. In December of 2023, PECO issued over 580 rebates for Natural Gas Energy Efficiency Equipment.

[6] In March, November, and December 2023, the Company issued an average of 435 rebates compared to an average of 343 rebates during those same months from 2018 to 2022.

12. Q. Please describe the components of the SEHP, including customer eligibility requirements.

A. The SEHP serves PECO natural gas heating customers who meet the following criteria: (1) the customer has household income that is at or below 100% of the Federal Poverty Level ("FPL"); (2) the customer has an average monthly wintertime usage of no more than 149 cubic feet ("ccf") of natural gas; (3) the customer has not received a LIURP heating audit in the past two years; and (4) the customer owns the premise, unless the customer is at or below 50% of FPL, in which case ownership is not required.

When a customer who qualifies for SEHP receives a free energy checkup through the Phase IV Plan or a LIURP audit, the following additional measures are available through SEHP:

- Inspection of the natural gas furnace and/or boiler, including tune-ups and repairs;
- Heating system replacement for furnaces over 25 years old and boilers over 30 years old;
- Inspection of the natural gas water heaters including repairs;
- Replacement of natural gas water heaters in poor condition or nearing end-of-life (at least 15 years old);[7]
- Installation of smart water heater controls;
- Installation of a carbon monoxide detector with a 10-year lithium-ion battery;

[7] Natural gas storage tank water heaters are typically replaced about every 13 years. *See* The Mid-Atlantic Technical Resource Manual, p. 192, available at https://neep.org/sites/default/files/resources/Mid_Atlantic_TRM_V9_Final_clean_wUpdateSummary%20-%20CT%20FORMAT.pdf.

- Installation of energy savings products such as low flow faucet aerators, low flow showerheads, pipe wrap, thermostatic showerhead combos and more (for customers who heat water using natural gas); and

- A 12-month supply of filter replacements in addition to education and regular reminders on the frequency of filter replacement (for customers with natural gas supplied furnaces).

13. Q. What levels of customer participation, program spending and gas savings have PECO's residential natural gas EE&C programs achieved in the last several years?

A. As shown in the chart below, PECO has seen consistent growth since 2018 in terms of PECO's annual spending, customer participation and energy savings. 2023 reflects the highest year in all three categories, leading to 94% utilization of the Commission-approved budget for PECO's residential natural gas EE&C rebate program.

Table 1

Residential Natural Gas EE&C Programs				
Program Year	Customer Participation	Programs Spend	Programs Budget	Estimated Gas Energy Savings (Mcf)
2023	7,709	$2,556,703	$2,727,500	54,805
2022	4,105	$1,772,275	$2,727,500	44,334
2021	3,607	$1,150,522	$2,367,750	43,925
2020	3,869	$1,184,466	$2,008,000	36,171
2019	3,575	$1,121,793	$2,008,000	33,895
2018	3,344	$1,055,655	$2,008,000	31,615

14. Q. How does PECO recover its residential natural gas EE&C program costs?

A. Consistent with the 2020 Gas Order, the Company recovers $2.727 million for residential natural gas EE&C programs through gas distribution base rates. If the

Company spends less than $2.727 million, then the difference is credited to customers through the Universal Service Fund Charge ("USFC").

15. Q. In the Commission-approved settlement of PECO's most recent gas base rate proceeding,[8] PECO committed to perform an analysis of residential and small commercial natural gas EE&C measures. Did PECO fulfill this commitment?

A. Yes. In 2023, PECO engaged two vendors familiar with the PECO's natural gas EE&C programs to perform an analysis of the residential and small commercial natural gas EE&C measures (the "Measure Study"). The Measure Study includes both: (1) an evaluation of the cost effectiveness of the residential (non-SEHP) and small commercial portfolio based on implementation data from 2021 and 2022; and (2) a residential measure adoption rate analysis and forecast of measure performance for 2024 and 2025. The Measure Study also included some recommendations derived from the above-described analyses.

Overall, for the 2021-2022 period evaluated, the Measure Study concluded that the portfolio of natural gas EE&C programs was cost-effective. *See* DLM-1 at PDF p. 10. In response to recommendations in the Measure Study, the Company has made some changes to the residential natural gas EE&C portfolio. First, the Company is implementing two new direct install measures in 2024: (1) weather stripping; and (2) outlet gaskets. These two measures will help support the program's cost effectiveness by implementing weatherization measures through

[8] *See* Docket No. R-2022-3031113.

the direct install portion of the program. Second, beginning in 2024, the Company plans to adjust education efforts to promote the highest efficiency furnaces, boilers, and water heaters and direct install measures to maximize energy savings. Finally, the Company will continue to explore opportunities to implement additional rebate and direct install measures such as hybrid heat pumps, additional home weatherization measures and building optimization.[9]

I will discuss how the Company believes that additional funding will help to ensure the program can support projected growth in participation later in my testimony.

16. Q. Does PECO plan to continue evaluating its natural gas EE&C portfolio to ensure customers are provided reasons measures that reduce natural gas usage?

A. Yes. Consistent with the Company's statement in its most recent base rate proceeding,[10] the Company will perform an evaluation, measurement and verification ("EM&V") study in 2024 to evaluate program years 2021-2023. The Company will perform the next EM&V study in 2027, evaluating program years 2024-2026 and will retain the ability to determine the necessity, cadence and scope of future evaluations beyond 2027.

[9] *See* Exhibit DLM-1, PDF Pgs. 11-12 of 35 (recommending exploration of new measures for weatherization, hybrid heat pumps, and building optimization as well as recommending efforts to promote the highest efficiency furnaces and water heaters).

[10] *See* Direct Testimony of Doreen Masalta, Docket No. R-2022-3031113, p. 8 (PDF page 745), https://www.puc.pa.gov/pcdocs/1739246.pdf.

B. Proposed Revisions To The Overall Residential Natural Gas EE&C Budget and SEHP Administration

17. Q. Is the Company proposing to revise the existing budget for PECO's residential natural gas EE&C programs?

A. Yes. The Company is requesting to increase the current residential natural gas EE&C budget of $2.727 million by an additional $350,000. As shown in Exhibit DLM-2, Table 1, the Company expended 94% of the residential budget in 2023.[11] The additional $350,000 would support the projected growth in customer participation from 2023 levels and support future EM&V and customer education activities. Exhibit DLM-2, Tables 1 and 2, provide additional information about forecasted customer participation, energy savings, and costs. As outlined in DLM-2 Table-2, the Company forecasts a 8% growth in energy savings between program years 2024 and 2025 and a 7%-8% growth in energy savings year-over-year through 2027.

18. Q. Why is the Company forecasting continued growth in customer participation above 2023 levels?

A. PECO has made great strides in customer participation as a result of increases to customer education efforts and an increasing number of measures. Since 2022, the Company has added four new rebate measures, six direct install measures, online discounts for thermostats and the SEHP. PECO intends to maintain robust

[11] *See* Exhibit DLM-2, Table 1 2023 Spend Total and 2023 Budget Total. ($2,556,703 (Spend) ÷ $2,727,500 (budget) = 94%).

marketing efforts and continue to enhance the portfolio of measures available to customers. Some recent and anticipated highlights include the following:

Addition of Tankless Water Heater Measures. PECO evaluated this measure in response to 2023 ENERGY STAR changes to tank water heater criteria that sharply reduced the number of models that would be eligible for a rebate (from over 400 to less than 40). With the addition of a tankless water heater measure, PECO customers can receive a rebate on over 200 different models of ENERGY STAR-certified water heaters. The $400 rebate level for tankless water heaters was set to be consistent with similar programs in the region.[12] Based on the findings in the Measure Study, the Company could see an adoption of up to 300 rebates per year, which represents a substantial increase to the incentive cost budget.[13]

New Direct Installation Measures. As described earlier, the Company began planning for the implementation of weatherstripping and outlet gaskets measures in 2023, to be made available in 2024, based on findings in the 2023 Measure Study.[14] These new measures require an increase in incentive costs based on the Company's current spend for direct install measures.[15]

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[12] The Company reviewed tankless water heater measure offerings at UGI, PGW, New Jersey Natural & South Jersey Gas. These utilities offered rebates of $400-$750.

[13] *See* Exhibit DLM-1 Measure Study Pg. 28 of 35. In 2023, the Company paid out about $28,000 in version 4 tank water heater rebates whereas tankless water heater measures will cost up to or exceed $120,000.

[14] *See* Exhibit DLM-1 Measure Study Pg. 11 of 35, Findings 3, Finding 4 Recommendations & Pg. 30 of 35 New Measures, Envelope Measures.

[15] In 2023, the program spent over $2,500 towards direct install measures whereas the Company's 2024 forecast will expend over $18,000 on direct install measures increasing to approximately $35,000 by 2027.

Increased Education & Strategy. Since 2021, the Company has increased customer education substantially to include social media and email campaigns, as previously described in my testimony. The success of these campaigns warrants increasing the education budget to support continued growth. Additionally, the Company intends to target education efforts towards measures which have a high savings yield and cost effectiveness, through the use of more costly digital advertising such as social media. By highlighting the highest efficiency natural gas equipment and direct install measures, the Company can drive participation for residential measures (non-SEHP) that help achieve overall portfolio cost effectiveness in future program years.

19. Q. Is the Company recommending any changes to the SEHP?

A. Yes, the Company has identified a few programmatic changes which would allow the Company to adapt the SEHP to meet the needs of customers, including adjusting heating system replacement criteria and adding flexibility to adjust customer eligibility requirements and SEHP funding.

Heating System Replacement Criteria. The SEHP is currently focused on replacing heating systems based on age as noted earlier in my testimony, with occasional exceptions made for customers who require replacements due to system failures under the age requirements. The Company proposes to remove the age requirements for eligible customer heating systems and evaluate equipment based on a range of criteria including age, end-of-life, safety, ability to repair and system efficiency. This flexibility would allow the Company to properly manage replacement activity based on field conditions, rather than solely

age requirements.

Customer Eligibility Requirements. The Company is requesting the ability to adjust eligibility requirements as follows:

- Adjust eligibility to up to 200% of the Federal Poverty Level for homeowners and renters.
- Adjust winter monthly usage requirements.

This flexibility would allow the Company to adjust the program based on changes to other low-income programs or to align the program with the needs of income-eligible customers within PECO's service territory. For example, if the Company is trending towards a reduced spend within the SEHP budget, the Company could use this flexibility to reach more customers. There are no plans to change eligibility requirements at this time, and any future changes would be reported during the quarterly Universal Service Advisory Committee ("USAC") meetings.

SEHP Budget Flexibility. In the event that the SEHP requires additional funds within a program year, the Company is proposing to have the ability to move funding within the total proposed $3.078 million budget for residential natural gas EE&C programs to meet the needs of SEHP customers. The Company would limit annual budget transfers to 50% of the allocated SEHP budget.[16] The Company would have sole discretion on moving funding into the SEHP and will notify stakeholders of plans to move funding at quarterly USAC meetings, including if current SEHP funding levels were in excess of forecasted

[16] 50% of the current SEHP allocated budget would allow the company to move up to $359,500 of forecasted unused funds within the residential natural gas EE&C budget. ($719,000 * 50% = $359,500).

participation. This flexibility would allow the Company to continue to effectively manage the residential natural gas EE&C budget at the program level, by expanding the flexibility to shift funding towards the SEHP. This flexibility would align with the Company's current ability to adjust non-SEHP program budgets within the overall budget for residential natural gas EE&C programs to support growth, increase education or support program evaluation.

20. Q. Exhibit DLM-2, Table 2, shows the programs will underspend the increased budget in program year ("PY") 2025 and 2026, please explain.

A. The forecast shown in Exhibit DLM-2 Table 1 shows the estimated PY's 2025 and 2026 spending based on expected participation. As shown, the Company would manage spending within 93% and 97% of the overall residential natural gas EE&C budget respectively, if the increase is approved. The underspend is simply a result of the Company's participation forecasting and would still be available for use within the programs, including the SEHP if the aforementioned budget flexibility is approved. Nonetheless, any overall underspend would be refunded to rate payers through the USFC mechanism.

21. Q. What is the projected annual cost of the expanded residential natural gas EE&C programs?

A. The projected annual cost of the residential natural gas EE&C programs is $3.078 million, which reflects a $350,000 increase from the current budget to support increased participation from the Company's efforts to expand the program since 2022. The projected annual breakdown of costs by program is provided in Exhibit DLM-2.

22. Q. Has the Company evaluated the cost effectiveness of the residential natural gas EE&C programs?

A. Yes. The Company utilized a total resource cost ("TRC") methodology similar to what was used in the 2022 gas base rate proceeding with the following key changes:

- Updates were made to unit energy savings estimates and incremental cost estimates based on the Maryland Technical Reference Manual version 11 including weather normalization for the Philadelphia region.
- New measures were included as outlined in this testimony.
- Incremental adjustments were made such as adding electric savings, where applicable, that are not being claimed in other energy efficiency programs, i.e., direct install water savings measures.

23. Q. Is the current suite of residential natural gas EE&C programs cost-effective?

A. On a combined basis, the residential programs have a TRC of 0.70 in 2023 which will increase to 0.90 by 2027. Table 3 below shows the residential programs' cost effectiveness for years 2023 through 2027. The Company expects the residential market rate offerings, shown as "Residential Portfolio" in Table 3, to be cost-effective with a TRC of 1.00 by PY 2026; however, the low-income offerings will not be cost-effective with a TRC of 0.17. The Company recognizes the importance of maintaining cost effectiveness for energy efficiency programs and will continue to manage the program with cost effectiveness as a paramount feature of the combined non-income eligible portfolio.

Table 3

Residential Natural Gas EE&C Programs, TRC Results 2023-2027					
	2023	2024	2025	2026	2027
Residential Portfolio	0.83	0.90	0.94	1.00	1.05
Low Income Portfolio (SEHP)	0.16	0.16	0.17	0.17	0.17
Residential Sector Subtotal	***0.70***	***0.76***	***0.80***	***0.85***	***0.90***

24. Q. What adjustments is the Company making within the residential natural gas EE&C portfolio (non-SEHP) to move towards greater cost effectiveness?

A. As previously stated, the Company is implementing new weatherization measures to help achieve greater cost effectiveness and will focus promotion and education efforts on more cost effective and high efficiency measures. As an example, PECO will be changing its approach to smart thermostats in light of a significantly lower level of deemed savings than was originally projected. The smart thermostat measure was implemented in late 2022 with an expected TRC value of 1.4. As a result of the program's 2023 Measures Study[17], the Company learned this measure is now much less cost effective at a TRC value of 0.62. While the Company believes it is appropriate to retain smart thermostats as part of PECO's diverse residential natural gas EE&C offerings, the Company will move from an active to a passive approach towards promoting smart thermostat discounts. Exhibit DLM-2, Table 2, reflects the expected reduced participation based on this approach.[18]

[17] *See* Exhibit DLM-1, Pg. 7 of 35, Table 1. The referenced Measure Study benefit cost analysis ("BCA") was updated for the TRC used as part of this testimony. The Measure Study BCA TRC value of 0.31 for smart thermostats was updated to 0.62.

[18] *See* Exhibit DLM 2, Table 2. In 2023, the program provided discounts on over 3,000 thermostats and expects the participation to drop to ~1,000 units, based on a more passive approach to education for this measure.

Moving forward, the education budget will be more strongly focused on more cost effective and highly efficient measures, such as the direct install measures and furnace rebates offered through the Company. PECO would still build awareness around the entire natural gas EE&C portfolio through channels such as the Company newsletters, website and email campaigns. More costly targeted channels, such as direct mail or digital advertising, would be focused on helping the program achieve cost effectiveness. Additionally, the Company would continue to evaluate new measures to help with cost effectiveness.

25. Q. How is PECO proposing to recover the costs of the residential natural gas EE&C programs?

A. PECO is proposing to recover $3.078 million through residential gas distribution base rates. If less than $3.078 million is spent, the difference would be credited to the following year's USFC, as is currently PECO's practice. PECO Exhibit JAB-2 shows the proposed changes to the USFC to incorporate the $3.078 million annual spending amount.

III. PECO'S NEIGHBORHOOD GAS PILOT

26. Q. Please describe PECO's Neighborhood Gas Pilot Rider.

A. The Commission approved PECO's Neighborhood Gas Pilot Rider ("NGPR") on October 1, 2015.[19] The NGPR was designed to study two coordinated strategies to increase access to natural gas service by: (1) allowing a customer to pay a contribution in aid of construction ("CIAC") for a gas main extension through a

[19] *See* Docket No. P-2014-2451772.

fixed monthly surcharge instead of requiring an upfront, lump-sum payment; and (2) calculating the required CIAC by taking into account the revenue (including the fixed monthly CIAC payment) expected from the applicant or applicants requesting service and from prospective customers located along the proposed main extension who are expected to connect to the main in the future.

The NGPR is available to PECO residential customers who will receive natural gas service under Rate GR, including customers on the Customer Assistance Program ("CAP") Rider. Certain cost and customer interest thresholds must be met to qualify for the pilot (e.g., the proposed extension must be greater than $15,000 and at least 20% of eligible customers must execute contracts for gas service). Customers may pay for the main extension in either one upfront payment or a fixed monthly fee with interest on their PECO bill.

The NGPR originally had a three-year term and the Company's investment was limited to no more than: (1) $10 million over three years; and (2) $4 million for any particular year. On January 17, 2019, the Commission approved extending the pilot from three to five years (ending March 31, 2021) and the overall pilot investment limit was increased from $10 million to $25 million.[20] In the 2020 Gas Order, the Commission approved a five-year pilot extension (now ending June 30, 2026) with an additional investment of $25 million. The Commission further approved PECO's proposal to provide the first forty feet of gas main extension at no cost to each prospective residential natural gas service customer

[20] PECO Supplement No. 12 to Tariff Gas PA P.U.C. No. 3, Docket No. R-2018-3006218 (Order entered January 17, 2019).

within the project. On July 13, 2023, the Commission approved PECO's petition to remove the $5 million annual spending limitation.[21]

27. Q. How many main extension projects have been funded under the NGPR?

A. Since the program launched with modifications on July 1, 2021, through December 31, 2023, 99 projects encompassing over 2,048 homes have been funded through the NGPR with a total design estimate cost of $25 million. Due to overwhelming customer demand and funding limitations, PECO stopped accepting new NGPR projects in August 2022. Many more potential gas main extension projects were analyzed by the Company before August of 2022, but either did not garner sufficient neighborhood interest to move forward or had not advanced sufficiently to proceed prior to funding limitations.

28. Q. Please describe the Company's proposed NGPR revision.

A. The Company is proposing to extend the pilot with a programmatic change to facilitate access to natural gas service in more communities. The revised NGPR would be implemented for a five-year term beginning January 1, 2025, through December 31, 2029.

PECO's proposed programmatic change is to modify the percentage of customers the Company models will convert in the first year of a neighborhood project from 66% to 50% to more accurately reflect the percentages that we have seen in the modified pilot. The remainder of the 66% will be modeled within 20 years of the

[21] *Petition of PECO Energy Company-Gas for Approval to Modify its Neighborhood Gas Pilot Rider*, Docket No. P-2023-3040480 (Order entered July 13, 2023).

completion of the project. The revised NGPR would continue to apply to any existing premise that is not located along an existing PECO gas main and where there is an application for natural gas service within the Company's natural gas service territory under Rate Schedule GR, including the CAP Rider. Consistent with the existing pilot, a main extension project must meet the following criteria to qualify for the revised NGPR:

(1) The project area must contain at least two prospective premises;

(2) The cost of the project must equal or exceed $15,000;

(3) A minimum of twenty percent (20%) of the existing residences located along the proposed main extension must commit to receive natural gas service by signing an agreement prior to the start of construction;

(4) The Company must have adequate system capacity to serve the customers that are eligible to receive natural gas service from the proposed main extension; and

(5) The project must be consistent with the overall spending cap for the revised pilot.

The limited tariff changes required to implement the revised NGPR are discussed by Company witness Megan A. McDevitt in PECO Statement No. 8 and shown in PECO Exhibit JAB-2.

29. Q. Why is it appropriate to extend the term of the NGPR?

A. The Company continues to see strong demand for natural gas conversion from potential customers. Since PECO stopped accepting new NGPR projects in August 2022 because of fully contracting the $25 million program budget, there have been over 800 customer inquiries about extending natural gas into new neighborhoods. Potential cost savings from oil or propane conversion to natural gas is typically a driver of interest from customers. As of March 2024, PECO's

natural gas prices, including distribution costs, are approximately 63% less than fuel oil and approximately 69% less than propane prices.[22]

30. Q. Please explain further why the Company is proposing to update its modeling to reflect a 50% conversion in the first year.

A. PECO is proposing to update the Net Present Value ("NPV") model to reflect 50% of customers in a neighborhood converting in the first year to more accurately reflect recent implementation experience. Under the most recent iteration of the pilot, approximately 45% of customers have signed contracts prior to installation. It is not uncommon for additional contracts to be signed within a week or two of the beginning of installation activities.

31. Q. What is the projected cost of the five-year revised NGPR?

A. The Company is proposing to invest a maximum of $40 million in capital over the five-year term of the revised NGPR. PECO has reviewed customer demand, the number of potential jobs that go through various stages of the process, and updated installation costs, among other factors to determine the proposed capital request.

The projected spend in Table 4 below is an estimate of annual costs. The Company is not proposing annual spending restrictions but would instead manage NGPR spending to the overall budget. From the beginning of the revised NGPR

[22] *See* U.S. Energy Information Administration ("EIA"), Weekly Heating Oil and Propane Prices (October-March) for Pennsylvania, https://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_sPA_w.htm. According to the EIA, Pennsylvania state-wide residential heating oil cost an average $3.81 per gallon and residential propane cost $3.00 per gallon. According to the EIA's "Definitions, Sources & Notes, these prices include delivery. PECO's residential natural gas price on March 1, 2024, was $1.05 per Ccf excluding customer charge.

(July 1, 2021) through February 29, 2024, the NGPR spend has been approximately $13 million.

Table 4

	2025	2026	2027	2028	2029
Projected Spend of the Revised NGPR	$4M	$8M	$9M	$9M	$10M

32. Q. How would the Company transition from the current NGPR to the revised NGPR?

A. PECO intends to complete construction of the projects for neighborhoods participating in the currently effective NGPR through December 31, 2024, with no additional payment requirements until the existing $25 million budget is reached. Some work may continue into 2025, which PECO would propose to count towards the proposed program extension budget to ensure easier calendar year budgeting. For potential main extension projects where at least 20% of potential customers have submitted an application for natural gas service, but contracts for the project have not yet been issued, PECO will provide a notification to all potential customers. The notification will explain that the Company has proposed changes to the NGPR that could allow for additional projects in the future, if such revisions are approved by the Commission. The Company would provide similar information in response to future customer inquiries about the NGPR while its proposal is pending before the Commission.

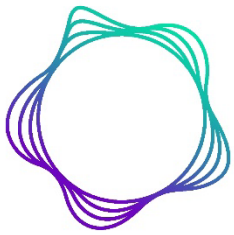
IV. CONCLUSION

33. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

PECO Exhibit DLM-1:

PECO Natural Gas Energy Efficiency Programs - 2023 Measure Study



peco[SM]

AN EXELON COMPANY

PECO Natural Gas Energy Efficiency Programs

2023 Measure Study

Prepared by: PECO Marketing Department, Strategic Programs

Prepared in partnership with:

Guidehouse

CLEAResult®

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Section 1: Introduction, Background and Scope

In accordance with PECO's Base Rate Filing Docket R-2022-3031113[1], PECO has performed a measure analysis (the "Measure Study") of the Natural Gas Energy Efficiency Programs (the "Gas EE&C Programs"). The purpose and intent of the analysis is to meet regulatory requirements as part of PECO's 2022 Gas Base Rate settlement terms & evaluate the rebate products offered in program years (PY) 2021 & 2022.

2022 Gas Rate Case Settlement Term[2]

G. Customer Programs

(1) Gas Energy Efficiency and Conservation ("EE&C") Program

31. PECO will maintain the original $2.008 million budget for Residential rebates under PECO's Gas EE&C Program along with the two originally proposed additional rebates. The Company agrees to perform an analysis of Residential and Small Commercial natural gas EE&C measures in 2023. The analysis will include items such as cost effectiveness, projected impact, adoption estimates, costs of incentives, and savings to ensure that PECO promotes reasonable measures to reduce natural gas use among residential and small commercial customers. PECO will also retain the ability to add measures and adjust incentive levels and energy efficiency requirements.

Background & Scope

The above referenced language from Docket R-2022-3031113, was used as an outline to determine a scope of PECO's Measure Study. PECO tailored the scope to meet program, budget and timeline requirements. As Energy Efficiency Program evaluations can vary greatly in scope, costs and time, the company outlined requirements that would help alleviate any redundancies when performing an Evaluation, Measurement and Verification study in 2024[3]. For these purposes, the following elements were determined in scope for the Measure Study and scaled accordingly:

- Measure Cost Effectiveness
- Projected Impact
- Adoption Estimate
- Cost of Incentives

Not included in the scope of the Measure Study:

[1] PA PUC Docket R-2022-3031113
[2] https://www.puc.pa.gov/pcdocs/1759065.pdf
[3] https://www.puc.pa.gov/pcdocs/1739246.pdf, Pg. 745 of Volume II, Statement No. 9 (Masalta) EM&V Commitment

- Services and Measures offered through PECO's Income Eligible Safe and Efficient Heating Program (SEHP)[4].
- Evaluation of future changes or measure implementations

Section 2: Measure Study Partners

Measure Study Partners

Two Gas EE&C Program vendors were contracted to meet the Measure Study scope, as previously described.

Guidehouse[5]

Guidehouse Inc. is a consulting firm that provides program design and evaluation services for PECO's energy efficiency programs. In the past, Guidehouse has provide Total Resource Cost analysis (TRC), program design and measure consulting for the Gas EE&C Programs. Guidehouse was selected due to their historical knowledge of the PECO EE&C Gas Programs as well as to leverage previous work performed, for use in the Measure Study. Guidehouse was selected to:

- Perform an impact evaluation
- Perform a cost effectiveness evaluation
- Provide a memo based on the above analysis

CLEAResult Inc.[6]

CLEAResult Inc. provides program implementation services for PECO's energy efficiency programs. For the Gas EE&C Programs, CLEAResult manages the residential and commercial rebates, PECO Marketplace and residential direct install measures. CLEAResult was selected due to their status as an implementor of PECO's energy efficiency programs and expertise in the HVAC and appliance product market for PECO's service territory. CLEAResult was selected to provide:

- Adoption rate analysis
- Market conditions evaluation
- Program benchmarking
- An outline based on the above analysis

For the purpose of this study and to keep the Measure Study within scope and budget, Guidehouse was instructed to review program years 2021 and 2022 for performing historical performance analysis and CLEAResult was instructed to review all current products for PECO's Gas EE&C Programs non-SEHP offerings.

[4] https://www.puc.pa.gov/pcdocs/1739246.pdf SEHP description can be found on Pg. 742 of Volume II, Statement No. 9 (Masalta)
[5] https://guidehouse.com/
[6] https://www.clearesult.com/

Section 3: Guidehouse Analysis

Draft Memorandum

To:	**Clifton Krausz, Nicholas Mart**
CC:	**Marina Geneles**
From:	**Guidehouse – Mark van Eeghen, Jenny Hampton, Carina Grady, and Garnet Parks**
Date:	**September 27, 2023**
Re:	**PECO Gas Energy Efficiency and Conservation Program Study for Program Years 2021 and 2022**

PECO filed the current rate case in March 2022, and the Joint Petition for Settlement of Rate Investigation[1] was approved in fall 2022. PECO's program is implemented by CLEAResult. As part of the settlement, PECO contracted Guidehouse to evaluate the verified gross impact and cost effectiveness of PECO's 2021-2022 program to inform measure and incentive efficacy and program design for the remainder of the 2021-2024 program cycle. This memo outlines the results of the evaluation and cost effectiveness analysis and recommends relevant program updates.

1. Impact Evaluation

In the absence of a Pennsylvania TRM specific to gas measures, Guidehouse evaluated savings using algorithms and inputs from the Maryland TRM v11.[2] This TRM was developed in 2023 and incorporates the most recent code updates from the Department of Energy (DOE) for residential and commercial boiler measures (from 82% to 84% efficiency) and it incorporates updates to algorithms for gas hot water heaters. In addition, Guidehouse made the following input assumptions and adjustments:

- Effective full load heating hours (EFLH):
    - For residential heating measures, Guidehouse applied an EFLH of 761 hours, consistent with the value used in the 2021 PA TRM[3]. In comparison, the plan design applied an EFLH of 854 hours, consistent with the value used from the Philadelphia Gas Works (PGW) TRM.
    - For commercial heating measures, Guidehouse applied an EFLH of 456.5 hours, which is the average of Philadelphia's retail (632) and office (281) EFLH values, as per the 2021 PA TRM. The retail and office locations are the most common commercial participants in the program in 2021 and 2022. In comparison, the

[1] https://www.puc.pa.gov/pcdocs/1759065.pdf

[2] Maryland EmPOWER Technical Reference Manual, v11.0. May 2023.

[3] PA PUC. *Technical Reference Manual; State of Pennsylvania Act 129 Energy Efficiency and Conservation Program & Act 213 Alternative Energy Portfolio Standards*. Dated August 2019, re-issued February 2021.

plan design applied an EFLH of 643 hours, taken by applying the median of the average sums across all space types listed in the MD TRM v9 TRM.

- The tracking data didn't include input capacity data for 7% of rebated furnaces and boilers. Guidehouse applied the average input capacity from the 93% of rebated units where capacity data was available, which is 86,996 Btuh for residential measures and 95,641 Btuh for commercial measures. In comparison, the plan design used an average capacity of 100,000 Btuh for residential furnaces and boilers, 112,500 Btuh for commercial furnaces, and 300,000 Btuh for commercial boilers.

- Evaluated savings incorporated the most recent code changes from the DOE, such as residential boilers[4] and commercial boilers.[5] This code change increased the baseline Annual Fuel Utilization Efficiency (AFUE) from 82% to 84%.

- For smart thermostats, the Maryland TRM awards deemed savings for the installation of a smart thermostat, and the TRM awards deemed savings for the optimization of a smart thermostat. Guidehouse weather normalized the deemed savings for both the installation and the optimization of smart thermostats from Maryland to Philadelphia. In addition, the Maryland TRM awards thermostat optimization savings to all NEST and Ecobee thermostats. Optimization savings were not rewarded to thermostats from other manufacturers, because no data was available to indicate those thermostats were optimized. In total, 72% of rebated thermostats are NEST or Ecobee and hence received optimization savings. Table 1 summarizes the deemed thermostat optimization savings applied in this evaluation.

Table 1. Evaluated per Unit Thermostat and Thermostat Optimization Savings

Measure	NEST and Ecobee Thermostat (MCF/unit)	All other Thermostats (MCF/unit)
Deemed Smart Thermostat Savings	0.97	0.97
Deemed Optimization Savings	0.97	2.24
Total	**1.94**	**3.21**

Source: Guidehouse analysis

For this evaluation, Guidehouse believes it is appropriate to evaluate savings for PECO using the Maryland TRM v11, which are based on a rigorous study conducted in 2021 in Maryland . that found 1.90% savings, equivalent to the MCF-results included in Table 1.[6] However, Guidehouse recommends that PECO conducts additional secondary research through benchmarking and literature review to further refine the savings estimates for smart thermostats, because:

1. Savings for smart thermostat vary significantly depending on the cited study, with savings percentages for gas heating ranging from 1.13% up to 13.40%.[7] Guidehouse

[4] https://www.ecfr.gov/current/title-10/part-430/section-430.32#p-430.32(e)(2)(iii)

[5] https://www.ecfr.gov/current/title-10/part-431/section-431.87#p-431.87(a)

[6] EmPOWER Phase 2 Residential Thermostat EE Program Evaluation. June 28, 2021. See Source/Reference Documents.

[7] See slide 28 of Guidehouse Tier 3 Thermostat Calibration Study, April 18, 2023.

notes that older studies generally found higher savings that more recent studies, with more recent studies generally finding savings up to 7%.

2. The Maryland study does not account for differences in building stock and usage patterns between Maryland and Pennsylvania.

Table 2 and Table 3 include the evaluated measure level savings for 2021 and 2022 program activity.

Table 2. Evaluated Natural Gas Savings by Residential Measure (2021-2022)

Measure Name (Plan Design)	Evaluated Quantity (2021 and 2022)	2021 Evaluated Savings (MCF)	2022 Evaluated Savings (MCF)	Total Savings (MCF)
ENERGY STAR Furnace (>=95% AFUE)	6,203	41,221	37,997	79,218
ENERGY STAR Boiler (>=90 AFUE)	422	1,770	2,151	3,921
ENERGY STAR Furnace (>=97% AFUE)	160	179	2,269	2,448
Storage Hot Water Heater (0.67 EF)	540	754	1,185	1,939
Smart Thermostat Optimization	306	-	386	386
Smart Thermostat		-	250	250
Low Flow Showerhead (<=2.0 GPM)	76	-	94	
Low Flow Faucet Aerator (<=1.5 GPM)	5	-	2	2
Residential Total	**7,712**	**43,925**	**44,334**	**88,258**

Source: Guidehouse analysis

Guidehouse evaluated some electric savings for low flow showerheads and low flow aerators that are associated with savings at water facilities due to reduced water consumption. Total water savings for 2021 and 2022 combined are 210,963 gallons for showerheads and 7,351 gallons for low flow aerators. Total electricity savings is 604 kWh for aerators and showerheads, respectively.

Table 3. Evaluated Natural Gas Savings by Commercial Measure (2021-2022)

Measure Name (Plan Design)	Evaluated Quantity (2021 and 2022)	2021 Evaluated Savings (MCF)	2022 Evaluated Savings (MCF)	Total Savings (MCF)
ENERGY STAR Furnace <225 kBTU/h (>=95% AFUE)	38	226	69	295
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	10	21	50	71
Commercial Total	**48**	**247**	**119**	**366**

Source: Guidehouse analysis

Residential furnaces contribute 92.1% of the evaluated savings for 2021 and 2022. The vast majority of those savings is coming from 95% AFUE furnaces, and a smaller portion is coming from 97% AFUE furnaces, relative to a current baseline of 80% AFUE. DOE recently finalized a final rule for residential furnaces, which requires non-weatherized gas furnaces to to meet a

standard of 95% AFUE in starting late 2028.[8] This rule significantly reduces the savings potential for this measure starting 2028. In addition, DOE proposed standards include a condensing standard for tankless water heaters, and an increase to the non-condensing standard for storage water heaters in 2029.[9]

2. Cost Effectiveness Evaluation

The benefit-cost results equal the ratio of the present value of the benefits to the present value of the costs; this ratio has been calculated for PECO's individual market sectors as well as the portfolio as a whole.

Guidehouse conducted one commonly used cost-effectiveness tests for this report, the Total Resource Cost (TRC) test. A TRC ratio greater than 1.0 indicate the benefits that accrue over the life of the measures exceed the costs, specifically utility program administration costs and customer outlays for the efficiency measures. The evaluation team estimated the TRC benefit-cost ratios based on methods described in the California Standard Practice Manual for assessing energy efficiency programs cost-effectiveness.[10] To estimate the TRC ratios, Guidehouse examined program benefits, which include the avoided cost of gas over the effective useful life (EUL) of each measure, and program costs, which include incentives to customers, administrative costs, and incremental measure costs. Table 4 shows the EULs and Incremental Measure Costs (IMCs) used for the analysis.

Table 4. Measure Incentives, Incremental Cost and EULs

Program	Measure	Incentive ($/unit)	IMC (2021$)	EUL (Years)
Residential	ENERGY STAR Furnace (>=95% AFUE)	$350.00	$529	21
	ENERGY STAR Furnace (>=97% AFUE)	$600.00	$649	21
	ENERGY STAR Boiler (>=90 AFUE)	$350.00	$521	25
	Storage Hot Water Heater (0.67 EF)	$125.00	$159	13
	Smart Thermostat	$25.00	$161	7.5
	Low Flow Faucet Aerator (<=1.5 GPM)*	Direct Install	$11.61	10
	Low Flow Showerhead (<=2.0 GPM)*	Direct Install	$21.00	10
Commercial	ENERGY STAR Furnace <225 kBTU/h (>=90% AFUE)	$300.00	$433	20
	ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	$300.00	$519	20

* Direct install measure offered free of charge to the customer. The incremental measure costs for aerators and showerheads represents the full measure costs and installation costs.

Source: PECO Tracking Data and MD TRM v11

Table 5 shows the sector and portfolio level TRC results for 2021 and 2022.

[8] https://www.energy.gov/articles/doe-finalizes-energy-efficiency-standards-residential-furnaces-save-americans-15-billion#:~:text=These%20standards%2C%20which%20take%20effect,energy%20and%20improving%20residential%20heating.

[9] DOE EERE_ECS Consumer Water Heaters_NOPR_0.pdf (energy.gov)

[10] California Standard Practice Manual

Table 5. TRC Results by Sector for PECOs 2021 and 2022 Programs

Program	2021 TRC Results	2022 TRC Results	Total TRC
Residential	1.08	0.99	**1.03**
Commercial	0.81	0.31	**0.52**
Portfolio	**1.07**	**0.98**	**1.03**

Source: Guidehouse analysis

Overall, the PECOs gas programs are cost effective with a TRC of 1.03 for 2021 and 2022. The TRC for 2021 is 1.07, and the TRC for 2022 is 0.98. The cost effectiveness for 2022 is lower due to an increase in administrative costs ($117,955 in 2021 compared to $273,612 in 2022). Guidehouse notes that the increase in administrative costs is due to increased investments in customer education and marketing activities in 2022, specifically for smart thermostats, which were recently added to the program. PECO indicated that the marketing activities are expected to scale down again in 2023.

For 2021, the residential sector accounts for 99.5% of total TRC benefits and 96.1% of costs (including program administrative and customer costs before incentives). Overall, 91.2% of 2021 portfolio spending was directed towards incentives. The remaining 8.8% of portfolio spending was utilized for administrative activities. For 2022, the residential sector accounts for 99.7% of total TRC benefits and 89.1% of costs (including program administrative and customer costs before incentives). Overall, 82.4% of 2022 portfolio spending was directed towards incentives, a 4.1% increase from 2021. The remaining 17.6% of portfolio spending was utilized for administrative activities.

Guidehouse compared the present value of the gas savings benefits against the incremental measure costs to analyze which measures, ignoring fixed administrative costs, make positive contributions to the TRC. These results are summarized in Table 6.

Table 6. Average Present Value of Program Benefits Results for 2021 and 2022 Programs

Program	Measure	PV of Benefits ($/unit)	IMC ($/unit)	PV Benefits / IMC
Residential	ENERGY STAR Furnace (>=95% AFUE)	$616.48	$528.70	1.17
	ENERGY STAR Furnace (>=97% AFUE)	$738.40	$649.07	1.14
	ENERGY STAR Boiler (>=90 AFUE)	$497.69	$521.30	0.95
	Storage Hot Water Heater (0.67 EF)	$95.66	$159.26	0.60
	Smart Thermostat	$50.65	$161.11	0.31
	Low Flow Faucet Aerator (<=1.5 GPM)	$129.35	$10.75	12.31
	Low Flow Showerhead (<=2.0 GPM)	$615.75	$19.44	13.32
Commercial	ENERGY STAR Furnace <225 kBTU/h (>=90% AFUE)	$371.01	$433.33	0.86
	ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	$318.35	$518.52	0.61

Source: Guidehouse analysis

Guidehouse compared PECOs measure mix against the measure mix of other gas utilities, including Washington Gas and Nicor Gas.[11,12,13] The offered residential measures are in line with what other gas utilities offer in their rebate programs. Guidehouse notes that PECOs commercial program is smaller than of other gas utilities, however the commercial boiler and commercial furnace measure are a common offering in other gas utility programs.

3. Findings and Recommendations

This section summarizes Guidehouse's key findings and recommendations derived from the evaluation activities.

- **Finding 1:** PECO's portfolio saved 88,625 MCF savings in 2021 and 2022. The residential program contributes 99.6% percent of the portfolio savings, with the furnaces contributing a total of 81,666 MCF, or 92.1% of total savings.
- **Finding 2:** The evaluation team confirmed PECO's 2021-2022 energy efficiency portfolio cost-effectiveness using the TRC test with a TRC of 1.03. The TRC for 2022 was lower than for 2021 due to investments in customer education and marketing for smart thermostats.
- **Finding 3:** Residential furnaces, low flow faucet aerators and low flow showerheads have the largest benefits relative to their incremental costs, thus making the largest positive contributions to TRC.
    - **Recommendation:** Focus implementation on measures that are most cost-effective, such as residential furnaces, low flow faucet aerators and low flow showerheads to maintain program cost-effectiveness**.**
- **Finding 4:** DOE's finalized standards for residential furnaces, increasing the baseline to 95% AFUE for non-weatherized furnaces in 2028. For residential water heaters DOE is proposing new standards that would go into effect in 2029 and would reduce the savings potential if that rule is finalized as proposed.
    - **Recommendation:** PECO should push the highest possible efficiency for furnaces (97% AFUE or higher furnaces) and water heaters to maximize savings, and to maintain some savings giving DOEs rulemaking activities for furnaces and water heaters.
    - **Recommendation:** Explore new measures and implementation approaches to maintain program benefits in case benefits for residential furnaces and residential water heaters are reduced. These could include: exploring new measures, such as weatherization measures, hybrid heat pumps, and building optimization systems, exploring fuel switching opportunities (i.e. from gas heating to electric heating).
- **Finding 5:** Guidehouse recognizes that there is significant variability in smart thermostat savings depending on the study that is cited**.**[14] For this evaluation, Guidehouse weather normalized savings from the Maryland TRM to Philadelphia. Guidehouse believes this is

[11] See Case No. 9648 – Washington Gas 2021-2023 EmPOWER Maryland Regulatory Plan; filed on September 1, 2020

[12] See People's Gas Energy Efficiency Plan 4 for the period of January 1, 2022 – December 31, 2025

[13] See North Shore Gas Energy Efficiency Plan 4 for the period of January 1, 2022 – December 31, 2025

[14] See slide 28 of Guidehouse Tier 3 Thermostat Calibration Study, April 18, 2023.

appropriate to use weather normalized savings from the Maryland TRM, because: the relative proximity of Maryland to PECOs service territory, the rigor that was used to develop smart thermostat savings in the Maryland TRM, and the recency when the study was conducted (June 2021). Nevertheless, the evaluation did not account for differences between building stock and usage patterns between Maryland and Philadelphia that may affect savings.

- **Recommendation:** Guidehouse recommends that PECO conducts additional secondary research through benchmarking and literature review to further refine the savings estimates for smart thermostats.

2021 Portfolio Summary	Programs	Portfolio Dashboard		2021 Savings Summary				2021 Program Budget							2021 Benefit-Cost Inputs							
		% of Total Spending (ALL Programs/ Sectors)	% of Total Savings	Net Annual Natural Gas Savings (MCF)	Net Annual Energy Savings (MWh)	Net Annual Demand Savings (MW)	Net Water Savings (thousand gallons)	Incentive Costs ($)	Utility Admin Costs	CSP Admin	Direct Install	Total Non-Incentive Implementation Costs ($)	EM&V Costs	Total Cost ($)	Utility Benefits ($)	Utility Costs (Incentive) ($)	TRC Benefits ($)	TRC Costs ($)	Societal Benefits ($)	Societal Costs ($)	Participant Benefits ($)	Participant Costs ($)
Residential Portfolio	Residential	99%	99%	43,543.2	0.0	0.00	0	$1,218,425	$43,500	$74,222	$0	$117,722	$0	$1,336,147	$2,094,285	$1,336,147	$2,094,285	$1,947,616	$2,094,285	$1,947,616	$1,218,425	$1,829,894
	Residential Sector Subtotal	**99%**	**99%**	**43,543.2**	**0.0**	**0.00**	**0**	**$1,218,425**	**$43,500**	**$74,222**	**$0**	**$117,722**	**$0**	**$1,336,147**	**$2,094,285**	**$1,336,147**	**$2,094,285**	**$1,947,616**	**$2,094,285**	**$1,947,616**	**$1,218,425**	**$1,829,894**
Commercial & Industrial Portfolio	Commercial	1%	1%	236.9	0.0	0.00	0	$9,300	$0	$233	$0	$233	$0	$9,533	$11,343	$9,533	$11,343	$13,922	$11,343	$13,922	$9,300	$13,689
	Commercial Sector Subtotal	**1%**	**1%**	**236.9**	**0.0**	**0.00**	**0**	**$9,300**	**$0**	**$233**	**$0**	**$233**	**$0**	**$9,533**	**$11,343**	**$9,533**	**$11,343**	**$13,922**	**$11,343**	**$13,922**	**$9,300**	**$13,689**
Total	**Portfolio Total**	**100%**	**100%**	**43,780.0**	**0.0**	**0.00**	**0**	**$1,227,725**	**$43,500**	**$74,455**	**$0**	**$117,955**	**$0**	**$1,345,680**	**$2,105,628**	**$1,345,680**	**$2,105,628**	**$1,961,538**	**$2,105,628**	**$1,961,538**	**$1,227,725**	**$1,843,583**
	Percent of Cost by Category							**91.2%**	3.2%	5.5%	0.0%	**8.8%**	**0.0%**	**100.0%**								

2022 Portfolio Summary	Programs	Portfolio Dashboard		2022 Savings Summary				2022 Program Budget							2022 Benefit-Cost Inputs							
		% of Total Spending (ALL Programs/ Sectors)	% of Total Savings	Net Annual Natural Gas Savings (MCF)	Net Annual Energy Savings (MWh)	Net Annual Demand Savings (MW)	Net Water Savings (thousand gallons)	Incentive Costs ($)	Utility Admin Costs	CSP Admin	Direct Install	Total Non-Incentive Implementation Costs ($)	EM&V Costs	Total Cost ($)	Utility Benefits ($)	Utility Costs (Incentive) ($)	TRC Benefits ($)	TRC Costs ($)	Societal Benefits ($)	Societal Costs ($)	Participant Benefits ($)	Participant Costs ($)
Residential Portfolio	Residential	99%	100%	44,755.3	11.1	0.04	547	$1,273,129	$153,468	$107,392	$1,658	$262,518	$0	$1,535,647	$2,126,160	$1,535,647	$2,172,979	$2,172,843	$2,172,979	$2,172,843	$1,319,949	$1,910,325
	Residential Sector Subtotal	**99%**	**100%**	**44,755.3**	**11.1**	**0.04**	**547**	**$1,273,129**	**$153,468**	**$107,392**	**$1,658**	**$262,518**	**$0**	**$1,535,647**	**$2,126,160**	**$1,535,647**	**$2,172,979**	**$2,172,843**	**$2,172,979**	**$2,172,843**	**$1,319,949**	**$1,910,325**
Commercial & Industrial Portfolio	Commercial	1%	0%	124.0	0.0	0.00	0	$5,100	$10,942	$152	$0	$11,094	$0	$16,194	$5,939	$16,194	$5,939	$19,057	$5,939	$19,057	$5,100	$7,963
	Commercial Sector Subtotal	**1%**	**0%**	**124.0**	**0.0**	**0.00**	**0**	**$5,100**	**$10,942**	**$152**	**$0**	**$11,094**	**$0**	**$16,194**	**$5,939**	**$16,194**	**$5,939**	**$19,057**	**$5,939**	**$19,057**	**$5,100**	**$7,963**
Total	**Portfolio Total**	**100%**	**100%**	**44,879.3**	**11.1**	**0.04**	**547**	**$1,278,229**	**$164,410**	**$107,544**	**$1,658**	**$273,612**	**$0**	**$1,551,841**	**$2,132,098**	**$1,551,841**	**$2,178,918**	**$2,191,900**	**$2,178,918**	**$2,191,900**	**$1,325,049**	**$1,918,288**
	Percent of Cost by Category							**82.4%**	10.6%	6.9%	0.1%	**17.6%**	**0.0%**	**100.0%**								

2021 and 2022 Portfolio Summary	Programs	Portfolio Dashboard		2021 and 2022 Savings Summary				2021 and 2022 Program Budget							2021 and 2022 Benefit-Cost Inputs							
		% of Total Spending (ALL Programs/ Sectors)	% of Total Savings	Net Annual Natural Gas Savings (MCF)	Net Annual Energy Savings (MWh)	Net Annual Demand Savings (MW)	Net Water Savings (thousand gallons)	Incentive Costs ($)	Utility Admin Costs	CSP Admin	Direct Install	Total Non-Incentive Implementation Costs ($)	EM&V Costs	Total Cost ($)	Utility Benefits ($)	Utility Costs (Incentive) ($)	TRC Benefits ($)	TRC Costs ($)	Societal Benefits ($)	Societal Costs ($)	Participant Benefits ($)	Participant Costs ($)
Residential Portfolio	Residential	99%	100%	88,298.5	11.1	0.0	547.4	2,491,554.1	$196,968	$181,614	$1,658	$380,240	$0	$2,871,794	4,220,445.0	2,871,794.1	4,267,264.5	4,120,459.5	4,267,264.5	4,120,459.5	2,538,373.5	3,740,219.5
	Residential Sector Subtotal	**99%**	**100%**	**88,298.5**	**11.1**	**0.04**	**547**	**$2,491,554**	**$196,968**	**$181,614**	**$1,658**	**$380,240**	**$0**	**$2,871,794**	**$4,220,445**	**$2,871,794**	**$4,267,265**	**$4,120,459**	**$4,267,265**	**$4,120,459**	**$2,538,374**	**$3,740,219**
Commercial & Industrial Portfolio	Commercial	1%	0%	360.9	0.0	0.0	0.0	14,400.0	$10,942	$385	$0	$11,327	$0	$25,727	17,281.9	25,727.0	17,281.9	32,978.9	17,281.9	32,978.9	14,400.0	21,651.9
	Commercial Sector Subtotal	**1%**	**0%**	**360.9**	**0.0**	**0.00**	**0**	**$14,400**	**$10,942**	**$385**	**$0**	**$11,327**	**$0**	**$25,727**	**$17,282**	**$25,727**	**$17,282**	**$32,979**	**$17,282**	**$32,979**	**$14,400**	**$21,652**
Total	**Portfolio Total**	**100%**	**100%**	**88,659.3**	**11.1**	**0.04**	**547**	**$2,505,954**	**$207,910**	**$181,999**	**$1,658**	**$391,567**	**$0**	**$2,897,521**	**$4,237,727**	**$2,897,521**	**$4,284,546**	**$4,153,438**	**$4,284,546**	**$4,153,438**	**$2,552,774**	**$3,761,871**
	Percent of Cost by Category							**86.5%**	7.2%	6.3%	0.1%	**13.5%**	**0.0%**	**100.0%**								

2021 Portfolio Summary	Programs			2021 Benefit-Cost Test Results					2021 Program Summary							
		Ratepayer Benefits ($)	Ratepayer Costs ($)	Utility Cost Test	TRC Test	Participant Test	Ratepayer Impact Test	Societal Cost Test	Lifetime Energy Savings (MWh)	Lifetime Gas Savings (MCF)	First-Year CCE ($/kWh)	Lifetime CCE ($/kWh)	First-Year CCE ($/MCF)	Lifetime CCE ($/MCF)	Percent of Total Gas Savings	Percent of Total Budget
Residential Portfolio	Residential	$2,094,285	$1,336,147	1.57	1.08	0.67	1.57	1.08	0	915,276	$0.00	$0.00	$30.69	$1.46	99%	99%
	Residential Sector Subtotal	**$2,094,285**	**$1,336,147**	**1.57**	**1.08**	**0.67**	**1.57**	**1.08**	**0**	**915,276**	**N/A**	**$0.00**	**$30.69**	**$1.46**	**99%**	**99%**
Commercial & Industrial Portfolio	Commercial	$11,343	$9,533	1.19	0.81	0.68	1.19	0.81	0	4,737	$0.00	$0.00	$40.25	$2.01	1%	1%
	Commercial Sector Subtotal	**$11,343**	**$9,533**	**1.19**	**0.81**	**0.68**	**1.19**	**0.81**	**0**	**4,737**	**N/A**	**$0.00**	**$40.25**	**$2.01**	**1%**	**1%**
Total	**Portfolio Total**	**$2,105,628**	**$1,345,680**	**1.56**	**1.07**	**0.67**	**1.56**	**1.07**	**0**	**920,014**	**N/A**	**$0.00**	**$30.74**	**$1.46**	**100%**	100%
	Percent of Cost by Category															

2022 Portfolio Summary	Programs			2022 Benefit-Cost Test Results					2022 Program Summary							
		Ratepayer Benefits ($)	Ratepayer Costs ($)	Utility Cost Test	TRC Test	Participant Test	Ratepayer Impact Test	Societal Cost Test	Lifetime Energy Savings (MWh)	Lifetime Gas Savings (MCF)	First-Year CCE ($/kWh)	Lifetime CCE ($/kWh)	First-Year CCE ($/MCF)	Lifetime CCE ($/MCF)	Percent of Total Gas Savings	Percent of Total Budget
Residential Portfolio	Residential	$2,126,160	$1,535,647	1.38	1.00	0.69	1.38	1.00	111	929,485	$138.36	$13.84	$34.31	$1.65	100%	99%
	Residential Sector Subtotal	**$2,126,160**	**$1,535,647**	**1.38**	**1.00**	**0.69**	**1.38**	**1.00**	**111**	**929,485**	**$138.36**	**$13.84**	**$34.31**	**$1.65**	**100%**	**99%**
Commercial & Industrial Portfolio	Commercial	$5,939	$16,194	0.37	0.31	0.64	0.37	0.31	0	2,480	$0.00	$0.00	$130.59	$6.53	0%	1%
	Commercial Sector Subtotal	**$5,939**	**$16,194**	**0.37**	**0.31**	**0.64**	**0.37**	**0.31**	**0**	**2,480**	**N/A**	**$0.00**	**$130.59**	**$6.53**	**0%**	**1%**
Total	**Portfolio Total**	**$2,132,098**	**$1,551,841**	**1.37**	**0.99**	**0.69**	**1.37**	**0.99**	**111**	**931,965**	**$139.82**	**$13.98**	**$34.58**	**$1.67**	**100%**	100%
	Percent of Cost by Category															

2021 and 2022 Portfolio Summary	Programs			2021 and 2022 Benefit-Cost Test Results					2021 and 2022 Program Summary							
		Ratepayer Benefits ($)	Ratepayer Costs ($)	Utility Cost Test	TRC Test	Participant Test	Ratepayer Impact Test	Societal Cost Test	Lifetime Energy Savings (MWh)	Lifetime Gas Savings (MCF)	First-Year CCE ($/kWh)	Lifetime CCE ($/kWh)	First-Year CCE ($/MCF)	Lifetime CCE ($/MCF)	Percent of Total Gas Savings	Percent of Total Budget
Residential Portfolio	Residential	4,220,445.0	2,871,794.1	1.47	1.04	0.68	1.47	1.04	111.0	1,844,761.1	$258.75	$25.87	$32.52	$1.56	100%	99%
	Residential Sector Subtotal	**$4,220,445**	**$2,871,794**	**1.47**	**1.04**	**0.68**	**1.47**	**1.04**	**111**	**1,844,761**	**$258.75**	**$25.87**	**$32.52**	**$1.56**	**100%**	**99%**
Commercial & Industrial Portfolio	Commercial	17,281.9	25,727.0	0.67	0.52	0.67	0.67	0.52	0.0	7,217.5	$0.00	$0.00	$71.29	$3.56	0%	1%
	Commercial Sector Subtotal	**$17,282**	**$25,727**	**0.67**	**0.52**	**0.67**	**0.67**	**0.52**	**0**	**7,218**	**N/A**	**$0.00**	**$71.29**	**$3.56**	**0%**	**1%**
Total	**Portfolio Total**	**$4,237,727**	**$2,897,521**	**1.46**	**1.03**	**0.68**	**1.46**	**1.03**	**111**	**1,851,979**	**$261.07**	**$26.11**	**$32.68**	**$1.56**	**100%**	100%
	Percent of Cost by Category															

1 MMBtu = 0.973 MCF

				Verified Savings (Ex-Post)				Reported Savings (Ex-Ante)	
Measure Name - TRM	Measure Name - Plan Design	Program	Quantity	2021 Total Savings (MCF)	2022 Total Savings (MCF)	Unit Savings (MCF)	Total Savings (MCF)	Unit Savings from Plan Design (MCF)	Total Savings from Plan Design (MCF)
commercial gas boiler	ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	Commercial	10	21	50	7.13	71	20.91	209
commercial gas furnace <255,000 BTU/h	ENERGY STAR Furnace <225 kBTU/h (>=90% AFUE)	Commercial	38	226	69	7.76	295	11.47	436
faucet aerators	Low Flow Faucet Aerator (<=1.5 GPM)	Residential	5	-	1	0.23	1	0.29	1.45
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=97% AFUE)*	Residential	160	179	2,269	15.30	2,448	17.66	2,826
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=95% AFUE)*	Residential	6,203	41,221	37,997	12.77	79,218	15.58	96,643
high efficiency gas boiler	ENERGY STAR Boiler (>=90 AFUE)	Residential	422	1,770	2,151	9.29	3,921	8.11	3,422
high efficiency gas water heater	Storage Hot Water Heater (0.67 EF)**	Residential	540	754	1,185	3.59	1,939	1.13	610
low flow shower head	Low Flow Showerhead (<=2.0 GPM)	Residential	76	-	50	0.66	50	1.2	91.20
smart thermostat	Smart Thermostat	Residential	306	-	250	0.97	250	5.61	1,717
smart thermostat optimization	Smart Thermostat	Residential		-	386	1.32	386	0	-
Grand Total			**7,760**	**44,172**	**44,408**		**88,580**		**105,955**

* Designated by measure code, not AFUE value

** Water heaters EF range from 0.58 to 0.95

Assumptions

1. Residential HVAC EFLH is 761 (Philadelpha value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelpha value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacties for Residential furnaces and boilers are assigned per model number encoder
5. All commercial boilers are for water (not steam)

1 MMBtu = 0.973 MCF

				Verified Savings (Ex-Post)				
Measure Name - TRM	**Measure Name - Plan Design**	**Program**	**Verified and Reported Ratios (Per Unit)**	**Unit Savings (kWh)**	**Total Savings (kWh)**	**Total Unit Demand (kW)**	**Unit Water Savings (Gals)**	**Total Water Savings (Gals)**
commercial gas boiler	ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	Commercial	34%	-	-	-	-	-
commercial gas furnace <255,000 BTU/h	ENERGY STAR Furnace <225 kBTU/h (>=90% AFUE)	Commercial	68%	-	-	-	-	-
faucet aerators	Low Flow Faucet Aerator (<=1.5 GPM)	Residential	79%	58.22	291.10	0.012	1,470	7,351
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=97% AFUE)*	Residential	87%	-	-	-	-	-
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=95% AFUE)*	Residential	82%	-	-	-	-	-
high efficiency gas boiler	ENERGY STAR Boiler (>=90 AFUE)	Residential	115%	-	-	-	-	-
high efficiency gas water heater	Storage Hot Water Heater (0.67 EF)**	Residential	318%	-	-	-	-	-
low flow shower head	Low Flow Showerhead (<=2.0 GPM)	Residential	55%	142.21	10,808	0.557	7,106	540,065
smart thermostat	Smart Thermostat	Residential	17%	-	-	-	-	-
smart thermostat optimization	Smart Thermostat	Residential		-	-	-	-	-
Grand Total				**200.43**	**11,099**	**0.569**	**8,576**	**547,416**

* Designated by measure code, not AFUE value

** Water heaters EF range from 0.58 to 0.95

Assumptions

1. Residential HVAC EFLH is 761 (Philadelpha value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelpha value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacties for Residential furnaces and boilers are assigned per model number encoder
5. All commercial boilers are for water (not steam)

1 MMBtu = 0.973 MCF

Measure Name - TRM	Measure Name - Plan Design	Program	Drivers
commercial gas boiler	ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	Commercial	Implemented boilers are all <110 kBtu, whereas plan assumed 300 kBtu; reduced EFLH
commercial gas furnace <255,000 BTU/h	ENERGY STAR Furnace <225 kBTU/h (>=90% AFUE)	Commercial	Average furnace capacity is 95 kBtu, compared to the plan which assumed 112.5 kBtu; reduced EFLH
faucet aerators	Low Flow Faucet Aerator (<=1.5 GPM)	Residential	*Design plan measure characterization unavailable*
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=97% AFUE)*	Residential	Reduced EFLH; average furnace capacity is 94 kBtu, compared to the plan which assumed 100 kBtu
high efficiency furnace (gas) tos	ENERGY STAR Furnace (>=95% AFUE)*	Residential	Reduced EFLH; average AFUE is 96%, whereas plan assumed 95%; average furnace capacity is 86 kBtu, compared to the plan which assumed 100 kBtu
high efficiency gas boiler	ENERGY STAR Boiler (>=90 AFUE)	Residential	Reduced EFLH; average AFUE is 95%, whereas plan assumed 90%; average furnace capacity is 98.5 kBtu, compared to the plan which assumed 100 kBtu; DOE baseline code update from
high efficiency gas water heater	Storage Hot Water Heater (0.67 EF)**	Residential	MD TRM v11 updates for efficient and baseline values; average tank size is 46 gal, whereas plan assumed 40 gal
low flow shower head	Low Flow Showerhead (<=2.0 GPM)	Residential	MD TRM v11 updates for deemed values; showers per person value multiplier of 0.6 is considered, which plan does not take into account
smart thermostat	Smart Thermostat	Residential	Deemed values from MD TRM v11 but weather normalized to Philadelphia
smart thermostat optimization	Smart Thermostat	Residential	Deemed values from MD TRM v11 but weather normalized to Philadelphia
Grand Total			

* Designated by measure code, not AFUE value

** Water heaters EF range from 0.58 to 0.95

Assumptions

1. Residential HVAC EFLH is 761 (Philadelpha value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelpha value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacties for Residential furnaces and boilers are assigned per model number encoder
5. All commercial boilers are for water (not steam)

Section 4: CLEAResult Program and Adoption Analysis



PECO Gas Measure Analysis

December 8, 2023

Prepared By
CLEAResult

Prepared For
PECO

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Adoption Rate Analysis: Residential Size Measures

The adoption rate analysis involved two distinct studies focused on the residential size equipment market: (1) defining the overall and efficient market for the specified product type and determining how much of that market was captured via the PECO rebate program, and (2) benchmarking the performance of the PECO program with other natural gas rebate programs. After the completion of these analyses the results were leveraged to discuss opportunity and develop a forecast for the PECO rebate program for the next two years.

These two analyses are focused on equipment that is sized for the residential market, as that is the target market for the PECO Gas rebate programs. A separate analysis was not completed for commercial sized equipment as that is not a focus of the PECO gas rebate programs. When benchmarking against other programs, these other programs are defined as residential as the target customer. Thus, their target audience may be slightly smaller than that of the PECO program. It is difficult to find a direct comparison to the PECO program as business or commercial gas rebate programs will usually include commercial sized equipment.

Defining the Market

The focus of the analysis was to determine the per product annual market in the PECO territory to quantify the opportunity. The analysis began by leveraging national shipment data and then narrowing down that data to the PECO service territory. There were two different sources utilized for the National shipment data, dependent upon the product type. For furnaces and storage tank water heaters, data from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI) for residential product shipments was utilized. For boilers and natural gas dryers, shipment data was sourced from ENERGY STAR Shipment data specific to residential models.

To convert the national shipment data into utility level data, the Residential Energy Consumption Survey (RECS)data from the 2020 study completed by the U.S. Energy Information Administration (EIA) was leveraged. As availability and usage of natural gas equipment is not ubiquitous across the country, this data source breaks it down by US Census Region to translate the National data to a regional level. With the data converted to a regional level, the EIA customer count data for all natural gas utilities within the Mid-Atlantic Census region was utilized to convert from a regional level down to the PECO territory.

With the total annual market defined including efficient and inefficient equipment, ENERGY STAR® Shipment data can be leveraged to narrow the market down to just the efficient models. Shipment data includes a market penetration data point that represents the percentage of shipments that were ENERGY STAR qualified. With a total annual market and efficient annual market defined, analysis can be completed regarding the effectiveness of the PECO rebate program to capture the available market. This data is helpful in determining the remaining market opportunity for future growth of the program. Below is an example analysis for one product type to further demonstrate the methodology utilized.

Market Analysis Example

Shipment Info							
	2017	2018	2019	2020	2021	2022	Source
Gas Warm Air Furnaces	3,113,768	3,416,571	3,441,872	3,351,176	4,008,894	3,872,368	AHRI

Table HC6.7 Space heating in homes in the Northeast and Midwest regions, 2020

	Number of housing units (million)				
		Northeast Census Region			
	Total U.S.[a]	Total Northeast	New England	Middle Atlantic	% Mid Atlantic
Central warm-air furnace	53.26	7.52	1.57	**5.96**	**11.2%**

Area	Company	Item	2017	2018	2019	2020
New Jersey	Total of All Companies	Residential Sales Consumers	2,638,248	2,691,931	2,738,622	2,772,476
New York	Total of All Companies	Residential Sales Consumers	3,760,894	3,915,334	4,024,167	4,080,590
Pennsylvania	Total of All Companies	Residential Sales Consumers	2,434,083	2,449,664	2,444,554	2,471,893
		Mid-Atlantic Residential Consumers	8,833,225	9,056,929	9,207,343	9,324,959
Pennsylvania	PECO ENERGY COMPANY	Residential Sales Consumers	403,878	403,552	398,793	405,616
		PECO Consumers as a % of Mid-Atlantic Consumers		4.46%	4.33%	4.35%

2022 PECO Residential Market for natural gas furnace: 3,872,368 (US Annual Shipment) * 11.2% (% in Mid-Atlantic) * 4.35% (PECO as % of Mid-Atlantic NG customers) = 18,849

ENERGY STAR Estimated Market Penetration						
		2018	2019	2020	2021	2022
Gas Warm Air Furnaces		26%	30%	40%	41%	36%

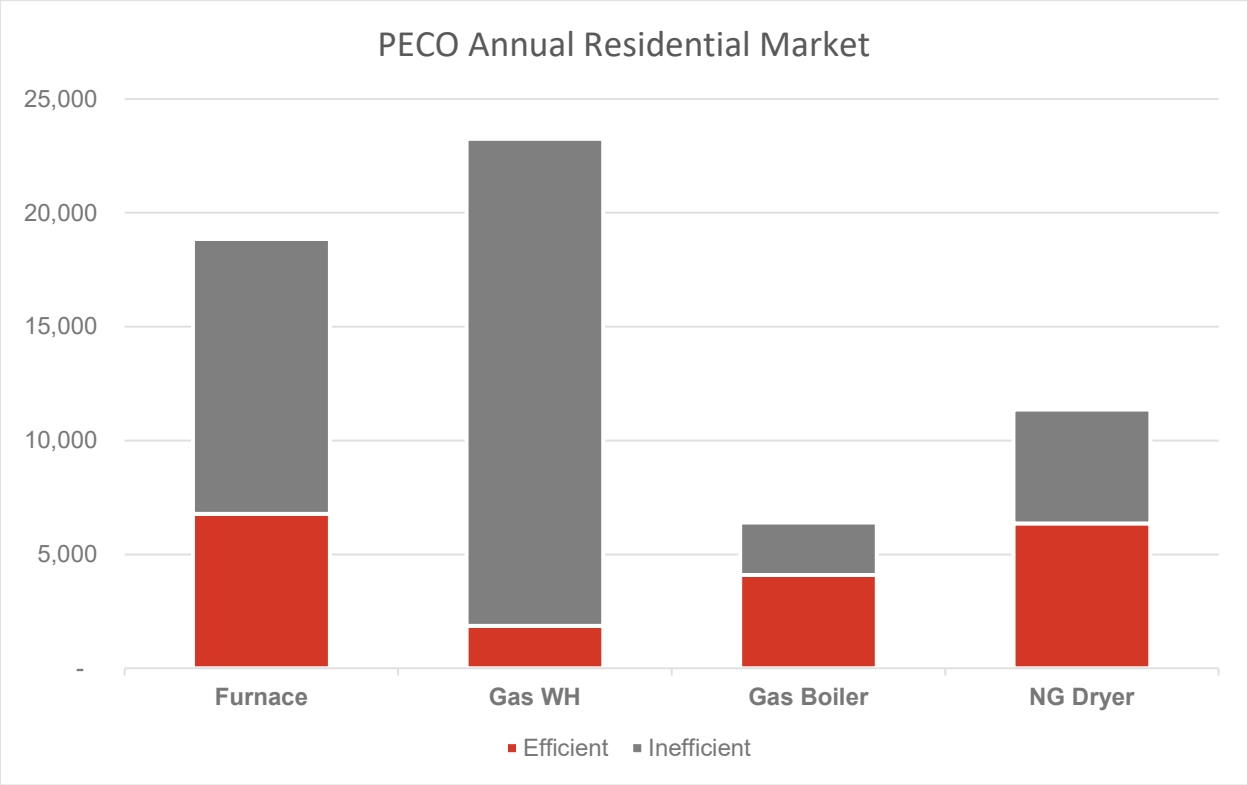
2022 PECO Residential Market for ENERGY STAR natural gas furnace: 18,849 * 36% = 6,786

Rebates Paid in PECO Territory						
	2017	2018	2019	2020	2021	2022
Gas Warm Air Furnaces		2,904	3,240	3,566	3,241	3,160

2022 PECO natural gas furnace rebate capture rate whole market: 3,160/18,849 = 17%

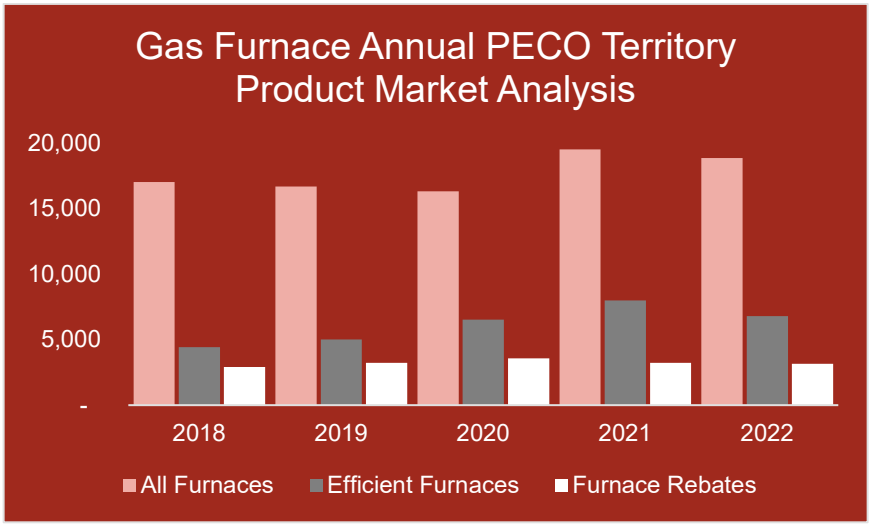
2022 PECO natural gas furnace rebate capture rate efficient market: 3,160/6,786 = 47%

The largest market in the PECO territory is gas water heaters but given the low ENERGY STAR penetration of that product type the efficient opportunity is the smallest of all measures (1,860 units). The biggest efficient market is seen in natural gas furnaces, followed closely by natural gas dryers. Digging in a bit more we can look at the analysis at a measure level to get a better idea of the opportunity, and how well the current PECO rebate program is capturing that opportunity.

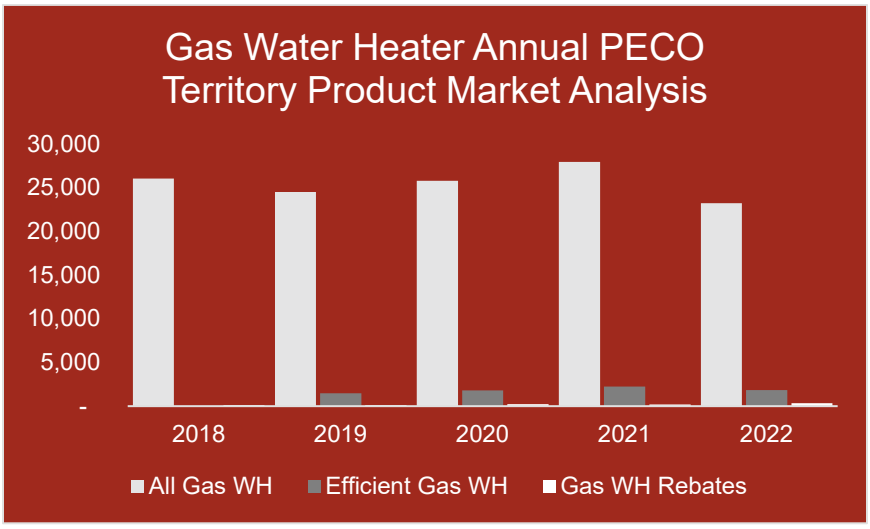


The first equipment type analyzed are natural gas furnaces. The furnace market is the only equipment type where a strong rebate capture rate was found per industry standards, with an efficient market capture rate averaging out at 54%. This is the measure that PECO has been most successfully influencing the market with the rebate offering, though there remains some opportunity to push more rebates.

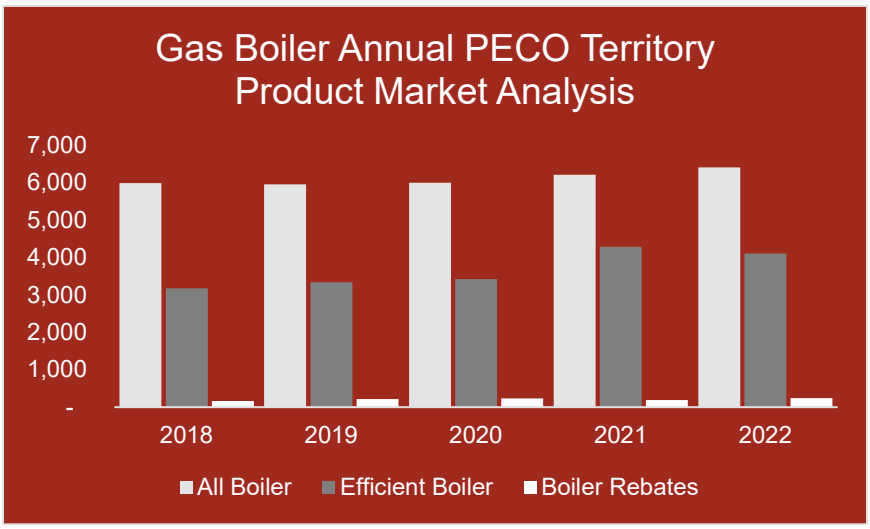
The next graph and table analyze natural gas storage tank water heaters. As noted earlier, this measure has a very low ENERGY STAR market penetration, resulting in a small efficient market opportunity within the territory. The PECO rebate program has not been able to successfully capture this limited efficient market with only 331 rebates in 2022 which was 18% of the estimated annual sales. The Boiler graph and table show a similar story to water heaters in terms of the inability of the PECO rebate program to drive strong efficient market capture, with a market capture rate of only 6% in 2022. The final graph is for Natural Gas Dryers. This is a measure that was only added to the rebate program in 2023. The market size data does show an opportunity in capturing quite a few rebates through this new offering.



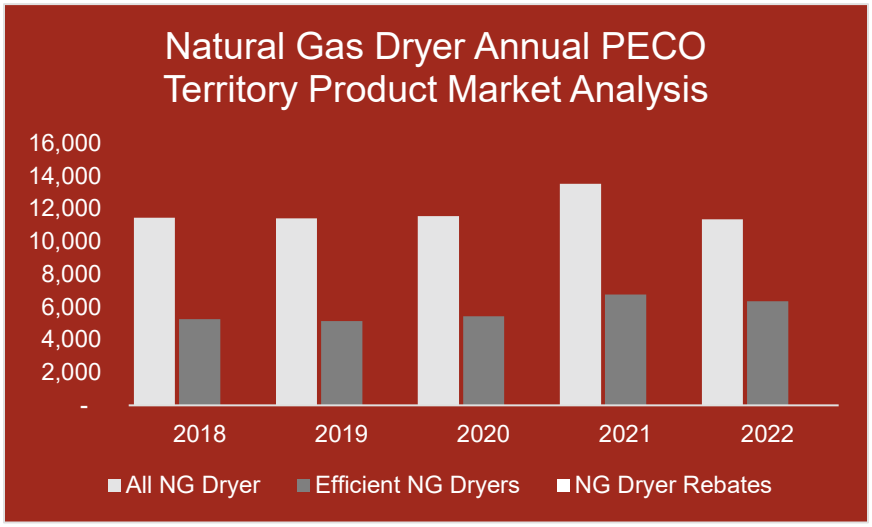
Rebate Capture Rate		
	Whole Market	Efficient Market
2018	17%	54%
2019	19%	65%
2020	22%	55%
2021	17%	41%
2022	17%	47%



Rebate Capture Rate		
	Whole Market	Efficient Market
2018	0%	0%
2019	1%	8%
2020	1%	12%
2021	1%	9%
2022	1%	18%



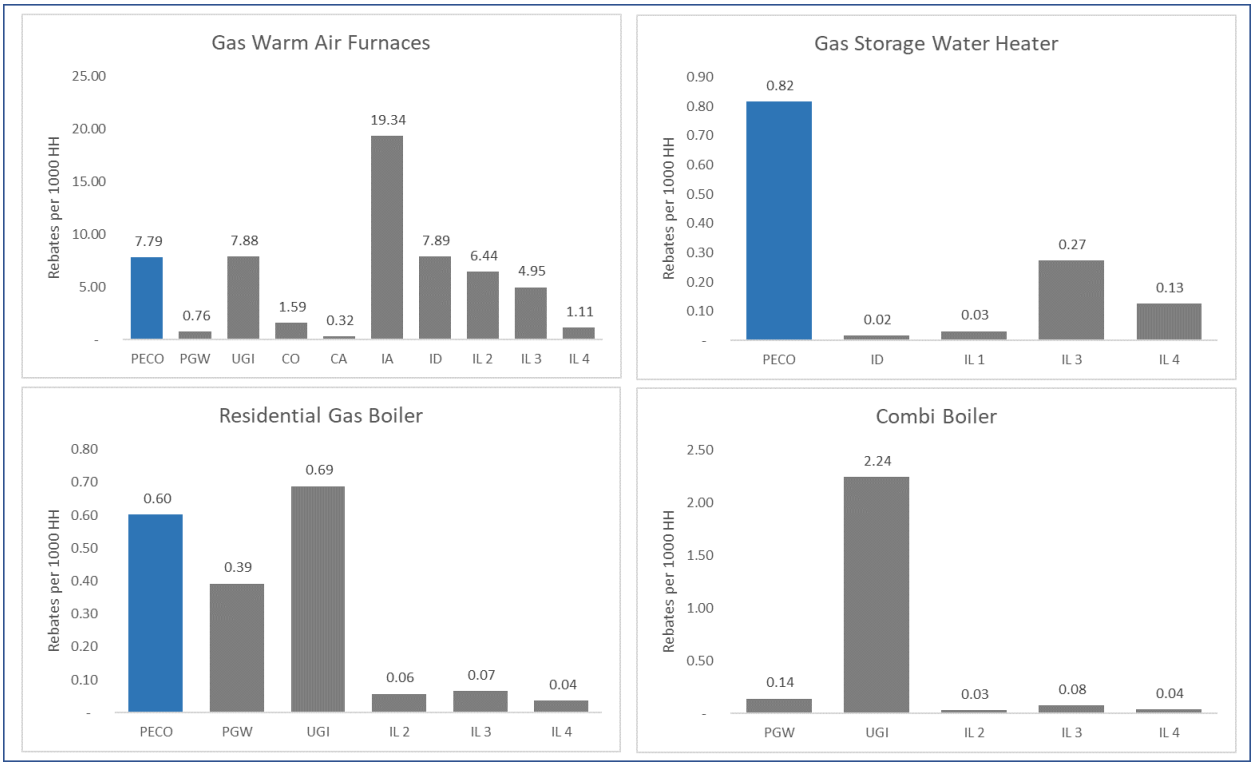
Rebate Capture Rate		
	Whole Market	Efficient Market
2018	3%	5%
2019	4%	7%
2020	4%	7%
2021	3%	4%
2022	4%	6%



The results of the market analysis show that there is opportunity remaining in the market to capture additional rebates by pushing more customers toward ENERGY STAR products, and by working to ensure those customers who are making the efficient purchase are in turn participating in the rebate program. Now that we have a better idea of the market opportunity, and market penetration of the current program we can shift to analyzing how well the PECO rebate program performs when compared to others. With these two pieces of information, we will be able to forecast current measures more confidently into the future.

Benchmark PECO Performance

Research was completed to analyze the performance of other natural gas rebate programs around the country to help put PECO's performance in perspective. These performance values are sourced from either published annual evaluation reports, or for a few programs run by CLEAResult the data comes directly via our program data warehouse, see Appendix A for more details. The results show that the PECO rebate program is a strong performer when compared with its peers. The charts below compare the rebates per 1000 HH in the PECO program to rebates seen in other utility programs in PA and other places throughout the country by equipment type.



A Shifting Market?

When looking to forecast for the next couple of years the one remaining component to consider is how the market is expected to change. In Pennsylvania there has been no action to ban natural gas as a heating or water heating fuel, and in fact, there is legislation on the table that would make it illegal to ban natural gas equipment. In addition, when looking at the market for natural gas equipment over the next few years, a variety of market research reports are pointing to a continued growth of the market at a compound annual growth rate (CAGR) of around 5%.[1] The other item to consider is potential efficiency changes that could impact the market. From a federal perspective there is legislation in play to increase the efficiency of natural gas furnaces with an anticipated effective date of 2029. Given the timeline of this legislation it will have no impact on the short-term forecasting. ENERGY STAR is looking to sunset the natural gas furnace specification at the end of 2024, and potentially boilers and natural gas dryers as well. This may have a slight impact on program participation as the ENERGY STAR program is helpful in raising awareness and educating consumers. But the rebate program will be able to continue using the standards previously used by ENERGY STAR to determine qualified models, and with proper marketing and education the impact on rebate volume can be mitigated. For Water Heaters, ENERGY STAR just released specification version 5 in 2023, which will impact rebate volumes in the near term as it narrows the number of qualifying models. This is a driving force in PECO's plans to potentially sunset this measure. [1]

[1] Based on reviewing a variety of studies to determine an industry consensus some of which included 1, 2, 3, 4

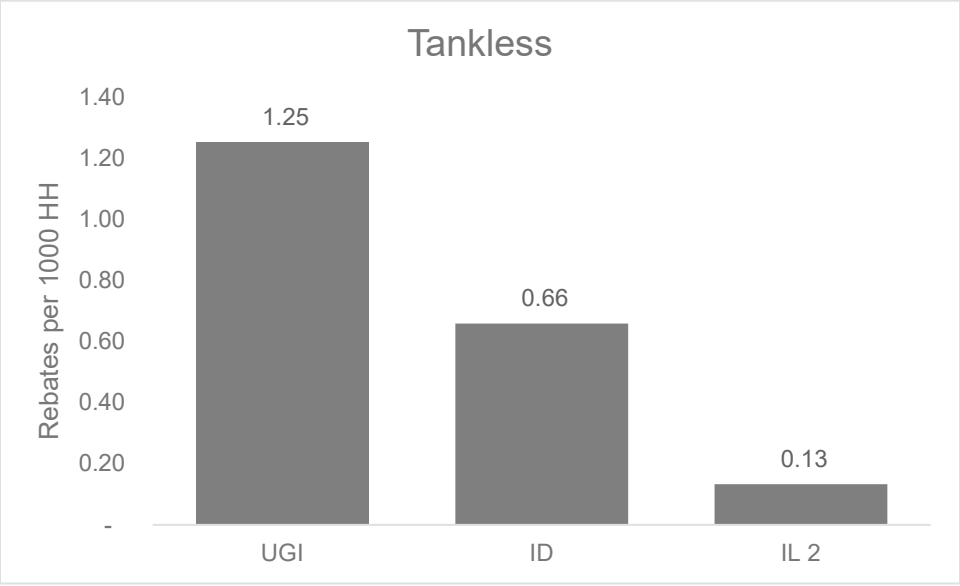
Measure Forecast

This additional market context presents some obstacles but overall presents no concrete concern around a shrinking efficient market for natural gas equipment. Adding this finding to the other two conclusions already reached; (1) the PECO rebate program is not fully capturing the available market and (2) PECO rebate performance is strong in comparison to peers; all signs point to a rebate program that should continue with current performance trends. The table below shows past performance per measure and outlines the forecast for 2024 and 2025. With the recent introduction of combination boilers and natural gas clothes dryers it is anticipated that noticeable growth will occur over the two-year period.

Measure	2018	2019	2020	2021	2022	2023	2024	2025
Gas Furnace	2,904	3,240	3,566	3,241	3,160	2,907	2,900	2,900
Gas WH	118	125	212	209	331	250		
Gas Boiler	164	220	236	190	244	165	165	165
Combi Boiler	0	0	0	0	0	146	150	200
Gas Clothes Dryer	0	0	0	0	0	254	275	300

New Opportunities

Through the research of other natural gas rebate programs there does appear to be an opportunity to add tankless water heaters to the PECO program and capture additional savings. CLEAResult recognizes it is PECO's discretion for the measure addition. The chart below outlines the performance seen from a few programs currently offering tankless water heater rebates. The UGI program has a considerably higher incentive at $400 than the other two programs with an incentive at $150. Based on this information, the recommendation if tankless water heaters are to be added, is offering an incentive of $150**.** ~~F~~orecasted units for 2024 are 250 and for 2025 are 300. Cost effectiveness should be considered for this measure and is referenced in section, New Measures.



Anticipated Program Performance 2024-2025

With forecasts completed for the major downstream rebates based on the market and historic performance we can now look to integrate the forecast for the two additional components of the natural gas program: smart thermostat sales on the online marketplace and direct install measures. The smart thermostat online marketplace forecast reflects heeding the recent evaluation and keeping the incentive at $25 for all of 2024 & 2025 and an associated drop in volume due to lower incentive during peak periods. For Direct install measures the recent shift toward pipe insulation has increased units and dropped the average incentive per measure. The forecast reflects the current measure offering with pipe wrap and is based on trends seen since this measure's introduction in around March 2023. The table below outlines the anticipated units and incentives for the recommended natural gas program for 2024 and 2025. Considering the annual incentive budget of $1,626,500, the program is estimated to perform below the incentive budget in 2024-2025.

	Units		Incentive Spend		Incentive per Unit
Measure	2024	2025	2024	2025	
Gas Furnace	2,900	2,900	$1,087,500	$1,087,500	$375
Gas WH					
Gas Boiler	165	165	$57,750	$57,750	$350
Combi Boiler	150	200	$150,000	$200,000	$1,000
Gas Clothes Dryer	275	300	$4,125	$4,500	$15
Thermostat	2,975	2,975	$74,375	$74,375	$25
Direct Install	1,200	1,200	$3,000	$3,000	$2.50
Tankless WH	250	300	$37,500	$45,000	$150
Program Total	5015	5,140	$1,416,274	$1,474,150	$287
Budget			$1,626,500	$1,626,500	
% of Budget			87%	91%	

New Measure Evaluation

Evaluation of Existing and New Gas Measures

Building Energy End Uses and Gas Savings

Space heating for homes and small commercial buildings is often the largest energy end use for many climate zones, regardless of the type of energy being supplied to the home or small commercial building. Water heating is typically the second largest energy end use for residential buildings. The largest opportunities to reduce gas usage are in the areas of the largest usages, specifically space heating and water heating. Current technologies for space and water heating are very efficient based on energy code and federal appliance standards. Increasing efficiencies of equipment will be minimal without technology evolving into newer products. AFUE (Annual Fuel Utilization Efficiency) can never exceed

100% efficiency, where the energy content of the natural gas is always greater than the output. With current AFUE's for efficient gas heating technology typically being above 95%, the room for efficiency improvement is relatively small.

Current Measure List

For this analysis, measures included in Exhibit B were initially analyzed for typical savings to compare with PECO's current savings assumptions. In addition, incentive amounts for PECO and for two nearby utility programs were also identified. Details are included in Table 1. From this, we see that for additional uptake, PECO may want to consider increasing incentive rates for some measures.

Table 1. Existing & New Measures

Measure	Savings Therms/yr	Incentive Amounts		
	Mid-Atlantic TRM	PECO	New Jersey Natural Gas	UGI Natural Gas
Existing Measures				
ENERGY STAR® Residential Gas Furnace >=95-96.9% AFUE	14.3	$350	$1,000	$500
ENERGY STAR® Residential Gas Furnace >=97% AFUE	16.2	$600	$1,500	NA
ENERGY STAR® Residential Gas Boiler >=90% AFUE	7.4	$350	$850	$1,200[2]
ENERGY STAR® Residential Gas Storage Tank Water Heater ≤ 55 gallons .81 UEF	5.5	$125	$500[4]	NA
ENERGY STAR® Residential Gas Storage Tank Water Heater > 55 gallons .86 UEF	6.3		NA	NA
High Efficiency Natural Gas Combination Gas Boiler (>=94% AFUE)	26.3 [3]	$1,000	$1,300[1]	$1,500
ENERGY STAR® Natural Gas Clothes Dryer	4.9	$15		NA
Thermostatic Shower Valves	5.1			NA
Low Flow Showerheads	9.1		Marketplace	NA (DIY kit)
Low Flow Faucet Aerators	2.62		Marketplace	NA (DIY kit)
ENERGY STAR® Smart Thermostat Discounts	55.7	$50[7]	$100	$50
ENERGY STAR® Commercial Gas Furnace Rebate >=95%	32.1	$300		

ENERGY STAR® Commercial Gas Boiler >= 90% AFUE	25.1	$300	$1,000	$2,000 + $2/MBH[6]
Potential New Measures				
Tankless water heater UEF>=0.87	0.96	NA	$750	$400
ENERGY STAR® Tankless water heater UEF>=0.95	2.1	NA		NA
Combi unit with greater than or equal to 97% AFUE	31.9	NA	$1,750	
Weatherization; Windows, Air Sealing, Duct Sealing, Wall Insulation, Attic Insulation	TBD	NA	Part of a whole home program	25% of cost up to $2,500[5]

[1] New Jersey Natural Gas measure requires >=95% AFUE

[2] UGI gas boiler requires 94+% AFUE

[3] Mid-Atlantic TRM calculation is for 90+% AFUE. This calculation is for 94+% AFUE.

[4] ENERGY STAR Water Heater V5.0 updated April 18th, 2023. Rebates based on previous version with .64 UEF.

[5]Incentive for insulation and/or air sealing.

[6]ENERGY STAR commercial boiler.

[7] PECO offers incentives based on PECO service type. $25 from electric funds and $25 from gas funds, with LTO Gas offer of $50 at select periods.

New Measures

Envelope Measures

Improvements of a home's envelope can result in reduced gas usage of heating equipment. Weatherization measures such as insulation, windows and air sealing can be marginally cost effective in the PECO service territory due to the heating dominated climate and hot, humid summers. Improvements in indoor air quality and comfort are benefits that result from weatherization measures being implemented.

Some utility programs do offer incentives for weatherization including air sealing and attic, wall and foundation insulation, air sealing, and duct sealing. Energy assessments for these programs may be required.

Comprehensive Packages of Measures

In some cases, programs leverage an initial energy assessment to encourage adoption of both simple, DIY measures such as low flow showerheads and faucet aerators and smart thermostats with the opportunity for installation of larger measures. As an example, New Jersey Natural Gas offers a whole home energy efficiency program. Customers are eligible for up to $5,000 in rebates and up to $15,000 in financing to address water heating, furnace/boiler, insulation, and air conditioning efficiency improvements. (See https://www.savegreenproject.com/homeowners#whole-home-efficiency). UGI Smart Save Home Energy Upgrades program starts with a $50 home energy evaluation that includes a

DIY install energy savings kit. From this, other energy efficiency upgrades can be implemented, including insulation and/or air sealing measures.

Measures Not Recommended and Measures Needing More Consideration

Emerging gas technologies such as Gas Absorption Heat Pumps (GAHP) are becoming increasingly interesting as AFUE equivalents are approximately around 120% as compared to efficient combination boiler systems which are ~95% AFUE. Analysis has shown that it is difficult for this technology to be cost effective except in commercial buildings in the coldest climates.

Gas furnace and boiler tune-up measures have been piloted in several areas and have shown a very small amount of savings, 1-2% of gas usage, which resulted in the measure being not cost effective. Around 1980, burners in gas furnaces evolved to “in shot” burners versus the older “ribbon” type of burners that got dirty on an annual basis. Old furnaces and boilers with ribbon style burners can provide 3-5% savings but screening the equipment to determine age and burner style would be required to reduce gas usage.

Tankless gas water heaters have the potential to be moved through the current delivery channels but more consideration is needed before approving the measure to be part of the 2024 portfolio. Though very efficient, they have a high baseline, which results in savings being smaller than expected leading to challenges to cost effectiveness.

Regulatory Changes

The primary intention of this section is to address growing efforts around building electrification including the 2022 Inflation Reduction Act, changes in federal standards and ENERGY STAR specification updates.

Federal Standards

All measures must comply with federal appliance standards. The Department of Energy has proposed that in late 2028 the minimum AFUE for gas furnaces will increase to 95% AFUE. This will increase the baseline AFUE from 82% AFUE to the proposed 95% AFUE. Several legal challenges to the proposed ruling have already been initiated, so it is unclear at this time whether this proposed rule will be passed.

ENERGY STAR

As of May 18th, 2023, EPA proposed sunsetting the ENERGY STAR specifications for residential gas furnaces and central air conditioners as of December 30th, 2024. EPA is currently reviewing the comments that the industry has provided in the comment period to assess if they will move forward with this proposal.

Consistent with the Environmental Protection Agency’s (EPA) focus on the potential for electric heat pumps to deliver energy-efficiency gains, pollution reduction and cost-savings to consumers, the ENERGY STAR program is proposing to sunset the certification pathway to the ENERGY STAR label for residential furnaces and central air conditioners (CACs). This will allow EPA to evolve the ENERGY STAR

portfolio of product specifications toward identifying the most efficient electric equipment now available to consumers.

This proposal involves sunsetting the ENERGY STAR Version 4.1 Specification for Furnaces and removing CACs from the ENERGY STAR Version 6.1 Specification for CAC and Heat Pump Equipment. A similar sunset proposal will be considered for gas and oil appliances in the context of forthcoming revisions of the ENERGY STAR Version 3.0 Specification for Boilers, the ENERGY STAR Version 1.0 Specification for Dryers, and the ENERGY STAR Version 1.0 for Commercial Packaged Boilers. Heat Pump specifications will be revised, and a new version will be produced.

Electrification

Electrification Hurdles & Antidotes

Electrification and decarbonization does come with several challenges including the need to upgrade electrical panels, electrical services to the home, and electrical wiring in homes to support the new electrical loads. Determining how the cost will be covered for these upgrades is a topic that continues to evolve, especially for low to moderate income households. These costs are not trivial, running from several thousand dollars to tens of thousands of dollars.

Increased utility bills are also a concern as the difference between electrical and natural gas rates may have a negative impact on electric utility customers. Weatherizing older homes is likely key to hedge chances of negative bill impacts. By providing weatherization measures now, households can see savings on current natural gas costs for space heating, but these upgrades will also prepare them should they choose to electrify in the future.

IRA Implications

The Inflation Reduction Act introduces a societal shift to decarbonize and electrify homes. This shift allocates significant government funding into the market. Implications are a market shift from primarily fossil fuel heated homes to electrically heated homes. The hurdles for this shift to be successful include the overall carbon content of the local electrical supply. Primarily coal burning utilities (for electricity) can have the unintended counter effect of increasing the emission rates of chemicals and compounds that enter the atmosphere.

IRA is focused on low to moderate income households, which leaves gaps where some households may not be able to participate due to financial reasons. And even with the significant amounts of funding that are available, many households will be unable to participate, either due to the participating requirements for low-income households or due to lack of available equipment and qualified installers.

Emerging Gas Technology Opportunities and Challenges

Extremely Highly Efficient Gas Heating Technologies

Manufacturers have been making improvements to AFUE to achieve the highest possible efficiency furnaces and boilers. 99% AFUE heating equipment are entering the market. These highly efficient products come with a larger cost than the current minimum efficiency threshold that ENERGY STAR

requires. At the same time, baseline efficiency is also increasing either through increased standards or as installation of higher efficient products becomes standard practice. Cost effectiveness of the very high efficiency products is challenged due to these higher baseline assumptions.

Dual-Fuel Heat Pumps

Dual-fuel heat pumps can reduce gas usage during mild temperatures. Heat pumps operate the most efficiently during mild temperatures and switch over to gas furnace operation during colder temperatures. The most effective switchover point is around 40°F outdoor air temperature. The switchover temperature is typically a setting within the thermostat. A switchover point of 40-45°F can avoid the need to defrost the outdoor coil from the frost that builds up on the outdoor coil as the unit operates. There are several methods that can be deployed if defrost occurs due to choice to select a lower switchover temperature. Gas furnaces and heat pumps should never run at the same time, with minimal exceptions for defrost if a method is employed to limit the gas furnace from causing too much pressure within the refrigeration system. The addition of refrigerants to a system via a heat pump are subject to refrigerant leakage if the heat pump is not properly installed. The refrigerants that will be used in new heat pumps starting in 2025 are classified as A2L refrigerants and have some low flammability propagation. Refrigerant leakage has some potential climate impacts as refrigerants are hundreds to thousands of times more damaging to the climate than methane and carbon dioxide.

Renewable Natural Gas

The 2021 Northwest Power Plan is a 20-year utility forecast for the Pacific Northwest. In the forecast there is a 0.5 percent per year increase of natural gas use at the utility scale. The “Plan” includes a small shift (<10%) of fossil fuel natural gas to “Renewable Natural Gas” (RNG) which is biogas that has been conditioned and upgraded so that it can directly displace fossil based natural gas. This indicates that natural gas usage for electric power production will continue to increase over the next 20 years regardless of the societal pressure to electrify and decarbonize.

Appendix

Exhibit A: Source for Historical Performance of other Natural Gas Rebate Programs

Illinois Natural Gas Utility data was found via the Illinois Energy Efficiency Stakeholder Group Final Evaluation Reports site.

- IL 1 is Ameren Illinois
- IL 2 is Nicor Gas
- IL 3 is North Shore Gas
- IL 4 is Peoples Gas

Pennsylvania Natural Gas Utility data was found via the Pennsylvania Public Utility Commissions site. Links for each report utilized are included below.

- PGW
- UGI

Data for two CLEAResult run programs were included with the data being pulled directly from the CLEAResult program reporting system.

- CO – Black Hills Energy
- CA – BAYREN

Additional research was conducted to find performance data from other gas utilities.

- IA – MidAmerican
- ID – InterMountain Gas

Exhibit B: Measure List

Measure	Program	Measure Type	Program Type
ENERGY STAR® Residential Gas Furnace >=95-96.9% AFUE	Residential	Downstream Rebate	Market Rate
ENERGY STAR® Residential Gas Furnace >=97% AFUE	Residential	Downstream Rebate	Market Rate
ENERGY STAR® Residential Gas Boiler >=90% AFUE	Residential	Downstream Rebate	Market Rate
ENERGY STAR® Residential Gas Storage Tank Water Heater >=.064 UEF	Residential	Downstream Rebate	Market Rate
High Efficiency Natural Gas Combination Gas Boiler (>=94% AFUE)**	Residential	Downstream Rebate	Market Rate
ENERGY STAR® *Natural Gas Clothes Dryer* **	Residential	Downstream Rebate	Market Rate
Thermostatic Shower Valves	Residential	Direct Install **	Market Rate
Low Flow Showerheads	Residential	Direct Install **	Market Rate
Low Flow Faucet Aerators	Residential	Direct Install **	Market Rate
ENERGY STAR® *Smart Thermostat Discounts*	Residential	Instant Discount	Market Rate
ENERGY STA® *Commercial Gas Furnace Rebate >=95%*	Commercial**	Downstream Rebate	Market Rate
ENERGY STAR® *Commercial Gas Boiler >= 90% AFUE*	Commercial**	Downstream Rebate	Market Rate

PECO Exhibit DLM-2:

Historic and Forecasted EE&C Program Information (2023-2027)

Residential Natural Gas EE&C Programs, 2023 Historical & 2024-2027 Forecasted Annual Spend/Budget - Table 1

	2023 Budget	2023 Spend	2024 Budget	2024 Forecast	*Added Funds*	2025 Budget	2025 Forecast	2026 Budget	2026 Forecast	2027 Budget	2027 Forecast
Incentive Costs (Rebates, Direct Install, Smart T-Stats)	**$1,646,500**	**$1,601,015**	**$1,678,500**	**$1,678,064**	*$350,000*	**$2,028,500**	**$1,813,216**	**$2,028,500**	**$1,931,230**	**$2,059,500**	**$2,058,565**
Incentive Administration Costs	**$115,000**	**$106,774**	**$115,000**	**$100,771**		**$115,000**	**$106,870**	**$115,000**	**$112,793**	**$120,000**	**$119,523**
Safe and Efficient Heating Program Total Costs	**$719,000**	**$707,956**	**$719,000**	**$719,000**		**$719,000**	**$719,000**	**$719,000**	**$719,000**	**$719,000**	**$719,000**
SEHP Direct Install Costs	$659,000	$647,956	$659,000	$659,000		$659,000	$659,000	$659,000	$659,000	$659,000	$659,000
SEHP Administration Costs	$60,000	$60,000	$60,000	$60,000		$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Other Admin Total Costs (Education & Program Evaluation)	**$247,000**	**$140,959**	**$215,000**	**$215,000**		**$215,000**	**$215,000**	**$215,000**	**$215,000**	**$179,000**	**$179,000**
Education	$187,000	$85,473	$115,000	$115,000		$215,000	$215,000	$215,000	$215,000	$79,000	$79,000
Evaluation & Program Design	$60,000	$55,485	$100,000	$100,000		$0	$0	$0	$0	$100,000	$100,000
Total	**$2,727,500**	$2,556,703	**$2,727,500**	**$2,712,835**	***$350,000***	**$3,077,500**	**$2,854,086**	**$3,077,500**	**$2,978,023**	**$3,077,500**	**$3,076,088**
Budget Variance		$170,797		*$14,665*			*$223,414*		*$99,477*		*$1,412*

Residential Natural Gas EE&C Programs, 2023 Historical & 2024-2027 Forecasted Annual Measure Participation & Natural Gas Energy Savings (Mcf) - Table 2

	2023 Program Year		2024 Program Year			2025 Program Year		2026 Program Year		2027 Program Year	
Participation & Savings 2023-2027	*Participation*	*Savings (Mcf)*	*Participation*	*Savings (Mcf)*		*Participation*	*Savings (Mcf)*	*Participation*	*Savings (Mcf)*	*Participation*	*Savings (Mcf)*
Residential ENERGY STAR®+ Gas Furnace Rebate ≥97% AFUE	495	7,574	530	8,109		568	8,691	608	9,303	651	9,961
Residential ENERGY STAR® Gas Furnace Rebate >95%-96.9% AFUE	2638	33,698	2823	36,061		3021	38,590	3232	41,286	3458	44,173
Residential ENERGY STAR® Gas Boiler >90% AFUE	159	1,477	175	1,626		193	1,793	213	1,979	235	2,184
Residential ENERGY STAR® Gas Storage Hot Water Heater	244	877	12	43	**$350K Budget Increase**	13	47	14	50	15	54
Residential ENERGY STAR® Tankless Water Heater	0	-	188	1,393		250	1,853	250	1,853	250	1,853
High Efficiency Combi Boiler >=94% AFUE	167	2,500	167	2,500		172	2,575	177	2,650	182	2,725
Residential ENERGY STAR® Gas Dryer	270	128	270	128		277	131	284	135	292	139
Direct Install Measures (Households)	324	246	405	1,360		506	1,700	633	2,124	791	2,655
ENERGY STAR® Smart Thermostats	3083	7,060	1000	2,290		1050	2,405	1103	2,526	1160	2,656
Safe & Efficient Heating Program (Income Eligible)	329	1,245	329	1,245		329	1,245	329	1,245	329	1,245
Total	7,709	54,805	5,899	54,756		6,379	59,029	6,843	63,150	7,363	67,642

PECO ENERGY COMPANY
STATEMENT NO. 9-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: DOREEN L. MASALTA

SUBJECT: PROPOSED CHANGES TO PECO'S RESIDENTIAL NATURAL GAS ENERGY EFFICIENCY AND CONSERVATION PROGRAMS AND NEIGHBORHOOD GAS PILOT

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
DOREEN L. MASALTA

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Doreen L. Masalta. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Energy and Marketing Services. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 9. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to the direct testimony of Mr. Christopher Keller on behalf of the Bureau of Investigation and Enforcement concerning PECO's proposed changes to its residential natural gas Energy Efficiency and Conservation ("EE&C") program.

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes. I have prepared PECO Exhibit DLM-3 which I describe later in my testimony.

II. PECO'S RESIDENTIAL GAS EE&C PROGRAM

5. Q. Please explain Mr. Keller's concern with PECO's proposal to increase the residential natural gas EE&C program budget.

A. Mr. Keller recommends the disallowance of PECO's proposed residential natural gas EE&C program budget increase of $350,000. Mr. Keller's recommended disallowance is based on three factors he identified in his testimony. He first points to the program's customer participation rate, which was 1.5% in 2023. Second, he highlights the amount of unspent EE&C program funding in 2021 and 2022. Third, Mr. Keller notes that the Company's projected customer participation in the future test year ("FTY") and fully projected future test year ("FPFTY") is lower than actual participation in 2023. Based on these three factors, Mr. Keller argues that the EE&C program has been unsuccessful in encouraging customer participation, and it is therefore inappropriate to increase the program's budget.

6. Q. Please respond to Mr. Keller's concerns about the historic levels of customer participation in the EE&C program.

A. As an initial matter, the customer participation rate in isolation is a poor metric to judge the overall success of the EE&C program. The ultimate goal of the program is gas savings, and the Company has designed this budget-limited program to provide a range of savings opportunities for customers. As I discussed in my direct testimony, PECO has been successful in steadily increasing the estimated gas energy savings every year of the program.[1] Of course, gas energy savings and customer participation have some correlation, which is reflected by

[1] *See* PECO St. No. 9, p. 9, tbl. 1.

the fact that PECO's estimated gas energy savings increased along with customer participation from 2018 through 2023.[2]

While Mr. Keller is correct that 1.5% of the Company's total residential gas customers participated in the EE&C program in 2023, he fails to explain why that percentage is unacceptable. Notably, PECO's residential natural gas EE&C program has a similar customer participation rate to other energy efficiency programs. For example, as shown in Table 1 below, the customer participation rate in PECO's Commission-approved Act 129 program in Program Year ("PY") 14[3] was the same as the customer participation rate in the 2023 gas EE&C program.[4]

Program and Component	PECO Act 129 PY14 Participation	PECO Gas EE&C Program PY2023 Participation
Rebates and Marketplace	15,959	7,056
Direct Install Measures	3,102	324
Single-Family (Income Eligible)	4,528	329
Total	23,589	7,709
Total Residential Customer Count	1,535,927	507,197
Percentage of Participation	1.5%	1.5%

Table 1

Customer participation in PECO's residential natural gas EE&C program is also similar to customer participation in other companies' EE&C programs. For

[2] *Id.* Customer participation is defined as the sum of measures rebated, smart thermostats discounted, unique households receiving direct install measures, and unique households receiving no-cost, direct-install measures through the Safe and Efficient Heating Program.

[3] Program Year 14 was from June 1, 2022 through May 31, 2023.

[4] *See* PECO Act 129 PY 14 Annual Report, tbl. 2-3 (Sept. 29, 2023), https://www.puc.pa.gov/pcdocs/1800771.pdf. Total EE&C program participation used for comparison in Table 1 is the summation of the participants in the Rebates & Marketplace (15,959), In-Home Assessment (3,102), and Single Family (Income Eligible) (4,528) programs. These programs were chosen to compare participation in programs similar to those offered by PECO's Natural Gas EE&C program. The "Total Residential Customer Count" in the Act 129 column is PECO's residential electric customer population as of the end of 2023. The "Total Residential Customer Count" in the Gas EE&C column is PECO's residential gas customer population as of the end of 2023.

example, UGI Utilities, Inc. – Gas Division ("UGI") also maintains a Commission-approved EE&C program. UGI's PY 4 report shows that its gas EE&C program had a customer participation rate of approximately 1.7%, having spent just under $6.5 million (about 50% more than the budget PECO is requesting in this proceeding) with a residential customer base of 616,132 (about 20% greater than PECO's residential customer base).[5] In sum, PECO's 1.5% customer participation rate is in-line with both PECO's electric efficiency program and another natural gas utility's EE&C program, which directly contradicts Mr. Keller's contention.

PECO acknowledges that customer participation rates were lower in 2021 and 2022 at around 1% of total residential customers. But as I explained in my direct testimony, PECO has continued to educate customers about the EE&C program and conducted social media and email advertising campaigns to promote the EE&C program. These advertising campaigns led to increased customer participation year-over-year since 2021. PECO continues to promote its EE&C program and has seen strong customer participation in 2024.

7. Q. Why is PECO projecting a lower level of customer participation in the FTY and FPFTY than it experienced in 2023?

A. The customer participation rate in 2023 reflects, among other things, PECO's customer outreach and successful promotion of the smart thermostat measure. In

[5] *See* UGI Utilities, Inc. – Gas Division Annual Report for Program Year 4, p. 11, tbl. 12 (Jan 31, 2024), https://www.puc.pa.gov/pcdocs/1814740.pdfh. The participation rate in UGI's EE&C program was calculated by dividing the program participants in Table 12 by UGI's residential customers (612,132). *See* UGI, Information Submitted Pursuant to Section 53.51 of the Commission's Regulations at p. 24 (Jan. 29, 2022) (stating total residential customers), https://www.puc.pa.gov/pcdocs/1732632.pdf.

2023, the smart thermostat measures accounts for a substantial percentage (40%) of all EE&C program participation. PECO's recent analysis of its EE&C programs, however, found that the smart thermostat rebate measure was not cost effective.[6]

In response to this finding, PECO decided to stop actively promoting smart thermostat rebates and instead focus on promoting more cost-effective measures, such as furnace rebates and direct-install measures. As a result of this change in promotional activity, the Company expects that participation in the smart thermostat measure will drop as compared to 2023. As shown in PECO Exhibit DLM-2, 3,083 smart thermostat rebates were issued in 2023, whereas the Company is forecasting that it will issue 1,000 rebates in 2024. Actual EE&C program participation in 2024 so far reflects a lower level of smart thermostat rebates. Through the first five months of 2024, PECO has discounted the purchase of just 270 smart thermostats through the residential natural gas EE&C program.

8. Q. If PECO expects the number of EE&C program participants to decrease in 2024, why did PECO project that it will use more of the EE&C program's funding in 2024 than 2023?

A. PECO has seen increased interest in other rebate measures with higher rebate amounts. In particular, the ENERGY STAR® Natural Gas Furnace, Natural Gas Combi Boiler, and new Tankless Water Heater measures are expected to drive the

[6] *See* PECO St. No. 9, p. 18.

rebate measure costs above the forecast in 2024 and in years 2025 to 2027. PECO Exhibit DLM-3 is a table of the EE&C program equipment rebate measures. The table shows the 2024 projected and actual year-to-date participation in the various measures. The table also shows the projected incentive spend on each measure for 2024 based on the year-to-date actual participation and compares that against the 2024 forecast. This data shows that the Company expects to spend $175,340 more on incentives than PECO's originally forecasted spending of $1,615,050. Overall, through June 2024, PECO has spent 50% of the program's total budget and is on pace to exhaust the entire $2.7 million program budget for 2024.

9. Q. Do you agree with Mr. Keller's contention that the proposed EE&C program budget increase should be disallowed because the Company did not fully spend the annual program budget over the last three years?

A. No. PECO acknowledges the historical program underspend in 2021 and 2022. But Mr. Keller's claim that PECO refunded an average of 29.95% of the program budget from 2021 to 2023 is skewed by two years of underspend in 2021 and 2022, which is not representative of current and forecasted participation and spending levels. In 2023, the Company increased the EE&C program participation by 88% from 2022. As a result of this increased participation, PECO spent 94% of the program budget in 2023. For 2024, as shown in PECO Exhibit DLM-3, the Company projects that it will exhaust the EE&C program's annual budget based on customer participation and spending through June 2024.

10. Q. Overall, Mr. Keller contends that it would be "unreasonable" to collect additional funds for a natural gas EE&C program that he believes has been underperforming. Please respond.

A. Mr. Keller's contention that the program has seen limited success ignores both trends of increased customer participation, program spend and increased gas energy savings. As I discussed in my direct testimony, customer participation has continually increased since 2018 as has the estimated gas savings. Since 2018, the program has seen a 22% increase in participation, 21% increase in program spend, and a 12% increase in estimated savings, on average, year-over-year. Even when accounting for the forecasted decrease in estimated customer participation in 2024 (FTY), there is still an average growth of 14% in participation and an average of 10% increase in gas savings year-over-year. As shown in PECO Exhibit DLM-2, although participation will decrease from 2023 to 2024, estimated savings will remain almost the same, with a slight decrease of 49 Mcf. In program year 2025, the estimated savings is expected to increase by over 4,000 Mcf from 2023 and 2024, which would represent an 8% increase in estimated savings.

Mr. Keller's contention also ignores the success PECO has seen in its customer outreach efforts which began in 2021 and has continued to drive increases in customer participation and estimated gas savings. The proposed budget increase will allow PECO to focus on measures with the greatest natural gas savings while increasing customer participation in more cost-effective measures through 2027.

Furthermore, the Universal Service Fund Charge mechanism allows any unspent funds to be returned to customers.

11. Q. Do you contend that the recent and projected performance of the residential natural gas EE&C program supports the requested program budget increase?

A. Yes. The Company evaluated the EE&C program's needs based on year-over-year trends, which show increases in customer participation, gas energy savings, and program spending. As stated in my testimony and shown in the exhibits to my testimony, the requested modest increase is necessary to sustain the EE&C program's growth in energy savings and customer participation while focusing on more cost-effective measures through 2027. Disallowing the requested increase would negatively impact the EE&C program and limit customer participation, restricting any opportunity for additional organic growth of the program.

III. CONCLUSION

12. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I	Column J
Natural Gas EE&C Rebate Program Component	**2023 Program Year Participation Actuals**	**2024 Program Year Participation (DLM-2 Forecast)**	**2024 YTD Participation Actuals (As of June 30, 2024)**	**2024 Monthly Average**	**2024 Re-Forecast Calculated as: Column D + (Column E x 6 Months)**	**(Over)/Under Variance to DLM-2 2024 Forecast**	**2024 Re-Forecasted Cost Calculated as: Column F x Measure Incentive**	**2024 Original Forecast (DLM-2)**	**(Over)/Under Variance to 2024 Original Forecast**
Residential ENERGY STAR®+ Gas Furnace Rebate ≥97% AFUE	495	530	636	106	1,272	(742)	$763,200	$318,000	($445,200)
Residential ENERGY STAR® Gas Furnace Rebate >95%-96.9% AFUE	2,638	2,823	990	165	1,980	843	$693,000	$988,050	$295,050
Residential ENERGY STAR® Gas Boiler >90% AFUE	159	175	49	9	103	72	$36,050	$61,250	$25,200
Residential ENERGY STAR® Gas Storage Hot Water Heater	244	12	18	3	36	(24)	$4,500	$1,500	($3,000)
Residential ENERGY STAR® Tankless Water Heater	-	188	19	4	43	145	$17,200	$75,200	$58,000
High Efficiency Combi Boiler >=94% AFUE	167	167	134	23	272	(105)	$272,000	$167,000	($105,000)
Residential ENERGY STAR® Gas Dryer	270	270	146	25	296	(26)	$4,440	$4,050	($390)
Total	3,973	4,165	1,992	335	4,002	163	$1,790,390	$1,615,050	($175,340)
Note: This table only includes incentive costs associated with the measures shown, excluding admin.									

PECO Statement No. 10:

Direct Testimony of Jacqueline F. Golden

PECO ENERGY COMPANY
STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

DIRECT TESTIMONY

WITNESS: JACQUELINE F. GOLDEN

SUBJECTS: RECOVERY OF CAP COSTS; EXISTING UNIVERSAL SERVICE PROGRAMS; REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND; THE SMALL BUSINESS GRANT PROGRAM; AND THE GAS CUSTOMER SAFETY PROGRAM

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
JACQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Jacqueline F. Golden. 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 Director of Customer Financial Operations. In that capacity, I am responsible for Customer Financial Operations (Billing, Payment Processing, Revenue Management, and Universal Services).

3. Q. Please describe your educational background.

A. I have a Bachelor of Science in Business Administration from Drexel University and a Master of Business Administration from La Salle University.

4. Q. Please describe your professional experience.

A. I began my career with PECO in 1981 as a customer service representative. Between 1981 and 2000, I held positions of increasing responsibility in several departments including customer operations, large customer accounts, Gas Supply and Transportation ("GS&T"), Energy Acquisition, and Finance. My immediate past position was in Regulatory Policy and Strategy as the Director of Strategy. In September 2022, I became the Director of Customer Financial Operations at PECO.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe: (1) PECO's proposal for the recovery of Customer Assistance Program ("CAP") costs; (2) PECO's existing universal service programs in addition to CAP; (3) PECO's proposed revisions to its Matching Energy Assistance Fund ("MEAF"); (4) PECO's proposed revisions to its Small Business Grant Program; and (5) PECO's proposed revisions to the Gas Customer Safety Program.

II. RECOVERY OF CUSTOMER ASSISTANCE PROGRAM ("CAP") COSTS

6. Q. Ms. Golden, please describe PECO's current CAP for gas customers.

A. In accordance with the universal service obligations set forth in the Public Utility Code, PECO's CAP assists low-income customers in its service territory through discounted energy bills. PECO's CAP is a special rate rider for customers with an annual household gross income level at or below 150% of the federal poverty level ("FPL") as established by the US Department of Health and Human Services. As of December 31, 2023, approximately 23,000 residential gas customers in PECO's service territory – around 4.5% of PECO residential gas customers – were participating in CAP.

The structure of PECO's CAP discount has evolved over time. Most recently, in December 2022, PECO implemented a new CAP Percentage of Income Payment Plan ("PIPP"), approved by the Commission in Docket No. M-2018-3005795, to

provide a percentage of income-based benefit to CAP customers.[1] The PIPP design provides eligible customers with a fixed maximum monthly bill equal to what the CAP customer can afford to pay for utility service. The fixed bill amount is determined by applying an energy burden percentage[2] to the customer's annual income. CAP bill credits are applied to reduce the customer's monthly undiscounted bill to the monthly PIPP bill amount. For billing purposes, PECO applies the lesser of the CAP PIPP bill or actual charges. Bills issued under the CAP PIPP are subject to monthly minimum bill amounts.

Prior to employing a PIPP design, the Company utilized a Fixed Credit Option ("FCO") design (from October 2016 to December 2022) and a tiered rate discount CAP structure (prior to October 2016).

7. Q. What was the dollar amount of the aggregate PIPP bill credits provided to CAP customers in 2023 and how were those costs recovered?

A. The value of the CAP bill credits provided to low-income customers through PECO's gas CAP was approximately $10.9 million in 2023. These costs are recovered through a combination of base rates and a surcharge mechanism under Section 1307 of the Public Utility Code. In the settlement of PECO's 2010 gas base rate case ("2010 Settlement"), the parties agreed that PECO's base rates would reflect recovery of $9.7 million for the costs of providing CAP bill credits to low-

[1] *PECO Energy Co. Universal Serv. and Energy Conservation Plan for 2019-2024 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*., Docket No. M-2018-3005795 (Opinion and Order entered June 16, 2022) ("USECP Order").

[2] The energy burden percentage is the target percentage of household income that may be utilized to pay for utility service. Energy burden percentages vary based on the commodity (electric, electric heat, and gas) and household income level/number of residents.

income customers.[3] Since that time, PECO has implemented several CAP enhancements to provide more affordable monthly bills to low-income customers based on the Commission's energy burden levels set forth in its CAP Policy Statement, which have caused the cost of the CAP program to increase substantially.[4]

The CAP "shortfall" refers to the amount of aggregate bill credits (in dollars) provided to CAP customers each year that is not reflected in base rates. This shortfall is recovered from or refunded to PECO's residential customers on an ongoing basis through PECO's Universal Service Fund Charge ("USFC"), with annual reconciliation of any over/under collections. Pursuant to the Commission-approved settlement of PECO's first default service proceeding (the "DSP Settlement"), the USFC is adjusted so that residential customers pay 73% of the total CAP shortfall amount.[5] The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to PECO's uncollectible expense (22%) and cash working capital requirements (5%). At that time, the 27% factor was associated with CAP program enhancements agreed to in the DSP Settlement, which would be implemented at the same time as base rates established in PECO's 2010 gas rate case.

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[3] *Pa. P.U.C. v. PECO Energy Co. – Gas Div., Docket No. R-2010-2161592 (Order entered Dec. 29, 2010), p. 9.* In subsequent base rate cases, PECO increased the negotiated amount established in the 2010 settlement by the overall percentage of distribution revenue increase approved by the Commission. As such, PECO currently recovers approximately $11 million of CAP costs through base rates each year.

[4] 52 Pa. Code §§ 69.261–69.267.

[5] *See Petition of PECO Energy Co. for Approval of Its Default Serv. Program and Rate Mitigation Plan*, Docket No. P-2008-2062739 (Order entered June 2, 2009).

8. Q. Is PECO proposing to increase the amount of electric CAP bill credits included in its base rates in this proceeding?

A. Yes. The Commission's CAP Policy Statement was amended effective March 21, 2020, which, among other things, established lower recommended maximum energy burden targets for electric and gas CAP bills.[6] In accordance with the USECP Order, PECO's energy burdens were updated in late July 2022. As previously noted, in December 2022, PECO implemented its PIPP – providing eligible customers with a maximum monthly bill amount that is determined by applying an energy burden percentage to the customer's annual income. These two changes greatly increased the value of the bill credits provided to CAP customers.

In the fully projected future test year ("FPFTY"), the total estimated amount of PIPP bill credits for customers projected to be enrolled in CAP as of December 31, 2025 will be approximately $13.7 million. As explained by Company witness Joseph A. Bisti in PECO Statement No. 7, PECO proposes to update its base rate recovery to reflect this amount. Annual reconciliation of any over/under collections will continue to be via the USFC.

9. Q. Ms. Golden, is PECO proposing to change the 27% offset percentage applied to the CAP shortfall, which is recovered through the USFC?

A. Yes. PECO proposes to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%. When additional low-income customers enroll in CAP, PECO is more likely to recover at least a portion of the

[6] *See Universal Service Rulemaking*, Docket No. M-2019-3012599 (Final Policy Statement Order and Annex entered on Nov. 5, 2019); 50 Pa.B. 1652 (Mar. 21, 2020).

costs attributable to those customers because those costs will be collected from all residential customers through the USFC. PECO currently applies a 22% offset factor to reconcilable CAP costs in the USFC formula to reflect uncollectible expense increases or savings associated with incremental changes in the level of CAP bill credits embedded in PECO's base rates. PECO also applies a 5% USFC offset factor for cash working capital.

In light of the increase in value of CAP bill credits provided under the Company's PIPP, PECO has evaluated its recent uncollectible trends for CAP and all residential non-CAP customers to assess the remaining potential improvement in charge-offs. Based on that analysis, PECO is proposing to lower the uncollectible offset percentage to 5.5%.[7]

As explained by Company witness Michael J. Trzaska in PECO Statement No. 3, PECO calculated its claim for uncollectible accounts expense using a three-year historic average ratio of net charge-offs as a percentage of billed revenues. As shown in the table below, the uncollectible accounts rate for CAP customers was calculated in the same manner by using the Company's actual charge-off experience for 2021 through 2023 divided by PECO's total billed revenues for the same three years. The offset percentage of 5.5% represents the difference between the uncollectible accounts rate for CAP customers (6.6%) and all residential non-CAP customers (1.1%).

[7] The Company is not proposing to change the 5% USFC offset factor applied to working capital requirements in this case.

	CAP Customer Billings vs Net Charge-Offs				All Residential Non-CAP Customer Billings vs Net Charge-Offs			
	2021	2022	2023		2021	2022	2023	
Annual Billings ($M)	$109.3	$118.7	$94.3	3-Year Average	$2,387.2	$2,861.1	$2,868.7	3-Year Average
Net Charge-Offs ($M)*	$3.3	$10.3	$7.7		$22.9	$28.9	$34.2	
Ratio (%)	3.0%	8.7%	8.2%	**6.6%**	1.0%	1.0%	1.2%	**1.1%**

*Excludes October 2016 one-time In-Program Arrearage ("InPA") forgiveness and Pre-Program Arrearage ("PPA") forgiveness.

III. OTHER UNIVERSAL SERVICE PROGRAMS

10. Q. What other types of universal service programs does PECO offer or administer to support the Company's low-income customers?

A. In addition to ongoing bill payment assistance through CAP, PECO provides usage reduction services via its Low-Income Usage Reduction Program ("LIURP"). LIURP is designed to complement CAP by providing usage reduction education and, if eligible, remediation measures to decrease the amount of energy used by customers, thereby reducing their bills, and increasing affordability.

PECO also supports the Low-Income Home Energy Assistance Program ("LIHEAP"), a Federally-funded grant program that provides supplemental payments to eligible customers' accounts. PECO conducts extensive outreach and education regarding LIHEAP and provides support for customers seeking LIHEAP grants. The LIHEAP application is available in English and Spanish on PECO's website, and the Company operates a LIHEAP hotline to assist customers with LIHEAP questions. Additionally, for LIHEAP Crisis customers who have a balance after the LIHEAP Crisis grant is applied to the bill, PECO offers payment agreements for the remaining balance. Finally, PECO targets LIHEAP customers for other assistance programs that may be available.

PECO has a Customer Assistance Referral and Evaluation Service ("CARES") team that provides referral and information services to assist special-needs, low-income customers who have financial hardships.

PECO also has a hardship program – MEAF – that provides customers at or below 200% of the FPL whose service is in threat of termination or has been terminated for non-payment with a grant to cure arrears. As discussed below, PECO is proposing a modification to its MEAF program as part of this filing to allow more customers to qualify for these grants.[8]

In addition to these universal service programs, PECO's Safe and Efficient Heating Program ("SEHP") offers eligible low-income customers no-cost: (1) tune-ups and repairs of natural gas furnaces, boilers and water heaters; (2) replacement of qualifying natural gas furnaces, boilers and water heaters; and (3) direct installation of energy savings measures.[9]

IV. REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND

11. Q. Please describe the MEAF established by PECO.

A. MEAF is a hardship program funded through donations[10] and matching PECO shareholder contributions. The program is administered in coordination with local community-based organizations ("CBOs") in each of the counties within the

[8] PECO notes that MEAF is a combined program for gas and electric customers. Changes to MEAF approved in this proceeding would apply to both gas and electric customers. The Company has made an identical MEAF proposal in its electric base rate filing at Docket No. R-2024-3046931.

[9] The SEHP is part of PECO's portfolio of natural gas energy efficiency programs and is discussed in detail by Company witness Doreen L. Masalta in PECO Statement No. 9.

[10] Customers or interested parties can pledge donations through bill payments or the PECO website. Donations can be either one-time or recurring, which can be charged via the customer's bill on a monthly basis.

Company's service territory. The maximum MEAF grant is five hundred dollars ($500) per commodity (electric or gas). If the grant amount does not bring the account balance to zero, the customer will be required to make a payment and/or obtain other third-party funding (e.g., LIHEAP) to satisfy the remaining total amount due before being approved to receive the MEAF grant.

12. Q. What are the eligibility requirements for a MEAF grant?

A. PECO residential customers who apply for MEAF assistance are approved[11] if they:

- Have income at or below 200% of the FPL as defined by US Department of Health and Human Services ("HHS");
- Demonstrate hardship (i.e. service is in imminent danger of termination or has already been terminated);
- Reside within the county where they are applying for a MEAF grant;
- Have not received a MEAF grant in the past 12 months; and
- Have an account balance that would be brought down to zero with the MEAF distribution (note: this requirement can be met via a combination of MEAF grant, customer co-payments, and/or other grants).

13. Q. Could you please quantify the value of MEAF grants awarded in 2021-2023?

A. The value of MEAF grants varied yearly and ranged from approximately $80,000 to $250,000 (including the PECO shareholder match) for this period. In accordance with the Settlement in PECO's 2022 gas base rate case, PECO guaranteed to provide shareholder funding for MEAF grants of up to $300,000 annually, regardless of the amount of customer donations in a given year.[12] For the year of

[11] MEAF funds are distributed on a first-come, first-serve basis until exhausted.

[12] Consistent with the Commission-approved settlement of PECO's 2022 gas base rate case at Docket No. R-2022-3031113 ("2022 PECO Gas Rate Case"), at the end of each program year, PECO allocates any funds for which it has not received a customer match – up to $300,000 annually – to the MEAF agencies in proportion to the number of low-income customers in each county within PECO's service territory.

2023, PECO matched $90,000 and provided the remaining balance of $210,000 to the MEAF agencies as additional grant funding available for 2024. PECO notes that this $210,000 is eligible to be matched by PECO in 2024.

14. Q. Is the Company proposing any modifications to its MEAF program as part of this rate case?

A. Yes. To expand the impact of MEAF and the number of customers eligible for the program, PECO is proposing to change the maximum allowable MEAF grant from $500 per commodity to $1,000 per account. This change should allow additional customers to meet the MEAF eligibility criteria of bringing the customer's account balance to zero by permitting all eligible customers (regardless of service type) to qualify for a MEAF grant of up to $1,000.

V. REVISIONS TO THE SMALL BUSINESS GRANT PROGRAM

15. Q. Does PECO currently offer bill relief to payment-troubled small business customers?

A. Yes, PECO has offered a Small Business Grant Program since December of 2021. Under that Program, PECO provides a one-time grant of $500 to a qualifying small business as a credit on the customer's existing gas account. The small business must be an existing PECO gas customer, take service under Rate Schedule GC – General Service Commercial and Industrial ("Rate GC"), and have less than 25 employees. The grant can be applied to pay off existing arrearages or offset future gas bills.

During the initial term of the Grant Program (December of 2021 through December of 2022), applicants were required to demonstrate financial hardship due to the

COVID-19 pandemic. PECO had a total budget of $500,000 (approximately $450,000 for incentives and $50,000 for administration) and the Company awarded grants totaling $422,000 to 844 small business customers in need, with $33,000 of the administrative funds used.

During the second term of the Grant Program (which began in January of 2023 and runs until funds are exhausted), applicants are required to have an arrearage of $500 at the time of their application. The second term also has a budget of $500,000 (approximately $450,000 for incentives and $50,000 for administration), and through January of 2024, the Company has awarded grants totaling $55,000 to 110 qualifying small business customers in need, with $4,205 of the administrative funds used.

16. Q. Is the Company proposing to continue operating the Small Business Grant Program?

A. Yes, with some programmatic changes to improve accessibility to small business customers.

17. Q. Is PECO proposing any new allocation of funds to support a continuation of the Small Business Grant Program?

A. No. In the 2022 PECO Gas Rate Case, the Company committed to continue the Grant Program until the funds allocated in that case were exhausted. Based on grants awarded in both terms of the Program through January of 2024, PECO has a total remaining amount of approximately $485,795.

18. Q. What programmatic changes is the Company proposing to the Small Business Grant Program?

A. The Company intends to make changes to improve grant accessibility for our small business customers. We found that the requirement of a $500 arrearage balance on the account at the time of application was a significant barrier. In 2023, 83% of small business customers who applied to the Grant Program were ineligible primarily due to failure to meet the $500 arrearage requirement. Consequently, PECO is proposing to remove that requirement and utilize the following criteria:

PECO will continue to require applicants to:

- Have an active PECO gas account on or before March 31, 2020;
- Take service under Rate GC;
- Attest to a financial hardship; and
- Attest (via completion of the application) to having fewer than 25 employees.

PECO will newly require applicants to:

- Have an average arrearage balance of at least $150 over the prior 18-month period directly preceding application;
- Have previously had an arrearage balance on their account at least four times in that same 18-month period; and
- Have no deposit on hold for poor payment history.

Based on account information from the fourth quarter of 2023, approximately 2,477 small business customers would be eligible under the revised criteria. Following approval, eligible small business customers would receive a $200 grant applied as a credit to the active PECO account on a first come, first serve basis.

19. Q. How will the Company encourage applications to the updated Grant Program?

A. To advertise and encourage applications, the Company will utilize current customer contact information to send out a blast email notification about the Small Business Grant to eligible small business customers. Additionally, the Small Business Account Managers will employ a new strategy to make specific outreach to eligible small business customers starting with those who have the highest average arrearage amount in the applicable 18-month timespan and the highest number of previous arrearage balance instances on their account (with at least 4 instances being the threshold) in the same applicable 18-month period. The goals of the specific outreach are to: (1) make the customer aware of their eligibility; (2) discuss options for helping the customer manage their energy costs; and (3) encourage the customer to apply for a grant.

VI. REVISIONS TO THE GAS CUSTOMER SAFETY PROGRAM

20. Q. Does PECO currently offer a Gas Customer Safety Program?

A. Yes. In 2023, PECO launched a Program with an annual budget of $400,000 that utilizes a two-pronged approach to deliver gas safety materials to residential customers.[13] First, all new residential gas customers who move into an existing home and sign up for gas service along an existing gas main (referred to as "gas along the main service") receive a PECO "Safety Package" that includes printed

[13] The Gas Customer Safety Program was included in PECO's 2022 Gas Rate Case filing.

educational materials and a gas safety device.[14] The educational materials include, at a minimum: (1) mercaptan "scratch n sniff" information so that customers understand how to recognize natural gas odor leaks; and (2) pamphlets or brochures illustrating where gas detectors should be placed in the home and explaining the importance of installing and maintaining smoke detectors in the home.

Second, all residential customers who receive a gas odor response visit (i.e., a home visit in response to a gas odor complaint) are provided with the educational material component of the Safety Package. There are approximately 20,000 gas odor complaints made each year that require a formal gas odor response by PECO.

21. Q. Is PECO proposing to continue this Program?

A. Yes, with some modifications. First, PECO intends to incorporate gas safety advertising as a new component of the Program. In addition, the Company plans to modify the delivery channel for gas safety devices to new "gas along the main" customers and provide a magnet to new residentials along with educational materials. The revised Program would operate as follows:

New Residential Gas Customers. New "gas along the main" customers would receive safety literature, a refrigerator magnet about responding to gas emergencies, and a voucher to procure a safety device (i.e., CO detector). To accomplish safety

[14] The Company originally intended to distribute a gas safety device to both new residential "gas along the main" customers and residential new construction customers. As PECO began Program implementation, however, the Company found that new construction homes already had gas safety devices installed. The Company, therefore, has provided new construction customers with the educational component of the Safety Package. The reduced need for gas safety devices among new residential customers resulted in smaller Program expenditures in 2023 than originally anticipated ($75,000).

device and gas safety literature distribution, the Company will engage a fulfillment vendor. New construction customers would receive safety literature and the magnet.

Gas Odor Response. All residential customers who receive a gas odor response visit would continue to be provided with gas safety literature consistent with the existing program.

Gas Safety Advertising. PECO would provide enhanced gas safety advertising across multiple channels, including but not limited to digital, video, radio, out of home (e.g. signage, billboards, transit shelters), and social media. The advertising that is currently focused in late September through October and mid-November through December would be expanded to additional time periods throughout the year. On average, PECO currently spends $300,000 to $400,000 each year on natural gas safety advertising. In 2023, the Company's advertising provided 30 million impressions and approximately 38,000 clicks to our natural gas safety webpage. PECO is proposing to repurpose approximately $250,000 of the existing Gas Customer Safety Program budget towards enhanced advertising, bringing the Company's total annual gas safety advertising budget to approximately $650,000. This increased level of spending would facilitate expanded advertising and will increase the number of impressions and visits to the gas safety webpage.

22. Q. With these changes, does PECO expect to spend the full $400,000 Program budget?

A. Yes. PECO notes that if the annual budget is exhausted prior to the end of a Program year, the Company would stop distributing gas safety device vouchers.

VII. CONCLUSION

23. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 10-R (Corrected Version)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

REBUTTAL TESTIMONY

WITNESS: JAQUELINE F. GOLDEN

SUBJECT: LOW-INCOME CUSTOMER ISSUES; RECOVERY OF CUSTOMER ASSISTANCE PROGRAM COSTS; RESIDENTIAL CUSTOMER ISSUES; CUSTOMER SERVICE AND BILLING ISSUES

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
JAQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jacqueline F. Golden. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Customer Financial Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as PECO Statement No. 10. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following topics raised by other parties in direct testimony.

Low-Income Customer Issues: I will respond to the direct testimony of Elizabeth R. Marx on behalf of the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") and the direct testimony of Mr. Roger Colton on behalf of the Office of Consumer Advocate ("OCA") concerning bill affordability, the definition of "confirmed low-income customer", customer noticing regarding PECO's Customer Assistance Program ("CAP"), the use of speech analytics software, security deposit policies, and proposed changes to several of the Company's Universal Service programs.

Universal Service Fund Charge ("USFC") Offset Factors Costs: I will respond to Mr. Colton's testimony concerning the bad debt offset factor in the USFC formula.

Residential Customer Issues: I will respond to Mr. Colton's and Ms. Marx's proposals concerning language access, methodologies used for security deposits and termination scheduling, and the application of customer payments to dual customer bills. I will also address Mr. Colton's contention that PECO is not providing exemplary service in the areas of Universal Service, credit and collections.

Customer Service Issues: With respect to large customer account management and billing issues, I will respond to the direct testimony of James L. Crist on behalf of the Southeastern Pennsylvania Transportation Authority ("SEPTA"), as well as the direct testimony provided by OCA witness Nicolas A. DeMarco regarding customer service and satisfaction, call center performance and billing matters.

4. Q. Have you prepared any exhibits to accompany your rebuttal testimony?

A. Yes, I have prepared PECO Exhibit JFG-1 which I describe later in my testimony.

II. LOW-INCOME CUSTOMER ISSUES

5. Q. Ms. Marx and Mr. Colton each emphasize concerns about affordability for low-income customers in response to the Company's proposed base rate increase. Please describe the Company's existing efforts to connect customers in need with programs that can reduce their bill.

A. PECO has a robust Community Education and Outreach Plan ("CEOP") to facilitate customer awareness of and connection to assistance programs, along with enrollment in, the Company's Universal Services offerings. The CEOP is filed with the Commission, shared with PECO's Universal Services Advisory Committee ("USAC"), and updated on an annual basis. PECO conducts hundreds of outreach events in coordination with community-based organizations throughout the Company's service territory every year and utilizes both U.S. Census (zip code data for low-income and limited English proficiency "LEP" areas) and PECO customer data (zip codes with the highest termination rates) to determine event locations. When an event is focused on an LEP community, the Company provides interpretation services. PECO also partners with dozens of social service agencies by providing them with Universal Services materials and educating their staff (as well as customers) about important concepts such as income eligibility (i.e., how to read and interpret the Federal Poverty Level ("FPL") chart). PECO also sends CAP-specific mailings and conducts outbound calls to confirmed low-income customers and non-CAP recipients of Low-Income Home Energy Assistance Program ("LIHEAP") grants to encourage them to apply to CAP and provide instructions on how to apply. Additionally, the Company provides all new residential customers with a welcome packet which includes information on assistance services, such as CAP, the Matching Energy Assistance Fund ("MEAF"), the Low-Income Usage Reduction Program ("LIURP"), the Customer Assistance Referral and Evaluation Service ("CARES") and LIHEAP.

The Company has further integrated virtual outreach and enrollment activities and extensive programmatic information on its website (peco.com/help) to expand the ways in which customers can learn about assistance programs. This information is available on PECO's website in Spanish and Simplified Chinese. PECO has also implemented the Assistance Finder tool on PECO's website, which provides customers with access to information on financial assistance, bill management, and saving money and energy (e.g., PECO's Universal Services programs). In fact, from May 2023 through April 2024, almost 40,000 customers completed the survey in the tool and received personalized program recommendations along with nearly 5,000 customers submitting CAP applications. In addition, PECO monitors its education and outreach performance by tracking a variety of metrics, including some specific to activities for customers at or below 50% of the FPL as noted in the Company's 2024 CEOP filing.

6. Q. Ms. Marx and Mr. Colton each contend that PECO's definition of a "confirmed low-income customer" is not consistent with PUC regulations and recommend that PECO's tariff and policies reflect a definition that includes, among other things, customers who self-certify income without additional documentation. Please respond.

A. I disagree that PECO's definition of a "confirmed low-income customer" is inconsistent with PUC regulations. PECO defines "confirmed low-income" as customers who, in the last two years, have provided verified financial information (i.e., proof of income documentation) at or below 150% of FPL, and/or enrolled in CAP, and/or received a LIHEAP grant. This description is consistent with

electric and gas regulatory definitions of "confirmed low-income residential account" which both refer to a utility obtaining "information that would reasonably place the customer in a low-income designation."[1] Utilities are not required to accept self-certification without additional documentation.[2]

7. Q. Mr. Colton recommends that PECO utilize speech analytics software to assist with the quality monitoring of calls involving, or potentially involving, Universal Service programs and other low-income customer issues. He further recommends that PECO involve its USAC in terminology selection and report on monitoring results to the USAC. Please respond.

A. PECO's call center employs a natural language processing analytics solution to help the Company better understand reasons for calls and identify opportunities to improve processes and customer service representative performance. The Company currently uses this analytics solution to identify calls on current news publications, price impact on customer sentiment, system changes, and whether a customer may be having technical issues. PECO is open to sharing its common search terms with the USAC.

8. Q. Please summarize Ms. Marx's recommendations concerning the collection and refund of security deposits from low-income customers.

A. Ms. Marx recommends that PECO: (1) educate customers about the low-income security deposit exemption and income screening customers prior to assessing a

[1] 52 Pa. Code 54.72 (electric); 52 Pa. Code 62.2 (gas).

[2] The regulatory definition applicable to Natural Gas Distribution Companies ("NGDCs") at 52 Pa. Code §62.2 identifies self-certification as a type of information a NGDC *may* accept.

security deposit; (2) within 30 days of final order in this proceeding, review all prior security deposit collection from low-income customers, issue refunds and continue the monthly review moving forward; and (3) issue refunds as appropriate directly to customer, with account credits used only if the customer consents.

9. Q. Do you support the implementation of those proposals?

A. No. By way of background, I would like to explain the Company's processes with respect to low-income customers and security deposits.

When a new residential customer requests a connection for service, a deposit will be assessed based on the information provided by a third party vendor, whether the customer has limited or no credit history, or if the customer has a prior written off or "finaled" delinquent PECO account. If the customer says that they cannot pay the assessed deposit, PECO informs the customer that PECO will send a letter with contact information that the customer can use to call and speak to a Company representative regarding the customer's income information and request to waive the deposit after verifying their low-income eligibility for such a waiver. Customers who are verified low-to-moderate income ("LMI") ≤ 250% of FPL are excluded from being assessed a deposit.

PECO also reviews existing accounts to determine if a deposit may be required depending on where a customer may be in the collections process. Typically, a deposit is required if the customer meets the following criteria:

- There is not already a deposit assessed on the account;
- Late payment charges have been applied three times in the prior 12 months; and

- The account has received a deposit warning in the prior four months

If the first two conditions are met, but the third is not, PECO will send a deposit warning, rather than assess a deposit. In this instance, customers who are verified LMI ≤ 250% of FPL are also excluded from being assessed a deposit.

PECO also regularly reviews residential accounts to ensure that deposits have been properly assessed. If a customer paid a deposit and becomes a verified LMI customer subsequent to paying the deposit, PECO will apply the deposit to the customer's account to reduce the amounts they would otherwise owe. If a customer who does not need to maintain a deposit contacts PECO to request a cash refund of a security deposit credit, PECO will issue a check in the amount of any excess credit on the customer's account.

In sum, customers who are determined to require a deposit are excused from deposit obligations upon income verification, with credits or refunds available where appropriate. I do not believe there is any reason to change PECO's existing security deposit procedures.

A. <u>Customer Assistance Program</u>

10. Q. Please summarize Ms. Marx's recommendations concerning CAP enrollment processes.

A. Ms. Marx makes several enrollment-related recommendations, including: (1) participation by PECO in the Department of Human Services ("DHS") data sharing program; (2) routine Universal Services screening for new, moving and non-emergency calls, including a warm transfer process if necessary; and (3)

automatically enrolling or recertifying customers following receipt of a LIHEAP grant, which could include an "opt-out" component.

11. Q. Do you agree with Ms. Marx's proposals?

A. The Company is actively considering participation in the DHS data sharing program and, if the Company elects to participate, it will file a letter by July 31, 2024 as directed by the Commission.[3] The Company disagrees, however, with the proposal concerning routine screening. If a customer calls to discuss a past due balance, identifies affordability concerns, or asks about Universal Services programs, the Company already asks about income status to screen for potential CAP eligibility, establish payment arrangement terms, and advise of other assistance programs and external grant programs available. PECO does not agree that it would be appropriate to ask all customers about their income during all other types of non-emergency customer service calls (e.g., moving to a new service address) given that the purpose of the customer's call was not related to affordability or assistance programs and the Company would be requesting information that the customer may not be comfortable providing.

Regarding enrollment processes, the Company disagrees with the proposals on automatic enrollment. PECO believes customers should maintain the ability to affirmatively choose whether or not to enroll in CAP or participate in any other low-income program. While auto-enrollment may offer benefits to a customer in the form of bill discounts, it may also restrict other types of customer activities.

[3] *2023 Review of All Jurisdictional Fixed Utilities' Universal Service Programs*, Docket No. M-2023-3038944 (Order entered June 13, 2024).

For example, if a PECO customer is enrolled in CAP they cannot shop for an electric supplier, utilize budget billing, or retain their one-time opportunity for Pre-Program Arrearages ("PPA") forgiveness if they do not currently have a significant past-due balance. Furthermore, customers should have the opportunity to understand the specific program benefits and requirements before being enrolled in CAP.

Additionally, while the Commission has encouraged utilities to consider implementation of auto-enrollment of LIHEAP recipients into CAP, PECO believes that in addition to customers maintaining their right to affirmatively choose whether or not to enroll in CAP, it is important to consider the increased costs to all residential customers, including CAP and non-CAP LMI, of auto-enrollment. In 2023, PECO received LIHEAP grants for approximately 10,000 non-CAP customers. Using the forecasted 2025 average annual CAP bill credit of approximately $1,200,[4] auto-enrolling these customers in CAP would increase bill credits by up to $12 million. Additional enrollments of future non-CAP LIHEAP recipients would further increase bill credit costs. And while Ms. Marx proposes an "opt-out" option (i.e., auto-enrollment occurs unless a customer affirmatively chooses to "opt out" of any auto-enrollment), such an approach can be expected to also result in higher costs associated with CAP back office administration, PIPP correspondence mailings, and Information Technology ("IT") implementation costs.

[4] The Company is forecasting an average annual CAP bill credit of $1,216 in 2025 (2025 total CAP credit forecast of $159.2 million divided by the 2025 average CAP enrollment forecast of 130,875).

In addition, regarding recertification, PECO's Universal Service and Energy Conservation Plan ("USECP") already provides for an extended recertification cycle for LIHEAP recipients. Specifically, CAP customers who receive LIHEAP grants may recertify on a four-year cycle instead of the standard two-year cycle. Finally, as described in more detail in PECO's USECP, if a customer is removed from CAP and then re-enrolls within the following 12-month period, the customer is entitled to receive credits reflecting the CAP bill credits they would have received if they were enrolled during that period.

12. Q. Please summarize Mr. Colton's proposals concerning additional customer contacts during disconnection and reconnection related to CAP.

A. Mr. Colton recommends that PECO make personal contact with a confirmed low-income customer prior to disconnection to offer the opportunity to apply for CAP and the associated arrearage forgiveness. If the customer expresses a desire to apply, Mr. Colton proposes that PECO postpone the disconnection for a reasonable period of time to allow the CAP application process to be completed. When a confirmed low-income customer is being reconnected, Mr. Colton proposes that the customer be required to affirmatively acknowledge that they do not wish to participate in CAP (along with its arrearage forgiveness program) prior to being reconnected and required to pay either a portion of their outstanding arrears or any reconnection fee.

13. Q. Do you agree with his proposals?

A. No, PECO's existing termination noticing process already provides customers with appropriate information about the availability of assistance programs as well

as how to contact the Company about other customer protections that may prevent termination. PECO's terminations of service are performed consistent with Commission regulations and include repeated notices for each customer. A customer at risk for termination of service first receives a 10-day notice, which includes specific information on contacting PECO, availability of assistance programs, and rights a customer may have to continue service. A customer who receives this notice and then contacts a PECO customer service representative ("CSR") will be granted a 10-day collections hold following any credit call with the CSR that does not result in taking the customer out of collections. Likewise, a 10-day collections hold will be granted by the Interactive Voice Response ("IVR") when a customer seeks to use the minimum payment option or to enter into a deferred payment agreement but is unsuccessful in doing so. This permits the customer time to provide proof of income to enroll in CAP, make a payment, or request a payment arrangement if eligible.

If a customer still does not take action, PECO attempts to directly contact the customer 72 hours prior to termination through calls or direct contact by leaving a physical notice at the property, again with information that they may be eligible for available assistance and customer rights. When a customer calls PECO to make a payment to avoid termination or to reconnect, the CSR will explore options with the customer, which may include taking an income statement to confirm eligibility for longer payment arrangement terms and providing information about Universal Services program enrollment.

If a customer expresses the desire to apply for CAP, the customer is provided with instructions on how to access the online portal and/or pdf application. If the customer requests a paper copy they are mailed a CAP application. CAP applications can be submitted via mail, email, fax or the online portal, and as previously stated the customer has ample time to apply once the 10-day hold is placed on their account.

If termination does occur, the customer is provided with yet another notice of the steps they can take to restore service. If the customer demonstrates that they are confirmed low-income and are a first time CAP customer, they may be eligible for restoration with the full balance to be set aside under PECO's PPA forgiveness program. In sum, during pre- and post- termination calls, if a CSR determines that a customer may be low-income based on the information the customer provides on the call, the CSR will provide information on Universal Services programs including CAP and the discussions with the customer, including the customers decisions, are noted on their account.

14. Q. Please summarize Mr. Colton's proposals concerning "stand alone" noticing related to CAP.

A. Mr. Colton recommends that PECO provide stand-alone notices concerning CAP and associated arrearage forgiveness in the following situations: (1) when a customer is found to be without heating during cold weather survey; (2) when negotiating a deferred payment agreement with a confirmed low-income customer or a customer where information is generated during the payment arrangement process to place them in the Tier I income range (at or below 150% of FPL); (3)

when a confirmed low-income customer has accrued an unpaid balance of $300 or more; and (4) when requesting a cash security deposit from a confirmed low-income customer.

15. Q. Do you agree with his proposals?

A. No, PECO's existing processes already provide customers with appropriate information about CAP and other Universal Services programs. First, customers identified through the winter survey process already receive a range of materials from the Company, including a CAP Application, Universal Services Program Information Sheet, and a LIHEAP Application during LIHEAP season. Second, when a Tier 1 confirmed low-income customer is negotiating a deferred payment arrangement, they are provided information about CAP and how to apply. Third, confirmed low-income customers routinely receive information about CAP, regardless of their unpaid balance, and how they can enroll, including automatic mailings of CAP applications to non-CAP LIHEAP recipients.

Further, PECO conducts annual CAP outreach via direct dialed phone calls in May and U.S. mailings in October to confirmed and unconfirmed low-income[5] non-CAP customers, regardless of whether they have an unpaid balance. Customers with an unpaid balance also receive information about assistance programs and the multiple pre-disconnection notices and contacts as described earlier in my rebuttal testimony. Finally, with regard to security deposits, and as

[5] An unconfirmed low-income customer is a customer that has provided a verbal statement of income but has not provided physical documentation of income.

discussed above, customers who are verified LMI ≤ 250% of FPL are excluded from being assessed a deposit.

B. LIURP

16. Q. Ms. Marx is critical of PECO's LIURP job completion rate, spending per job and service of tenants. She recommends that PECO: (1) increase its LIURP budget by $1,850,000 to $5,000,000; (2) revise its high usage eligibility threshold to account for usage on a per square-foot basis; (3) improve direct solicitation to high usage CAP customers; and (4) provide reports to USAC about (i) barriers and solutions regarding tenant issues and (ii) barriers and solutions regarding coordination with other home repair and weatherization programs. Please respond.

A. At the outset, I note that PECO is actively participating in the Commission's LIURP Notice of Proposed Rulemaking ("NOPR") proceeding[6] and has filed comments regarding the Commission's efforts to update the LIURP regulations. To the extent Ms. Marx has programmatic LIURP recommendations, they would be more appropriately raised in the NOPR proceeding. Turning to the specific criticisms, I disagree with Ms. Marx that the success of PECO's LIURP can be measured by looking at individual statistics in isolation. Each LIURP participant household is evaluated and measures are implemented if they meet LIURP requirements, including certain payback period requirements as defined in the LIURP regulations.[7] The spending per household is a function of what measures

[6] *See* Docket No. L-2016-2557886.

[7] *See, e.g.,* 52 Pa. Code § 58.11 (establishing payback periods applicable to LIURP measures).

are appropriate in the homes we evaluate in a given year. The number of jobs completed in a year is also dependent upon a number of factors, including how many measures are being installed, and their costs, in each premise. We continue to focus on assisting high usage customers and installing measures that will maximize energy saving benefits.[8] Importantly, since the removal of COVID restrictions, PECO has been expending its full LIURP budget for the benefit of customers. Over the years we have consistently increased the LIURP budget and believe the current budget in appropriate. Just last year, the LIURP budget was increased by $1 million for electric service and $0.9 million for gas service. These increases, along with dedicated Health and Safety spending ($1.5 million for the permanent electric program and $100,000 for the gas pilot expiring at the end of 2025), brings PECO's LIURP spending to approximately $11.4 million annually.

Second, PECO does not have, and has no feasible way of collecting, the square footage of each customer premise in advance of a LIURP audit in order to deploy the type of usage per square-foot threshold recommended by Ms. Marx. PECO notes that Act 129 can provide electric energy efficiency support for low-income customers who reside in smaller dwellings and do not meet LIURP's usage threshold. Similarly, on the gas side, certain low-income customers with lower total usage but higher usage per square-foot can access no-cost measures through the Safe and Efficient Heating Program. In addition, in response to Ms. Marx's

[8] Notably, the energy savings resulting from LIURP jobs has increased significantly. The latest APPRISE LIURP Evaluation Final Report completed in 2024 for 2022 found that: (1) savings from electric heating jobs averaged 10.5%, compared to recent years that had savings below 6%; and (2) savings from gas heating jobs were 7.2% compared to recent years that were all below 5% and often below 3%. *See* PECO Exhibit JFG-1 for a copy of the APPRISE LIURP Evaluation Final Report.

comments on barriers to tenants, PECO does work with customers who are renters to minimize the barriers. If a customer is a renter, the LIURP contractor will contact the property owner and provide a consent form and a self-addressed postage paid envelope. The contractor will follow-up for receipt of the consent form before the work begins. Consent from the owner can also be obtained verbally over the phone a recorded line. A letter shall be delivered to the customer and property owner confirming consent has been obtained.

Regarding the final recommendation about reporting to the USAC on various LIURP issues, PECO already appropriately engages the USAC and program partners. In addition to regularly sharing LIURP information, PECO conducted two multi-family collaboratives (one in 2022 and one in 2023) with a range of stakeholders, including the OCA, Community Legal Services, and the Public Utility Law Project.[9] During the collaborative, the Company discussed how PECO could support all types of dwellings by utilizing LIURP and its energy efficiency and conservation ("EE&C") programs. PECO also collaborates with the PEA and its Built to Last Program ("BTL") by accepting direct referrals from BTL for PECO's Act 129 EE&C low-income programming. Eligible customers are scheduled for a free energy checkup and measures are provided to the customer at no cost.

[9] The collaboratives were held in accordance with a Commission-approved settlement in PECO's most recent gas base rate proceeding (Docket No. R-2022-3031113).

C. MEAF

17. Q. Ms. Marx recommends that: (1) MEAF grant amounts be increased to $1,000 for baseload electric service with an additional $1,000 for heating customers; (2) MEAF funds be distributed proportional to low-income populations in each county; and (3) PECO replace MEAF's zero balance requirement with a requirement that a grant be sufficient to "resolve the crisis." Do you agree with these recommendations?

A. I do not. PECO continues to believe that the Company's proposal to change the maximum allowable MEAF grant from $500 per commodity to $1,000 per account is appropriate. This change should allow additional customers to meet the MEAF eligibility criteria of bringing the customer's account balance to zero by permitting all eligible customers (regardless of service type) to qualify for a MEAF grant of up to $1,000. Fundamentally, the MEAF program is an emergency program to help customers avoid termination, and an increase in grants for higher balances will provide assistance to fewer people.

Regarding the distribution of MEAF funds, as I explained in my direct testimony, PECO already distributes any funds for which it has not received a customer match – up to $300,000 annually – to the MEAF agencies in proportion to the number of low-income customers in each county within PECO's service territory. The distribution of these remaining funds to the agencies then becomes available as a contribution for the agency to use as their portion of the grant, to be matched by an additional PECO shareholder contribution per the normal MEAF process, thereby increasing the funds available in the counties for future application to

customer accounts. Finally, PECO does not believe the zero-balance requirement should be waived because MEAF is not intended to be a supplemental grant program, but rather a means to address collections risk by achieving a zero balance.

18. Q. Please summarize Ms. Marx's recommendations concerning MEAF grant availability and oversight of MEAF agencies.

A. Ms. Marx generally expressed concern about the number of grants issued and the underspending of available funds. She recommends that: (1) PECO monitor the performance of each MEAF agency including requiring monthly reports from each agency; (2) PECO file monthly reports on the status and availability of MEAF; and (3) MEAF operation issues be referred to the Commission's Bureau of Audits and Bureau of Investigation and Enforcement.

19. Q. Do you agree with her recommendations?

A. I believe that PECO already has sufficient processes in place to monitor MEAF agency activity. On a weekly basis, PECO reviews MEAF grants received and posting of matching PECO shareholder contributions. On a monthly basis, PECO reviews invoices from MEAF agencies to track and confirm each agency's activity. PECO also hosts quarterly USAC meetings where MEAF agencies attend and have the opportunity to address issues and answer questions. The Company does not believe that MEAF implementation issues warrant investigation by the Commission because PECO will affirmatively communicate significant issues with a MEAF agency to the Commission's Bureau of Consumer Services ("BCS") and provide them with status reports as appropriate.

III. OFFSET FACTORS IN THE UNIVERSAL SERVICE FUND CHARGE

20. Q. Have any parties opposed PECO's proposal to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%?

A. Yes. Mr. Colton contends that PECO's proposal to lower the bad debt component of the USFC offset factor from 22% to 5.5% based on the difference between the three-year average (2021-2023) uncollectible rate for CAP customers and all residential customers artificially reduces the offset factor. Mr. Colton makes some additional contentions regarding the cash working capital offset which are addressed in the rebuttal testimony of Mr. Trzaska.

21. Q. Does Mr. Colton dispute that the difference between the three-year average uncollectible rate for CAP customers and all residential customers is a reasonable methodology to determine the offset (positive or negative) to PECO's bad debt expense arising from incremental changes (increases or decreases) in CAP enrollment levels?

A. No. However, Mr. Colton contends that using 2021 in the three-year average is unreasonable since PECO's rate of net charge-offs was abnormally low in that year due to the impact of the COVID-19 pandemic on customer collections activities.

22. Q. Is PECO making any changes to its proposed update to the bad debt adjustment in the USFC formula to address Mr. Colton's concerns?

A. Yes. PECO proposes removing 2021 from the three-year average rate of net write offs in the calculation described in my direct testimony. As shown in Table 1

below, using a three-year average for calendar years 2019, 2022 and 2023 produces a bad debt offset percentage of 7.1%, which is 1.6% higher than the PECO's original proposal.

Table 1

	CAP Customer Billings vs Net Charge-Offs				All Residential Customer Billings vs Net Charge-Offs			
	2019	2022	2023		2019	2022	2023	
Annual Billings ($M)	$102.0	$118.7	$94.3	**3-Year Average**	$2,331.4	$2,861.1	$2,868.7	**3-Year Average**
Net Charge-Offs ($M)*	$7.2	$10.3	$7.7		$14.8	$28.9	$34.2	
Ratio (%)	7.0%	8.7%	8.2%	**8.0%**	0.6%	1.0%	1.2%	**0.9%**

*Excludes October 2016 one-time In-Program Arrearage ("InPA") forgiveness and Pre-Program Arrearage ("PPA") forgiveness.

IV. RESIDENTIAL CUSTOMER ISSUES

23. Q. Mr. Colton contends that PECO has no claim for "exemplary management" in the area of (1) Universal Service and (2) credit and collections performance, citing CAP enrollment numbers and payment arrangement and disconnection statistics for low-income customers, and the level of residential arrears. He further argues that PECO does not appropriately query customer satisfaction or utilize technology to enable assistance with program enrollment. Please respond.

A. I believe we have provided extensive support for PECO's exemplary management performance. In light of Mr. Colton's testimony, however, I want to highlight several areas where we have provided substantial assistance to the low-income customers we serve.

- In July of 2022, PECO incorporated the updated energy burdens in the CAP Policy Statement and then converted the structure of its CAP to a PIPP in December 2022. Overall CAP bill credits to customers increased

by approximately $27 million for electric and gas from 2021 to 2022. Additionally, in 2023, the first full year of the PIPP, CAP customer bill credits increased by approximately 64% for electric service (from $86 million in 2022 to $140.7 million) and more than 100% for gas service (from $5.3 million in 2022 to $10.9 million). While CAP enrollment varies throughout the year, it has remained relatively consistent over the last several years averaging approximately 122,000 customers since 2021. As evidenced by our CEOP, PECO is focused on outreach to customers who are in need of financial support while also ensuring that customers enrolled in CAP remain eligible through requiring income recertification so that more program funds are available for those most vulnerable. In addition, as discussed earlier, PECO has recently increased its LIURP budget.

- PECO's termination procedures and other credit and collection processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's credit and collections activities are focused on reducing arrears and annual write-off amounts. While it is not our objective to terminate customers for nonpayment, terminations are necessary to support the objective of reducing the arrears and write-offs for all customers including verified low-income customers <250%, who represent ~22% of terminations in 2023. In regard to payment arrangements, PECO provided approximately 78,000 payment agreements in 2023.

- As I have already explained, we are conducting hundreds of outreach events to increase enrollment every year, and we are succeeding at ensuring that our low-income customers have sufficient assistance as well as access to a range of programs that can help them save energy.
- We process applications in a timely manner and provide a range of enhanced communications to assist customers with recertification as well as obtaining "retro" reinstatement credits for up to 12 months in which they may not have been on our CAP program due to a failure to recertify.
- The Company is utilizing technology to assist customers in connecting with assistance programs. In fact, as stated previously in my testimony, customers can submit CAP enrollment information online via PECO.com, noting that information explaining the program is provided in English, Spanish and Simplified Chinese. In addition, PECO's Assistance Finder provides customers with information on where they can go to apply for various programs including CAP, which makes the available online CAP application easier to access and therefore improve the enrollment experience for the customer. The Company also includes on the website the link to the DHS's Compass website where customers can apply for LIHEAP.

Finally, PECO collects information about the level of customer satisfaction of LMI customers. A third-party vendor surveys residential customers (by phone and digitally) after customer interactions with PECO. In addition to collecting information about customer satisfaction, those surveys ask customers to provide

income information. Based on the survey responses, customer satisfaction improvement plans are developed to address themes of opportunity identified.

24. Q. Mr. Colton contends that PECO should amend its tariff Rule 16.7, Application of Payment, to permit dual customers to designate that all or part of their combined PECO bill payment be applied to electric service – including past due balances and current charges –before being applied to natural gas service, or vice versa. Does PECO support the implementation of these recommendations?

A. No. PECO provides customers who receive electric and gas service with a total bill for their utility service, not one for gas and one for electric. There is no basis for permitting customers to "prefer" one service over another, and a customer in arrears is at risk for termination of both services.

25. Q. Ms. Marx makes several recommendations related to language access, including that PECO should: (1) track the primary language of its customers as part of its customer information system; (2) send residential bills (or key portions thereof) and residential termination notices in English and Spanish to all households; and (3) include a tagline about interpretation service in five languages on residential customer bills and termination notices. Does PECO agree with these recommendations?

A. No, PECO believes that its existing processes to address language access issues are appropriate and meet or exceed Commission requirements. Implementing Ms. Marx's proposals, including the proposed software upgrade for tracking a

"primary" language of customers, would create new costs that PECO does not believe are warranted at this time.

With respect to written documents, PECO's current collection notices already include a sentence in Spanish alerting customers that the notice is important and that they should contact the Company for help if needed. Similarly, PECO's bills include a sentence in Spanish explaining how a customer can contact PECO if they have questions or concerns. When an LEP customer contacts PECO, they have access to translation service in over 100 available languages. PECO provides its CAP and LIHEAP applications in English and Spanish (in PDF format on PECO's website and in hard copy at outreach events). PECO also provides our low-income program brochure in English and Spanish.

Furthermore, for low-income outreach events in Spanish-speaking areas / zip codes, PECO provides representatives fluent in spoken and written Spanish to conduct those events. For non-Spanish speaking LEP outreach events, PECO provides interpreters upon request. Those interpreters are typically members of LEP organizations with whom PECO partners. PECO provides documents such as assistance program brochures, the CAP application, the LEP language line card, and website translation assistance to community-based organizations and our customers in various languages.

26. Q. Please summarize Mr. Colton's recommendations concerning processes related to residential security deposits and disconnections.

A. Citing the potential for discriminatory effects, Mr. Colton argues that the Commission should mandate additional review of certain PECO processes. First,

he recommends that PECO's risk analysis methodology underlying its disconnection of service and cash security deposits should be subject to a public review by the Bureau of Consumer Services and stakeholders. Next, he argues that PECO should conduct a root cause analysis to determine and address the cause of an alleged "disproportionate" level of disconnections in certain zip codes with relatively greater numbers of Black households. Finally, Mr. Colton recommends that PECO's Tariff be modified to state that its credit scoring methodology "does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act."

27. Q. Do you support Mr. Colton's proposals?

A. No. PECO's termination procedures, credit scoring, and other processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's risk assessment procedures that are used to determine whether and/or when to schedule a disconnection of service to a residential customer for nonpayment are based on PECO's goal to improve its collection activities, decrease its annual write-off amounts, and reduce the overall cost of field collections activities. Factors used in the risk assessment include account balance, monthly bill amount, probability of cut success, percentage of balance paid if cut, percentage of balance paid if not cut, probability of account finaling if cut, and probability of account finaling if not cut. PECO does not know, nor does it track, customers by demographics such as race or ethnicity for purposes of disconnection.

I note that PECO partners with energy assistance organizations to identify and implement initiatives to remove barriers for underserved communities to access federal, state and local energy assistance funding. PECO contracts with 30 community-based organizations strategically located throughout PECO's entire service territory. These agencies are trusted by the communities they serve and PECO's affiliation with these organizations only serves to expand our outreach. Additionally, PECO provides training to agency workers to ensure each agency is aware of PECO's comprehensive suite of assistance programs to maximize assistance options for LMI customers.

V. LARGE CUSTOMER ACCOUNT MANAGEMENT AND BILLING ISSUES

28. Q. SEPTA witness Crist has submitted the same testimony in this PECO Gas rate case proceeding (Docket No. R-2024-3046931) and the current PECO Electric rate case proceeding (docket No. R-2024-3046931). How do you respond?

A. In my rebuttal testimony, I do not respond to any of Mr. Crist's discussions about issues presented by the PECO Electric rate case proceeding because they are not relevant to the issues before the Commission in this docket. However, I note for the record that I have submitted rebuttal testimony in the PECO Electric rate case docket that addresses all of Mr. Crist's electric-focused large customer account management and billing exceptions.

29. Q. Mr. Crist raises similar concerns with respect to account management and billing issues for large customers and testifies that "[t]hese have all been relayed to PECO but there has been no follow up on confirmations of the

timing for resolution." How do you respond to this statement?

A. I would like to start first by providing an explanation of how PECO handles service matters for its large customers, including SEPTA. Specifically, PECO has assigned an Account Manager ("AM") that is dedicated to working directly with SEPTA on all matters. The PECO AM is the primary point of contact who directly supports or coordinates within PECO most of the inquiries from SEPTA to ensures seamless communication and excellent customer service. The PECO AM is available to receive SEPTA's questions and concerns on a 24/7 basis, meaning that SEPTA can connect with the PECO AM at any time during the day or the night. In addition, the PECO AM has an assigned "back-up buddy" to assist SEPTA when the PECO AM is not otherwise available. In addition, each large customer, including SEPTA, is provided with an toll-free number that rings to the on-duty shift manager in case the more urgent after-hours needs.

SEPTA's designated PECO AM has the primary responsibilities delineated below.

1. ***Consolidation, review and distribution of monthly invoices for all of SEPTA's accounts***. This includes ensuring billing accuracy and promptly addressing any discrepancies.

2. ***Receive and review all new service requests from SEPTA***. This involves coordination with various internal teams to assess the feasibility, plan the service implementation, and ensure timely delivery.

3. ***Collaborate with SEPTA's internal teams, such as regional engineering and billing, to resolve any customer concerns***. This collaboration is crucial for

addressing technical issues, ensuring accurate billing, and maintaining high customer satisfaction.

4. ***Serve as the emergency contact for addressing outage related concerns after hours and during weekends***. The PECO AM works directly with the outage control center to ensure swift resolution of any power outages or disruptions to minimize the impact on SEPTA operations.

With respect to specific billing issues raised by Mr. Crist, PECO met with large customers, including SEPTA, before implementation of the new billing system to discuss changes and timelines, and we have been in frequent contact throughout the process. In fact, in his direct testimony, Mr. Crist provided a copy of the notification in October 2023 PECO provided regarding the transition to the new billing system in 2024.

In addition, after implementation, the PECO AM for SEPTA has had regular meetings and multiple phone calls with the SEPTA Management Analyst regarding billing exceptions, including bill presentation and summary bill. Resolution of exceptions is a top priority for PECO and we are working diligently to resolve any outstanding issues, including invoice delivery and confirmation of account additions and deletions from SEPTA's billing. PECO continues its commitment to keeping SEPTA fully informed throughout the resolution process.

VI. CUSTOMER SERVICE AND SATISFACTION

30. Q. In his testimony, OCA witness DeMarco notes customer service improvements the Company has made with its website and Mobile App and increased enrollment in "My Accounts" for both PECO Gas and PECO

Electric but expresses concern that the Company does not identify the cost savings associated with these improvements.

A. The "My Accounts" enrollments for both the website and mobile app have increased for residential customers. However, since this technology offering is relatively new to customers, it is premature to quantify cost savings associated with this improvement. It is important to note that this technology is designed to facilitate an improved customer experience and ease for customer of access to customer account information, and an overall cost savings may be difficult to quantify.

31. Q. Do you agree with Mr. DeMarco's recommendation to implement a "two-step identification" process to protect customer account information?

A. I disagree with Mr. DeMarco's recommendation to implement Two-Step Identification because the process is already a part of our customer security protocol. Voluntary Two-Step Identification went live as part of our offering in the first quarter of 2022. Mandatory Two-Step Identification for new residential customers is scheduled to go live by the end of 2024 and for all residential customers in 2025.

32. Q. Mr. DeMarco claims that the Company has made inconsistent statements about whether the improvements and costs savings associated with the website and the Mobile App form the basis for its request for a management performance adder and requests clarification in rebuttal. Can you please respond?

A. I disagree that the statements are inconsistent. For example, as Ms. Hamilton testified in her direct at page 25, lines 11-18, the Company added "other features and capabilities" to the PECO website. In response to OCA-16-3, Ms. Hamilton answered "no" as to whether her discussion of the added "features and capabilities" supported the management performance adder. While the new "features and capabilities" alone do not support the management performance adder, the success in terms of customer efficiency and support that has been achieved through the Company's proactive implementation of the additional "features and capabilities" contributes to the Company's recommended addition of fifteen (15) basis points to the allowed return on equity for management performance.

33. Q. Please summarize Mr. DeMarco's concern about the Company's plan to improve customer satisfaction.

A. Mr. DeMarco states that the Company fails to define its objectives or provide support for how it plans to reach its objectives. He further alleges that the Company has not performed a cost-benefit analysis or identified any goal metrics to assess results. He states that a management performance adder is appropriate only once those improvements are in place.

34. Q. How do you respond to his concern that the Company did not define its objectives or providing support for how it plans to reach its objectives?

A. PECO's plan to improve customer satisfaction begins with routine customer satisfaction surveys administered by a third-party vendor throughout the year. PECO's third-party vendor will randomly select residential customers and contact

them either by phone or email to solicit feedback on various customer service topics. For commercial customers, the vendor reaches out directly by phone to discuss PECO's level of customer service. After PECO receives and studies the survey responses, the Company takes action to implement solutions to the feedback provided by the customers. As an example of actions taken, in 2023 PECO enhanced the promotion of digital adoption, which increased the web activity for billing and payment options. The Company also sent out 3.1 million emails to educate customers about price-to-compare and created an animated video about third-party suppliers for additional education. Moreover, in response to survey feedback from small and medium business customers, PECO assigned account managers (just like the ones assigned to the large customers). As a result, PECO has created more touch points with this customer class and our outreach has increased significantly.

In 2024, PECO continues to focus on improving customer satisfaction by strategically communicating with customers to promote self-service tools including My Account and e-bill. PECO has developed a new self-service video to explain how to use the new tools, and is currently developing a new *'Understanding Your Bill'* customer video. The self-service offerings allow customers to do business with the Company when it is convenient for them, which is often after regular business hours and on the weekend. I can report that we are seeing positive results. For example, self-service adoption grew approximately 22% between 2022 and 2023 (from 5.3 million users to nearly 6.5 million users) with utilization of the Company's self-service offerings increasing nearly 22%

between 2022 and 2023.

Finally, as I discuss in more detail below, PECO is focusing on the CSR component of customer satisfaction as evidenced by the "Universal Agent" training.

35. Q. Do you agree with Mr. DeMarco assessment of the Company's plan to improve customer satisfaction?

A. No. I disagree with Mr. DeMarco's assessment of the Company's plan to improve customer satisfaction primarily because the Company has identified strategies to improve customer satisfaction year-over-year. Such strategies include using targeted communications to promote self-service tools and services available to customers including MyAccount and e-bill enrollments. As noted above, the Company is incorporating new self-service videos in PECO's external outreach and is currently developing a new *'Understanding Your Bill'* customer video. Lastly, the Assistance Finder tool uses technology that helps customers find programs designed to support their specific needs all in one place.

36. Q. Do you agree with Mr. DeMarco that the Company has not supported its claim that customer benefits will come from investment in customer operation?

A. No. The investments implemented to date are designed to improve the availability of customer products and the reliability of the underlying platforms. As I noted above, these projects consist of enhancing digital self-service options and offering personalized solutions that meet customers' needs. One investment to "help promote and improve affordability" is "My Account," which has enabled

customers to navigate more efficiently and utilize online options to manage their individual needs. The use of Assistance Finder tool provides customers with personalized program recommendations to allow them to manage their bills and energy usage and, as mentioned previously in my testimony, helps them find programs designed to support their specific needs all in one place.

VII. CALL CENTER PERFORMANCE

37. Q. Mr. DeMarco recognizes 2023 improvement in PECO's call abandonment rate and average calls answered within 30 seconds but notes that PECO has not reached its goal for the 2022-2025 period. How do you respond?

A. PECO sets aggressive internal targets for the call abandonment rate and the percent of calls answered within thirty (30) seconds to meet customer needs. PECO achieved significant improvements in both call abandonment rate and the percent of calls answered within thirty (30) seconds from 2022 to 2023. While these metrics are important and will continue to be a focus of the Customer Care team, we believe that First Contact Resolution ("FCR") is a better measure of the ease of doing business with PECO. The abandonment rate and the percent of calls answered within thirty (30) seconds are an indication of how quickly calls are answered while FCR is an indication that the customer's issue was resolved on the first attempt. Customer satisfaction research has indicated that resolution of the customer's issue on the first attempt is a higher priority to the customer than short wait times. Our Customer Care team is focused on making improvements in this area.

38. Q. Mr. DeMarco acknowledges the Company's improvement to call center performance through implementation of a FCR approach and a "Universal Agent" strategy. Do you agree with his recommendations to conduct further analysis on how to improve the FCR process and investigate any issues regarding call handling that have not been resolved since the July 2022 Audit Report?

A. No. In fact, prior to the July 2022 Audit Report, upon its own initiative the Company transitioned to FCR and made it a top priority metric for Customer Care. Customer Care has made several changes to enhance FCR since that time, including increasing call evaluations, implementing a new process flow tool for agents, realigning resources within the organization to increase agent coaching support, and investigating FCR by call type to identify opportunities for process improvements. In a sense, the Company has already implemented Mr. DeMarco's recommendation as Customer Care continues to focus on ways to improve FCR.

39. Q. Citing UCARE statistics, Mr. DeMarco notes an increase in the number of customer complaints and verified infractions. He recommends the PECO create a plan with metrics to reduce the level of information complaints and verified infractions. Do you agree?

No. First, let me say that PECO's operations team continually strives to minimize the number of customer complaints and verified infractions, and as I noted above, conducts third-party surveys throughout the year to identify areas of improvement and provide solutions. Second, I believe Mr. DeMarco is incorrect about an increase in the number of residential complaints and verified infractions. If 2021

is excluded from the data – consistent with OCA Witness Colton's argument that 2021 was an atypical year (Statement 4, pages 104-106)) – the results show a decrease in residential complaints and a "remains steady" trend in verified infractions. As a result, I disagree with Mr. DeMarco's recommendation that PECO should conduct a root cause analysis and create a plan with actional metrics providing how PECO will reduce informal complaints and verified infractions.

40. Q. In response to questions about bill payment options and fees, Mr. DeMarco notes discovery regarding fee revenues from transactions (pay as guest and by phone) received from customers had not been received from the Company. Can you provide an update?

A. PECO provided the responses to the interrogatories referenced by Mr. DeMarco in this proceeding on June 14, 2024, and confirmed that the Company does not receive revenues from customer payment fees.

41. Q. Mr. DeMarco expresses concern about the potential for discrimination by charging customers a fee to pay their bill when they are not doing so via My Account or when they pay by phone and recommends that PECO eliminate these fees as a direct cost to consumers. Do you agree?

A. No, I note that PECO offers multiple no fee payment options, including mailing payments directly through the United States Postal Service, submitting an electronic payment via MyAccount (e-check) or the customers' bank or third-party institution, as well as for those customers that have a MyAccount but wish to pay by phone, with agent assisted payments using e-check.

Additionally, while a payment fee initially is charged to customers who make payments at authorized bill payment locations (e.g., large retail stores and drug stores) via check or cash, payment fees collected are reimbursed to the customer on their next bill. PECO began the process of reimbursing the fee for walk-in payments in recognition of supporting our most vulnerable communities. In 2023, for example, more than two hundred and fifty thousand (250,000) payments were made at authorized bill payment locations. Importantly, more than half – sixty four percent (64%) or ninety-four (94) out of one hundred forty-six (146) of the available authorized bill locations – are in the City of Philadelphia, where a majority of PECO's low-income customers are geographically located and most likely to utilize this payment option. Moreover, the fees associated with payments made at authorized bill locations are absorbed by the Company at a cost of approximately five hundred thousand dollars ($500,000) annually.

The fees assessed for payments made outside of PECO's no-fee payment options are primarily associated with the processing of debit and credit card payments and are collected by the third-party processing vendor. As I am sure Mr. DeMarco is aware, credit card companies can charge significant fees for payments or purchases. The fees assessed to customers utilizing these methods are intended to offset the credit card fees assessed by the credit card industry. If PECO were to include these third-party processing vendor fees in its revenue requirement, this could potentially increase the revenue requirement by a minimum of five million dollars ($5,000,000) annually for residential payments, which is an amount that

would be collected from all customers, including those currently using the no-fee payment option.

42. Q. Regarding Personal Identification Information ("PII"), Mr. DeMarco is waiting for discovery responses from the Company. Can you provide an update?

A. The discovery responses for OCA-21-12 and OCA-21-13 were served to the parties on June 16, 2024.

43. Q. What is your response to Mr. DeMarco's recommendation that PECO reduce the use and retention of PII and develop workflow and cybersecurity measures to reduce the threat of disclosure or theft of PII?

A. I would refer Mr. DeMarco to the discovery served to the parties in response to OCA OCA-21-12 and OCA-21-13. PECO follows industry best practices around cybersecurity to safeguard and protect customer's PII. This includes, but is not limited to, multiple levels of access restrictions and encryption. However, due to the nature of PECO's business as a provider of retail electric and natural gas service, the retention of customer PII is vital to reduce the likelihood of fraudulent accounts being created and to provide needed creditworthiness information upon the creation of new accounts.

VIII. CONCLUSION

44. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.



PECO Energy
2022 LIURP Evaluation
Final Report

April 2024

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Executive Summary

This report presents the findings from the Evaluation of PECO's 2022 Low Income Usage Reduction Program (LIURP). LIURP provides energy efficiency services and energy education to PECO's low-income customers to help them reduce their energy usage and increase the affordability of their energy bills. The Program addresses both electric and gas energy usage. This report describes the LIURP services and analyzes the impact of the Program on customers' energy usage, energy bills, and payments.

Evaluation

The goals of the evaluation were to analyze the LIURP services provided and the impacts of the services on participating customers. The following activities were undertaken.

- *Process Evaluation:* We requested program information from the PECO LIURP Manager, interviewed the CMC Program Manager, and reviewed and analyzed the quality control inspection findings.

- *Program Database Analysis:* We analyzed the 2022 LIURP services, homes, and customer characteristics.

- *Program Impacts Analysis:* We analyzed LIURP's impact on energy usage, energy costs, and bill payment.

PECO's LIURP

The Low Income Usage Reduction Program provides education, conservation, and weatherization measures to reduce electric and gas usage. Customers must meet the following usage and income eligibility criteria for participation.

- Household usage levels at or above 600 kWh per month for electric baseload, 1,400 kWh average seasonal heating usage for electric heat, or 50 ccf average seasonal heating usage for gas heat.

- Residential customers with household income at or below 200 percent of the federal poverty level (FPL).

CAP customers are targeted for Program services, but participation in CAP is not currently required for LIURP services. CAP customers are required to participate in LIURP if they are identified as high users (monthly usage of at least 500 kWh).

The number of customers who receive LIURP services each year is largely determined by the annual Program budget established in the settlement agreement of PECO's electric restructuring case (PUC Docket Numbers R-00973953 and P-00971265). The annual budget

for 2022 was $5.6 million for electric and $2.25 million for gas. In 2022, 3,667 customers received LIURP services.[1]

PECO contracts with CMC Energy Services to administer LIURP. PECO provides CMC with a list of potentially eligible customers and their energy usage data. CMC recruits these households in descending order based on highest usage and largest arrearages. CMC also contacts households who are directly referred from external organizations, including social and government agencies, and has begun advertising to households using Facebook.

CMC conducts an energy audit to determine the behavioral changes and measures required for usage reduction. Following the audit, CMC technicians and CMC subcontractors schedule appointments to install measures. For one year after LIURP services have been provided, PECO and CMC monitor the customer's monthly energy usage. CMC mails monthly progress letters to customers to highlight any changes in monthly usage, as compared to the customer's individual goal.

Program Statistics

In 2022, 20,417 customers were evaluated for LIURP services. There were 11,883 cancelled jobs and 4,867 customers who were ineligible for the Program. The cancellations were primarily due to lack of response to contact attempts.[2] In total, 3,667 customers received LIURP services in 2022; 82 of these received only education services and no measures, as there were no LIURP opportunities in these homes.

Table ES-1 displays how LIURP funds were expended in 2022. In total, $7.84 million was spent. Approximately 78 percent was for weatherization measures, 15 percent for the audit and education, and eight percent for administration.

Table ES-1
2022 LIURP Expenditures
By Category

Category	Amount Spent	Percent of Funds
Weatherization Measures	$6,092,230	78%
Audit/Education	$1,158,322	15%
PECO Administration	$592,699	8%
TOTAL	**$7,843,251**	**100%**

Table ES-2 displays the distribution of 2022 LIURP jobs by job type, for both electric and gas accounts. The table shows that 74 percent of jobs were classified as baseload, meaning that measures primarily address electric baseload usage. Since baseload jobs have lower job costs, they represent only 29 percent of total costs. The average cost for measures on these jobs was

[1] Eighty-two customers did not receive measures through LIURP. These customers only received education.
[2] See Table III-3.

$496. Gas heating jobs represented 13 percent of jobs and 34 percent of costs, averaging $3,312 in measure costs per home. Electric heating jobs averaged $4,272 per home.

Table ES-2
2022 LIURP Service Delivery and Expenditures
By Job Type

Job Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Job Cost
Baseload	2,715	74%	$1,346,978	29%	$496
Electric Heating	394	11%	$1,683,040	37%	$4,272
Gas Heating	476	13%	$1,576,594	34%	$3,312
No LIURP Measure Costs*	82	2%	$0	0%	$0
TOTAL	**3,667**	**100%**	**$4,606,612**	**100%**	**$1,256**

*There were 82 accounts that received education only.

Participant Characteristics

PECO's LIURP database allows for extensive analysis of home and participant characteristics. Some of the important findings from this analysis included the following.

- *Supplemental heating:* Overall, 36 percent of customers who were treated by LIURP used supplemental heat. Thirty-five percent of the customers who had baseload LIURP services used electric supplemental heat.

- *Health and safety:* Over 4,000 smoke detectors were provided in 1,994 homes. Carbon monoxide detectors were provided in 1,640 homes.

- *LED bulbs:* LEDs were provided to 87 percent of the homes serviced. On average, 11 bulbs were provided in the homes that received LEDs.

- *Refrigerator replacement:* Refrigerators were replaced in 239 homes.

- *Air conditioner replacement:* Air conditioners were replaced in 846 homes.

- *Aerators and showerheads:* A total of 776 aerators were provided in 523 homes, and 511 showerheads were provided in 443 homes.

- *Water heaters:* Electric water heater replacements were performed in 34 homes, and heat pump water heaters were installed in 18 homes. Gas water heater replacements were provided in 36 homes.

- *Air sealing:* Air sealing was completed in 263 homes. However, only 130 customers received a blower door test.

- *Insulation:* Insulation was provided in 154 homes.

- *Door Sweeping/Weatherstripping:* Door sweeping/weatherstripping was provided in 976 homes.

- *Heat system repair:* Heating system repair work was performed in 401 homes.

- *Heating system replacement:* Heat pumps were replaced in 122 homes, furnaces in 44 homes, and boilers in 38 homes.

Usage Impacts

Energy usage was analyzed for the year prior to the LIURP audit visit and the year after service delivery was completed. The analysis included as close to a full year of pre- and post-treatment data as possible. Data were available for approximately 81 to 90 percent of the jobs that received measure installation.

Energy usage data were weather-normalized in the pre- and the post-usage periods to ensure that changes in energy usage were due to changes in usage patterns, rather than changes in weather. We used a degree-day normalization process to conduct this analysis, as well as a comparison group comprised of later LIURP participants to control for other changes that were exogenous to the Program.

Table ES-3 summarizes the overall usage impact results.

- *Baseload jobs* had average annual savings of approximately 847 kWh, or 7.1 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 1,030 kWh, or 8.6 percent of pre-treatment usage.

- *Electric heat* jobs had average annual savings of approximately 2,192 kWh, or 10.5 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 2,439 kWh, or 11.7 percent of pre-treatment usage.

- *Gas heat* jobs had savings of 88 ccf, or 7.2 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 95 ccf, or 7.8 percent of pre-treatment usage.

Table ES-3
Average Annual Usage and Saving

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
Electric Baseload (kWh)									
Non-Normalized	2,456	11,616	10,680	937***	8.1%	854	7.3%	83	0.7%
Degree Day Normalized	2,456	11,991	11,144	847***	7.1%	764	6.4%	83	0.7%
Electric Heat (kWh)									
Non-Normalized	320	19,630	17,100	2,530***	12.9%	2,458	12.5%	72	0.4%
Degree Day Normalized	320	20,838	18,646	2,192***	10.5%	2120	10.2%	72	0.3%
Gas Heat (ccf)									
Non-Normalized	412	1,122	969	153***	13.7%	153	13.7%	0	0.0%
Degree Day Normalized	412	1,214	1,126	88***	7.2%	88	7.2%	0	0.0%

***Denotes significance at the 99 percent level.

We compared the usage impact results to historical savings results.[3]

- Electric Baseload Jobs: The 2022 jobs had savings that were lower than the 2000-2021 average savings. Savings were 7.1 percent in 2022 compared to the historical average of 7.8 percent.

- Electric Heating Jobs: The 2022 jobs had savings that were higher than the 2000-2021 average. Savings were 10.5 percent in 2022 compared to the historical average of 7.0 percent.

- Gas Heating Jobs: The 2022 jobs had savings that were consistent with the 2000-2021 average. Savings were 7.2 percent in 2022, the same as the historical average of 7.2 percent from 2000-2021.

Measure Savings

The analysis also estimated the impact of specific LIURP measures on kWh and ccf savings. Table ES-4 displays results from this analysis. Savings were computed by running a regression model that predicted savings based on the measures provided.

In 2022, customers who only received LEDs and no other measures had average savings of 803 kWh, about the same as such homes in 2021. Heating systems provided some of the

[3] Tables IV-3A, 3B, and 3C provide the historical comparison of energy savings by job type.

highest savings, with heat pumps estimated to save 2,318 kWh per home and gas furnaces and boilers estimated to save 74 and 79 ccf per home.

Table ES-4
Measure Savings Estimates

	Savings	Cost/Home	$/Unit Saved	Measure Life	$/Unit Saved Over Lifetime
Electric Baseload (kWh)					
LED Only[1]	803 (±303)	$316[2]	--	10	--
LED	8 (±6)	$0	$0.02	10	<$0.01
Refrigerator	756 (±230)	$1,171	$1.55	12	$0.17
Freezer	756 (±230)	$267	$0.35	12	$0.04
Air Conditioner	108 (±120)	$885	$8.20	13	$0.87
Gas Heat (ccf)					
Gas Furnace	74 (±36)	$5,663	$76.52	15	$7.37
Boiler	79 (±39)	$11,030	$139.62	15	$13.45
Electric Heat (kWh)					
LED	24 (±20)	$1,011	$42.13	10	$5.46
Air Conditioner	1,521 (±727)	$658	$0.43	13	$0.05
Water heater	665 (±804)	$628	$0.94	12	$0.11
Air sealing only	1,030 (±854)	$1,237	$1.20	15	$0.12
Air sealing and insulation	713 (±530)	$3,539	$4.96	15	$0.48
Heat Pump	2,318 (±495)	$6,085	$2.63	15	$0.25

[1]The average number of LEDs provided to these customers was 11.5.
[2]This is the cost for the audit and education of customers who only received LEDs. The cost for the LEDs is paid for by the Act 129 Program.

LIURP Cost Effectiveness

We also analyzed the cost-effectiveness of LIURP by job type. Table ES-5 estimates the cost per unit saved based on different assumptions about measure life. These costs should be compared to retail rates to evaluate the cost-effectiveness of the LIURP at different measure lives.

The most reasonable assumption for electric baseload reduction is a ten-year measure life. The current cost per kWh of electricity is approximately $0.17. This table shows that the electric baseload investments were cost-effective in 2022, given that the cost per unit saved was slightly lower than the retail rate.

The most reasonable assumption for gas heating is a 15-year measure life. The current cost per ccf of gas is approximately $0.99. The table shows that the gas measures were not cost-

effective in 2022, given that the cost per unit saved was $3.69. LIURP would need to increase the savings that were obtained from the gas measures that were installed to be cost-effective.

Table ES-5
Cost Per Unit Saved
By Measure Life Assumption

	#	Average Savings	Average Total Cost	Cost Per Unit Saved	5-Year Measure Life	10-Year Measure Life	15-Year Measure Life
Electric Baseload							
Electric (kWh)	2,456	847	$887	$1.05	$0.24	$0.14	$0.10
Gas (ccf)	160	26	$931	$35.80	$8.27	$4.64	$3.45
Electric Heat							
Electric (kWh)	320	2,192	$4,503	$2.05	$0.47	$0.27	$0.20
Gas Heat							
Electric (kWh)	395	693	$459	$0.66	$0.15	$0.09	$0.06
Gas (ccf)	412	88	$3,374	$38.34	$8.86	$4.97	$3.69

Bill and Payment Impacts

The evaluation also included an analysis of the charges and payments made by customers in the pre- and post-treatment periods. Table ES-6 summarizes the results of this analysis. Total charges decreased by an average of $113, and total payments and credits decreased by an average of $115 from the pre to post period. The total bill coverage rate did not change significantly.[4] Customers were paying an average of 102.8 percent of their bills prior to LIURP treatment and an average of 103.5 percent of their bills following LIURP treatment.

Table ES-6
Bills, Payments, and Coverage Rates
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Total Charges	1,540	$1,149	$1,034	-$115***	-10.0%
Total Credits		$1,148	$1,044	-$104***	-9.0%
Total Coverage Rate		102.3%	104.1%	1.8%	1.7%

[4] The total coverage rate is the total of all customer payments, customer assistance, and other credits divided by the bill.

	#	Pre	Post	Change	Percent Change
Electric Heat					
Total Charges	99	$1,851	$1,650	-$201***	-10.9%
Total Credits		$1,887	$1,577	-$310***	-16.4%
Total Coverage Rate		102.0%	95.7%	-6.3%*	-6.2%
Gas Heat					
Total Charges	134	$1,916	$1,906	-$10	-0.5%
Total Credits		$2,020	$1,966	-$55	-2.7%
Total Coverage Rate		108.2%	104.6%	-3.7%	-3.4%
Education Only					
Total Charges	41	$1,072	$892	-$181***	-16.8%
Total Credits		$1,124	$851	-$273***	-24.3%
Total Coverage Rate		108.0%	98.0%	-10.0%	-9.3%
All Job Types					
Total Charges	1,814	$1,242	$1,129	-$113***	-9.1%
Total Credits		$1,252	$1,137	-$115***	-9.2%
Total Coverage Rate		102.8%	103.5%	0.7%	0.6%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.

Key Findings and Recommendations

PECO's LIURP delivered usage reduction services and energy education to over 3,500 customers in 2022, many of whom had vulnerable household members. The program performed significantly better than recent years in terms of energy savings from electric heating jobs and gas heating jobs. Savings from electric heating jobs averaged 10.5 percent, compared to recent years that had savings below six percent. Savings from gas heating jobs were 7.2 percent compared to recent years that were all below five percent and often below three percent. Savings from electric baseload jobs were in line with the 20-year historic average. When accounting for the comparison group change, both electric baseload and electric and gas heating net savings were even higher compared to recent years.

The average measure cost remained more than double the historic average and stable compared to the previous year, which reduced the cost-effectiveness of LIURP. The increase in job costs was likely driven by rising material and labor costs stemming from the inflationary environment in the post-COVID economy. These cost increases are expected to continue to impact the program in future years.

We have the following recommendations to improve energy savings and the cost-effectiveness of LIURP.

- *Outreach:* While CMC was successful in increasing the number of contacted customers to pre-COVID levels, most customers did not respond to contact attempts. The current

procedure is to make at least three phone calls and send a follow-up letter.[5] CMC should increase the number of calls to high-usage customers and pilot additional methods of outreach to targeted neighbors when they are in the field, such as leaving door hangers. PECO is continuing work with CMC to expand and improve LIURP outreach.

- *Targeting High Users:* The savings for electric baseload and gas heating jobs are significantly higher for customers with higher pre-program usage. CMC was successful in 2022 in reaching higher usage customers than in some of the other recent years. They should continue to target higher usage households and focus on deploying major measures to homes where they are likely to maximize impact.

- *Major Measure Installation*: Savings on jobs with more major measures are significantly higher. CMC was successful in increasing the rate of air sealing and insulation on electric heating jobs compared to recent years. They were also successful in installing heat pumps in a greater percentage of homes. These changes lead to historic savings for the electric heating jobs. However, electric and gas heating job still have low levels of air sealing and insulation. CMC should work to increase the rate of air sealing and insulation work on both electric and gas heating jobs.

- *Health and Safety Remediation:* The health and safety component of the LIURP program has been effective at allowing additional energy saving measures to be installed through health and safety work. PECO should consider expanding their health and safety program by providing additional remediation work (such as electrical upgrades) that would enable energy efficiency measures in older homes.

[5] This is PECO's minimum standard for the number of contact attempts.

I. Introduction

This report presents the findings from the 2022 PECO LIURP evaluation. PECO's LIURP provides energy efficiency services and energy education to low-income households to help them reduce their energy usage and increase the affordability of their energy bills. This report describes the Program services and analyzes the impact of the Program on customers' energy usage, energy bills, and payments.

A. Background

PECO Energy has implemented a set of Universal Services Programs to meet requirements set by Pennsylvania's electric and gas restructuring legislation and various Public Utility Commission orders and agreements. The Universal Service goals are as follows.

- To protect consumers' health and safety by helping low-income customers maintain affordable utility service.
- To provide affordable utility service by making available payment assistance to low-income customers.
- To help low-income customers conserve energy and reduce residential utility bills.
- To ensure utilities operate universal service and energy conservation programs in a cost-effective and efficient manner.

The Universal Services Programs include the following four initiatives.

- A CAP payment assistance program that is designed to make energy bills more affordable by furnishing payment subsidies.
- A LIURP program that is designed to make energy bills more affordable by helping to reduce usage.
- A CARES program that is designed to assist households in developing appropriate strategies for maintaining energy service.
- A MEAF hardship fund program that is designed to furnish emergency payments to households that cannot pay their energy bills.

B. Evaluation Objectives and Activities

The goals of the evaluation were to analyze the LIURP services provided and the impacts of the services on participating customers. Three key activities were undertaken as part of this evaluation.

- *Process Evaluation:* We requested program information from the PECO LIURP Manager, interviewed the CMC Program Manager, and reviewed and analyzed the quality control inspection findings.

- *Program Database Analysis:* We analyzed the 2022 LIURP services, homes, and customer characteristics.

- *Program Impacts Analysis:* We analyzed LIURP's impact on energy usage, energy costs, and bill payment.

C. Organization of the Report

Five sections follow this introduction.

- Section II – Low Income Usage Reduction Program: This section describes PECO's LIURP design and implementation.

- Section III – Program and Participant Statistics: This section provides descriptive statistics on LIURP services delivered in 2022 and the customers who received these services.

- Section IV – Usage Impacts: This section analyzes the impacts of LIURP on customers' electric and gas usage.

- Section V – Payment Impacts: This section analyzes changes in customers' bills, payments, and arrearages after receiving Program services.

- Section VI – Summary of Findings and Recommendations: This section provides a summary of the key findings and furnishes recommendations for PECO's LIURP based on the analyses in this report.

APPRISE prepared this report under contract to PECO. PECO facilitated this research by furnishing Program data to APPRISE. Any errors or omissions in this report are the responsibility of APPRISE. Further, the statements, findings, conclusions, and recommendations are solely those of analysts from APPRISE and do not necessarily reflect the views of PECO.

II. Low Income Usage Reduction Program

PECO has implemented a set of Universal Service Programs to comply with Public Utility Commission Regulations. The Programs are designed for low-income, residential customers. One of these Programs is the Low-Income Usage Reduction Program (LIURP).

The Pennsylvania Public Utility Commission (PUC) requires that all electric and gas utilities in the state offer a Low-Income Usage Reduction Program to their customers. PECO has contracted with CMC Energy Services (CMC) to administer LIURP since the implementation of the Program in 1991. PECO and CMC worked together to create Program procedures that complied with Chapter 58 guidelines and continue to work together to design and implement Program changes when necessary. CMC works with subcontractors to install major Program measures and deliver energy efficient refrigerators.

The total 2022 LIURP budget was $7.85 million with $5.6 million for electric usage reduction and $2.25 million for gas usage reduction.

A. Program Management and Administration

CMC's Director of Operations is responsible for oversight of the LIURP Program, final contract requirements, and tracking key performance indicators (KPIs). CMC Program Managers and Associate Program Managers oversee the daily operations and report to the Director of Operations. The Program Managers and Associate Program Managers are also responsible for client management. They interact frequently with their equivalents at PECO to ensure smooth operations.

CMC also has staff within several of their other business units, listed below, that contribute to PECO's LIURP.

- Customer Care
- Marketing
- Information Technology
- Finance
- Subcontractor Management

CMC also has a field team, an inspection team, and a program support team, that support LIURP. The Field Supervisor is responsible for reviewing work orders and coordinating the field team, made up of three levels of technicians. Technicians at Level 1 are still in training, and Level 2 technicians perform baseload visits only. Level 3 Technicians perform electric and gas heating jobs and those involving combustion testing, although they can also do baseload jobs as needed.

The inspection team is led by a Quality Control (QC) Supervisor who overlaps with other programs such as Act 129. The QC Supervisor is responsible for managing Quality Control,

reporting data, summarizing findings, and managing CMC's relationship with PSD, the third-party inspector.

The program support team consists of a manager and two analysts. They process all information and prepare it for the Program Manager's review. Throughout this process, they perform validation checks to look for possible data errors, identify missing data, and make sure subcontractors have submitted the necessary paperwork and documentation for each project.

Customer care staff conduct inbound and outbound calling with customers and schedule appointments. Within this business unit there are also levels of expertise. The team is cross-program, meaning they perform calling for various utilities and programs unaffiliated with PECO.

CMC auditors, who are a part of the field team, collect data in the home, install smoke detectors and water-saving devices as needed, install Act 129 measures, educate the customer, and generate work orders for other measures. Subcontractors usually perform heating service, insulation, weatherization, and other major measures, but there is also an internal HVAC technician who completes jobs which are urgent or need a quick turnaround.

Subcontractors complete the services and replacement of heating systems and water heating systems. They perform weatherization, air sealing, and insulation. They also replace refrigerators and air conditioning units and recycle the old ones. Subcontractors also perform electrical work such as service upgrades, baseboard thermostats, and health and safety measures. Health and safety measures were piloted in 2019 and became permanent in 2020. They play an important role in LIURP because they often provide a bridge to the installation of other LIURP measures.

CMC provides oversight and support to the subcontractors. When there is a customer who is not satisfied with the scope of work, CMC will speak with the customer and visit the job site if needed.

Subcontractors can call CMC program support, they can interact with CMC through a portal, by email, or using Microsoft Teams. The portal allows subcontractors to upload documentation, provide notes about a job, or apply for a change to the work order. CMC receives questions and feedback from subcontractors daily. Each week, there is a scheduled meeting between each subcontractor and the QC Supervisor.

B. LIURP Eligibility and Benefits

PECO customers must meet the following criteria to participate in the Program.

- Residential customer who is not planning to move in the next 12 months.
- Income at or below 200 percent of the Federal Poverty Level (FPL).[6]
- Usage requirements
  - At least 500 kWh average monthly usage for CAP customers.
  - At least 600 kWh average monthly usage for baseload customers.
  - At least 1,400 kWh average seasonal heating usage for electric heating customers.
  - At least 50 ccf average seasonal heating usage for gas heating customers.

LIURP provides weatherization and conservation measures to promote usage reduction. Energy education tailored to the individual household's energy use is also provided to facilitate usage reduction.

The following measures may be provided.

- Insulation
- Air sealing
- Heating system repair or replacement
- Air conditioner replacement
- Refrigerator replacement
- Freezer replacement
- Water heater and pipe wraps
- Line voltage thermostats
- Faucet aerators
- Showerheads
- Smoke detectors
- Carbon monoxide detectors
- LED bulbs (All lighting installations are paid for as part of Act 129 funding.)

PECO and the PUC have pre-approved all LIURP measures. They have placed no cap on the amount of money spent per home. Smoke detectors and LEDs are much more commonly provided than some of the more costly measures.

[6] Since 1998, LIURP regulations have permitted companies to spend up to 20 percent of their annual Program budgets on customers with income between 150 and 200 percent of the FPL.

C. Qualification of Leads

PECO sends a quarterly download of high usage, low-income customers to CMC. Customers are also referred to LIURP through the following mechanisms.

- PECO Universal Services staff
- CAP call center
- Community Based Organizations (CBOs)
- Government agencies
- Prior Program recipients
- Universal Services Cares Unit
- CMC social media outreach via Facebook
- CMC email campaigns

The electronic file downloaded from PECO contains high energy users who are also LIHEAP recipients, Customer Assistance Program (CAP) participants, payment-troubled customers, or customers with multiple payment agreements. CMC reviews the lists and eliminates customers who have received LIURP within the past two years, refused Program services, or moved within the past 12 months. Typically, after these removals, the remaining customers on the downloaded file are eligible for and receive services from LIURP.

CMC screens all referrals from other sources to determine Program eligibility. If the household income and usage history are available and the customer is determined to be eligible, CMC enrolls the customer immediately. If income eligibility cannot be determined from PECO's system, CMC collects income data from the customer during the telephone intake. Typically, 25 to 30 percent of customers referred through other sources are determined to be eligible for and receive services from LIURP.

Referred customers may not receive LIURP services because of one of the following reasons.

- Refusal of LIURP services
- Insufficient usage history[7]
- Inactive account
- Income over the eligibility limit
- Non-responsive to CMC contacts
- Recently moved or is planning to move within one year
- Deceased
- Usage below the required level[8]
- Tenant with a landlord who will not provide consent

CMC is required to obtain consent from the landlord to provide services to a tenant. A landlord may not provide approval if they want to choose Program measures, are evicting the tenant,

[7] This may be the case if the customer recently moved into the home.
[8] There are some hardship cases where PECO makes exceptions to the usage requirement.

or are concerned about potential housing code violations.[9] Some landlords never respond to CMC inquiries. CMC is typically able to obtain landlord consent for more than 50 percent of renters.

Approximately 90 percent of customers who receive LIURP services are identified through the downloaded list, and about ten percent through other referrals.

D. Customer Outreach

PECO has undertaken new marketing efforts to increase uptake of LIURP services, including the following.

- LIURP Website: PECO is updating the LIURP website to have a more contemporary look, be more user-friendly, and be more educational. This change is expected to go live in April 2024.
- Events: PECO is working with their outreach department to provide information on LIURP at large events.
- Email Campaigns: PECO is including information on LIURP in their winter outreach, including new video advertisements. Additionally, they have developed a series of four emails that are sent to the list of high usage customers targeted for LIURP over the course of a month.

CMC's customer service representatives contact potential Program participants by telephone to explain Program services, obtain customer information, and confirm or determine eligibility.

If the customer is eligible, an appointment is scheduled for the energy audit. CMC will attempt to make this contact three times by telephone followed by a minimum of one time by mail over a 90-day period.[10] Information collected during this contact includes the following.

- Name of person responsible for bill payment
- Age of each household member
- Income sources for each household member
- Income amounts for each household member
- Property status and, if applicable, landlord contact information
- Housing type
- Occupation
- Employment status, marital status, and level of education

CMC assigns technical resources to the customer service desk to answer technical questions and provide a resource for customer care representatives. CMC also provides regular training

[9] Landlords are not required to contribute to the cost of LIURP services.
[10] This is PECO's minimum standard for the number of contact attempts.

with some elements of building science, reinforced Program guidelines, and information on what to do in particular situations.

One of the most challenging responsibilities the customer care representatives have is convincing the customer to allow a stranger to enter their home. Hesitation increased during the COVID-19 pandemic, as customers had health and safety concerns about allowing people into their homes. However, these concerns are no longer widespread. CMC reports that their call center representatives do a good job of preparing the customer for what the appointment entails and ensuring that the auditor will have access to all areas of the home.

Since 2021, CMC has used a progressive dialer system to reach more customers. The dialer system continuously calls customers and leaves messages if the customers do not answer the phone. When a customer picks up, the system transfers the call to a customer care representative. These systems can make 10,000 to 20,000 outbound calls each week. While these systems can provide more efficient calling, they can be frustrating to customers when there is a delay before speaking to a representative. Therefore, this system may not result in better contact outcomes.

E. Job Types

There are two different LIURP job types: Baseload and Heating. Baseload jobs focus on a household's lighting and appliances. Heating jobs include weatherization, insulation, and heating system repair or replacement. Both heating and baseload issues in a household are addressed when necessary. Once consent is obtained from the property owner, a renter becomes eligible for the full suite of services offered by LIURP.

F. Service Delivery

CMC prioritizes CAP participants for LIURP service delivery. All CAP participants with monthly usage at or above 500 kWh are considered for LIURP. Those with the lowest income and the greatest CAP benefits or active safety-related concerns receive the highest priority. CMC prioritizes remaining LIURP participants by energy use and income.

The first step in direct service delivery is the Program audit, performed by CMC staff. The auditor verifies the previously reported household characteristics, including income, number of household occupants, age of home, and years of occupancy. They also calculate the average household energy use per day, the energy use for each household appliance, temperature settings, and water temperature. Based on this information, the auditor may wrap the water heater and pipes, and install aerators, smoke detectors, showerheads, and LEDs during this initial audit visit.

CMC provided training to their audit staff to increase the thoroughness of directions given to subcontractors and to provide more documentation for each appointment. CMC requires the auditors to provide additional notes, documentation, and photos (if the customer agrees). Since auditors started using tablets in the field, it has become easier to take photos and attach them to the work orders. This provides subcontractors with better information to address each home.

In 2020, Virtual Energy Assessments were introduced. Virtual audits are still provided as an option for customers who are uncomfortable with the normal auditing process. Prior evaluations indicated that virtual audits were substantially less effective and are no longer actively marketed to customers.

If an audit requires follow up, CMC schedules the appropriate subcontractors to complete any necessary major measures, such as insulation, heating system repair or replacement, or new appliances. A work order is sent to the subcontractor to communicate the work that is needed. CMC aims for the subcontractor to install the measures within 30 days of work being issued to them and complete a final inspection within 60 days of the initial audit. Some jobs have health and safety concerns which can require additional work. This can lead to a delay as more subcontractors need to complete work and, in general, multiple subcontractors do not work on the same job simultaneously. Once the work has been completed and the home inspection is passed, the job is immediately considered complete.

CMC has instituted a process where subcontractors can talk to a QC supervisor in a timely fashion about any questions they have on the work orders. Additionally, every work order is vetted at the supervisor level to look for missing information and needed documentation or photos. CMC makes sure that the auditor provides notes to help the subcontractor.

CMC developed requirements for the timing of subcontractor appointments and invoicing. CMC recommends that subcontractors contact customers with work orders on the day that the work orders are received. This has been successful with the subcontractors that are able to do so. When the customer is contacted within days of their audit, the work is fresh in the customer's mind, and they are excited to have it done. This makes it more likely that the subcontractor will get back into the home, they are likely to have greater success in scheduling appointments, and they notice higher customer satisfaction levels.

G. Energy Education

PECO and CMC designed the energy education portion of LIURP to facilitate customers' clear understanding of the reasons for high energy use and to communicate how their behaviors contribute to their energy use and bills. The auditor provides the primary LIURP energy education session during the initial audit visit. CMC reports that this session lasts at least 30 minutes.[11] Further education is often provided by subcontractors when measures are installed and by other CMC QC inspectors during quality control inspections and follow-up telephone calls.

During the initial education session, the auditor reviews the customer's audit results and identifies ways that the customer can modify the behaviors of household members to save energy and money. The auditor and the customer set a monthly usage and bill reduction goal for the household. The auditor also provides the customer with an education package, which includes the following materials.

[11] Previous observations of CMC audits found that the education sessions were often much shorter than 30 minutes.

- Tips for saving energy
- 'Dangers of Using a Space Heater' pamphlet
- A brochure outlining the energy-saving benefits of LEDs and responsible lighting practices
- A brochure describing how to properly care for heating and cooling systems and preparing the home for energy savings during cold and hot weather months
- A brochure describing how to properly care the hot water system, how to reduce hot water consumption, and tips for how to use appliances efficiently
- PECO Energy Saving Tips calendar
- Referrals to CAP rate and other programs that the customer may be eligible for by county
- A PECO-branded folder informing customers of the benefits of participating in LIURP
- A brochure explaining the benefits of PECO's new Customer Assistance Program – Percentage of Income Payment Plan and other financial assistance programs available from PECO

The auditor reviews these educational materials with the customer and compares the household's energy cost estimate to the household's actual energy bill. Additionally, the auditor refers the customer to programs and agencies that might help them meet household needs and answers any questions the customer may have about the Program or the education session. The auditor reviews the measures that have been installed and those that will be installed by subcontractors. In addition, the auditor reviews the LIURP follow-up procedures that the customer can expect.

For one year after LIURP services have been provided, PECO and CMC monitor the customer's monthly energy usage. CMC mails monthly progress letters to customers to highlight any changes in monthly usage, as compared to the customer's individual goal. Each quarter CMC revises the letters to emphasize season-specific energy saving tips.

H. Quality Control

Three methods are primarily used for LIURP quality control.

- An annual evaluation, conducted by an independent program evaluator.
- Customer satisfaction surveys administered by CMC.
- Inspections by the CMC QC Inspector and a third-party inspector.

Third-Party Inspections and Observations

Performance System Development (PSD) has been conducting quality control for PECO's LIURP since April 2019. In response to a request for all assessments performed in the past year, PSD furnished 140 LIURP inspection reports from January through December 2023 (the impact evaluation focuses on 2022 to have a full year of post-treatment data available, but the QC review focuses on the most recent year available). These reports included seven inspection areas covered by the PSD inspector, each considered an "item" for the sake of analysis.

Table II-1 provides a summary of PSD's findings. In total, 140 jobs, or four percent of the jobs completed in 2023 were inspected. While 85 percent passed, 16 percent were passed with comments, and two percent with positive feedback. Fourteen percent of the inspections failed.

Table II-1
Inspection Summary

Inspections		
Assessment	**Number**	**Percent**
Passed	94	67%
Passed with Positive Comments	3	2%
Passed with Comments	23	16%
Not Passed (Fail)	20	14%
Total	**140**	**100%**

Table II-2 provides a detailed breakdown of the items missed during the inspections. The table shows that the most common issue was a missed opportunity for a measure or improvement, followed by an invoicing issue.

Table II-2
Inspection Findings

Item	# of Inspections	% of Inspections
Missed Opportunity	19	14%
Invoicing Issue	11	8%
Customer Altered Measure	10	7%
Contractor Call Requested	7	5%
Measure Not Addressed Correctly	4	3%
Inaccurate or Failed Testing	3	2%
Active Gas Leak	2	1%
No Items Missed	95	68%

Table II-3 provides a summary of the number of issues noted during the inspections On average, 0.4 items were missed, and 6.5 items were passed. Ninety-four percent of inspection items were passed.

Table II-3
Inspection and Survey Findings

Statistic	Inspections
Number of Audits	140
Mean # Items Passed	6.5
Mean # Items Missed	0.4
% of Items Passed	94%

Table II-4 shows the distribution of the number of items which were missed in the inspections. Most of the inspections, 94 percent, had no more than one item missed.

Table II-4
Distribution of Missed Items

Number of Missed Items	Inspections
Customers	140
0	68%
1	26%
2	2%
3	3%
4	1%
Total	**100%**

CMC Quality Control

CMC tries to obtain customer satisfaction surveys from at least ten percent of participants. The survey addresses technicians' courtesy and ability to answer customers' questions. Survey responses are combined into an overall score for each respondent.

CMC has historically asked customers to complete the technician feedback survey over the phone but is now offering a digital survey option that can be accessed via a QR code on the customer action form. However, to keep the technician feedback survey as accessible as possible, CMC also retained the phone option. CMC provides a phone number to clients at the time of the audit, and participants can choose to call with their feedback.

CMC inspects a minimum of five percent of baseload jobs and tries to inspect all heating jobs. However, they are not able to reach the heating inspection goal because customers stop answering calls after the work is completed. CMC surpasses the five percent goal for baseload inspections. A minimum of three attempts are made to schedule an inspection with heating customers and auto-generated letters are sent to customers to encourage them to make an appointment. CMC tries to communicate to customers that this inspection is an important part

of the process. PECO has worked with CMC to try to reduce the lag time between job completion and the inspection to increase customer acceptance of the inspection visit.

The inspector works from an inspection checklist and has the customer satisfaction survey, the home's audit results, and the completed work order to assist in the inspection. The inspector also conducts blower door, heating equipment, and carbon monoxide testing, and confirms the presence of all invoiced measures. In addition to post-completion inspections, the inspector sometimes accompanies CMC staff on audits and subcontractor staff on installations. CMC has access to the subcontractors' schedules, so if the inspectors have cancelled appointments, they observe the work of a subcontractor.

If a problem can be fixed immediately by an inspector, they will correct the issue at the time of the inspection. If there were issues such as failure to clean up or behavior that upset a customer, these will be raised with the subcontractor in feedback, but would not require them to return to the home. Where a measure was incorrectly installed or there was other work that needed to be done, an "action required" notice will be issued, and the subcontractor will be required to return to the home. Only a marginal percentage of jobs require a CMC installer to return to the home.

PECO Quality Control

The PECO LIURP manager validates LIURP invoices. They plan to select random homes for site visits to further assess the invoices in the future.

PECO has worked with CMC to improve customer satisfaction. CMC started to trend their customer service problems by attaching codes to every call. For example, a call may be coded as a work order inquiry. CMC has codes for every type of call that comes in, such as an air conditioner service or a refrigerator service. They can report on the number of each type of problem and see if it is increasing or decreasing. CMC tracks the issues that arise and works to root out the problems.

PECO has also worked with CMC to provide additional training to call center staff on handling customer disputes and dealing with difficult customers. CMC monitors call center representatives each month to assess the quality of their interactions.

PECO is now working with PSD to improve the QC scoring and develop a Program manual that provides weatherization and building code standards based on ANSI/BPI 1200 and current International Residential Codes. The manual will include the following topics.

- CST – Combustion Safety Testing
- BD – Blower Door diagnostics
- ZPD – Zone Pressure Diagnostic
- PP – Pressure Pan diagnostics
- Mechanical ventilation
- Health and Safety

I. Data and Reporting

LIURP databases contain the following information.

- Personal and household demographics
- Landlord contact information
- Audit results
- Quantity and costs of installed measures
- Referrals made to other programs
- Post treatment follow-up outreach results
- Completion dates and usage history
- Performance scorecard

CMC and PECO check the database for completeness and accuracy. This data is used to generate regular reports, including the following.

- Completed audits compared to projected audits
- Completed jobs compared to projected jobs
- Program costs by category
- Average cost per job
- Completed jobs by type
- Outreach call volume
- Customer demographics

CMC uses tablets in the field to improve the accuracy of data collection. There are checks programmed into the data entry fields, and there is also additional post-entry data validation that is conducted by CMC program support staff.

CMC and PECO monitor Program data monthly and the independent evaluator monitors Program data annually. In addition to this evaluation report, CMC and PECO produce an annual report to the PUC.

J. LIURP Training

PECO states in their contract with CMC that they require LIURP staff members to be adequately trained. CMC's QC Manager assesses the training needs of the CMC field and subcontractor staff. The CMC Office Manager assesses the training needs of the CMC administrative staff. CMC provides full training to each LIURP staff member at the time of hire, as well as ongoing training.

CMC provides bi-monthly training for their staff. Half of the training day is spent on in-depth training for a particular topic, while the other half is spent on team-building activities. Each week, there are also field meetings where information and feedback from the previous week is discussed with staff. Further, there are weekly hour-long meetings to reiterate any changes to the program guidelines, and internal monthly HR training.

During these meetings, key metrics and goals are reinforced. Important metrics include the number of measures per appointment, work orders generated, and errors with revisions needed to work orders. The most important goals are the number of appointments completed and percentage inspected (there is a 100 percent goal for heating inspections and a five percent goal for baseload inspections). For customer care staff, an important metric is whether enough appointments are generated to hit their participation goals.

Technicians also receive training to obtain Building Performance Institute (BPI) certification, and customer service representatives receive training in communications. Cross training and industry certification training is promoted as much as possible. Technicians also train in communications, and customer service staff receive some training in building performance, though not to the level of BPI certification. CMC also conducts an increasing number of heat pump trainings now that this technology is becoming an important part of LIURP.

CMC has a library of resources on customer service, building science, communications, and other subjects, which was developed during 2020 when field work was halted due to COVID.

CMC performs vetting of potential subcontractors and ensures that they have the proper certifications to perform the work. After the subcontractor is approved, CMC has an onboarding process to ensure that the subcontractor understands the process, inspections, work orders, line items, and invoicing.

Subcontractors are initially given a small number of work orders, often just one. For the first job, CMC will go out to the site with the subcontractor to evaluate them. The inspectors check that the subcontractor is badged and follows all rules and regulations when performing their work. If there are no issues, more work orders are issued, although the monitoring may continue to be more rigorous for a while until the subcontractor has demonstrated that they are reliable.

CMC has field demonstrations where one of the subcontractors will do a demonstration for CMC out in the field. Both auditors and subcontractors benefit from the demonstrations because it shows the subcontractors that their work is valuable, and it makes subcontractors feel more appreciated.

K. Program Coordination

CMC maintains a LIURP referral list consisting of other Universal Services Programs and state and county agencies that assist low-income customers. CMC staff make referrals during the initial energy audit, as well as during inspection and post-treatment follow-up calls. During the follow-up, CMC staff members ask customers whether they were able to obtain any benefits from the referrals they were given. Additionally, the CMC auditor provides CAP and LIHEAP applications to customers at the time of the LIURP audit.

L. Challenges

While COVID-related supply chain issues that CMC faced in 2020 and 2021 are no longer prevalent, jobs requiring major appliances, notably refrigerators, experienced large disruptions in 2021, leading to a backlog in 2022. In 2022, CMC was able to resolve most of this backlog by working with a new refrigerator vendor. However, limitations in funding prevented a complete resolution of this issue in 2022. CMC reports that the maximum delay for measure delivery is now about three months and they expect to resolve the full backlog in the second quarter of 2024.

A significant challenge that LIURP currently faces is the aging housing stock. Older homes often lack ductwork which limits options to replace baseboards. To overcome this challenge, CMC has done electric service upgrades and makes use of mini-splits in houses that lack ductwork. CMC has also used mini-splits to help address some backlog issues.

In 2023, customer cancellations were around 22 percent. This is a notable improvement from the 30 percent rate observed in 2021 and represents a return to the pre-COVID level of 25 percent. However, the return to normalcy also comes with more standard challenges. Home accessibility has been the main challenge faced by field staff, as children, pets, and other environmental factors can delay or prevent work from being done due to staff health and safety concerns.

Reaching high-usage low-income customers remains the biggest challenge faced in PECO's LIURP. CMC identified via a needs assessment that there were more low-income high-usage customers that could be reached through an expansion of the program. CMC is trying to focus outreach to untreated customers and minimize re-treating customers who have been serviced before.

III. Program and Participant Statistics

This section provides statistics on the LIURP services that were provided in 2022, as well as the characteristics of the homes and the customers who were served by the Program.

A. Participation

PECO screened 20,417 customers for LIURP services in 2022. Table III-1 shows that 11,883 cancelled, 4,867 customers were not eligible, and 3,667 received Program services.

Table III-1
Customers Evaluated for Program Services

Category	Number	Percent of Total
Cancelled	11,883	58%
Ineligible	4,867	24%
Treated	3,667	18%
TOTAL	**20,417**	**100%**

Table III-2 displays the reasons why customers were deemed ineligible for LIURP. While 45 percent were ineligible because they had previously been treated by LIURP, 23 percent had usage below the Program's guidelines, 17 percent had an insufficient usage history, and 14 percent were over the income limit. Customers treated in the past two years are not eligible for services.

Table III-2
Ineligible Customers

Category	Number	Percent of Total
Previously Treated in LIURP	2,214	45%
Usage Below Guidelines	1,105	23%
Insufficient Usage History	837	17%
Over Income	678	14%
Other	20	<1%
Conversion Error	7	<1%
Scope of Work Beyond Guidelines	5	<1%
TOTAL	**4,867**	**100%**

Table III-3 displays reasons why customers were cancelled. The largest group of customers, 77 percent, did not respond to contact attempts.

Table III-3
Cancelled Customers

Category	Number	Percent of Total
No Response To Contact Attempts	9,131	77%
Customer Refused	1,205	10%
Inactive Account	699	6%
Customer Moving	636	5%
Do Not Contact	57	<1%
Cancelled Needs To Rescheduled 60 Days Out	50	<1%
Cancelled Due To Health Concerns	38	<1%
Rescheduled By Program Request	34	<1%
Cancelled Due To Unsafe Environment	15	<1%
Cancelled At The Door Due To Inactive Account	7	<1%
Renovations In Progress	7	<1%
No Landlord Consent	2	<1%
Office Cancelled Miscellaneous Reasons	1	<1%
Other	1	<1%
TOTAL	**11,883**	**100%**

B. LIURP Services

This section describes LIURP services that were delivered in 2022. The total budget was $7.85 million, with $5.6 million for electric usage reduction and $2.25 million for gas usage reduction. Table III-4 shows the distribution of the spending. Seventy-eight percent was spent on weatherization measures and labor, 15 percent was spent on audits and education, and eight percent was spent on PECO administration.

Table III-4
2022 LIURP Expenditures
By Category

Category	Amount Spent	Percent of Funds
Weatherization Measures	$6,092,230	78%
Audit/Education	$1,158,322	15%
PECO Administration	$592,699	8%
TOTAL	**$7,843,251**	**100%**

Table III-5 displays the distribution of LIURP jobs and expenditures by job type. Jobs are classified as baseload, electric heating, or gas heating.[12] While 74 percent of the jobs were classified as baseload, they represented 29 percent of the total costs. The average cost for measures on these jobs was $496. Electric heating jobs represented 11 percent of jobs and 37 percent of costs, averaging $4,272 in measure costs per home. Gas heating jobs averaged $3,312 per home.

Table III-5
2022 LIURP Service Delivery and Expenditures
By Job Type

Job Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Job Cost
Baseload	2,715	74%	$1,346,978	29%	$496
Electric Heating	394	11%	$1,683,040	37%	$4,272
Gas Heating	476	13%	$1,576,594	34%	$3,312
No LIURP Measure Costs*	82	2%	$0	0%	$0
TOTAL	**3,667**	**100%**	**$4,606,612**	**100%**	**$1,256**

*There were 82 accounts that received education only.

Table III-6 provides a more detailed breakdown of the type of work done in LIURP jobs, based on CMC's classification of measure types. Many jobs received more than one type of service. Ninety-seven percent of the customers received baseload services; but only seven percent received refrigerator replacement measures, which include refrigerator replacement, refrigerator removal, and freezer replacement. Seven percent received air sealing, six percent received weatherization, and four percent received insulation. Eight percent received a heating system tune-up, and 23 percent received an air conditioner replacement.

Table III-6
2022 LIURP Service Delivery and Expenditures

Work Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Cost
Baseload*	3,546	97%	$213,827	5%	$72
Refrigerator Replacement**	241	7%	$271,768	6%	$1,137
Air Sealing	246	7%	$405,088	9%	$1,647
Weatherization	213	6%	$138,986	3%	$653
Insulation	148	4%	$243,580	5%	$1,646
Electrical	71	2%	$75,732	2%	$1,067
Heating System Tune Up	302	8%	$178,451	4%	$597
Heating System Replacement	276	8%	$1,666,260	36%	$6,037
Air Conditioner Replacement	846	23%	$842,881	18%	$1,002

[12] The job type classification shown in this table, and in this section of the report, comes from the LIURP database. In the Usage Impacts section of this report, some heating jobs were reclassified for more appropriate analysis.

Work Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Cost
Water Heater Replacement	180	5%	$213,446	5%	$1,186
Water Heater Service	115	3%	$26,433	1%	$230
Health and Safety***	129	4%	$299,257	7%	$2,320
Direct Mail Weatherization Kit	18	<1%	$1,943	<1%	$108
TOTAL	**3,667**	**100%**	**$4,577,652**	**100%**	**-**

*2,961 of the 3,546 jobs with baseload measures had one or more baseload measures funded through LIURP. The other jobs had all baseload measures funded through Act 129. Average costs for the 6,154 baseload measures funded through LIURP are shown in this table.

**Measures that fall under the refrigerator replacement work type include refrigerator replacement, refrigerator removal, and freezer replacement. 239 of the 241 jobs with one of these measures had one or more of the measures funded through LIURP. The other jobs had all refrigerator replacement measures funded through Act 129. Average costs for the 242 refrigerator replacement measures funded through LIURP are shown in this table.

*** Health and Safety includes H&S appliance replacement, H&S basement waterproofing, H&S electric, H&S extermination, H&S heating system replacement, H&S miscellaneous repair, H&S site visit, H&S ventilation, H&S window replacement and H&S electric water heating system replacement, and H&S gas water heating system replacement.

Table III-7A provides information on the frequency of individual measures installed through LIURP. Some of the key pieces of information from this table are described below.

- *Health and safety:* Over 4,000 smoke detectors were provided in 1,994 homes. Carbon monoxide detectors were provided in 1,640 homes.
- *LED bulbs:* LEDs were provided in 87 percent of the homes serviced. On average, 11 bulbs were provided in the homes that received LEDs.
- *Refrigerator replacement:* Refrigerators were replaced in 239 homes.
- *Air conditioner replacement:* Air conditioners were replaced in 846 homes.
- *Aerators and showerheads:* A total of 776 aerators were provided in 523 homes, and 511 showerheads were provided in 443 homes.
- *Water heaters:* Electric water heater replacements were provided in 34 homes, and heat pump water heaters were installed in 18 homes. Gas water heater replacements were provided in 36 homes.
- *Air sealing:* Air sealing was completed in 263 homes. However, only 130 received a blower door test.
- *Insulation:* Insulation was provided in 154 homes.
- *Door Sweeping/Weatherstripping:* Door sweeping/weatherstripping was provided in 976 homes.
- *Direct Mail Weatherization Kit:* Direct mail weatherization kits were provided to 18 customers.

- *Heating system replacement:* Heat pumps were replaced in 122 homes, furnaces in 44 homes, and boilers in 38 homes.

Table III-7A
2022 LIURP Service Delivery and Expenditures
By Measure Type

Measure Category	Measure	Number of Jobs	% of Jobs	Total Number
Health and Safety	Carbon Monoxide Detectors	1,640	45%	1,794
	Smoke Detector	1,994	54%	4,271
	Smoke Detector Battery	234	6%	292
	H&S Appliance Replacement	8	<1%	22
	H&S Electrical	39	1%	39
	H&S Extermination	7	<1%	7
	H&S Heating System Replacement	2	<1%	2
	H&S Window Replacement	2	<1%	20
	H&S Electric Water Heating System Replacement	21	1%	21
	H&S Gas Water Heating System Replacement	42	1%	42
	Other Health and Safety*	37	1%	60
Electric Measure	LEDs	3,193	87%	36,295
	Refrigerator Replacement	239	7%	240
	Air Conditioner Replacement	846	23%	3,185
	AC Maintenance	6	<1%	6
	Power Strip	726	20%	1,341
	Freezer	4	<1%	4
Water Heating	Aerator	523	14%	776
	Showerhead	443	12%	511
	Water Heater Pipe Insulation	248	7%	248
	Water Heater Labor	158	4%	158
	Water Heater Part	145	4%	156
	Shower Valve	111	3%	132
	Electric Water Heater	34	1%	34
	Gas Water Heater	36	1%	36
	Heat Pump Water Heater	18	<1%	18

Measure Category	Measure	Number of Jobs	% of Jobs	Total Number
Insulation & Sealing	Air Sealing	263	7%	263
	Blower Door Test	130	4%	217
	Insulation	154	4%	154
	Weatherization	108	3%	108
	Duct/Pipe Insulation	78	2%	78
	Door Sweep/Weatherstripping	976	27%	2,033
	AC Sealing	122	3%	198
	Window Seal/Caulk	17	<1%	56
	Dryer Venting	39	1%	39
	Door/Lock	25	1%	35
	Direct Mail Weatherization Kit	18	<1%	1,570
Electrical	Electric Labor	57	2%	57
	Electric Part	54	1%	70
Thermostat	Line Voltage Thermostat	28	1%	98
	Manual Thermostat	2	<1%	2
	Programmable Thermostat	8	<1%	8
	Other Thermostat	65	2%	73
	SMART Thermostat	27	1%	28
Heating	Clean and Tune	119	3%	119
	Heating System Labor	401	11%	834
	Heating System Part	22	1%	25
	Electric Baseboard	15	<1%	26
	Gas Boiler	38	1%	38
	Furnace	44	1%	44
	Furnace Filter	50	1%	306
	Heat Pump	122	3%	122

* The measures that constitute this category are shown in Table III-7C

Table III-7B displays the measure installation rates by job type. The table shows that 30 percent of gas heat jobs and 31 percent of electric heat jobs received air sealing and that 13 percent of gas heat jobs and 23 percent of electric heat jobs received insulation.

Table III-7B
2022 LIURP Service Delivery
Measure Frequency by Job Type

Measure	All Participants			Analysis Group		
	Baseload	Electric Heat	Gas Heat	Baseload	Electric Heat	Gas Heat
Number of Customers	2,715	394	476	2,456	320	412
Carbon Monoxide Detector	51%	7%	50%	50%	8%	50%
Smoke Detector	54%	48%	68%	54%	47%	68%
Smoke Detector Battery	6%	4%	11%	7%	5%	10%
H&S Appliance Replacement	<1%	1%	<1%	<1%	1%	<1%
H&S Electrical	1%	4%	1%	1%	4%	1%
H&S Extermination	<1%	1%	<1%	<1%	0%	0%
H&S Heating System Replacement	<1%	0%	<1%	<1%	0%	<1%
H&S Window Replacement	0%	<1%	<1%	0%	<1%	0%
H&S Water Heating System Replacement	<1%	3%	<1%	<1%	3%	<1%
Other Health and Safety	<1%	5%	2%	<1%	5%	2%
LEDs	91%	83%	82%	91%	84%	83%
Refrigerator Replacement	6%	10%	9%	5%	9%	9%
Air Conditioner Replacement	25%	11%	25%	25%	10%	25%
AC Maintenance	0%	2%	0%	0%	2%	0%
Power Strip	20%	22%	20%	20%	22%	20%
Freezer	<1%	1%	0%	<1%	1%	0%
Aerator	7%	40%	37%	7%	39%	38%
Showerhead	8%	30%	25%	7%	28%	24%
Water Heater Pipe Insulation	3%	20%	21%	2%	20%	20%
Water Heater Labor	1%	9%	18%	1%	11%	17%
Water Heater Part	2%	14%	6%	2%	13%	6%
Shower Valve	2%	12%	4%	2%	10%	4%
Electric Water Heater	1%	4%	1%	1%	4%	<1%
Gas Water Heater	0%	1%	7%	0%	1%	6%
Heat Pump Water Heater	<1%	2%	<1%	<1%	1%	<1%
Air Sealing	<1%	31%	30%	<1%	31%	30%
Blower Door Test	0%	18%	13%	0%	18%	13%
Insulation	0%	23%	13%	0%	23%	14%
Weatherization	0%	12%	13%	0%	12%	13%
Duct/Pipe Insulation	0%	4%	13%	0%	4%	13%
Door Sweep/Weatherstripping	24%	40%	37%	23%	40%	37%

Measure	All Participants			Analysis Group		
	Baseload	Electric Heat	Gas Heat	Baseload	Electric Heat	Gas Heat
AC Sealing	2%	10%	8%	2%	10%	9%
Window Seal/Caulk	0%	3%	1%	0%	2%	1%
Dryer Venting	0%	2%	6%	0%	2%	6%
Door/Lock	0%	3%	3%	0%	4%	2%
Direct Mail Weatherization Kit	<1%	2%	<1%	<1%	1%	<1%
Electric Labor	<1%	11%	1%	<1%	11%	1%
Electric Part	<1%	11%	1%	<1%	11%	1%
Line Voltage Thermostat	<1%	6%	<1%	0%	7%	<1%
Manual Thermostat	0%	0%	<1%	0%	0%	<1%
Programmable Thermostat	<1%	1%	<1%	<1%	1%	<1%
Other Thermostat	0%	0%	14%	0%	0%	13%
SMART Thermostat	1%	0%	3%	1%	0%	2%
Clean and Tune	1%	<1%	18%	1%	<1%	19%
Heating System Labor	2%	32%	46%	2%	34%	44%
Heating System Part	<1%	1%	4%	<1%	1%	3%
Electric Baseboard	<1%	3%	<1%	0%	4%	<1%
Gas Boiler	<1%	0%	7%	<1%	0%	7%
Furnace	<1%	<1%	8%	<1%	<1%	8%
Furnace Filter	1%	1%	3%	1%	2%	3%
Heat Pump	0%	30%	<1%	0%	30%	<1%

Table III-7C shows that 60 jobs received health and safety measures. These included water heating, heating, and setback thermostats.

Table III-7C
Other Health and Safety Measures

Measure	Number of Jobs	% of Jobs	Total Number of Measures
Total Number of Measures	60		
H&S Materials	24	1%	24
H&S Labor	28	1%	29
Water Heating	2	<1%	2
Heating	5	<1%	5

Table III-7D displays the key measure installation rates for electric baseload jobs from 2012 through 2022. The table shows that the refrigerator replacement rate has declined since 2014. The average number of LEDs per job decreased from previous years to around 11 per home.

Table III-7D
2012-2022 LIURP Measure Frequency
Electric Baseload Jobs – All Customers

Measure	Electric Baseload – All Customers										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# Customers	5,475	6,163	6,159	6,688	5,029	5,639	4,782	5,823	2,902	2,095	2,715
Refrigerator Removal	<1%	<1%	<1%	0%	<1%	<1%	0%	0%	<1%	0%	0%
Refrigerator Replacement	9%	15%	27%	26%	22%	21%	20%	10%	4%	12%	6%
LEDs	86%	85%	79%	71%	79%	93%	94%	92%	90%	94%	91%
Average # LEDs	7.0	4.7	6.6	4.4	6.3	10.5	11.9	12.5	14.0	14.4	11.3

Table III-7E displays electric baseload measures for the analysis group. This table shows the same general trends as the full sample.

Table III-7E
2012-2022 LIURP Measure Frequency
Electric Baseload Jobs – Analysis Group

Measure	Electric Baseload – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# Customers	3,982	4,781	4,798	4,971	3,876	4,787	3,800	4,773	1,263	1,460	2,456
Refrigerator Removal	<1%	<1%	<1%	0%	<1%	<1%	0%	0%	0%	0%	0%
Refrigerator Replacement	10%	16%	25%	16%	18%	18%	18%	7%	1%	11%	5%
LEDs	86%	84%	79%	73%	81%	94%	95%	93%	93%	94%	91%
Avg. # LEDs	7.1	4.6	6.6	4.6	6.2	10.7	12.1	12.4	16.6	13.1	11.3

Table III-7F displays the key measure installation rates for electric heating jobs from 2012 through 2022. The percent of electric heating jobs with a blower door test increased from only 5 percent in 2021 to 18 percent in 2022. Insulation rates also increased to 23 percent from 17 percent in 2018 to 2021. Heat pump installations increased from four percent in 2020 to 21 percent in 2021 and to 30 percent in 2022.

Table III-7F
2012-2022 LIURP Measure Frequency
Electric Heating Jobs – All Customers

Measure	Electric Heating – All Customers										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	494	743	981	777	710	782	695	628	404	563	394
LEDs	82%	71%	67%	64%	59%	81%	88%	91%	84%	82%	83%
Refrigerator Removal	0%	0%	0%	0%	<1%	0%	0%	0%	0%	0%	0%
Refrigerator Replacement	6%	11%	21%	22%	19%	20%	19%	16%	11%	17%	10%
Blower Door	32%	30%	27%	20%	30%	24%	18%	16%	11%	5%	18%
Air Sealing*	48%	42%	45%	45%	56%	45%	28%	26%	23%	27%	31%
Duct/Pipe Insulation	3%	4%	5%	2%	3%	2%	5%	3%	6%	2%	4%
Weatherization	24%	21%	21%	17%	26%	14%	10%	11%	10%	10%	12%
Insulation	37%	29%	31%	23%	32%	18%	17%	17%	17%	17%	23%
Line Voltage Thermostat	30%	29%	29%	33%	25%	16%	14%	21%	12%	22%	6%
Heating System Labor	10%	9%	12%	16%	19%	23%	17%	25%	31%	29%	32%
Heating System Part	2%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Electric Baseboard	9%	10%	5%	5%	2%	1%	2%	4%	7%	7%	3%
Heat Pump	3%	4%	3%	3%	3%	4%	5%	5%	4%	21%	30%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7G shows similar trends for the electric heating analysis group.

Table III-7G
2012-2022 LIURP Measure Frequency
Electric Heating Jobs – Analysis Group

Measure	Electric Heating – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	309	485	593	373	367	501	384	378	113	362	320
LEDs	84%	71%	64%	67%	54%	82%	89%	91%	83%	82%	84%
Refrigerator Removal	0%	0%	0%	0%	<1%	0%	0%	0%	0%	0%	0%
Refrigerator Replacement	7%	11%	19%	12%	16%	17%	16%	11%	3%	17%	9%
Blower Door	34%	30%	28%	10%	19%	16%	10%	9%	7%	5%	18%
Air Sealing*	49%	41%	44%	31%	41%	36%	16%	17%	18%	26%	31%
Duct/Pipe Insulation	4%	4%	6%	1%	1%	1%	3%	2%	6%	2%	4%

Measure	Electric Heating – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Weatherization	22%	19%	21%	8%	16%	7%	6%	6%	10%	9%	12%
Insulation	37%	27%	32%	9%	23%	14%	10%	10%	13%	15%	23%
Line Voltage Thermostat	28%	27%	25%	24%	22%	15%	13%	20%	4%	23%	7%
Heating System Labor	12%	8%	11%	10%	13%	18%	10%	21%	17%	32%	34%
Heating System Part	2%	1%	2%	0%	0%	<1%	0%	<1%	0%	1%	1%
Electric Baseboard	8%	9%	4%	3%	2%	1%	1%	4%	4%	7%	4%
Heat Pump	4%	4%	3%	1%	1%	2%	3%	3%	2%	19%	30%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7H displays the key measure installation rates for gas heating jobs from 2012 through 2022. The percent of jobs receiving insulation and weatherization in 2022 was consistent with 2021 but lower than the historical average. Only seven percent of jobs received gas boilers in 2022, returning to the 2012-2020 average.

Table III-7H
2012-2022 LIURP Measure Frequency
Gas Heating Jobs – All Participants

Measure	Gas Heating – All Participants										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	1,282	1,623	1,222	1,303	1,624	1,188	1,359	1,347	254	389	476
Blower Door Test	60%	41%	40%	35%	35%	28%	20%	19%	17%	12%	13%
Air Sealing*	74%	57%	61%	64%	65%	51%	30%	35%	33%	30%	30%
Duct/Pipe Insulation	15%	13%	15%	12%	8%	5%	8%	8%	11%	8%	13%
Weatherization	41%	31%	32%	28%	29%	18%	11%	13%	14%	11%	13%
Insulation	46%	30%	35%	27%	26%	19%	14%	16%	21%	13%	13%
Heating System Labor	23%	17%	23%	28%	28%	23%	24%	34%	50%	47%	46%
Heating System Part	20%	13%	12%	8%	9%	8%	8%	7%	7%	5%	4%
Furnace	10%	4%	4%	5%	5%	5%	6%	4%	7%	5%	8%
Gas Boiler	7%	5%	4%	5%	7%	5%	6%	6%	9%	16%	7%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7I shows similar trends in installation rates for the gas heating analysis group.

Table III-7I
2012-2022 LIURP Measure Frequency
Gas Heating Jobs – Analysis Group

Measure	Gas Heating – Analysis Group										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
# of Customers	833	1,170	845	551	577	728	667	698	32	287	412
Blower Door Test	59%	38%	39%	25%	21%	20%	8%	13%	13%	10%	13%
Air Sealing*	74%	55%	58%	51%	50%	43%	13%	27%	19%	27%	30%
Duct/Pipe Insulation	15%	13%	12%	7%	4%	4%	3%	3%	9%	7%	13%
Weatherization	42%	30%	30%	15%	14%	13%	3%	8%	9%	9%	13%
Insulation	45%	30%	33%	15%	17%	16%	6%	11%	16%	10%	14%
Heating System Labor	22%	15%	17%	19%	18%	14%	13%	26%	31%	45%	44%
Heating System Part	21%	11%	7%	5%	5%	3%	3%	3%	9%	5%	3%
Furnace	10%	3%	3%	3%	2%	2%	2%	3%	9%	4%	8%
Gas Boiler	6%	4%	3%	2%	2%	2%	2%	4%	6%	17%	7%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7J displays the number of major measures installed in electric heating jobs from 2012 through 2022. Major electric measures include refrigerator replacement, freezer replacement, air conditioner replacement, water heater replacement, heat pumps, electric baseboards, insulation, and blower door guided air sealing. The percentage of electric heating jobs with no major measures was 43 percent in 2022, consistent with but much lower than the previous years.

Table III-7J
2012-2022 Number of Major Measures Installed
Electric Heating Jobs

# Maj. Meas.	Electric Heating Jobs										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Obs.	309	485	593	373	367	501	384	378	113	362	320
0	49%	51%	50%	73%	59%	64%	68%	66%	75%	47%	43%
1	17%	23%	21%	17%	21%	22%	20%	20%	13%	29%	28%
2	27%	18%	23%	8%	17%	10%	9%	11%	9%	17%	19%
3+	8%	8%	6%	1%	4%	4%	3%	3%	3%	7%	10%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table III-7K displays the number of major measures installed in gas heating jobs from 2012 through 2022. Major gas measures include furnace replacement, water heater replacement, insulation, and blower door guided air sealing. As with electric heating jobs, the percent of gas heating jobs without a major measure in 2022 was consistent with 2021 but lower than other recent years.

Table III-7K
2012-2022 Number of Major Measures Installed
Gas Heating Jobs

# Maj. Meas.	Gas Heating Jobs										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Obs.	833	1,170	845	552	577	728	667	698	32	287	412
0	27%	49%	49%	67%	68%	73%	84%	78%	75%	63%	66%
1	29%	25%	23%	18%	17%	15%	10%	11%	9%	26%	21%
2+	44%	26%	28%	15%	15%	12%	6%	11%	16%	11%	13%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

C. Home Characteristics

CMC collects detailed information on customers who receive LIURP services, which allows for an in-depth analysis of the homes treated by the Program. We first examine the weather-normalized pre-treatment usage of customers who received LIURP treatments. Table III-8 shows that customers who received baseload services had an average electric usage of 11,991 kWh, electric heating customers had an average usage of 20,838 kWh, and gas heating customers had an average gas usage of 1,204 ccf.

Table III-8
Pre-Treatment Weather Normalized Usage

Job Type	**Number of Jobs**	**Jobs with Usage Data**	**Average Electric Usage (kWh)**	**Average Gas Usage (ccf)**
Baseload	2,715	2,456	11,991	741[1]
Electric Heating	394	320	20,838	0[2]
Gas Heating	476	412	10,049[3]	1,204
Total Excluding Those Without LIURP Measures	3,585	3,118	12,642[4]	1,074[5]
No LIURP Measures	82	60	10,961	764
Total Including Those Without LIURP Measures	**3,667**	**3,248**	**12,612**	**1,072**

[1]There are 160 baseload jobs with gas usage. [2]There are no electric heating jobs with gas usage. [3]There are 395 gas heating jobs with electric usage. [4]There are 58 education-only jobs with electric usage. [5]There are only four education-only jobs which have gas usage.

Table III-9 displays the primary heating source for LIURP jobs by job type and overall. Approximately 83 percent of all homes served had utility gas as their primary heating source.[13] Five percent used fuel oil and 11 percent had electric heat. Among baseload jobs a higher proportion had utility gas as their primary heating (91 percent) and far fewer had electric heat (one percent).

Table III-9
Primary Heating Source

Primary Heating Source	Baseload		Electric Heat		Gas Heat		All Jobs	
	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs
Gas	2,539	91%	26	7%	469	98%	3,034	83%
Fuel Oil	195	7%	2	<1%	1	<1%	198	5%
Electric	35	1%	372	93%	8	2%	415	11%
Other	20	1%	0	0%	0	0%	20	1%
TOTAL	**2,789**	**100%**	**400**	**100%**	**478**	**100%**	**3,667**	**100%**

Table III-10 describes the use of supplemental heating by job type. Overall, 36 percent of the customers who were treated by LIURP used supplemental heat, nearly all of whom used electric supplemental heat. Thirty-five percent of the customers who had baseload services used electric supplemental heat.

Table III-10
Supplemental Heating

Supp. Heating Source	Baseload		Electric Heat		Gas Heat		All Jobs	
	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs
None Used	1,789	64%	269	67%	298	62%	2,356	64%
Electric	982	35%	124	31%	176	37%	1,282	35%
Other	18	1%	7	2%	4	1%	29	1%
TOTAL	**2,789**	**100%**	**400**	**100%**	**478**	**100%**	**3,667**	**100%**

[13] Some jobs classified as Electric Heat had a rate type of Gas Heat and vice versa. These jobs were reclassified based on their rate type.

Table III-11 displays the type of air conditioning that LIURP recipients used. The most common type, with 66 percent, was a window unit. Eighteen percent had central air conditioning.

Table III-11
Air Conditioning

Air Conditioning	Number of Jobs	% of Jobs
Window Unit	2,437	66%
Central	668	18%
Wall Unit	183	5%
Central Heat Pump	131	4%
Portable Unit	99	3%
None Used	149	4%
TOTAL	**3,667**	**100%**

Table III-12 shows the home ownership characteristics of LIURP recipients. This table shows that 33 percent of the LIURP recipients were renters. Renters are not eligible for refrigerator replacement, air conditioner replacement, or furnace replacement.

Table III-12
Home Ownership

	Number of Jobs	% of Jobs
Own	2,463	67%
Rent	1,204	33%
TOTAL	**3,667**	**100%**

Homes treated by LIURP were fairly old. The average age of homes treated was 87 years, and 75 percent were more than 75 years old.

Table III-13
Home Age

	Number of Jobs	% of Jobs
≤ 25 Years	108	3%
26 – 50 Years	177	5%
51 – 75 Years	645	18%
76 Years or Older	2,737	75%
TOTAL	**3,667**	**100%**
Mean	87	

Table III-14A displays the dwelling type for the homes served under LIURP. The most common type was a row home, constituting 80 percent of homes served. Thirteen percent lived in other types of single-family homes, and four percent lived in multi-family homes.

Table III-14A
Dwelling Type

	Number of Jobs	% of Jobs
Row	2,939	80%
Other Single Family	489	13%
Multi	136	4%
Duplex	76	2%
Mobile	21	1%
Other	6	<1%
TOTAL	**3,667**	**100%**

Table III-14B displays the housing structure type for the homes served under LIURP. The most common type was wood with a full basement and an open joist attic.

Table III-14B
Type of Housing Structure

	Number of Jobs	% of Jobs
Wood, full basement, open joist attic	3,161	86%
Block, concrete or log, slab foundation, open joist attic	121	3%
Wood, full basement, knee wall attic	105	3%
Wood, crawl space, open joist attic	77	2%
Mobile home, post foundation	51	1%
Wood, slab foundation, open joist attic	21	1%
Wood, crawl space/basement, open joist attic	15	<1%
Other	116	3%
TOTAL	**3,667**	**100%**

Table III-15 describes the heated square footage of the homes treated by LIURP. Homes averaged 1,351 square feet. Fifty-four percent of the homes were more than 1,200 square feet.

Table III-15
Heated Square Footage

	Number of Jobs	% of Jobs
≤ 800	191	5%
801 - 1,000	408	11%
1,001 - 1,200	1,105	30%
1,201 or More	1,963	54%
TOTAL	**3,667**	**100%**
Mean	1,351	

D. Participant Characteristics

The Program also captures detailed information on the characteristics of participating households. Table III-16 shows that 79 percent of the households were female-headed, 45 percent contained at least one child, and 34 percent contained at least one elderly member.

Table III-16
Household Composition

	Number of Jobs*	% of Jobs
Female Household Head	2,876	79%
Male Household Head	766	21%
Child in Household (<18)	1,647	45%
Elderly in Household (>62)	1,240	34%

*Twenty-five customers were missing information about gender. Twelve customers were missing information about children and elderly in the household.

Table III-17 shows that the mean annual household income was $13,432. More than a third of households served had an annual income at or below $10,000. Only 19 percent had an annual income above $20,000.

Table III-17
Annual Income

	Number of Jobs	% of Jobs
≤ $5,000	615	17%
$5,001 - $10,000	751	21%
$10,001 - $15,000	1,016	28%
$15,001 - $20,000	565	16%
$20,001 or More	696	19%
TOTAL	**3,643**	**100%**
Mean	$13,423	

*Twenty-four customers were missing income information.

Table III-18 displays the household poverty level. Approximately 33 percent of the households had income below 50 percent of the Federal Poverty Level (FPL) and approximately four percent had income above 150 percent of the FPL.

Table III-18
Poverty Level

	Number of Jobs	% of Jobs
≤ 25%	646	18%
26% - 50%	542	15%
51% - 100%	1,668	46%
101% - 150%	621	17%
151% - 175%	109	3%
176% - 200%	50	1%
TOTAL	**3,636***	**100%**
Mean	67%	

*Thirty-one customers were missing income information.

Table III-19 describes the account type of households who participated in the Program. Approximately 76 percent were CAP participants and nine percent were Customer Choice participants.

Table III-19
Account Type

	Number of Jobs	% of Jobs
Jobs with Data	3,666	
CAP	2,787	76%
Customer Choice	318	9%

*One customer was missing data on CAP Enrollment and Customer Choice status.

Table III-20 displays the education level of the head of household. The majority of participants, 68 percent, had a high school education. Three percent had some high school, 17 percent had some college, and 11 percent had a college degree or higher.

Table III-20
Education Level

	Number of Jobs	% of Jobs
No Formal Education	10	<1%
Some Grade School	27	1%
Grade School	31	1%
Some High School	121	3%
High School	2,459	68%
Some College	602	17%
College Degree	285	8%
Some Graduate Work	5	<1%
Graduate Degree	102	3%
TOTAL	**3,642***	**100%**

*Twenty-five customers were missing education level information.

Table III-21 displays the primary income source for the LIURP participants. The table shows that the most common sources of income were work, public assistance, and pension or retirement. Thirty-four percent had full-time work as their primary source of income, 19 percent had public assistance, 14 percent had pension and/or retirement, ten percent had part-time work, and seven percent were dependent on another.

Table III-21
Income Source

	Number of Jobs	% of Jobs
Full Time	1,224	34%
Public Assistance	706	19%
Pension/Retirement	513	14%
Part-Time Work	353	10%
Dependent on Another	251	7%
Self-Employment	55	2%
Seasonal Employment	1	<1%
Other	540	15%
TOTAL	**3,643***	**100%**

*Twenty-four customers were missing income source information.

IV. Usage Impacts

This section of the report provides analysis of the impacts of LIURP on participants' annual electric and gas usage. The section describes the methodology for the analysis, the results for all participants by job type, and the results by type of service. We then provide estimates of the impacts of individual measures and the cost-effectiveness of LIURP.

A. Methodology

Customers who received LIURP services in 2022 were treated as the analysis group for this evaluation. We focus on the electric impacts for customers who were treated as electric baseload and electric heating jobs, and the gas impacts for customers who were treated as gas heating jobs, but we also analyze changes in the other fuel's usage.

Energy usage was analyzed for the year prior to the LIURP audit visit and the year after service delivery was completed. The analysis included as close to a full year of data pre- and post-treatment as possible. Table IV-1A displays the attrition statistics for the usage analysis. Customers were included in the analysis if their pre- and post-usage data each spanned between 270 and 390 days. Some additional customers were removed from the analysis if their usage was below 1,200 kWh or 300 ccf, or if their change in usage was greater than 65 percent. After these eliminations, we included 90 percent of the treated baseload households in the usage analysis, 81 percent of the treated electric heating households, and 87 percent of the treated gas heating households.

Table IV-1A
Usage Impact Data Attrition

	Electric Baseload	Electric Heating	Gas Heating	Education Only
Original Population*	2,715	394	476	82
Not Enough Pre-Treatment Days	20	13	8	1
Not Enough Post-Treatment Days	167	43	36	8
All Estimated Reads in Pre or Post	4	0	2	0
Pre-Usage Below 1200 kWh or 300 ccf	0	0	2	0
Post-Usage Below 1200 kWh or 300 ccf	2	0	2	0
Change in Total Usage>65%	55	3	7	3
Additional Outliers	11	15	7	10
Final Sample	2,456	320	412	60
% Included in Analysis	**90%**	**81%**	**87%**	**73%**

*As Program data did not furnish rate types (electric or gas), only the customers with usage data were included in the number of original populations for Education Only groups.

Table IV-1B displays the attrition for the comparison group of 2022 participants. Between 72 and 77 percent of these comparison group customers were included in the final analysis.

Table IV-1B
Comparison Group Data Attrition

	Electric Baseload	Electric Heating	Gas Heating
Original Population	3,813	416	371
Not Enough Pre-Treatment Days	463	64	57
Not Enough Post-Treatment Days	243	16	24
All Estimated Reads in Pre or Post	3	2	0
Pre-Usage Below 1200 kWh or 300 ccf	1	2	1
Post-Usage Below 1200 kWh or 300 ccf	0	0	0
Change in Total Usage>65%	149	24	3
Additional Outliers	25	9	6
Final Sample	2,929	299	280
% Included in Analysis	**77%**	**72%**	**75%**

Energy usage data were weather normalized in the pre- and the post-usage period to ensure that changes in energy usage were due to changes in usage patterns, rather than due to changes in weather. We used a degree-day normalization process to conduct this analysis. This process involved the following steps.

1. Calculate the heating and cooling degree-days that are included in each usage period.

2. Determine whether periods should be classified as baseload periods, heating periods, or cooling periods, based on the number of usage and heating and cooling degree-days in the period.

3. Calculate the total baseload period usage, heating period usage, and cooling period usage.

4. Calculate the relationship between heating usage minus baseload usage and degree- days. Use that slope and the average long-term heating degree-days to calculate normalized heating period usage.

5. Follow the same method to calculate normalized cooling period usage.

6. Add up the baseload usage, heating period usage, and cooling period usage to obtain the normalized annual usage.

For comparison, we also produced weather normalized results using PRISM analysis. We discuss differences between the degree day and PRISM results in the following section. The degree-day approach allowed for a higher percentage of cases to be included, due to fewer restrictions on data availability and the fact that cases did not need to be removed because the model did not run, or the model had a poor fit.

While the PUC does not require that baseload usage is normalized, we conducted the normalization process on the baseload usage as well as the heating and cooling usage. Baseload usage may vary with weather because of the use of air conditioning, the gas furnace's electric fan, the refrigerator, and use of electric space heaters.

B. Energy Savings Impacts

This section provides the average weather-normalized usage for the pre- and post-treatment periods and the average energy savings. Table IV-2A displays these results by job type.

The table shows the following degree-day normalized savings.

- Baseload jobs had average annual savings of approximately 847 kWh, or 7.1 percent of pre-treatment usage. Baseload jobs also had a 26 ccf decrease in gas usage, or 3.4 percent of pre-treatment usage.

- Electric heat jobs had average annual savings of approximately 2,192 kWh, or 10.5 percent of pre-treatment usage. (All electric heat jobs had low gas usage and were dropped from the analysis.)

- Gas heat jobs had savings of 88 ccf, or 7.2 percent of pre-treatment usage. Gas heat jobs also had electric savings of 693 kWh, or 6.9 percent of pre-treatment usage.

Table IV-2A
Average Annual Usage and Saving

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
Electric Baseload (kWh)									
Non-Normalized	2,456	11,616	10,680	937***	8.1%	854	7.3%	83	0.7%
Degree Day Normalized	2,456	11,991	11,144	847***	7.1%	764	6.4%	83	0.7%
Degree Day-PRISM cases	2,412	12,019	11,150	869***	7.2%	786	6.5%	83	0.7%
PRISM Normalized	2,412	11,922	11,120	802***	6.7%	719	6.0%	83	0.7%
Electric Heat (kWh)									
Non-Normalized	320	19,630	17,100	2,530***	12.9%	2,458	12.5%	72	0.4%
Degree Day Normalized	320	20,838	18,646	2,192***	10.5%	2120	10.2%	72	0.3%
PRISM Normalized	320	20,755	19,039	1,716***	8.3%	1644	7.9%	72	0.3%
Gas Heat (ccf)									
Non-Normalized	412	1,122	969	153***	13.7%	153	13.7%	0	0.0%
Degree Day Normalized	412	1,214	1,126	88***	7.2%	88	7.2%	0	0.0%
Degree Day-PRISM cases	409	1,216	1,127	89***	7.3%	89	7.3%	0	0.0%

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
PRISM Normalized	409	1,192	1,122	70***	5.9%	70	5.9%	0	0.0%
Gas Heat (kWh)									
Non-Normalized	395	9,726	9,152	574***	5.9%	484	5.0%	90	0.9%
Degree Day Normalized	395	10,049	9,355	693***	6.9%	603	6.0%	90	0.9%
Degree Day-PRISM cases	385	10,045	9,367	677***	6.7%	587	5.8%	90	0.9%
PRISM Normalized	385	9,859	9,385	474***	4.8%	384	3.9%	90	0.9%
Electric Baseload (ccf)									
Non-Normalized	160	687	636	50***	7.3%	50	7.3%	0	0.0%
Degree Day Normalized	160	748	722	26***	3.4%	26	3.5%	0	0.0%
Degree Day-PRISM cases	156	754	724	31***	4.1%	31	4.1%	0	0.0%
PRISM Normalized	156	750	731	19**	2.5%	19	2.5%	0	0.0%
Education Only (kWh)									
Non-Normalized	58	10,811	10,220	591***	5.5%	591	5.5%	0	0.0%
Degree Day Normalized	58	10,961	10,592	369*	3.4%	369	3.4%	0	0.0%
Degree Day-PRISM cases	56	11,051	10,732	319	2.9%	319	2.9%	0	0.0%
PRISM Normalized	56	10,870	10,668	202	1.9%	202	1.9%	0	0.0%
Education Only (ccf)									
Non-Normalized	4	707	635	73	10.3%	73	10.3%	0	0.0%
Degree Day Normalized	4	767	751	15	2.0%	15	2.0%	0	0.0%
PRISM Normalized	4	759	765	-6	-0.8%	-6	-0.8%	0	0.00%

Note: All Electric Heat (kWh), and Education Only (ccf) accounts survived PRISM attrition, thus the lack of a "Degree Day-PRISM cases" row. Additionally, usage for Electric Heat (ccf) accounts were not displayed in this table because all such accounts were dropped from the analysis for low usage.

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table IV-2B uses the comparison group of later LIURP participants to control for the impact of other factors exogenous to LIURP that may have impacted usage. The comparison group adjustment increased savings slightly for electric baseload, electric heating, and gas heat main fuel impacts. The comparison group adjustment reduced savings for electric use of gas heating jobs and gas use of electric baseload jobs.

Table IV-2B
Average Annual Usage and Savings
With Comparison Group

	Treatment Group Savings					Comparison Group Savings					Net Savings	
	#	Usage		Annual Savings		#	Usage		Annual Savings			
		Pre	Post	kWh/ccf	%		Pre	Post	kWh/ccf	%	kWh/ccf	%
Elec BL (kWh)	2,456	11,991	11,144	847***	7.1%	2,929	11,412	11,595	-183***	-1.6%	1030***	8.6%
Elec Heat (kWh)	320	20,838	18,646	2,192***	10.5%	299	22,423	22,649	-227	-1.0%	2419***	11.6%
Gas Heat (ccf)	412	1,214	1,126	88***	7.2%	280	1,402	1,409	-7	-0.5%	95***	7.8%
Gas Heat (kWh)	395	10,049	9,355	693***	6.9%	262	9,659	9,496	163	1.7%	530***	5.3%
Elec BL (ccf)	160	748	722	26***	3.4%	233	760	737	24***	3.1%	2	0.2%

***Denotes significance at the 99 percent level.

Table IV-2C displays average heating and cooling degree days in the pre- and post-treatment usage periods for the 2022 LIURP participants, compared to the 20-year average that was used in the normalization process. The table shows that the post-treatment heating degree days were fifteen to eighteen percent lower than the pre-treatment heating degree days for all job types. The table also shows a decrease in the number of cooling degree days for all job types.

Table IV-2C
Average Heating and Cooling Degree Days
Relative to 20-year Average

Job Type	#	Pre-CDD	Post-CDD	CDD Difference		Pre-HDD	Post-HDD	HDD Difference	
				#	%			#	%
Electric Baseload	2,456	905	818	-87***	-10%	3,981	3,397	-584***	-15%
Electric Heat	320	897	814	-84***	-9%	3,939	3,391	-547***	-14%
Gas Heat	412	888	868	-20**	-2%	4,041	3,329	-712***	-18%
Education Only (kWh)	58	947	803	-145***	-15%	3,960	3,378	-582***	-15%
Education Only (ccf)	4	917	745	-172	-19%	3,940	3,226	-714	-18%
20-Year Average (2004-2023)		843				4,304			

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.

Another important factor in estimating energy savings is the degree to which the final analysis group, with enough usage data to include in the results, is comparable to the full population of treated households. In 2022, the analysis group was similar to the overall treatment group in terms of the number of major measures installed. The following tables show that when adjusting for differences between the treatment group and the analysis group there is no substantial change in the net savings.

Table IV-2D shows that the analysis group is representative of the overall treatment group for electric baseload customers with major measures. Twenty-nine percent of all electric baseload jobs and the electric baseload analysis group received a major measure. Since the proportions between the analysis group and all customers are identical, the weighted savings of 847 kWh and 7.1 percent are also identical to the unweighted savings. We found that the weighted net savings estimate of 1,030 kWh, or 8.6 percent of pre-treatment usage, was also identical to the unweighted net savings. This is our best estimate of savings for the electric baseload jobs.

Table IV-2D
Electric Baseload Savings
By Level of Service

Savings Estimate	Measure Type	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	kWh	%	kWh	%	kWh	%
Gross Savings	Basic	1,924	71%	1,742	71%	758***	6.4%	847	7.1%	847	7.1%
	Major	791	29%	714	29%	1,065***	8.8%				
Net Savings								1,030	8.6%	1,030	8.6%

***Denotes significance at the 99 percent level.

Table IV-2E shows that the analysis group is representative of the overall treatment group for electric heating customers with major measures. While 29 percent of all electric heating jobs had one major measure and 29 percent had two or more major measures, 28 percent of the electric heating analysis group had one major measure and 29 percent had two or more major measures. When accounting for this slight difference, the savings estimate increases from 2,192 kWh, or 10.5 percent, to 2,210 kWh, or 10.6 percent.

We adjusted the net savings by the same percentage to develop a comparison group adjusted, weighted savings estimate of 2,439 kWh, or 11.7 percent of pre-treatment usage. This is our best estimate of savings for the electric heating jobs.

Table IV-2E
Electric Heating Customers Savings
By Number of Major Measures

Savings Estimate	Number of Major Measures	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	kWh	%	kWh	%	kWh	%
Gross Savings	0	163	42%	138	43%	1,258***	6.1%	2,192	10.5%	2,210	10.6%
	1	116	29%	89	28%	2,877***	13.8%				
	2 or More	115	29%	93	29%	2,922***	13.6%				
Net Savings								2,419	11.6%	2,439	11.7%

***Denotes significance at the 99 percent level.

Table IV-2F shows that the analysis group is representative of the overall treatment group for gas heating customers with major measures. While 21 percent of all gas heating jobs had one major measure and 12 percent had two or more major measures, 21 percent of the gas heating analysis group had one major measure and 13 percent had two or more major measures. Accounting for this change does not change the savings estimate of 88 ccf or 7.2 percent.

We adjusted the net savings by the same percentage to develop a comparison group adjusted, weighted savings estimate of 95 ccf or 7.8 percent of pre-treatment usage. This is our best estimate of savings for the gas heating jobs.

Table IV-2F
Gas Heating Customers Savings
By Number of Major Measures

Savings Estimate	Number of Major Measures	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	ccf	%	ccf	%	ccf	%
Gross Savings	0	316	67%	273	66%	70***	5.7%	88	7.2%	88	7.2%
	1	101	21%	86	21%	103***	8.8%				
	2 or More	59	12%	53	13%	153***	13.3%				
Net Savings								95	7.8%	95	7.8%

***Denotes significance at the 99 percent level.

The rest of the report focuses on the degree day normalized savings. Tables IV-3A, 3B, and 3C provide the historical comparison of energy savings by job type.

Table IV-3A displays historical savings of electric baseload jobs. The table shows that the 2022 jobs had percentage savings that were lower than the 2000-2021 average savings. Savings were 7.1 percent in 2022 compared to the historical average of 7.8 percent (not accounting for the comparison group change). However, the average annual household savings of 847 kWh were higher than the historical average of 831 kWh and significantly higher than electric savings in recent years. The 2022 jobs had pre-treatment usage that was about 12 percent higher than the historical average and spending that was more than double the historical average (some due to inflation), both of which should lead to greater savings.

Table IV-3A
Time-Series Comparison of Annual Usage and Savings
Electric Baseload Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**11,991**	**11,144**	**847**	**7.1%**	**$487**
2000-2021 Average	**10,734**	**9,903**	**831**	**7.8%**	**$221**
2021	12,543	11,642	900	7.2%	$466
2020	11,394	11,190	203	1.8%	$295
2019	10,399	9,760	640	6.2%	$128
2018	10,010	9,336	674	6.7%	$223
2017	10,508	9,888	620	5.9%	$184
2016	10,557	9,885	673	6.4%	$213
2015	10,035	9,226	809	8.1%	$173
2014	9,969	9,120	849	8.5%	$161
2013	10,707	9,877	830	7.7%	$182
2012	11,461	10,911	550	4.8%	$161
2011	10,758	10,148	610	5.7%	$258
2010	11,370	10,147	1,223	10.8%	$201
2009	12,144	11,090	1,054	8.7%	$186
2008	10,990	10,276	714	6.5%	$191
2007	10,919	10,032	887	8.1%	$240
2006	10,695	9,953	742	6.9%	$214
2005	11,188	10,073	1,115	10.0%	$208
2004	9,309	8,384	925	9.9%	$215
2003	10,040	8,679	1,361	13.6%	$214
2002	10,591	9,687	904	8.5%	$192
2001	10,821	9,722	1,099	10.2%	$296
2000	9,741	8,843	898	9.2%	$268

Table IV-3B displays historical savings of electric heating jobs. The table shows that the 2022 jobs had savings that were higher than the 2000-2021 average. Savings were 10.5 percent in 2022 compared to the historical average of seven percent (not accounting for the comparison group change). The electric heating pre-treatment usage was higher than in the past, averaging 20,838 kWh, compared to the historical average of 20,182 kWh. Moreover, the cost of measures was more than double the historical average, however this is at least partly due to inflation.

Table IV-3B
Time-Series Comparison of Annual Usage and Savings
Electric Heating Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**20,838**	**18,646**	**2,192**	**10.5%**	**$4,057**
2000-2021 Average	**20,182**	**18,756**	**1,426**	**7.0%**	**$1,659**
2021	20,771	19,936	835	4.0%	$3,423
2020	21,319	20,477	842	4.0%	$1,809
2019	18,909	17,928	981	5.2%	$1,131
2018	16,041	15,064	977	6.1%	$772
2017	15,920	15,152	767	4.8%	$831
2016	17,180	16,182	998	5.8%	$991
2015	14,760	13,653	1,106	7.5%	$622
2014	16,263	15,150	1,113	6.8%	$1,301
2013	21,350	19,416	1,934	9.1%	$1,310
2012	20,700	19,465	1,235	6.0%	$1,430
2011	19,402	17,899	1,503	7.7%	$1,798
2010	19,662	18,534	1,128	5.7%	$2,094
2009	23,179	21,493	1,686	7.3%	$2,514
2008	20,786	18,614	2,172	10.4%	$2,332
2007	21,017	19,888	1,129	5.4%	$1,735
2006	21,890	20,458	1,433	6.5%	$1,643
2005	21,956	20,326	1,629	7.4%	$1,824
2004	23,449	21,148	2,301	9.8%	$1,782
2003	22,510	20,220	2,290	10.2%	$1,646
2002	22,745	21,441	1,304	5.7%	$1,753
2001	22,825	20,469	2,356	10.3%	$2,234
2000	21,368	19,724	1,644	7.7%	$1,521

Table IV-3C displays historical savings for gas heating jobs. The table shows that the 2022 gas heating jobs had savings that were in line with the 2000-2021 average. Savings were 7.2 percent in 2022, equal to the historical average of 7.2 percent (not accounting for the comparison group change). Pre-treatment usage in 2022 was about 10 percent higher than the historical average and spending in 2022 was slightly less than double the historical average, again partly due to inflation.

Table IV-3C
Time-Series Comparison of Annual Usage and Savings
Gas Heating Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**1,214**	**1,126**	**88**	**7.2%**	**$3,357**
2000-2021 Average	**1,093**	**1,011**	**82**	**7.2%**	**$1,732**
2021	1,195	1,172	23	1.9%	$3,864
2020	1,262	1,202	60	4.7%	$3,107
2019	1,025	975	51	4.9%	$1,233
2018	904	888	16	1.8%	$666
2017	968	944	24	2.5%	$912
2016	944	914	31	3.3%	$918
2015	977	946	31	3.2%	$934
2014	906	879	27	2.9%	$1,117
2013	1,022	945	77	7.5%	$1,086
2012	989	924	65	6.6%	$1,820
2011	1,025	959	67	6.5%	$2,410
2010	1,052	991	61	5.8%	$2,253
2009	1,090	998	92	8.4%	$2,100
2008	1,087	984	103	9.5%	$2,016
2007	1,054	965	89	8.4%	$1,914
2006	1,128	1,037	91	8.0%	$1,640
2005	1,206	1,039	168	13.9%	$1,643
2004	1,205	1,037	168	13.9%	$1,789
2003	1,227	1,086	141	11.5%	$1,422
2002	1,253	1,159	94	7.5%	$1,488
2001	1,262	1,097	165	13.1%	$2,003
2000	1,265	1,106	159	12.6%	$1,763

Table IV-4 displays the seasonal analysis of energy savings by job type. The table shows that jobs achieved savings from baseload, heating, and cooling usage across all job types, with the exception of education only.

Table IV-4
Seasonal Usage Analysis

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Share of Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Baseload	2,456	7,338	6,886	452***	6.2%	53.4%	369	5.0%	83	1.1%
Heating		2,426	2,310	117***	4.8%	13.8%	117	4.8%	0	0.0%
Cooling		2,226	1,948	278***	12.5%	32.8%	278	12.5%	0	0.0%
Electric Heating (kWh)										
Baseload	320	8,871	8,294	577***	6.5%	26.3%	505	5.7%	72	0.8%
Heating		10,732	9,231	1,501***	14.0%	68.5%	1501	14.0%	0	0.0%
Cooling		1,235	1,121	114**	9.2%	5.2%	114	9.2%	0	0.0%
Gas Heat (ccf)										
Baseload	412	211	187	24***	11.3%	27.4%	24	11.3%	0	0.0%
Heating		982	918	63***	6.5%	72.6%	63	6.5%	0	0.0%
Education Only (kWh)										
Baseload	58	6,783	6,815	-33	0%	0%	-33	0.00%	0	0.0%
Heating		2,006	1,718	288*	14.3%	71.6%	288	14.3%	0	0.0%
Cooling		2,172	2,058	114	5.3%	28.4%	114	5.3%	0	0.0%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.

Energy efficiency program savings are often found to correlate with the level of pre-treatment usage. This is because households with higher pre-treatment usage have greater opportunities for energy savings and often receive greater energy efficiency investments. Table IV-5 shows that the 2022 savings were generally consistent with this expectation.

- Baseload jobs with pre-treatment usage over 12,000 kWh had savings of 9.6 percent, compared to savings of 4.6 percent for baseload jobs with pre-treatment usage between 8,000 and 12,000 kWh.

- Electric heat jobs with pre-treatment usage over 26,000 kWh had average savings of 9.2 percent, while those jobs with pre-treatment usage between 16,000 and 26,000 kWh had savings of 11.2 percent, and jobs with usage below 16,000 kWh had savings of 10.8 percent. However the electric heat jobs with the highest pre-treatment usage had the highest kWh savings.

- Gas heat jobs with pre-treatment usage over 1,400 ccf saved an average of 175 ccf or 10.2 percent, those with pre-treatment usage between 800 and 1,400 ccf saved an average of 6.5 percent, and those with pre-treatment usage below 800 ccf had an increase in usage.

Table IV-5
Change in Annual Usage
By Pre-Program Usage

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
< 8,000 kWh	426	7,079	6,953	126*	1.8%	$412	41	0.6%	85	1.2%
8,000 – 12,000 kWh	1,023	9,781	9,336	446***	4.6%	$420	362	3.7%	84	0.9%
> 12,000 kWh	1,007	16,313	14,753	1,560***	9.6%	$588	1,478	9.1%	82	0.5%
Electric Heat (kWh)										
< 16,000 kWh	83	12,912	11,512	1,400***	10.8%	$3,174	1,327	10.3%	73	0.6%
16,000 – 26,000 kWh	171	20,642	18,336	2,306***	11.2%	$4,403	2,235	10.8%	71	0.3%
> 26,000 kWh	66	31,315	28,423	2,893***	9.2%	$4,233	2,820	9.0%	73	0.2%
Gas Heat[1] (ccf)										
< 800 ccf	52	725	732	-7	-1.0%	$2,329	-7	-1.0%	0	0.0%
800 – 1,400 ccf	257	1,112	1,039	72***	6.5%	$3,012	72	6.5%	0	0.0%
> 1,400 ccf	103	1,715	1,540	175***	10.2%	$3,125	175	10.2%	0	0.0%

***Denotes significance at the 99 percent level. * Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-6 displays usage impacts by job type and by whether the household participated in CAP in the pre- or post-treatment period. Electric baseload savings were 741 kWh for CAP participants compared to 1,132 kWh for non-CAP participants. Gas heating savings were similarly higher for the non-CAP participants.

Table IV-6
Change in Annual Usage
By CAP Participation

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
CAP	1,792	12,172	11,431	741***	6.1%	$477	663	5.4%	78	0.6%
Non-CAP	664	11,501	10,369	1,132***	9.8%	$517	1,035	9.0%	97	0.8%
Electric Heat (kWh)										
CAP	237	21,275	19,084	2,191***	10.3%	$4,460	2,126	10.0%	65	0.3%
Non-CAP	83	19,591	17,395	2,196***	11.2%	$2,869	2,106	10.8%	90	0.5%
Gas Heat[1] (ccf)										
CAP	252	1,203	1,154	50***	4.1%	$2,587	50	4.1%	0	0.0%
Non-CAP	160	1,230	1,082	147***	12.0%	$3,531	147	12.0%	0	0.0%
Education Only (kWh)										
CAP	42	11,063	10,760	303	2.7%	--	303	2.7%	0	0.0%
Non-CAP	16	10,693	10,151	542	5.1%	--	542	5.1%	0	0.0%

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-7 displays the change in usage by whether the customer had selected an alternate supplier in the pre or post period. Only a small percentage of customers had an alternate supplier. Electric baseload customers with an alternate supplier had significantly higher savings than those who did not and electric heating customers with an alternate supplier had lower savings.

Table IV-7
Change in Annual Usage
By Customer Choice

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Choice	165	11,588	10,416	1,172***	10.1%	$705	1,059	9.1%	113	1.0%
Non-Choice	2,291	12,020	11,196	824***	6.9%	$472	743	6.2%	81	0.7%
Electric Heat (kWh)										
Choice	20	19,764	18,316	1,448*	7.3%	$4,481	1,059	9.1%	113	1.0%
Non-Choice	300	20,910	18,668	2,242***	10.7%	$4,029	743	6.2%	81	0.7%
Gas Heat (ccf)										
Choice	74	1,252	1,122	130***	10.4%	$3,362	130	10.4%	0	0.0%
Non-Choice	338	1,205	1,127	79***	6.5%	$2,864	79	6.5%	0	0.0%
Education Only (kWh)										
Choice	2	8,660	6,867	1,793	20.7%	--	1,793	20.7%	0	0.0%
Non-Choice	56	11,043	10,725	318	2.9%	--	318	2.9%	0	0.0%

***Denotes significance at the 99 percent level.

Table IV-8 displays the change in usage by home ownership status. Owners had higher savings and measure costs than renters.

Table IV-8
Change in Annual Usage
By Home Ownership

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Owner	1,702	11,974	11,038	937***	7.8%	$562	852	7.1%	85	0.7%
Renter	754	12,028	11,384	645***	5.4%	$320	566	4.7%	79	0.7%
Electric Heat (kWh)										
Owner	177	21,423	18,750	2,673***	12.5%	$5,695	2591	12.1%	82	0.4%
Renter	143	20,115	18,518	1,597***	7.9%	$2,050	1538	7.6%	59	0.3%
Gas Heat[1] (ccf)										
Owner	308	1,218	1,120	98***	8.0%	$3,401	98	8.0%	0	0.0%
Renter	104	1,200	1,142	58***	4.9%	$1,630	58	4.9%	0	0.0%
Education Only (kWh)										
Owner	40	11,083	10,600	483*	4.4%	--	483	4.4%	0	0.0%
Renter	18	10,690	10,574	116	1.1%	--	116	1.1%	0	0.0%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-9 displays energy savings by whether the customer used supplemental heat. Average savings for electric baseload customers with supplemental heat were 8.7 percent, compared to six percent for baseload jobs without supplemental heat. Conversely, average savings for electric heating jobs with supplemental heat were 9.9 percent, compared to 10.8 percent for those without supplemental heat. Electric savings for gas heating jobs with supplemental heat were 10.1 percent compared to savings of 4.7 percent for those without supplemental heating.

Table IV-9
Change in Annual Usage
By Supplemental Heat

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Supplemental Heat	864	13,305	12,144	1,161***	8.7%	$590	1,077	8.1%	84	0.6%
No Supp Heat	1,592	11,278	10,601	677***	6.0%	$432	594	5.3%	83	0.7%
Electric Heat (kWh)										
Supplemental Heat	103	21,004	18,931	2,073***	9.9%	$4,331	1988	9.5%	85	0.4%
No Supp Heat	217	20,760	18,511	2,249***	10.8%	$3,928	2183	10.5%	66	0.3%
Gas Heat[1] (ccf)										
Supplemental Heat	148	1,236	1,158	78***	6.3%	$3,308	78	6.3%	0	0.0%
No Supp Heat	264	1,201	1,108	93***	7.7%	$2,755	93	7.7%	0	0.0%
Gas Heat[2] (kWh)										
Supplemental Heat	138	11,961	10,758	1,203***	10.1%	$3,052	1124	9.4%	79	0.7%
No Supp Heat	257	9,022	8,602	420***	4.7%	$2,737	324	3.6%	96	1.1%
Electric Baseload (ccf)										
Supplemental Heat	48	763	734	28	3.7%	$1,448	28	3.7%	0	0.0%
No Supp Heat	112	742	717	24**	3.3%	$746	24	3.2%	0	0.0%
Education Only (kWh)										
Supplemental Heat	13	13,182	12,397	784*	5.9%	--	784	5.9%	0	0.0%
No Supp Heat	45	10,320	10,070	249	2.4%	--	249	2.4%	0	0.0%
Education Only (ccf)										
Supplemental Heat	1	841	845	-4	-0.5%	--	-4	-0.5%	0	0.0%
No Supp Heat	3	742	720	22	2.9%	--	22	2.9%	0	0.0%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs (ccf) exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

C. Measure Specific Savings

This section attributes savings to specific measures that were provided through LIURP. We begin by analyzing savings by whether major measures were provided. Major measures are defined as the following.

- Baseload Jobs: Major measures include refrigerator replacement, freezer replacement, air conditioner replacement, and water heater replacement.

- Electric Heat Jobs: Major measures include refrigerator replacement, freezer replacement, air conditioner replacement, water heater replacement, heat pumps, electric baseboards, insulation, and blower door guided air sealing.

- Gas Heat Jobs – Gas Measures: Major measures include furnace replacement, water heater replacement, insulation, and blower door guided air sealing.

- Gas Heat Jobs – Electric Measures: Major measures include refrigerator replacement, freezer replacement, and air conditioner replacement.

Homes that did not receive one of the major measures listed above were considered to have basic measures.

Table IV-10 displays energy savings by whether the job received one or more major measures.

- Baseload Jobs – Electric Savings: Savings for baseload jobs with major measures averaged 8.8 percent, compared to savings that averaged 6.4 percent for baseload jobs that did not receive major measures.

- Electric Heat Jobs: Savings for jobs that received major measures averaged 13.7 percent, compared to average savings of 6.1 percent for jobs that did not receive major measures. Spending on jobs that received major measures averaged $6,570, compared to average spending of $644 for jobs that did not receive major measures.

- Gas Heat Jobs – Gas Measures: Gas savings for jobs with major measures averaged 10.5 percent, compared to average savings of 5.7 percent for jobs that did not receive major measures. Costs for gas jobs with major measures averaged $7,119 compared to average costs of $833 for jobs that did not receive major measures.

- Gas Heat Jobs – Electric Measures: Savings for jobs that received major measures averaged 8.9 percent, compared to average savings of six percent for jobs that did not receive major measures. Costs for gas heat jobs that received major electric measures averaged $1,230 compared to average costs of $22 for jobs that did not receive major measures.

- Baseload Jobs – Gas Savings: Savings for jobs that received major measures averaged 3.3 percent, compared to an average savings of 3.5 percent for jobs that did not receive major measures.

Table IV-10
Change in Annual Usage
By Level of Service

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Basic	1,742	11,917	11,159	758***	6.4%	$135	675	5.7%	83	0.7%
Major	714	12,171	11,106	1,065***	8.8%	$1,347	981	8.1%	84	0.7%
Electric Heat (kWh)										
Basic	138	20,474	19,216	1,258***	6.1%	$644	1,188	5.8%	70	0.3%
Major	182	21,114	18,214	2,900***	13.7%	$6,570	2,827	13.4%	73	0.3%
Gas Heat[1] (ccf)										
Basic	273	1,239	1,169	70***	5.7%	$833	70	5.7%	0	0.0%
Major	139	1,164	1,042	122***	10.5%	$7,119	122	10.5%	0	0.0%
Gas Heat[2] (kWh)										
Basic	271	10,103	9,498	605***	6.0%	$22	514	5.1%	91	0.9%
Major	124	9,931	9,044	887***	8.9%	$1,230	800	8.1%	87	0.9%
Electric Baseload (ccf)										
Basic	129	739	713	26***	3.5%	$841	26	3.5%	0	0.0%
Major	31	786	761	26	3.3%	$1,439	26	3.3%	0	0.0%

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

Table IV-11A displays savings for electric heat jobs by the number of major measures installed. The table shows that customers who received one or more major measures had higher pre-treatment usage and higher savings than customers who received no major measures. However, customers who received two or more major measures had approximately the same average savings as those with one major measure, despite having 80 percent higher measure costs.

Table IV-11A
Change in Annual Electric Heat Usage (kWh)
By Number of Major Measures

Major Measures	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
0	138	20,474	19,216	1,258***	6.1%	$644	1,188	5.8%	70	0.3%
1	89	20,777	17,900	2,877***	13.8%	$4,688	2,804	13.5%	73	0.3%
2 or More	93	21,437	18,515	2,922***	13.6%	$8,372	2,849	13.3%	73	0.3%

***Denotes significance at the 99 percent level.

Table IV-11B displays savings for gas heat jobs by the number of major measures installed. The table shows that customers who received one or more major measures had lower pre-treatment usage and higher savings than customers who received no major measures. Customers who received two or more major measures had the highest savings, averaging 153 ccf or 13.3 percent of pre-treatment usage.

Table IV-11B
Change in Annual Gas Heat Usage (ccf)
By Number of Major Measures

Major Measures	#	Pre-Use	Post-Use	Savings	% Savings	Measure Cost[1]
0	273	1,239	1,169	70***	5.7%	$833
1	86	1,172	1,069	103***	8.8%	$7,040
2 or More	53	1,151	997	153***	13.3%	$7,248

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-12 displays energy savings by whether participants received particular measures. Some of the key findings were as follows.

- *Air Conditioner*: Baseload customers who received an air conditioner had savings of 8.1 percent compared to savings of 6.7 percent for those who did not. Gas heating customers who received an air conditioner had higher savings (9.4%) compared to those who did not (6.1%).

- *Refrigerator*: Baseload participants who received a refrigerator had higher savings (11.9%) than those who did not (6.7%). Gas heating customers who received a refrigerator had higher savings (13.6%) compared to those who did not (6.3%).

- *Blower Door Guided Air Sealing:* Gas heating customers who received blower door guided air sealing had savings of 9.3 percent compared to savings of 6.9 percent for those

who did not. Electric heating customers who received blower door guided air sealing had higher savings (13.2%) than those who did not (9.9%).

- *Insulation:* Gas heating customers who received insulation had savings of nine percent compared to savings of seven percent for those who did not receive insulation. Electric heating customers who received insulation had higher savings (13.7%) than those who did not (9.5%).

- *Furnace:* Gas heating customers who received a new furnace had savings of 14.2 percent compared to 6.6 percent for those who did not.

Table IV-12
Change in Annual Usage
By Major Measures

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Savings	% Savings	Total Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Air Conditioner	625	11,899	10,937	962***	8.1%	$1,327	879	7.4%	83	0.7%
No Air Conditioner	1,831	12,022	11,214	808***	6.7%	$201	725	6.0%	83	0.7%
Refrigerator	134	13,728	12,091	1,638***	11.9%	$1,793	1,549	11.3%	89	0.6%
No Refrigerator	2,322	11,891	11,089	801***	6.7%	$412	718	6.0%	83	0.7%
Air Conditioner/ Refrigerator	56	13,635	12,138	1,497***	11.0%	$2,353	1,412	10.4%	85	0.6%
Air Conditioner/ No Refrigerator	569	11,728	10,819	909***	7.8%	$1,226	826	7.0%	83	0.7%
No Air Conditioner/ Refrigerator	78	13,796	12,057	1,739***	12.6%	$1,391	1,647	11.9%	92	0.7%
No Air Conditioner/ No Refrigerator	1,753	11,943	11,177	767***	6.4%	$148	684	5.7%	83	0.7%
Electric Heat (kWh)										
Refrigerator	28	20,934	18,933	2,000**	9.6%	$6,461	1,881	9.0%	119	0.6%
No Refrigerator	292	20,829	18,619	2,211***	10.6%	$3,824	2,144	10.3%	67	0.3%
Blower Door Test/Air Sealing	57	21,696	18,831	2,864***	13.2%	$7,251	2,799	12.9%	65	0.3%
No Blower Door Test or No Air Sealing	263	20,652	18,606	2,046***	9.9%	$3,354	1,973	9.6%	73	0.4%
Insulation	75	21,122	18,218	2,903***	13.7%	$8,194	2,839	13.4%	64	0.3%
No Insulation	245	20,752	18,777	1,974***	9.5%	$2,770	1,900	9.2%	74	0.4%

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Savings	% Savings	Total Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Gas Heat[1] (ccf)										
Blower Door Test and Air Sealing	55	1,136	1,031	105***	9.3%	$5,724	105	9.3%	0	0.0%
No Blower Door Test or No Air Sealing	357	1,226	1,140	85***	6.9%	$2,527	85	6.9%	0	0.0%
Insulation	57	1,130	1,028	101***	9.0%	$5,668	101	9.0%	0	0.0%
No Insulation	355	1,227	1,142	86***	7.0%	$2,518	86	7.0%	0	0.0%
Furnace	34	1,160	995	165***	14.2%	$9,084	165	14.2%	0	0.0%
No Furnace	378	1,218	1,138	81***	6.6%	$2,402	81	6.6%	0	0.0%
Gas Heat[2] (kWh)										
Refrigerator	34	9,210	7,961	1,250***	13.6%	$1,509	1157	12.6%	93	1.0%
No Refrigerator	361	10,128	9,487	641***	6.3%	$297	551	5.4%	90	0.9%
Air Conditioner	99	9,947	9,014	933***	9.4%	$1,209	846	8.5%	87	0.9%
No Air Conditioner	296	10,083	9,470	613***	6.1%	$131	522	5.2%	91	0.9%
Electric Baseload (ccf)										
Air Conditioner	30	788	754	34	4.3%	$1,456	34	4.3%	0	0.0%
No Air Conditioner	130	739	715	24***	3.2%	$842	24	3.2%	0	0.0%
Refrigerator	4	623	690	-67	-10.7%	$1,801	-67	-10.8%	0	0.0%
No Refrigerator	156	751	723	28***	3.7%	$935	28	3.7%	0	0.0%
Air Conditioner/ Refrigerator	3	588	601	-14	-2.3%	$2,086	-14	-2.4%	0	0.0%
Air Conditioner/ No Refrigerator	27	811	771	39	4.8%	$1,386	39	4.8%	0	0.0%
No Air Conditioner/ Refrigerator	1	730	957	-226	-31.0%	$945	-226	-31.0%	0	0.0%
No Air Conditioner/ No Refrigerator	129	739	713	26***	3.5%	$841	26	3.5%	0	0.0%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

Table IV-13A displays measure-specific savings estimates. These savings were calculated by running a regression model that predicted savings based on the measures that were provided. The table also shows the cost per unit saved, but those measures fully funded by Act 129 have no LIURP costs, so this information is not included for those measures.

In 2022, customers who only received LEDs and no other measures had average savings of 803 kWh. By comparison, in 2021, customers receiving only LEDs had average savings of 863 kWh.

The table also shows that refrigerators and freezers saved an average of 756 kWh per home. While the vast majority of refrigerators were funded through LIURP, some were funded through Act 129. Heat pumps installed in electric heat homes had average savings of 2,318 kWh.

Table IV-13A
Measure Savings Estimates

	Savings	Cost/Home	$/Unit Saved	Measure Life	$/Unit Saved Over Lifetime
Electric Baseload (kWh)					
LED Only[1]	803 (±303)	$316[2]	--	10	--
LED	8 (±6)	$0	$0.02	10	<$0.01
Refrigerator	756 (±230)	$1,171	$1.55	12	$0.17
Freezer	756 (±230)	$267	$0.35	12	$0.04
Air Conditioner	108 (±120)	$885	$8.20	13	$0.87
Gas Heat (ccf)					
Gas Furnace	74 (±36)	$5,663	$76.52	15	$7.37
Boiler	79 (±39)	$11,030	$139.62	15	$13.45
Electric Heat (kWh)					
LED	24 (±20)	$1,011	$42.13	10	$5.46
Air Conditioner	1,521 (±727)	$658	$0.43	13	$0.05
Water heater	665 (±804)	$628	$0.94	12	$0.11
Air sealing only	1,030 (±854)	$1,237	$1.20	15	$0.12
Air sealing and insulation	713 (±530)	$3,539	$4.96	15	$0.48
Heat Pump	2,318 (±495)	$6,085	$2.63	15	$0.25

[1]The average number of LEDs provided to these customers was 11.5.
[2]This is the cost for the audit and education of customers who only received LEDs. The cost for the LEDs is paid for by the Act 129 Program.

Table IV-13B displays the savings for jobs that received health and safety measures other than carbon monoxide detectors and smoke alarms and batteries. The table shows that baseload and gas heat jobs had higher energy savings than jobs overall. Savings averaged 1,471 kWh for baseload jobs with health and safety measures, compared to 847 kWh overall. Savings averaged 1,225 kWh for electric heating jobs (not statistically significant due to the small sample size), lower than electric heating job savings overall. Additionally, gas heating jobs achieved average savings of 97 ccf compared to savings of 88 ccf for all gas heating jobs.

Table IV-13B
Degree Day-Normalized Usage and Savings
Jobs with Health & Safety Measures

Job Type	#	Pre	Post	Savings	
				#	%
Electric Baseload (kWh)	86	13,697	12,227	1,471***	10.7%
Electric Heat (kWh)	24	22,506	21,281	1,225	5.4%
Gas Heat (ccf)	29	1,043	946	97***	9.3%

***Denotes significance at the 99 percent level.

D. Cost Effectiveness

This section examines the cost-effectiveness of the Program services delivered by job type. Audit and administrative costs were assigned to electric and gas costs in the same proportion as the measure costs. Table IV-14 shows the measure costs, audit/education costs, and administrative costs by job type and electric and gas reduction. Cost per unit saved was calculated as the average total cost divided by the unit savings. The cost per kWh saved was $1.05 for baseload jobs and $2.05 for electric heat jobs. The cost per ccf saved was $38.34 for gas heat jobs.

Table IV-14
Cost per Unit Saved

	#	Average Savings	Average Measure Cost	Average Audit/ Education Cost	Average Admin Cost	Average Total Cost	Cost Per Unit Saved
Electric Baseload							
Electric (kWh)	2,456	847	$428	$303	$155	$887	$1.05
Gas (ccf)	160	26	$644	$190	$97	$931	$35.80
Electric Heat							
Electric (kWh)	320	2192	$4,026	$316	$162	$4,503	$2.05
Gas Heat							
Electric (kWh)	395	693	$402	$38	$19	$459	$0.66
Gas (ccf)	412	88	$2,954	$278	$142	$3,374	$38.34

The previous analysis displayed the total job cost divided by the total savings as an indicator of how cost-effective the services were. Table IV-15 displays the discounted present value of the job savings under 5-year, 10-year and 15-year measure life assumptions. The costs per unit saved should be compared to retail rates to evaluate the cost-effectiveness of the Program at different measure life values.

The most reasonable assumption for electric baseload reduction is a ten-year measure life. Current electricity costs are approximately $0.17 per kWh. This table shows that the electric

baseload investments were cost-effective in 2022, given that the cost per unit saved was slightly lower than the retail rate.

The most reasonable assumption for gas heating is a 15-year measure life. Under the 15-year measure life assumption, the cost per ccf saved is $3.69, which is not cost-effective. The cost to save a ccf of gas would need to be lower than the price for a ccf for LIURP to be cost-effective. Since the current gas cost is approximately $0.99 per ccf, LIURP would need to increase the savings that were obtained from the measures that were installed to be cost-effective.

Table IV-15
Cost Per Unit Saved
By Measure Life Assumption

	#	Average Savings	Average Total Cost	Cost Per Unit Saved	5-Year Measure Life	10-Year Measure Life	15-Year Measure Life
Electric Baseload							
Electric (kWh)	2,456	847	$887	$1.05	$0.24	$0.14	$0.10
Gas (ccf)	160	26	$931	$35.80	$8.27	$4.64	$3.45
Electric Heat							
Electric (kWh)	320	2,192	$4,503	$2.05	$0.47	$0.27	$0.20
Gas Heat							
Electric (kWh)	395	693	$459	$0.66	$0.15	$0.09	$0.06
Gas (ccf)	412	88	$3,374	$38.34	$8.86	$4.97	$3.69

V. Bill and Payment Impacts

This section of the report examines the bill and payment impacts for the 2022 LIURP participants. We review the methodology used in the analysis, and then analyze the billing and payment impacts.

A. Methodology

Billing and payment transactions data were used to analyze the pre- and post-treatment billing and payment statistics. Accounts were required to have between 300 and 390 days of transactions data in both the pre and post periods to be included in the analysis.

Table V-1 displays the data attrition statistics. Overall, sufficient data were available for 49 percent of Program participants.

Table V-1
Payment Impact Data Attrition

	Electric Baseload	Electric Heating	Gas Heating	Education Only	All Jobs
Original Population	2,715	394	476	82	3,667
No Transactions Data	0	0	1	0	1
Not Enough Pre-Treatment Days	789	223	260	9	1,281
Not Enough Post-Treatment Days	237	25	27	12	301
Data Outliers	149	47	54	20	270
Final Sample	1,540	99	134	41	1,814
% Included in Analysis	57%	25%	28%	50%	49%

Note: For Table V-2 only, the final sample included in the analysis is 1,668 accounts (45% of the original population), this was due to a smaller number of accounts with complete revenue data.

B. Billing and Payment Impacts

Table V-2 displays the billing revenue data obtained from the usage file. Not all accounts with 300 to 390 days of usage data for the analysis had revenue data for the whole period. Table V-2 includes only accounts that had between 300 and 390 days of usage and revenue data. There were 1,668 accounts that had enough pre-treatment and post-treatment days with revenue data, which represents 45 percent of the original population and 92 percent of the financial analysis group. These data show the changes in charges that were associated with electric and gas usage only. For example, charges related to service agreements or late payment charges would not be included in this table.

Table V-2 shows that electric revenue decreased by an average of $205 for baseload jobs and by $431 for electric heat jobs. Gas revenue decreased by $62 for gas heat jobs.

Table V-2
Billing Revenue

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric Revenue	1,435	$937	$733	-$205***	-21.8%
Gas Revenue		$40[1]	$39[1]	-$1	-3.4%
Total Revenue		$978	$772	-$206***	-21.1%
Electric Heat[2]					
Electric Revenue	85	$1,658	$1,227	-$431***	-26.0%
Gas Revenue		$3	$2	-$1	-22.0%
Total Revenue		$1,661	$1,230	-$432***	-26.0%
Gas Heat					
Electric Revenue	108	$946	$888	-$58	-6.1%
Gas Revenue		$694	$632	-$62**	-8.9%
Total Revenue		$1,640	$1,520	-$120**	-7.3%
Education Only					
Electric Revenue	40	$884	$668	-$216***	-24.4%
Gas Revenue		$55	$66	$11	20.2%
Total Revenue		$938	$734	-$205***	-21.8%
All Job Types					
Electric Revenue	1,668	$973	$767	-$207***	-21.3%
Gas Revenue		$81	$76	-$5**	-6.1%
Total Revenue		$1,055	$843	-$212***	-20.1%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.
[1]Only 31 Electric Baseload accounts have gas usage data.
[2]Only 1 Electric Heat account has gas usage data.

Table V-3A displays the change in customer electric and gas bills and total charges, between the pre- and the post-treatment periods, based on analysis of the transactions file. Total charges decreased by 10.0 percent for electric baseload jobs, 10.9 percent for electric heat jobs, and 0.5 percent for gas heat jobs. Total charges decreased by 9.1 percent for all job types.

Differences in results between the revenue analysis from the billing data (shown in Table V-2) and the billing analysis from the transactions data (shown in Table V-3A) are due to the fact that the transactions data include all charges, while the revenue data only include charges for electric and gas usage.

Table V-3A
Bills and Total Charges

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric and Gas Charges	1,540	$1,138	$1,020	-$119***	-10.4%
Other Charges		$10	$14	$4***	39.4%
Total Charges		$1,149	$1,034	-$115***	-10.0%
Electric Heat					
Electric and Gas Charges	99	$1,828	$1,625	-$203***	-11.1%
Other Charges		$23	$25	$2	7.3%
Total Charges		$1,851	$1,650	-$201***	-10.9%
Gas Heat					
Electric and Gas Charges	134	$1,898	$1,874	-$24	-1.3%
Other Charges		$18	$33	$14	78.9%
Total Charges		$1,916	$1,906	-$10	-0.5%
Education Only					
Electric and Gas Charges	41	$1,071	$889	-$182***	-17.0%
Other Charges		$1	$3	$2	133.0%
Total Charges		$1,072	$892	-$181***	-16.8%
All Job Types					
Electric and Gas Charges	1,814	$1,231	$1,113	-$118***	-9.6%
Other Charges		$11	$16	$5***	40.8%
Total Charges		$1,242	$1,129	-$113***	-9.1%

***Denotes significance at the 99 percent level.

Table V-3B displays bills and total charges for customers who had CAP rates for the full pre-period and for the full post-treatment period. The table shows that across all job types, total charges decreased by 20.2 percent for this population, compared to the 9.1 percent decrease overall, as shown in the previous table.

Table V-3B
Bills and Total Charges
Customers with CAP Rates In All Pre and Post Periods

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric and Gas Charges	1,077	$995	$775	-$221***	-22.2%
Other Charges		$7	$9	$2	32.2%
Total Charges		$1,002	$784	-$218***	-21.8%

	#	Pre	Post	Change	Percent Change
Electric Heat					
Electric and Gas Charges	69	$1,662	$1,357	-$305***	-18.4%
Other Charges		$18	$8	-$10	-55.3%
Total Charges		$1,681	$1,365	-$315***	-18.8%
Gas Heat					
Electric and Gas Charges	78	$1,714	$1,538	-$175***	-10.2%
Other Charges		$5	$26	$21**	403.4%
Total Charges		$1,719	$1,564	-$154**	-9.0%
Education Only					
Electric and Gas Charges	31	$1,011	$826	-$186***	-18.3%
Other Charges		$1	$2	$1	-84.0%
Total Charges		$1,012	$828	-$185***	-18.2%
All Job Types					
Electric and Gas Charges	1,255	$1,077	$855	-$222***	-20.6%
Other Charges		$7	$10	$3*	36.5%
Total Charges		$1,084	$866	-$219***	-20.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-4 displays payment statistics for the 2022 LIURP participants. Across all job types, total credits decreased by $115 from the pre-treatment year to the post-treatment year.

Table V-4
Annual Payments
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
# Payments	1,540	8.9	8.5	-0.4***	-4.2%
Cash Payments		$1,035	$949	-$86***	-8.3%
Assistance Payments		$103	$90	-$13*	-12.8%
Other Credits		$10	$5	-$4***	-44.1%
Total Credits		$1,148	$1,044	-$104***	-9.0%
Electric Heat					
# Payments	99	8.8	8.6	-0.2	-2.1%
Cash Payments		$1,541	$1,368	-$172**	-11.2%
Assistance Payments		$334	$208	-$127***	-37.9%
Other Credits		$12	$2	-$10**	-87.0%
Total Credits		$1,887	$1,577	-$310***	-16.4%

	#	Pre	Post	Change	Percent Change
Gas Heat					
# Payments	134	8.9	8.4	-0.5*	-5.5%
Cash Payments		$1,667	$1,642	-$25	-1.5%
Assistance Payments		$342	$316	-$26	-7.7%
Other Credits		$11	$8	-$3	-26.7%
Total Credits		$2,020	$1,966	-$55	-2.7%
Education Only					
# Payments	41	10.4	9.4	-1.0***	-10.0%
Cash Payments		$1,007	$773	-$235***	-23.3%
Assistance Payments		$115	$78	-$38	-32.7%
Other Credits		$1	$1	-$1	-53.4%
Total Credits		$1,124	$851	-$273***	-24.3%
All Job Types					
# Payments	1,814	8.9	8.5	-0.4***	-4.3%
Cash Payments		$1,109	$1,019	-$90***	-8.1%
Assistance Payments		$134	$113	-$21***	-15.7%
Other Credits		$10	$5	-$4***	-45.6%
Total Credits		$1,252	$1,137	-$115***	-9.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-5 displays payments for CAP and non-CAP customers in the year prior to and after receipt of LIURP. For CAP customers across all job types, total credits decreased by $191. For non-CAP Customers across all job types, total credits increased by $77.

Table V-5
Payments for CAP Customers
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
CAP Customers – All Job Types					
# Payments	1,302	8.5	8.1	-0.5***	-5.3%
Cash Payments		$916	$764	-$152***	-16.2%
Assistance Payments		$158	$124	-$34***	-21.6%
Other Credits		$9	$5	-$4***	-46.6%
Total Credits		$1,084	$894	-$191***	-17.6%
Non-CAP Customers – All Job Types					
# Payments	512	9.8	9.6	-0.2	-2.1%
Cash Payments		$1,597	$1,666	$68**	4.3%
Assistance Payments		$71	$84	$13	18.6%

	#	Pre	Post	Change	Percent Change
Other Credits		$10.9	$6.2	-$4.7*	-43.3%
Total Credits		$1,679	$1,755	$77**	4.6%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-6 displays a more detailed analysis of the types of assistance payments received by the 2022 LIURP participants in the pre- and the post-treatment periods. The table shows that, across all job types, total assistance payments decreased by an average of $21 from the pre-treatment year to the post-treatment year.

Table V-6
Assistance Payments
Pre and Post-LIURP Treatment

	#	Pre	Post	Change	% Change
Electric Baseload					
LIHEAP Cash	1,540	$84	$70	-$14**	-16.7%
LIHEAP Crisis		$19	$20	$1	4.3%
MEAF		$0	$0	$0	0.0%
Total Assistance		$103	$90	-$13*	-12.8%
Electric Heat					
LIHEAP Cash	99	$276	$202	-$74**	-26.8%
LIHEAP Crisis		$58	$5	-$53**	-91.0%
MEAF		$0	$0	$0	0.0%
Total Assistance		$334	$208	-$127***	-37.9%
Gas Heat					
LIHEAP Cash	134	$284	$291	$7	2.4%
LIHEAP Crisis		$58	$25	-$33*	-57.5%
MEAF		$0	$0	$0	0.0%
Total Assistance		$342	$316	-$26	-7.7%
Education Only					
LIHEAP Cash	41	$81	$78	-$3	-4.3%
LIHEAP Crisis		$34	$0	-$34	-100.0%
MEAF		$0	$0	$0	0.0%
Total Assistance		$115	$78	-$38	-32.7%

	#	Pre	Post	Change	% Change
All Job Types					
LIHEAP Cash	1,814	$109	$94	-$15***	-14.2%
LIHEAP Crisis		$24	$19	-$5	-22.1%
MEAF		$0	$0	$0	0.0%
Total Assistance		$134	$113	-$21***	-15.7%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-7 displays changes in cash and total bill coverage[14] rates between the pre- and the post-treatment periods. On average, the cash coverage rate and the total coverage rate increased by 0.6 percentage points and 0.7 percentage points respectively for all job types.

Table V-7
Coverage Rates
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Cash Coverage Rate	1,540	90.6%	92.0%	1.4%	1.5%
Total Coverage Rate		102.3%	104.1%	1.8%	1.7%
Electric Heat					
Cash Coverage Rate	99	79.2%	77.2%	-2.0%	-2.5%
Total Coverage Rate		102.0%	95.7%	-6.3%*	-6.2%
Gas Heat					
Cash Coverage Rate	134	85.6%	81.3%	-4.3%	-5.0%
Total Coverage Rate		108.2%	104.6%	-3.7%	-3.4%
Education Only					
Cash Coverage Rate	41	97.6%	88.8%	-8.8%	-9.0%
Total Coverage Rate		108.0%	98.0%	-10.0%	-9.3%
All Job Types					
Cash Coverage Rate	1,814	89.8%	90.4%	0.6%	0.6%
Total Coverage Rate		102.8%	103.5%	0.7%	0.6%

*Denotes significance at the 90 percent level.

[14] The cash coverage rate is the amount of cash payments made divided by the bill. The total coverage rate is the total of all customer payments, customer assistance, and other credits divided by the bill.

Table V-8 displays changes in customer balances. While balances from the beginning to the end of the pre-treatment period declined by 3.9 percent, balances from the beginning to the end of the post-treatment period declined by 28.2 percent.

Table V-8
Change in Customer Balance

	#	Start	End	Change	Percent Change
Electric Baseload					
Pre Balance	1,540	$138	$144	$6	4.4%
Post Balance		$140	$102	-$38***	-27.2%
Electric Heat					
Pre Balance	99	$194	$150	-$44	-22.6%
Post Balance		$151	$136	-$15	-10.0%
Gas Heat					
Pre Balance	134	$243	$143	-$100**	-41.0%
Post Balance		$226	$125	-$102***	-44.9%
Education Only					
Pre Balance	41	$100	$48	-$52	-52.2%
Post Balance		$52	$42	-$10	-18.8%
All Job Types					
Pre Balance	1,814	$148	$142	-$6	-3.9%
Post Balance		$145	$104	-$41***	-28.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.

VI. Summary of Findings and Recommendations

PECO's LIURP delivered usage reduction services and energy education to over 3,500 customers in 2022, many of whom had vulnerable household members. The program performed significantly better than recent years in terms of energy savings from electric heating jobs and gas heating jobs. Savings from electric heating jobs averaged 10.5 percent, compared to recent years that had savings below six percent. Savings from gas heating jobs were 7.2 percent compared to recent years that were all below five percent and often below three percent. Savings from electric baseload jobs were in line with the 20-year historic average. When accounting for the comparison group change, both electric baseload and electric and gas heating net savings were even higher compared to recent years.

The average measure cost remained more than double the historic average and stable compared to the previous year, which reduced the cost-effectiveness of LIURP. The increase in job costs was likely driven by rising material and labor costs stemming from the inflationary environment in the post-COVID economy. These cost increases are expected to continue to impact the program in future years.

We have the following recommendations to improve energy savings and the cost-effectiveness of LIURP.

- *Outreach:* While CMC was successful in increasing the number of contacted customers to pre-COVID levels, most customers did not respond to contact attempts. The current procedure is to make at least three phone calls and send a follow-up letter.[15] CMC should increase the number of calls to high-usage customers and pilot additional methods of outreach to targeted neighbors when they are in the field, such as leaving door hangers. PECO is continuing work with CMC to expand and improve LIURP outreach.

- *Targeting High Users:* The savings for electric baseload and gas heating jobs are significantly higher for customers with higher pre-program usage. CMC was successful in 2022 in reaching higher usage customers than in some of the other recent years. They should continue to target higher usage households and focus on deploying major measures to homes where they are likely to maximize impact.

- *Major Measure Installation*: Savings on jobs with more major measures are significantly higher. CMC was successful in increasing the rate of air sealing and insulation on electric heating jobs compared to recent years. They were also successful in installing heat pumps in a greater percentage of homes. These changes lead to historic savings for the electric heating jobs. However, electric and gas heating job still have low levels of air sealing and insulation. CMC should work to increase the rate of air sealing and insulation work on both electric and gas heating jobs.

[15] This is PECO's minimum standard for the number of contact attempts.

- *Health and Safety Remediation:* The health and safety component of the LIURP program has been effective at allowing additional energy saving measures to be installed through health and safety work. PECO should consider expanding their health and safety program by providing additional remediation work (such as electrical upgrades) that would enable energy efficiency measures in older homes.

PECO ENERGY COMPANY
STATEMENT NO. 10-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2024-3046932

SURREBUTTAL TESTIMONY

WITNESS: JAQUELINE F. GOLDEN

SUBJECT: CUSTOMER SERVICE REPRESENTATIVE ISSUES

DATED: AUGUST 2, 2024

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SURREBUTTAL TESTIMONY
OF
JAQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jacqueline F. Golden. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Customer Financial Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 10 and 10-R, respectively.

3. Q. What is the purpose of your rebuttal testimony?

A. My surrebuttal testimony will respond to the concerns and recommendations of James Glenn on behalf of the Local 614 of the International Brotherhood of Electrical Workers, AFL-CIO ("Local 614") regarding the level of training and support to PECO's customer service representatives ("CSRs") as the Company works through the implementation of the new customer service software ("Customer Care and Billing" or the "CC&B").[1]

[1] Mr. Glenn mistakenly refers to the new customer service software as "CCMV" throughout his rebuttal testimony. Here, I will refer to the new customer service software as CC&B rather than CCMV.

II. CUSTOMER SERVICE REPRESENTATIVES

4. Q. Could you please summarize Mr. Glenn's concerns regarding the Company's training of CSRs in response to Question 13 of his rebuttal testimony?

A. Yes. First, I would like to highlight that Mr. Glenn begins his answer by applauding PECO's efforts to address customer service by hiring approximately two hundred (200) additional CSRs in August and September of 2023. Despite this significant effort, however, he expresses concerns that: (1) CSR supervisors need additional training to provide adequate support and knowledgeable feedback to CSRs; (2) CSRs were not given adequate training and time to practice use of the new customer service software (CC&B), nor were they given "cheat sheets" to know where to assess information when handling customer calls; (3) the Company has inappropriately reduced the amount of training provided to CSRs to handle credit and collection calls and supervisors are not available to answer questions; and (4) there is a spike in the number of customers calls due to billing exceptions related to the CC&B software which has caused "great stress and pressure on CSRs" and caused unplanned mandatory overtime.

5. Q. How do you respond to his concerns?

A. I do not agree with the concerns raised in his rebuttal testimony given the extensive training that the Company provided to CSRs in anticipation of the software transition. The Company's training approach for the CSRs followed industry best practices and was broken out across three phases, intentionally starting early in the project timeline, and continuing up until CC&B was put into service.

The first phase of training, “Set the Foundation”, began in February 2022 and concluded in October 2022. This phase introduced CSRs to core CC&B concepts like the V-Model and included thirty-two (32) video demonstrations and training materials which are accessible to CSRs via the project's New Horizons Resource Hub.

The second phase of the training, “Make it Real”, began in February 2023 and concluded in July 2023. This phase of training consisted of twenty-six (26) courses, focused on core processes that CSRs would need to follow in CC&B. Notably, approximately three hundred seventy-five (375) job aids were created to accompany these twenty-six (26) courses, all of which are accessible to CSRs via the project's New Horizons Resource Hub. In addition, answers to questions CSRs asked in Make It Real were posted on the New Horizons Resource Hub.

The third phase of the training, “Practice and Prepare”, began in September 2023 and concluded in January 2024. This phase of training consisted of practice labs and refresher training on key topics. Many of these topics were solicited from CSRs themselves. Notably, one hundred percent (100%) of the CSRs completed this Practice and Prepare phase of the training.

6. Q. Did PECO solicit and receive feedback from the CSRs upon completion of the training?

A. Yes, we did, and I am happy to report that the survey results were positive. For example, the Practice & Prepare survey questions and results are as follows:

- The activities in the class helped me learn the materials: 4.78 out of 5.

- The course material was clear and easy to follow: 4.7 out of 5.
- I was given enough time to learn and practice the intended knowledge and skills: 4.74 out of 5.
- I thought the instructor facilitated the session in a clear and organized manner: 4.88 out of 5.
- I felt engaged during the session because the instructor recognized the students' needs: 4.88 out of 5.
- I thought the knowledge check related directly to the practice scenario: 4.82 out of 5.
- I would recommend this training to my peers: 4.77 out of 5.

In response to Mr. Glenn's comments about pressure on CSRs, while it is true that CSR responsibility includes mandatory overtime to support the business as needed in accordance with the existing collective bargaining agreement and PECO makes best efforts to provide as much advanced notice as possible, the Company does recognize the challenges that the CSRs have experienced with the transition to CC&B. Fortunately, the Company has made significant progress resolving exceptions and the CSRs quickly have built proficiency levels that should have reduced stress levels. In fact, as I describe further in response to Question 7 below, most CSRs have reached a proficiency level that has enabled them to return to a nearly fully remote-hybrid work schedule.

7. Q. Mr. Glenn concludes by making six (6) recommendations. How do you respond?

A. ***First, Mr. Glenn states that the Company should provide "formal and uniform training regarding use of the CC&B program to CSRs, and their supervisors."*** As noted in my answer to question 6 above, the Company has provided extensive CC&B training.

Second, Mr. Glenn asks for "provision of the prior format of training for credit to CSRs." The credit and collections process within CC&B did not become functional until recently, which is why the CSRs were not trained initially on this aspect of the new software. Moreover, I don't believe that this specific recommendation is necessary because all CSRs were trained on the credit and collections functionality within CC&B beginning the week of May 27, 2024.

Third, he recommends that CSR be allowed access to the prior program (CIMS) while the CC&B program is further finessed. However, it is not possible for PECO to implement this recommendation because, effective July 16, 2024, CIMS and its associated tasks were permanently shut down and user access to CIMS has been removed.

Fourth, Mr. Glenn requests periodic training for supervisors regarding the role of the CSR and how they can better support the CSR. PECO makes every effort to ensure that supervisors are provided with required leadership skills to support the CSRs. As an example, PECO sends CSR supervisors to development programs, such as the "Exelon Supervisory Development Program" which is a four-week program designed to strengthen and increase the participant's

leadership effectiveness, build business insight and industry perspective, as well as foster cross-functional relationship. Participants integrate key knowledge, skills, and capabilities through a series of interactive learning modules. Leadership core modules coupled with various functional business topics help align Exelon's first line supervisors with leadership at all levels.

With respect to CC&B specific support, PECO has created and is in the process of implementing additional CC&B training for front line supervisors and coaches to enable them to be a reliable resource to support the CSRs in real time. This additional training for supervisors and coaches will be completed by the end of the year. However, it should be noted that coaches were trained on CC&B at the same time as the CSRs and are readily available to provide support today.

Fifth, Mr. Glenn requests faster training of new hires so that they can do more than "stop/start" and emergency calls. I agree with this recommendation and confirm that the Company is already working on speeding up CSR training and has revamped its new hire training to be coordinated with CC&B training.

Finally, Mr. Glenn request that there be no additional evaluations of CSRs while PECO is working through the implementation of the new software. PECO has done this. Specifically, in recognition of the significant changes associated with implementation of CC&B, CSRs were not held accountable for the performance on their score cards starting upon the initial rollout until May 20, 2024. Moreover, once a CSR was able to demonstrate proficiency with CC&B, that CSR was allowed to return to a nearly fully remote-hybrid work schedule. Most CSRs returned to a hybrid work schedule by the end of June. In fact, the

CSRs are part of the only department at PECO that is permitted to be fully remote except for occasional in-office requirements.

III. CONCLUSION

8. Q. Does this complete your surrebuttal testimony at this time?

A. Yes, it does.