

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY - GAS DIVISION**

DOCKET NO. R-2024-3046932

VOLUME III OF VI

PECO Statement No. 5:	Direct Testimony of Paul R. Moul (and related exhibit)
PECO Statement No. 6:	Direct Testimony of Jiang Ding (and related exhibits)
PECO Statement No. 7:	Direct Testimony of Joseph A. Bisti (and related exhibits)
PECO Statement No. 8:	Direct Testimony of Megan A. McDevitt (and related exhibits)
PECO Statement No. 9:	Direct Testimony of Doreen L. Masalta (and related exhibits)
PECO Statement No. 10:	Direct Testimony of Jacqueline F. Golden

March 28, 2024

PECO Statement No. 5:

Direct Testimony of Paul R. Moul

**PECO ENERGY COMPANY
STATEMENT NO. 5**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION
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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

TABLE OF CONTENTS

Page No.

I.	INTRODUCTION AND SUMMARY OF RECOMMENDATIONS	1
II.	NATURAL GAS RISK FACTORS	10
III.	FUNDAMENTAL RISK ANALYSIS	14
IV.	RECOMMENDED CAPITAL STRUCTURE RATIOS.....	20
V.	COSTS OF SENIOR CAPITAL.....	24
VI.	COST OF EQUITY – GENERAL APPROACH	25
VII.	DISCOUNTED CASH FLOW	25
VIII.	RISK PREMIUM ANALYSIS	42
IX.	CAPITAL ASSET PRICING MODEL	46
X.	COMPARABLE EARNINGS APPROACH.....	51
XI.	CONCLUSION ON COST OF EQUITY	54

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

1 **DIRECT TESTIMONY**

2 **OF**

3 **PAUL R. MOUL**

4 **I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS**

5 **1. Q. Please state your name, occupation and business address.**

6 A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road,
7 Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P.
8 Moul & Associates, an independent financial and regulatory consulting firm. My
9 educational background, business experience and qualifications are provided in
10 Appendix A, which follows my direct testimony.

11 **2. Q. What is the purpose of your direct testimony?**

12 A. My testimony presents evidence, analysis, and a recommendation concerning the
13 appropriate cost of common equity and overall rate of return that the Pennsylvania
14 Public Utility Commission ("Commission") should recognize in determining the
15 revenues that the Natural Gas Division of PECO Energy Company ("PECO" or
16 the "Company") will be authorized to realize at the conclusion of this proceeding.
17 My analysis and recommendation are supported by the detailed financial data
18 contained in PECO Exhibit PRM-1, which is a multi-page document divided into
19 fourteen (14) schedules. My testimony is based upon my first-hand knowledge of
20 PECO, consisting of information obtained from meetings with the Company's
21 management and Company-specific data that is widely disseminated within the
22 financial community.

1 **3. Q. Based upon your analysis, what is your conclusion concerning the**
2 **appropriate rate of return for the Company in this case?**
3 A. My conclusion is that the Company should be afforded an opportunity to earn a
4 rate of return on common equity of 11.15% for its Gas Division. The 11.15% rate
5 of return on common equity is composed of an 11.00% cost of equity determined
6 from the results of my proxy group analysis and 0.15% in recognition of the
7 exemplary performance of the Company's management. The cost of equity is
8 derived from a blended rate plus a risk adjustment applicable to the Gas Division.
9 This rate reflects the risk reducing benefits that arise from PECO being a
10 combination utility that has a diversified portfolio of utility investments, as well
11 as the additional risk of the Gas Division.

12 My analysis of the Company and its superior performance is based
13 upon the direct testimony of Ms. Amy E. Hamilton, the Company's Vice
14 President of Gas Operations and the direct testimony of other Company witnesses.
15 As shown on page 1 of Schedule 1, I have calculated an 8.08% overall cost of
16 capital for the Company's fully projected future test year ("FPFTY") estimated at
17 December 31, 2025. This return, which is the product of weighting the individual
18 capital costs by the proportion of each respective type of capital, should establish
19 a compensatory level of return for the use of capital and provide the Company
20 with the ability to attract capital on reasonable terms.

21

1 **4. Q. What background information have you considered in reaching a conclusion**
2 **concerning the Company’s cost of capital?**

3 A. The Company is a wholly-owned subsidiary of Exelon Corporation (“Exelon”).
4 The common stock of Exelon is traded on the Nasdaq Global Select Market.
5 Exelon is a component of the S&P 500 Composite Index. PECO provides natural
6 gas distribution service to over half a million retail customers located in the
7 suburban counties surrounding the City of Philadelphia. Electric delivery service
8 is also provided to approximately 1.7 million electric customers in both the City
9 of Philadelphia and the surrounding counties. Throughput to the Company’s
10 natural gas customers in 2023 was composed of approximately 45% to residential
11 customers, approximately 28% to small commercial and industrial customers, and
12 approximately 27% to large commercial and industrial customers. Approximately
13 29% of throughput goes to transportation customers. With about 636 large
14 commercial and industrial customers, the energy needs of a few customers can
15 have a significant impact on the Company’s operations. PECO obtains its natural
16 gas supplies from producers and marketers with transportation arrangements
17 through interconnections with three interstate pipelines. The Company has
18 storage arrangements with pipeline service providers and owns liquefied natural
19 gas and propane facilities to supplement flowing gas. Since the restructuring of
20 the gas utility industry in Pennsylvania, PECO has been the supplier of last resort
21 for customers that do not obtain their own supply.

22

1 **5. Q. How have you determined the cost of common equity in this case?**

2 A. The cost of common equity is established using capital-market and financial data
3 that investors rely upon to assess the relative risk, and hence the cost of equity for
4 a gas utility. In this regard, I employed four well-recognized measures of the cost
5 of equity: (1) the Discounted Cash Flow (“DCF”) model; (2) the Risk Premium
6 (“RP”) analysis; (3) the Capital Asset Pricing Model (“CAPM”); and (4) the
7 Comparable Earnings (“CE”) approach.

8 **6. Q. In your opinion, what factors should the Commission consider when**
9 **determining the Company’s cost of capital in this proceeding?**

10 A. The Commission’s rate of return allowance must be set to cover the Company’s
11 interest and dividend payments, provide a reasonable level of earnings retention,
12 produce an adequate level of internally generated funds to meet capital
13 requirements, be commensurate with the risk to which the Company’s capital is
14 exposed, assure confidence in the financial integrity of the Company, support
15 reasonable credit quality, and allow the Company to raise capital on reasonable
16 terms. The return that I propose fulfills these established standards of a fair rate
17 of return set forth by the landmark *Bluefield* and *Hope* cases.¹ That is to say, my
18 proposed rate of return is commensurate with returns available on investments
19 having corresponding risks.

20

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”).

1 **7. Q. How have you measured the cost of equity in this case?**

2 A. The models that I used to measure the cost of common equity for the Company
3 were applied with market and financial data developed from a group of eight (8)
4 gas companies. I will refer to these companies as the “Gas Group” throughout my
5 testimony. I began with all of the natural gas utilities contained in The Value
6 Line Investment Survey, which consists of nine companies. Value Line is an
7 investment advisory service that is a widely used source in public utility rate
8 cases. I eliminated one company from the Value Line group. UGI Corporation
9 was removed due to its diversified businesses consisting of six reportable
10 segments, including propane, two international LPG segments, natural gas utility,
11 energy services, and electric generation. The companies in the Gas Group are
12 identified on page 2 of Schedule 3. These are the same companies that were used
13 to apply the cost of equity models in the recent Quarterly Earnings Report
14 (Docket No. M-2023-3044811) approved by the Commission on January 18,
15 2024.

16 **8. Q. How have you performed your cost of equity analysis with the market data**
17 **for the Gas Group?**

18 A. I have applied the models/methods for estimating the cost of equity using the
19 average data for the Gas Group. I have not measured separately the cost of equity
20 for the individual companies within the Gas Group because the determination of
21 the cost of equity for an individual company has become increasingly
22 problematic. By employing group average data, I have helped to reduce the effect
23 of extraneous influences on the market data for an individual company.

1 **9. Q. What noteworthy factors have influenced your cost of equity analysis?**

2 A. My cost of equity analysis reflects the impact of high levels of inflation, which
3 have not been seen for four decades. Indeed, the rate of inflation spiked upward
4 to 9.1% in June 2022, and by February 2024 it had fallen to 3.2%. High levels of
5 inflation, i.e., those above the Federal Open Market Committee (“FOMC”) policy
6 goal of 2%, have an impact on the level of economic activity, the cost of capital –
7 particularly the interest cost of debt, and the need for more cautious financial
8 practices, such as a prudent level of borrowing. While short-term interest rates
9 were at historically low levels during much of the Pandemic, longer-term interest
10 rates began to rise in February 2021 and have continued at high levels throughout
11 2022 and 2023. Following the Pandemic, the accommodative policy by the
12 FOMC has ended, and higher interest rates have occurred. The FOMC uses its
13 open market operations to control the Fed Funds rate as a means of implementing
14 its dual mandate of healthy employment and price stability. This was revealed by
15 the Fed Funds rate, which increased 525 basis points since the beginning of 2022
16 through 11 increases in 21 months. The FOMC paused its rate increases and held
17 rates steady at its meeting on June 14, 2023. Thereafter, another rate increase
18 occurred on July 26, 2023. The FOMC paused again at its meetings on
19 September 20, November 1, and December 13, 2023, and January 31, 2024. It
20 appears that we are at the end of the current interest rate tightening cycle. Modest
21 reductions in the future would not reduce the Fed Funds rate to Pandemic or pre-
22 Pandemic levels, which were very low after the financial crisis of 2007-08.

23

1 **10. Q. Please summarize your cost of equity analysis.**

2 A. My cost of equity determination was derived from the results of the
3 methods/models identified above. In general, the use of more than one method
4 provides a superior foundation to arrive at the cost of equity. At any point in
5 time, any single method can provide an incomplete measure of the cost of equity
6 depending upon extraneous factors that may influence market sentiment. The
7 specific application of these methods/models will be described later in my
8 testimony. The following table provides a summary of the indicated costs of
9 equity using each of these approaches.

	<u>Gas Group</u>
DCF	12.05%
Risk Premium	11.50%
CAPM	12.84%
Comparable Earnings	13.10%

11 To arrive at my recommended equity return, I have incorporated the risk reducing
12 benefits of the combination characteristics of both the Company's gas and electric
13 operations.

14 **11. Q. How have you used this data to set the rate of return on common equity for**
15 **the Gas Division of PECO?**

16 A. I have used this data along with the data for the Electric Group assembled for the
17 Electric Division rate case being filed by PECO. In this regard, I selected as the
18 low end of the range the DCF result for the Gas Group and the Electric Group

1 computed without regard to the leverage adjustment, i.e., 10.74%, and the DCF
2 stated on the same basis in the Company's Electric Division rate case. By doing
3 so I have reduced the equity return in recognition of the combined Gas and
4 Electric utility operations of the Company. That is not to say that diversification
5 in any way changes the fact that the market value leverage and the book value
6 leverage is altered through diversification, but rather it is a convenient way to
7 reduce the return for a combined utility, rather than a stand-alone utility.

8 As revealed in the Electric Division rate case, the cost of equity was 10.80% by
9 considering both the DCF and Risk Premium methods. That return was prior to
10 recognition of the 15 basis points for superior management performance. I will
11 refer to the 10.80% equity return as the baseline cost of equity that reflects the
12 risk reducing benefits of the diversified electric and gas operations of PECO.

13 **12. Q. With the baseline cost of equity for PECO, have you made an adjustment to**
14 **recognize the risk of the Gas Division in this case?**

15 A. Yes. To the 10.80% baseline cost of equity for PECO, I have increased that
16 return by 20 basis points (i.e., 0.20%) to recognize the higher risk of the
17 Company's Gas Division that increases the equity return to 11.00% prior to the
18 recognition of management performance. It is well recognized, including by the
19 Commission, that natural gas utilities require a higher cost of equity than other
20 types of utilities. To identify the difference in return, I have analyzed the
21 earnings/price ("E/P") ratio for my Gas Group and the E/P ratio for the Electric
22 Group used in the Company's companion rate case for the Electric Division. The
23 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% ($1 \div 22$) for the Gas Group and 4.35% ($1 \div 23$) 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.

1 some form of WNA mechanism that is intended to accomplish the same result as
2 the Company's proposal in this case. As a group, the market prices of these
3 companies' common equity reflect the expectations of investors that the
4 companies' revenues are stabilized to some extent by a WNA. Therefore, my
5 analysis reflects the impacts of decoupling on investor expectations through the use
6 of market-determined models.

7 As such, the market prices of these companies' common stocks reflect the
8 expectations of investors related to a regulatory mechanism that adjusts revenues
9 for conservation, abnormal weather, and other items. The trend in the industry is
10 to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed,
11 there has been a proliferation of these mechanisms in the LDC business. Because
12 the Gas Group that I use to measure the cost of equity has the risk attributes
13 related to the revenue decoupling mechanism "baked in" to their stock prices, the
14 absence of the benefit of the WNA would increase the cost of equity as
15 determined by the models that are applied with the Gas Group data.

16 **18. Q. Are there other features of the Company's business that should be**
17 **considered when assessing the Company's risk?**

18 A. Yes. PECO's ten largest volume customers, which account for 10.9 million cubic
19 feet of throughput, are engaged in the manufacturing, pharmaceuticals, food
20 processing, health care, and electric generation (including cogeneration)
21 businesses. Changes in the business environment can negatively affect these
22 companies, and, in that way, cause material reductions in throughput on PECO's
23 distribution system. This risk is especially apparent in this time of economic

1 uncertainty attributed to inflation, supply-side issues, and global geopolitical
2 situations. Additionally, large volume users, which predominantly use
3 transportation service, may be located close enough to interstate pipelines to take
4 gas directly from those sources and bypass the local distribution company
5 ("LDC") entirely. The Company has identified customers with combined annual
6 throughput of approximately 7.6 million cubic feet ("MCF") of gas that have the
7 potential to bypass the Company's distribution system. Because a large part of
8 PECO's distribution revenue recovers fixed costs, which the Company continues
9 to bear even if a customer leaves the system, the loss of 7.6 million MCF of
10 throughput would impose a significant amount of uncompensated fixed costs that
11 PECO would not have the opportunity to recover until it could complete another
12 base rate case.

13 **19. Q. Can the Company's construction program affect its risk profile?**

14 A. Yes. The Company must undertake substantial investments to maintain and
15 upgrade existing facilities in its service territory to ensure safe and reliable service
16 to its customers. In particular, the rehabilitation of the Company's infrastructure
17 requires it to invest capital without adding any new customers and without
18 increasing sales to existing customers. In short, infrastructure rehabilitation
19 increases fixed costs without an attendant increase in revenues. Moreover, the
20 Company is confronting significant levels of infrastructure investment. For
21 example, at year-end 2023, 671 miles (or approximately 9%) of the Company's
22 distribution system consisted of cast iron and ductile iron pipe and steel pipe that
23 is not cathodically protected and is, therefore, susceptible to corrosion. These are

1 all considered vulnerable materials that will need to be replaced. The Company
2 projects that its construction expenditures will approximate \$9,260 million during
3 the period 2024-2028, which represents approximately 71% (\$9,260 million ÷
4 \$13,128 million) of its net utility plant as of December 31, 2023. Of these
5 amounts, construction expenditures for the gas division are expected to be \$1,907
6 million during the period 2024-2028.

<u>Year</u>	<u>Construction</u>
2024	\$1,691,000
2025	\$1,829,000
2026	\$1,930,000
2027	\$1,905,000
2028	\$1,905,000
Total	<u>\$9,260,000</u>

7 **20. Q. How should the Commission respond to the issues facing natural gas utilities**
8 **in general and PECO in particular?**

9 A. The Commission should recognize and take into account the high-risk profile of
10 PECO's Gas Division and its future capital requirements in determining the cost
11 of equity for the Company. A fair rate of return is key to PECO maintaining a
12 financial profile that will provide it with the ability to raise the capital necessary
13 to meet its capital needs on reasonable terms.

14 **21. Q. How should the Commission respond to the evolving business environment**
15 **facing the Company?**

16 A. In the situation where additional capital is required, as shown by the projected
17 construction expenditures indicated above, the regulatory process must establish a

1 return on equity that provides a reasonable opportunity for the Company to
2 actually achieve its cost of capital. Where ongoing capital investment is required
3 to meet the high quality of service that customers demand, supportive regulation
4 is essential to the Company's ability to raise capital in all market conditions and
5 to satisfy investor requirements in an evolving industry.

6 III. FUNDAMENTAL RISK ANALYSIS

7 **22. Q. Is it necessary to conduct a fundamental risk analysis to provide a**
8 **framework for the determination of the cost of equity?**

9 A. Yes. It is necessary to establish a company's relative risk position within its
10 industry through a fundamental analysis of various quantitative and qualitative
11 factors which bear upon investors' assessment of overall risk. The qualitative
12 factors that bear upon the Company's risk have already been discussed. The
13 quantitative risk analysis follows. For this purpose, I have compared PECO to the
14 S&P Public Utilities, an industry-wide proxy consisting of all types of public
15 utility endeavors, and the Gas Group.

16 **23. Q. What are the components of the S&P Public Utilities?**

17 A. The S&P Public Utilities is a widely recognized index comprised of electric
18 power and natural gas companies. These companies are identified on page 3 of
19 Schedule 4. I have used this group as a broad-based measure of all types of
20 regulated public utility endeavors.

1 **24. Q. What companies comprise your Gas Group?**

2 A. My Gas Group consists of the following companies: Atmos Energy Corp.,
3 Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc.,
4 Northwest Natural Holding Co., ONE Gas, Inc., Southwest Gas Holdings, and
5 Spire, Inc.

6 **25. Q. Is knowledge of a utility's bond rating an important factor in assessing its**
7 **risk and cost of capital?**

8 A. Yes. Knowledge of a company's credit quality rating is an important determinant
9 in analyzing a company's cost of equity because the cost of each type of capital is
10 directly related to the associated risk of the firm. So, while a company's credit
11 quality risk is directly shown by the rating and yield on its bonds, these relative
12 risk assessments also bear upon the cost of equity. This is because a firm's cost
13 of equity is represented by its borrowing cost plus a premium to recognize the
14 higher risk of an equity investment compared to debt.

15 **26. Q. How do the bond ratings compare for PECO, the Gas Group, and the S&P**
16 **Public Utilities?**

17 A. Presently, the issuer credit rating for PECO is BBB+ (A on First Mortgage
18 Bonds) from Standard and Poor's Corporation ("S&P") and the Long Term
19 ("LT") issuer rating is A2 (Aa3 on First Mortgage Bonds) from Moody's
20 Investors Services ("Moody's"). The issuer credit rating designation by S&P and
21 LT issuer rating by Moody's focus upon the credit quality of the issuer of the
22 debt, rather than upon the debt obligation itself. The Company's credit quality is
23 similar to that of the Gas Group, which has an average A3 and A- credit rating

1 from Moody's and S&P, respectively. For the S&P Public Utilities, the average
2 composite credit rating is A3 by Moody's and BBB+ by S&P. Many of the
3 financial indicators which I will subsequently discuss are considered during the
4 rating process.

5 **27. Q. How do the financial data compare for PECO, the Gas Group, and the S&P**
6 **Public Utilities?**

7 A. The broad categories of financial data that I will discuss are shown on Schedules
8 2, 3 and 4. The data cover the five-year period 2018-2022. I will highlight the
9 important categories of relative risk may be summarized as follows:

10 Size. In terms of capitalization, PECO is larger than the average size of
11 the Gas Group and the S&P Public Utilities. All other things being equal, a
12 smaller company is riskier than a larger company, because a given change in
13 revenue and expense has a proportionately greater impact on a small firm.

14 Market Ratios. Historical market-based financial ratios, such as price-
15 earnings multiples and dividend yields, provide a partial measure of the investor-
16 required cost of equity. If all other factors are equal, investors will require a
17 higher rate of return for companies which exhibit greater risk, in order to
18 compensate for that risk. That is to say, a firm that investors perceive to have
19 higher risks will experience a lower price per share in relation to expected
20 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).

1 Since PECO's stock is not traded, there are no market ratios for the
2 Company. The five-year average price-earnings multiple was equivalent for the
3 Gas Group and the S&P Public Utilities. The five-year average dividend yield
4 was lower for the Gas Group as compared to the S&P Public Utilities. The five-
5 year average market-to-book ratio was somewhat lower for the Gas Group as
6 compared to the S&P Public Utilities.

7 Common Equity Ratio. The level of financial risk is measured by the
8 proportion of long-term debt and other senior capital that is contained in a
9 company's capitalization. Financial risk is also analyzed by comparing common
10 equity ratios (the complement of the ratio of debt and other senior capital). That
11 is to say, a firm with a high common equity ratio has lower financial risk, while a
12 firm with a low common equity ratio has higher financial risk. The following
13 common equity ratios are computed from balance sheet values that represent book
14 value. The five-year average common equity ratios, based on permanent capital
15 book value, were 53.8% for PECO, 49.0% for the Gas Group, and 40.5% for the
16 S&P Public Utilities. The Company's common equity ratio was higher than the
17 Gas Group, thereby indicating somewhat lower financial risk. Significantly, for
18 this case, the Company's common equity ratio is within the range of other gas
19 distribution utilities.

20 Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's
21 earned returns signifies relatively greater levels of risk, as shown by the
22 coefficient of variation (standard deviation ÷ mean) of the rate of return on book
23 common equity. The higher the coefficients of variation, the greater degree of
24 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.

1 S&P Public Utilities. The interest coverages were similar for the Company and
2 the Gas Group, thereby indicating similar risk.

3 Quality of Earnings. Measures of earnings quality usually are revealed
4 by the percentage of AFUDC related to income available for common equity, the
5 effective income tax rate, and other cost deferrals. These measures of earnings
6 quality usually influence a firm's internally generated funds because poor quality
7 of earnings would not generate high levels of cash flow. Quality of earnings has
8 not been a significant concern for the Company, the Gas Group and the S&P
9 Public Utilities.

10 Internally Generated Funds. Internally generated funds ("IGF") provide
11 an important source of new investment capital for a utility and represent a key
12 measure of credit strength. Historically, the five-year average percentage of IGF
13 to capital expenditures was 49.9% for PECO, 56.3% for the Gas Group, and
14 62.3% for the S&P Public Utilities. The Company's average IGF to construction
15 percentage has been weaker than the Gas Group and S&P Public Utilities
16 indicating more risk for the Company. The Company's IGF to construction
17 expenditures will be under pressure in future years as its construction
18 expenditures continue to increase.

19 Betas. The financial data that I have been discussing relate primarily to
20 company-specific risks. Market risk for firms with publicly-traded stock is
21 measured by beta coefficients. Beta coefficients attempt to identify systematic
22 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.

1 markets, as PECO does, the operating public utility's own capital structure ratios
2 should be used to determine its overall rate of return. Additionally, if the
3 Company's actual capital structure ratios are used, as they should be, then
4 consistency requires that the embedded cost rates associated with the senior
5 securities reflected in those capital structure ratios should also be employed.

6 **30. Q. Does Schedule 5 provide the Company's capitalization and capital structure**
7 **ratios?**

8 A. Yes. The capitalization and capital structure ratios at December 31, 2023, 2024,
9 and 2025 correspond with the end of the historic test year ("HTY"), future test
10 year ("FTY"), and fully projected future test year ("FPFTY") in this case. The
11 capitalization and capital structure ratios for the FTY and FPFTY reflect the
12 Company's plan to issue \$575 million of new long-term debt in 2024, and \$975
13 million in 2025. There is a \$350 million debt maturity in FPFTY. Future equity
14 financings include \$580 million in the FTY and \$472 million in the FPFTY. The
15 build-up of retained earnings is also reflected. In presenting the Company's
16 capital structure on Schedule 5, I have removed the call premiums on the early
17 redemption of high-cost long-term debt and preferred stock.

18 **31. Q. Please describe the adjustment for the call premiums paid to redeem high-**
19 **cost debt and preferred stock**

20 A. I have adjusted the principal amounts of long-term debt to exclude the amounts
21 used to finance premiums paid for the early redemption of long-term debt and
22 preferred stock previously redeemed. To do otherwise would deny PECO the
23 opportunity to recover the costs (i.e., a return on and of the money used to fund

1 the call premiums) it incurred solely to redeem high-cost capital. The additional
2 debt PECO issued to finance the call premiums does not increase the Company's
3 rate base. That is to say, no additional rate base was created as a consequence of
4 issuing additional debt and preferred stock to finance the redemptions. Therefore,
5 an adjustment to the capitalization is required to provide the return necessary to
6 service the additional capital PECO issued to fund the call premiums. Thus,
7 while rate base does not change, the return component of the overall cost of
8 capital reflects an adjustment that, when applied to the rate base, furnishes the
9 return necessary to pay the cost of the incremental capitalization that supported
10 the call premiums paid by PECO.

11 The adjustment for call premiums is appropriate because customers
12 receive all of the cost savings, in the form of a lower overall rate of return,
13 produced by refinancing higher-cost debt and preferred stock, while PECO is
14 simply made whole by recovering the actual costs it incurred to provide these
15 benefits to its customers. In order to produce the savings that resulted from
16 redeeming higher-cost debt and preferred stock, the Company paid to the holders
17 of that debt and preferred stock a premium to surrender their securities prior to
18 maturity. Those premiums represented an investment made by PECO to reduce
19 its overall cost of capital. Because the reduced interest costs and preferred stock
20 dividends are reflected in the lower cost of capital to customers, it is proper that
21 the Company recover the costs incurred to produce these savings, which consist
22 of a return of and a return on the unamortized premiums. Adjusting the principal
23 amounts in the capital structure provides for the appropriate cost recovery by

1 providing a return on the funds used to pay the premiums, which is reflected as an
2 increment included in the embedded cost rates of PECO's total capital.

3 **32. Q. Should short-term debt be included in the capital structure for rate of return**
4 **purposes?**

5 A. No. There is no need to consider short-term debt in the capital structure because
6 the amount of short-term debt is well below the construction work in progress
7 ("CWIP") at the end of the FTY and the FPFTY. Exclusion of short-term debt is
8 required because it finances CWIP and hence the cost of short-term debt is
9 reflected in the AFUDC rate. To avoid double-counting, short-term debt must be
10 excluded from the capital structure ratios when setting base rates.

11 **33. Q. What capital structure ratios do you recommend for determining PECO's**
12 **overall cost of capital in this proceeding?**

13 A. Because rate-setting is prospective, the rate of return should, at a minimum,
14 reflect known or reasonably foreseeable changes which will occur during the
15 course of the test year. As a result, I will adopt the Company's FPFTY capital
16 structure ratios of 46.60% long-term debt and 53.40% common equity. These
17 ratios are consistent with the Company's current investment grade credit ratings
18 of A2/BBB+.

19

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.

1 **VI. COST OF EQUITY – GENERAL APPROACH**

2 **36. Q. Please describe how you determined the cost of equity for the Company.**

3 A. Although my fundamental financial analysis provides the required framework to
4 establish the risk relationships among PECO, the Gas Group and the S&P Public
5 Utilities, the cost of equity must be measured by standard financial models I
6 identified above. Differences in risk traits, such as size, business diversification,
7 geographical diversity, regulatory policy, financial leverage and bond ratings,
8 must be considered when analyzing the cost of equity.

9 It is also important to reiterate that no one method or model of the cost of
10 equity can be applied in an isolated manner. Rather, informed judgment must be
11 used to take into consideration the relative risk traits of the firm. It is for this
12 reason that I have used more than one method to measure the Company's cost of
13 equity. As I describe below, each of the methods used to measure the cost of
14 equity contains certain incomplete and/or overly restrictive assumptions and
15 constraints that are not optimal. Therefore, I favor considering the results from a
16 variety of methods. In this regard, I applied each of the methods with data taken
17 from the Gas Group and arrived at a cost of equity of 11.15% for PECO including
18 an increment for management performance.

19 **VII. DISCOUNTED CASH FLOW**

20 **37. Q. Please describe the DCF model.**

21 A. The DCF model seeks to explain the value of an asset as the present value of
22 future expected cash flows discounted at the appropriate risk-adjusted rate of

1 return. In its simplest form, the DCF-determined return on common stock
2 consists of a current cash (dividend) yield and future price appreciation (growth)
3 of the investment. The dividend discount equation is the familiar DCF valuation
4 model, which assumes that future dividends are systematically related to one
5 another by a constant growth rate. The DCF formula is derived from the standard
6 valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of
7 equity, and g = growth in cash flows. By rearranging the terms, we obtain the
8 familiar DCF equation: $k = D/P + g$. All of the terms in the DCF equation
9 represent investors' assessment of expected future cash flows that they will
10 receive in relation to the value that they set for a share of stock (P). The DCF
11 equation is sometimes referred to as the "Gordon" model.⁵ My DCF results are
12 provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 12.05%
13 with the leverage adjustment and 10.74% without the leverage adjustment for the
14 Gas Group. The leverage adjustment is discussed more fully below.

15 Among the limitations of the model, there is a certain element of
16 circularity in the DCF method when applied in rate cases. This is because
17 investors' expectations for the future depend upon regulatory decisions. In turn,
18 when regulators depend upon the DCF model to set the cost of equity, they rely
19 upon investor expectations that include an assessment of how regulators will
20 decide rate cases. Due to this circularity, the DCF model may not fully reflect the
21 true risk of a utility. Other limitations of the DCF include the constant P-E
22 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 expounded the DCF model in its present form nearly two decades earlier.

1 And, indeed, the FERC has moved to using multiple methods for measuring the
2 cost of equity due to the limitations of the DCF. Hence, the DCF should always
3 be used along with other methods that are more responsive to changes in interest
4 rates.

5 While the results of a DCF analysis should certainly be given weight, the
6 use of more than one method provides a superior foundation for the cost of equity
7 determination. Since all cost of equity methods contain certain unrealistic and
8 overly restrictive assumptions, the use of more than one method will capture the
9 multiplicity of factors that motivate investors to commit capital to an enterprise
10 (i.e., current income, capital appreciation, preservation of capital, level of risk
11 bearing). I am aware that the Commission usually expresses its cost of equity
12 determination in the context of the DCF model. But the Commission also
13 considers other methods as well. In its order entered on December 28, 2012, in
14 Docket No. R-2012-2290597, the Commission stated:

15 Sole reliance on one methodology without checking the
16 validity of the results of that methodology with other cost
17 of equity analyses does not always lend itself to
18 responsible ratemaking. We conclude that methodologies
19 other than the DCF can be used as a check upon the
20 reasonableness of the DCF derived equity return
21 calculation.⁶

22
23 Similarly, in the later Aqua Pennsylvania decision, the Commission observed:

24 In the 2012 PPL Order, the Commission considered PPL's
25 CAPM and RP methods, tempered by informed judgment,
26 instead of DCF-only results. We conclude that
27 methodologies other than the DCF can be used as a check
28 upon the reasonableness of the DCF derived ROE
29 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.

1 the DCF methodology in arriving at ROE determinations
2 and have utilized the results of the CAPM as a check upon
3 the reasonableness of the DCF derived equity return. As
4 such, where evidence based on other methods suggests that
5 the DCF-only results may understate the utility's ROE, we
6 will consider those other methods, to some degree, in
7 determining the appropriate range of reasonableness for
8 our equity return determination.⁷
9

10 Again, the Commission recognized the need for additional methods in its

11 decision for Columbia Water.

12 In *Aqua 2022*, the Commission determined the ROE by
13 using informed judgement based on I&E's DCF and CAPM
14 methodologies. We conclude that methodologies other than
15 the DCF can be used as a check upon the reasonableness of
16 the DCF derived ROE calculation. We historically have
17 primarily relied upon the DCF methodology in arriving at
18 ROE determinations and utilized the results of the CAPM,
19 as a check upon the reasonableness of the DCF derived
20 equity return. As such, where evidence based on other
21 methods suggests that the DCF-only results may understate
22 the utility's ROE, we will consider those other methods, to
23 some degree, in determining the appropriate range of
24 reasonableness for our ROE determination.⁸
25

26 The Commission has acknowledged the usefulness of other methods as a
27 means of establishing a range of reasonable returns. Indeed, it is clear that the
28 Commission has been guided by the results of other models and other factors
29 aside from DCF when setting the DSIC return. The Commission's selection of
30 the rate of return on equity for use in the DSIC is usually set well above the cost
31 of equity indicated by the DCF model alone.

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.

1 **38. Q. What is the dividend yield component of a DCF analysis?**

2 A. The dividend yield reveals the portion of investors' cash flow that is generated by
3 the return provided by the dividends an investor receives. It is measured by the
4 dividends per share relative to the price per share. The DCF methodology
5 requires the use of an expected dividend yield to establish the investor-required
6 cost of equity. For the 12 months ended December 2023, the monthly dividend
7 yields are shown on Schedule 7. The month-end prices were adjusted to reflect
8 the buildup of the dividend in the price that has occurred since the last ex-
9 dividend date (i.e., the date by which a shareholder must own the shares to be
10 entitled to the dividend payment – usually about two to three weeks prior to the
11 actual payment).

12 For the 12 months ended December 2023, the average dividend yield was
13 3.61% for the Gas Group based upon a calculation using annualized dividend
14 payments and adjusted month-end stock prices. The dividend yields for the more
15 recent six-month and three-month periods were 3.85% and 4.00%, respectively.
16 In applying the DCF model, I have used the six-month average dividend yield of
17 3.85% for the Gas Group. The use of this dividend yield will reflect current
18 capital costs while avoiding spot yields. For the purpose of a DCF calculation,
19 the average dividend yield must be adjusted to reflect the prospective nature of
20 the dividend payments, i.e., the higher expected dividends for the future. Recall
21 that the DCF is an expectational model that must reflect investors' anticipated
22 cash flows. I have adjusted the six-month average dividend yield in three
23 different but generally accepted manners and used the average of the three

1 adjusted values as calculated in the lower panel of data presented on Schedule 7.⁹
2 This adjustment adds 14 basis points to the six-month average historical yield,
3 thus producing the 3.99% adjusted dividend yield for the Gas Group.

4 **39. Q. What factors influence investors' growth expectations?**

5 A. As noted previously, investors are interested principally in the dividend yield and
6 future growth of their investment (i.e., the price per share of the stock). Future
7 growth in earnings per share is the DCF model's primary focus because, under the
8 model's assumption that the P-E multiple remains constant, the price per share of
9 stock will grow at the same rate as earnings per share. A growth rate analysis
10 considers a variety of variables to reach a consensus on prospective growth,
11 including historical data and widely available analysts' forecasts of earnings,
12 dividends, book value and cash flow (all stated on a per-share basis). A
13 fundamental growth rate analysis is frequently based upon internal growth
14 ("b x r"), where "r" is the expected rate of return on common equity and "b" is the
15 retention rate (a fraction representing the proportion of earnings not paid out as
16 dividends). To be complete, the internal growth rate should be modified to
17 account for sales of new common stock (external growth), which is represented
18 by the formula $s \times v$, 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.

1 expects to issue and “v” is the value that accrues to existing shareholders from
2 selling stock at a price above book value. Fundamental growth, which combines
3 internal and external growth, encompasses the factors that cause book value per
4 share to grow over time.

5 Growth also can be expressed in multiple stages. This expression of
6 growth consists of an initial “growth” stage during which a firm enjoys rapidly
7 expanding markets, high profit margins and abnormally high growth in earnings
8 per share. Thereafter, a firm enters a “transition” stage during which fewer
9 technological advances and increased product saturation begin to reduce the
10 growth rate and profit margins come under pressure. During the “transition”
11 stage, investment opportunities begin to mature, capital requirements decline and
12 a firm begins to pay out a larger percentage of earnings to shareholders. Finally,
13 the mature or “steady-state” stage is reached when a firm’s earnings growth,
14 payout ratio and return on equity stabilize at levels where they remain for the life
15 of a firm. The three stages of growth assume a step-down of high initial growth
16 to lower sustainable growth. Even if these three stages of growth can be
17 envisioned for a firm, the third “steady-state” growth stage, which is assumed to
18 remain fixed in perpetuity, represents an unrealistic expectation because the three
19 stages of growth can be repeated. That is to say, the stages can be repeated where
20 growth for a firm ramps up and ramps down in cycles over time. For these
21 reasons, there is no need to analyze growth rates individually for each cycle but
22 rather to rely upon analysts’ growth forecasts used by investors when pricing
23 common stocks.

- 1 **40. Q. What factor should be considered in the determination of an appropriate**
2 **growth rate?**
- 3 A. The growth rate used in a DCF calculation should measure investor expectations.
4 Investors consider both company-specific variables and overall market sentiment
5 (i.e., level of inflation rates, interest rates, economic conditions, etc.) when
6 balancing their capital gains expectations with their dividend yield requirements.
7 Investors are not influenced solely by a single set of company-specific variables
8 weighted in a formulaic manner. Therefore, all relevant growth rate indicators
9 should be evaluated using a variety of techniques when formulating a judgment of
10 investor-expected growth.
- 11 **41. Q. What data for the Gas Group have you considered in your growth rate**
12 **analysis?**
- 13 A. I considered the growth in the financial variables shown on Schedule 8 and
14 Schedule 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates
15 of growth in earnings per share, dividends per share, book value per share and
16 cash flow per share for the Gas Group. While analysts will review all measures of
17 growth, as I have done, earnings per share growth directly influences the
18 expectations of investors for the future performance of utility stocks. Forecasts of
19 earnings growth are required because the DCF model is forward-looking, and
20 with the constant P-E multiple and constant payout ratio that the DCF model
21 assumes, all other measures of growth will mirror earnings growth. The historical
22 growth rates, which were also reviewed to gain a perspective on the industry,
23 were obtained from the Value Line publication that provides this data. While

1 historical data cannot be ignored, they are much less significant when applying
2 the DCF model than projections of future growth. Investors cannot purchase the
3 past earnings of a utility. To the contrary, they are only entitled to future
4 earnings, which are the focus of growth projections. Furthermore, if significant
5 weight is assigned to historical performance, the historical data are double-
6 counted because they are already factored into analysts' forecasts of earnings
7 growth.

8 **42. Q. Is a five-year investment horizon associated with the analysts' forecasts**
9 **consistent with the traditional DCF model?**

10 A. Yes, it is. Although the constant form of the DCF model assumes an infinite
11 stream of cash flows, investors do not expect to hold an investment indefinitely.
12 Rather than viewing the DCF in the context of an endless stream of growing
13 dividends (e.g., a century of cash flows), the growth in the share value (i.e.,
14 capital appreciation or capital gains yield) is most relevant to investors' total
15 return expectations. Hence, the sale price of a stock can be viewed as a
16 liquidating dividend that can be discounted along with the annual dividend
17 receipts during the investment-holding period to arrive at the investors' expected
18 return. The growth in the price per share will equal the growth in earnings per
19 share if, as the DCF model assumes, there is no change in the P-E multiple. As
20 such, my company-specific growth analysis, which focuses principally on five-
21 year forecasts of earnings per share growth, conforms with the type of analysis
22 that influences investors' expectations of their actual total return. Moreover,
23 academic research also focuses on five-year growth rates specifically because

1 market outcomes occurring over that investment horizon are what influence stock
2 prices. Indeed, if investors required forecasts beyond five years in order to
3 properly value common stocks, then it would be reasonable to expect that some
4 investment advisory service would begin publishing that information for
5 individual stocks to meet the demands of the marketplace. The absence of such a
6 publication suggests that there is no market for this information because investors
7 do not require forecasts for an infinite series of future data points to make
8 informed decisions to purchase and sell stocks.

9 **43. Q. What are the analysts' forecasts of future growth that you considered?**

10 A. Schedule 9 provides projected earnings per share growth rates taken from
11 analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line.
12 These are all reliable authorities of projected growth that investors use to make
13 buy, sell and hold decisions. The IBES/First Call and Zacks estimates are
14 obtained from the Internet and are widely available to investors. The growth rates
15 reported by IBES/First Call and Zacks are consensus forecasts taken from a
16 survey of analysts that make growth projections for these companies. Notably,
17 First Call's earnings forecasts are frequently quoted in the financial press. The
18 Value Line forecasts are also widely available to investors and can be obtained by
19 subscription or free of charge at most public and collegiate libraries. The
20 IBES/First Call and Zacks forecasts are limited to earnings per share growth,
21 while Value Line makes projections of other financial variables. The Value Line
22 forecasts of dividends per share, book value per share, and cash flow per share for
23 the Gas Group are also included on Schedule 9.

1 **44. Q. What are the projected growth rates published by the sources you discussed?**

2 A. Schedule 9 shows the prospective five-year earnings per share growth rates
3 projected for the Gas Group by IBES/First Call (5.87%), Zacks (5.69%) and
4 Value Line (7.31%).

5 **45. Q. Are certain growth rate forecasts entitled to greater weight in developing a**
6 **growth rate for use in the DCF model?**

7 A. Yes. While various factors should be examined to reach a reasonable conclusion
8 on the DCF growth rate, growth in earnings per share should receive the greatest
9 emphasis. Growth in earnings per share is the primary determinant of investors'
10 expectations of the total returns they will obtain from stocks because the capital
11 gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple
12 remains constant, as the DCF model assumes. Moreover, earnings per share
13 (derived from net income) are the source of dividend payments and are the
14 primary driver of retention growth and its surrogate, i.e., book value per share
15 growth. As such, under these circumstances, greater emphasis must be placed
16 upon projected earnings per share growth. In fact, Professor Gordon, the
17 foremost proponent of the use of the DCF model in setting utility rates, concluded
18 that the best measure of growth for use in the DCF model is a forecast of earnings
19 per-share growth.¹⁰ Consistent with Professor Gordon's findings, projections of
20 earnings per share growth, such as those published by IBES/First Call, Zacks and
21 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).

1 **46. Q. What growth rate do you use in your DCF model?**

2 A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average
3 earnings per share growth rates from 5.69% to 7.31%. DCF growth rates should
4 not be established by mathematical formulation, and I have not done so. In my
5 opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected
6 growth for the Gas Group. This value is within the array of analysts' forecasts of
7 five-year earnings per share growth rates. The reasonableness of this growth rate
8 is also supported by the expected continuation of gas utility infrastructure
9 spending.

10 **47. Q. Are the dividend yield and growth components of the DCF adequate to**
11 **accurately depict the rate of return on common equity when it is used to**
12 **calculate a utility's weighted average overall cost of capital?**

13 A. The components of the DCF model are adequate for that purpose only if the
14 capital structure ratios are measured by the market value of debt and equity. In
15 the case of the Gas Group, average capital structure ratios are 37.01% long-term
16 debt, 1.37% preferred stock, and 61.62% common equity, as shown on Schedule
17 10. These ratios are calculated from market values based on the fair value of debt
18 and preferred stock, if any, and the price of each company's common stock.
19 Hence, all values here related to the investors' valuation of debt and equity in the
20 capital markets. If book values are used to compute the capital structure ratios,
21 then a leverage adjustment is required in the case where the capital structure ratios
22 vary from market values.

1 **48. Q. What is a leverage adjustment?**

2 A. If a firm's capitalization, as measured by its stock price, diverges from its
3 capitalization, measured at book value, the potential exists for a financial risk
4 difference. Such a risk difference arises because a market-valued capitalization
5 contains more equity and less debt than a book-value capitalization and, therefore,
6 has less risk than the book-value capitalization. A leverage adjustment properly
7 accounts for the risk differential between market-value and book-value capital
8 structures.

9 **49. Q. Why is a leverage adjustment appropriate?**

10 A. In order to make the DCF results relevant to the capitalization measured at book
11 value (as is done for rate-setting purposes), the market-derived cost rate must be
12 adjusted to account for this difference in financial risk. The only perspective that
13 is important to investors is the return they can realize on the market value of their
14 investment. As I have measured the DCF, the simple yield (D/P) plus growth (g)
15 provides a return applicable strictly to the price (P) that an investor is willing to
16 pay for a share of stock. The need for the leverage adjustment arises when the
17 results of the DCF model (k) are to be applied to a capital structure that is
18 different from the capital structure indicated by the market price (P). From the
19 market perspective, the financial risk of the Gas Group is accurately measured by
20 the capital structure ratios calculated from the market-valued capitalization of a
21 firm. If the ratemaking process utilized the market capitalization ratios, then no
22 additional analysis or adjustment would be required, and the simple yield (D/P)
23 plus growth (g) components of the DCF would satisfy the financial risk associated

1 with the market value of the equity capitalization. Because the ratemaking
2 process uses ratios calculated from a firm's book value capitalization, further
3 analysis is required to synchronize the financial risk of the book capitalization
4 with the required return on the book value of the firm's equity. This adjustment is
5 developed through precise mathematical calculations using well-recognized
6 analytical procedures that are widely accepted in the financial literature. To
7 arrive at that return, the rate of return on common equity is the unleveraged cost
8 of capital (or equity return at 100% equity) plus one or more terms reflecting the
9 increase in financial risk resulting from the use of leverage in the capital structure.
10 The calculations presented in the lower panel of data shown on Schedule 10,
11 under the heading "M&M,"¹¹ provide a return of 9.09% when applicable to a
12 capital structure with 100% common equity.

13 **50. Q. Are there specific factors that influence market-to-book ratios that**
14 **determine whether the leverage adjustment should be made?**

15 A. No. The leverage adjustment is not intended, nor was it designed, to address the
16 reasons that stock prices vary from book value. Hence, any observations
17 concerning market prices relative to book value are not on point. The leverage
18 adjustment deals with the issue of financial risk and does not transform the DCF
19 result to a book value return through a market-to-book adjustment. Again, the
20 leverage adjustment that I propose is based on the fundamental financial precept
21 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.

1 where the overall rate of return equates to the cost of equity with a capital
2 structure that contains 100% equity) plus the additional return required for
3 introducing debt and/or preferred stock leverage into the capital structure.

4 Further, as noted previously, the relatively high market prices of utility
5 stocks cannot be attributed solely to the notion that these companies are expected
6 to earn a return on the book value of equity that differs from their cost of equity
7 determined from stock market prices. Stock prices above book value are common
8 for utility stocks, and indeed, the stock prices of non-regulated companies exceed
9 book values by even greater margins. It is difficult to accept that the vast majority
10 of all firms operating in our economy are generating returns far in excess of their
11 cost of capital. Certainly, in our free-market economy, competition should
12 contain such “excesses” if they actually exist.

13 Finally, the leverage adjustment adds stability to the final DCF cost rate.
14 That is to say, as the market capitalization increases relative to its book value, the
15 leverage adjustment increases while the simple yield (D/P) plus growth (g) result
16 declines. The reverse is also true: when the market capitalization declines, the
17 leverage adjustment also declines as the simple yield (D/P) plus growth (g) result
18 increases.

19 **51. Q. Is the leverage adjustment that you propose designed to transform the**
20 **market return into one that is designed to produce a particular market-to-**
21 **book ratio?**

22 A. No, it is not. What I label a “leverage adjustment” is merely a convenient way of
23 showing the amount that must be added to (or subtracted from) the result of the

1 simple DCF model (i.e., $D/P + g$) when the DCF return applies to a capital
2 structure used for ratemaking that is computed with book-value weighting rather
3 than market-value weighting. Although I specify a separate factor, which I call
4 the leverage adjustment, there is no need to do so other than to identify this factor.
5 If I were to express my return solely in the context of the book value weighting
6 that we use to calculate the weighted average cost of capital and ignore the
7 familiar $D/P + g$ expression entirely, then a separate element in the DCF cost of
8 equity determination would not be needed to reflect the differential in financial
9 leverage between a market-value and book-value capitalization. As shown in the
10 bottom panel of data on Schedule 10, the equity return applicable to the book
11 value common equity ratio is equal to 9.09%, which is the return for the Gas
12 Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio)
13 plus 2.85% to compensate investors for the risk of 51.40% debt ratio and 0.11%
14 for a 1.59% preferred stock ratio. These are the book-value ratios that differ
15 markedly from the market-value based ratios I discussed previously. Under this
16 approach, the parts add up to 12.05% ($9.09\% + 2.85\% + 0.11\%$), and there is no
17 need to even address the cost of equity in terms of $D/P + g$. To express this same
18 return in the context of the familiar DCF model, I added the 3.99% dividend
19 yield, the 6.75% growth rate, and 1.31% for the leverage adjustment to arrive at
20 the same 12.05% return computed directly with the M&M formula. I know of no
21 means to mathematically solve for the 1.31% leverage adjustment by expressing it
22 in the terms of any particular relationship of market price to book value. The
23 1.31% adjustment is merely a convenient way to compare the 12.05% return
24 computed using the M&M formulas to the 10.74% return generated by the DCF

model (i.e., $D_1/P_0 + g$, 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 (D_1/P_0) 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:

$$D_1/P_0 + g + lev. = k$$

$$\text{Gas Group} \quad 3.99\% + 6.75\% + 1.31\% = 12.05\%$$

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

1 return on common stock market prices without regard to the prospect of a change
2 in the P-E multiple. An assumption that there will be no change in the P-E
3 multiple is not supported by the realities of the equity market because P-E
4 multiples do not remain constant. This is one of the constraints of this model that
5 makes it important to consider the results of other models when determining a
6 company's cost of equity.

7 **VIII. RISK PREMIUM ANALYSIS**

8 **53. Q. Please describe your use of the Risk Premium approach to determine the cost**
9 **of equity.**

10 A. With the Risk Premium approach, the cost of equity capital is determined by
11 corporate bond yields plus a premium to account for the fact that common equity
12 is exposed to greater investment risk than debt capital. The result of my Risk
13 Premium study is shown on page 2 of Schedule 1. That result is 11.50%.

14 **54. Q. What long-term public utility debt cost rate did you use in your Risk**
15 **Premium analysis?**

16 A. In my opinion, and as I will explain in more detail further in my testimony, a
17 5.00% yield represents a reasonable estimate of the prospective yield on long-
18 term, public utility bonds. The 5.00% public utility bond yield I used in the Risk
19 Premium method is very conservative given current interest rates.

20 **55. Q. What historical data are shown by the Moody's data?**

21 A. I have analyzed the historical yields on the Moody's index of long-term public
22 utility debt as shown on Schedule 11, page 1. For the 12 months ended December

1 2023 the average monthly yield on Moody's index A-rated public utility bonds
2 was 5.54%. For the six- and three-month periods ended December 2023, the
3 yields were 5.78% and 5.91%, respectively. During the 12 months ended
4 December 2023, the range of the yields on A-rated public utility bonds were
5 5.13% to 6.34%. Page 2 of Schedule 11 shows the long-run spread in yields
6 between A-rated public utility bonds and long-term Treasury bonds. As shown on
7 page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded
8 those on Treasury bonds by 1.45% on a twelve-month average basis, 1.37% on a
9 six-month average basis, and 1.32% on a three-month average basis. With these
10 data, 1.25% represents a reasonable, albeit conservative, spread for the yield on
11 A-rated public utility bonds over Treasury bonds.

12 **56. Q. What forecasts of interest rates have you considered in your analysis?**

13 A. I have determined the prospective yield on A-rated public utility debt by using the
14 Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields
15 that I describe above. Blue Chip is a reliable authority and contains consensus
16 forecasts of various interest rates compiled from a panel of banking, brokerage
17 and investment advisory services. In early 1999, Blue Chip stopped publishing
18 forecasts of yields on A-rated public utility bonds because the Federal Reserve
19 deleted these yields from its Statistical Release H.15. To independently project a
20 forecast of the yields on A-rated public utility bonds, I have combined the forecast
21 yields on long-term Treasury bonds published on December 28, 2023, and a yield
22 spread of 1.25%, derived from recent historical data.

1 **57. Q. How have you used these data to project the yield on A-rated public utility**
2 **bonds for the purpose of your Risk Premium analyses?**

3 A. Shown below is my calculation of the prospective yield on A-rated public utility
4 bonds using the building blocks discussed above, i.e., the Blue Chip forecast of
5 Treasury bond yields and the public utility bond yield spread. For comparative
6 purposes, I have also shown the Blue Chip forecasts of Aaa-rated and Baa-rated
7 corporate bonds. These forecasts are:

Blue Chip Financial Forecasts						
Year	Quarter	Corporate		30-Year	A-rated Public Utility	
		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%

8 **58. Q. Are there additional forecasts of interest rates that extend beyond those**
9 **shown above?**

10 A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In
11 its December 1, 2023 publication, Blue Chip published longer-term forecasts of
12 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%

1 The longer-term forecasts by Blue Chip suggest that interest rates will
2 continue to be above pre-Pandemic levels. A 5.00% yield on A-rated public
3 utility bonds represents a reasonably conservative benchmark for measuring the
4 cost of equity in this case. All the data I used to formulate my conclusion as to a
5 prospective yield on A-rated public utility debt are based on forecasts available to
6 investors, who regularly rely upon such data to make investment decisions. In
7 this case, I have taken a conservative approach in selecting a 5.00% yield on A-
8 rated public utility bonds, because current rates and forecasts would support a
9 higher rate. My rate will accommodate reductions that may occur later in 2024.

10 **59. Q. What equity risk premium have you determined for public utilities?**

11 A. To develop an appropriate equity risk premium, I analyzed the results from 2022
12 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that
13 the equity risk premium varies according to the level of interest rates. That is to
14 say, the equity risk premium increases as interest rates decline, and it declines as
15 interest rates increase. This inverse relationship is revealed by the summary data
16 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%

18 Based on my analysis of the historical data, the equity risk premium was
19 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:

$$i + RP = k$$

$$\text{Gas Group} \quad 5.00\% + 6.50\% = 11.50\%$$

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

1 excluding the leverage adjustment (i.e., $1.10 - 0.87 = 0.23$). To compute the cost
2 of equity with the CAPM, three components are necessary: a risk-free rate of
3 return (“Rf”), the beta measure of systematic risk (“ β ”) and the market risk
4 premium (“ $R_m - R_f$ ”) derived from the total return on the market of equities
5 reduced by the risk-free rate of return. The CAPM specifically accounts for
6 differences in systematic risk (i.e., market risk as measured by the beta) between
7 an individual firm or group of firms and the entire market of equities.

8 **62. Q. What betas have you considered in the CAPM?**

9 A. For my CAPM analysis, I initially considered the Value Line betas. As shown on
10 page 2 of Schedule 3, the average beta is 0.87 for the Gas Group.

11 **63. Q. Did you use the Value Line betas in the CAPM determined cost of equity?**

12 A. I used the Value Line betas as a foundation for the leverage-adjusted betas that I
13 used in the CAPM. The Value Line betas are measured over a five-year period.
14 The betas must be reflective of the financial risk associated with the ratemaking
15 capital structure that is measured at book value. Therefore, Value Line betas
16 cannot be used directly in the CAPM, unless the cost rate developed using those
17 betas is applied to a capital structure measured with market values. Since we used
18 book values in this case, the Value Line betas must be adjusted for the higher
19 financial risk associated with the book value capital structure. To develop a
20 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:

$$\beta_l = \beta_u [1 + (1 - t) D/E + P/E]$$

β_l = the leveraged beta, β_u = 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.

1 respectively. During the 12 months ended December 2023, the range of the yields
2 on 30-year Treasury bonds was 3.66% to 4.95%.

3 Due to high inflation rates above the policy goal of the FOMC, the
4 accommodative policy was ended by the FOMC in the first quarter of 2022. A
5 tighter monetary policy was put in place and resulted in higher interest rates.
6 After the FOMC ended its bond-buying program (i.e., quantitative easing) in
7 March 2022, it is in the process of running off its \$9 trillion asset portfolio, which
8 will keep interest rates at elevated levels.

9 High interest rates clearly point to high capital costs as indicated by
10 recent bond yields. The yield on 10-year Treasury bonds moved above the 3%
11 level on May 2, 2022, for the first time since late 2018. By December 2023, the
12 yield on 30-year Treasury bonds moved to 4.14%, or an increase of 2.47% (or
13 148%) since December 2020.

14 As shown on page 2 of Schedule 13, forecasts published by Blue Chip on
15 December 28, 2023, indicate that the yields on long-term Treasury bonds are
16 expected to be in the range of 4.0% to 4.3% during the next six quarters. This
17 means that elevated interest rates will continue near current levels. The longer-
18 term forecasts show that the yields on 30-year Treasury bonds will average 4.1%
19 from 2025 through 2029 and 4.2% from 2030 to 2034. Hence, I have used a
20 conservative 3.75% risk-free rate of return for CAPM purposes, which considers
21 the possibility of some moderation of rates prospectively.

- 1 **65. Q. What market premium have you used in the CAPM?**
- 2 A. As shown in the lower panel of data presented on page 2 of Schedule 13, the
- 3 market premium is derived from historical data and the forecast returns. For the
- 4 historically based market premium, I have used the arithmetic mean obtained
- 5 from the data presented on page 1 of Schedule 12. On that schedule, the market
- 6 return was 12.21% ($12.40\% + 12.02\% = 24.42\% \div 2$) as the midpoint of the “low”
- 7 and “average” interest rate environments. During those periods, the yield on
- 8 long-term government bonds was 3.87% ($2.83\% + 4.91\% = 7.74\% \div 2$). The
- 9 resulting market premium is 8.34% ($12.21\% - 3.87\%$) based on historical data, as
- 10 shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I
- 11 calculated the forecast returns, which show a 11.93% total market return based on
- 12 the Value Line forecasts. With these data, I calculated a market premium of
- 13 8.18% ($11.93\% - 3.75\%$) using the forecast data by Value Line. The resulting
- 14 market premium applicable to the CAPM derived from these sources equals
- 15 8.26% ($8.18\% + 8.34\% = 16.52\% \div 2$).
- 16 **66. Q. What does your CAPM analysis show?**
- 17 A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.10 for the
- 18 Gas Group, and the 8.26% market premium, the following result is indicated.

$$R_f + \beta \times (R_m - R_f) = k$$

$$\text{Gas Group} \quad 3.75\% + 1.10 \times (8.26\%) = 12.84\%$$

19

1 **X. COMPARABLE EARNINGS APPROACH**

2 **67. Q. What is the Comparable Earnings approach?**

3 A. The Comparable Earnings approach estimates a fair return on equity by
4 comparing returns realized by non-regulated companies to returns that a public
5 utility with similar risk characteristics would need to realize to compete for
6 capital. Because regulation is a substitute for competitively determined prices,
7 the returns realized by non-regulated firms with comparable risks to a public
8 utility provide useful insight into investor expectations for public utility returns.
9 The firms selected for the Comparable Earnings approach should be companies
10 whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms)
11 so that circularity is avoided.

12 There are two avenues available to implement the Comparable Earnings
13 approach. One method involves the selection of another industry (or industries)
14 with comparable risks to the public utility in question, and the results for all
15 companies within that industry serve as a benchmark. The second approach
16 requires the selection of parameters that represent similar risk traits for the public
17 utility and the comparable risk companies. Using this approach, the business lines
18 of the comparable companies become unimportant. The latter approach is
19 preferable with the further qualification that the comparable risk companies
20 exclude regulated firms in order to avoid the circular reasoning implicit in the use
21 of the achieved earnings/book ratios of other regulated firms. The United States
22 Supreme Court has held that:

23 A public utility is entitled to such rates as will permit it to
24 earn a return on the value of the property which it

1 employs for the convenience of the public equal to that
2 generally being made at the same time and in the same
3 general part of the country on investments in other
4 business undertakings which are attended by
5 corresponding risks and uncertainties. The return should
6 be reasonably sufficient to assure confidence in the
7 financial soundness of the utility and should be adequate,
8 under efficient and economical management, to maintain
9 and support its credit and enable it to raise the money
10 necessary for the proper discharge of its public duties.¹³

11 It is important to identify the returns earned by firms that compete for
12 capital with a public utility. This can be accomplished by analyzing the returns of
13 non-regulated firms that are subject to the competitive forces of the marketplace.

14 **68. Q. Did you compare the results of your DCF and CAPM analyses to the results**
15 **indicated by a Comparable Earnings approach?**

16 A. Yes. I selected companies from The Value Line Investment Survey that have six
17 categories of comparability designed to reflect the risk of the Gas Group. These
18 screening criteria were based upon the range as defined by the rankings of the
19 companies in the Gas Group. The items considered were Timeliness Rank, Safety
20 Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank.
21 The definition for these parameters is provided on page 3 of Schedule 14. The
22 identities of the companies comprising the Comparable Earnings group and their
23 associated rankings within the ranges are identified on Schedule 14, page 1.

24 I relied upon Value Line data because it provides a comprehensive basis
25 for evaluating the risks of the comparable firms. As to the returns calculated by
26 Value Line for these companies, there is some downward bias in the figures

¹³ *Bluefield*, at 668.

1 shown on page 2 of Schedule 14, because Value Line computes the returns on
2 year-end rather than average book value. If average book values had been
3 employed, the rates of return would have been slightly higher. Nevertheless,
4 these are the returns considered by investors when taking positions in these
5 stocks. Because many of the comparability factors, as well as the published
6 returns, are used by investors in selecting stocks, and the fact that investors rely
7 on the Value Line service to gauge returns, it is an appropriate database for
8 measuring comparable return opportunities

9 **69. Q. What data did you consider in your Comparable Earnings analysis?**

10 A. I used both historical realized returns and forecasted returns for non-utility
11 companies. As noted previously, I have not used returns for utility companies to
12 avoid the circularity that arises from using regulatory-influenced returns to
13 determine a regulated return. It is appropriate to consider a relatively long
14 measurement period in the Comparable Earnings approach to cover conditions
15 over an entire business cycle. A ten-year period (five historical years and five
16 projected years) is sufficient to cover an average business cycle. Unlike the DCF
17 and CAPM, the results of the Comparable Earnings method can be applied
18 directly to the book value capitalization. In other words, the Comparable
19 Earnings approach does not contain the potential misspecification contained in
20 market models when the market capitalization and book value capitalization
21 diverge significantly. A point of demarcation was chosen to eliminate the results
22 of highly profitable enterprises, which the *Bluefield* case stated were not the type
23 of returns that a utility was entitled to earn. For this purpose, I used 20% as the

1 point where those returns could be viewed as highly profitable and should be
2 excluded from the Comparable Earnings approach. The average historical rate of
3 return on book common equity was 12.6% using only the returns that were less
4 than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of
5 return, as published by Value Line, is 13.6% also using values less than 20%, as
6 provided on page 2 of Schedule 14. Using the average of these data, my
7 Comparable Earnings result is 13.10%, as shown on page 2 of Schedule 1.

8 **XI. CONCLUSION ON COST OF EQUITY**

9 **70. Q. What is your conclusion regarding the Company's cost of common equity?**

10 A. Based upon the application of a variety of methods and models described
11 previously, it is my opinion that a reasonable rate of return on common equity is
12 11.15% for the Gas Division of PECO, which includes my quantification of the
13 additional risk of the Gas Division using an analysis of E/P ratios and fifteen basis
14 points or 0.15% for recognition of the Company's strong management
15 performance (which is well within the 5 to 25 basis point range of management
16 performance provisions that the Commission has recognized previously). My
17 cost of equity recommendation is within the range of results and should be
18 considered in the context of the Company's risk characteristics relative to the Gas
19 Group companies. It is essential that the Commission employ a variety of
20 techniques to measure the Company's cost of equity because of the
21 limitations/infirmities that are inherent in each method. In summary, the
22 Company should be provided an opportunity to realize an 11.15% rate of return
23 on common equity so that it can compete in the capital markets, attain reasonable

1 credit quality, sustain its cash flow in the context of its high levels of capital
2 expenditures, and receive recognition of the significant accomplishments that
3 management has achieved.

4 **71. Q. Does this complete your direct testimony?**

5 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 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
Index of Schedules

	<u>Schedule</u>
Summary Cost of Capital	1
PECO Energy Company Historical Capitalization and Financial Statistics	2
Gas Group Historical Capitalization and Financial Statistics	3
Standard & Poor's Public Utilities Historical Capitalization and Financial Statistics	4
PECO Energy Company Capitalization and Capital Structure Ratios	5
PECO Energy Company Embedded Cost of Long-Term Debt	6
Dividend Yields	7
Historical Growth Rates	8
Projected Growth Rates	9
Financial Risk Adjustment	10
Interest Rates for Investment Grade Public Utility Bonds	11
Common Equity Risk Premium	12
Component Inputs for the Capital Market Pricing Model	13
Comparable Earnings Approach	14

PECO Energy Company
Proposed Rate of Return
Estimated at December 31, 2025

<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
Long-Term Debt	46.60%	4.58%	2.13%
Common Equity	<u>53.40%</u>	11.15%	<u>5.95%</u>
Total	<u>100.00%</u>		<u>8.08%</u>

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⁾	+	β	⁽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	<u>\$10,598.0</u>	<u>\$ 9,493.0</u>	<u>\$ 8,510.0</u>	<u>\$ 7,767.0</u>	<u>\$ 7,088.0</u>	
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%
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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%
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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

	<u>2022</u>	<u>2021</u>	<u>2020</u>	<u>2019</u>	<u>2018</u>	
	(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	<u>\$ 8,475.6</u>	<u>\$ 7,871.7</u>	<u>\$ 6,337.9</u>	<u>\$ 5,832.6</u>	<u>\$ 5,296.8</u>	
Market-Based Financial Ratios						<u>Average</u>
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⁾	<u>45.7%</u>	<u>44.2%</u>	<u>49.6%</u>	<u>52.0%</u>	<u>53.6%</u>	<u>49.0%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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⁾	<u>41.2%</u>	<u>39.7%</u>	<u>46.1%</u>	<u>47.2%</u>	<u>47.7%</u>	<u>44.4%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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.

Ticker	Company	Corporate Credit Ratings		Stock Traded	Value Line Beta
		Moody's	S&P		
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 Comp.	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		<u>A3</u>	<u>A-</u>		<u>0.87</u>

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

	<u>2022</u>	<u>2021</u>	<u>2020</u>	<u>2019</u>	<u>2018</u>	
			(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	<u>\$ 43,850.3</u>	<u>\$ 41,551.7</u>	<u>\$ 39,887.0</u>	<u>\$ 37,683.5</u>	<u>\$ 34,291.9</u>	
Market-Based Financial Ratios						<u>Average</u>
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 Capital:						
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⁾	<u>39.6%</u>	<u>40.4%</u>	<u>39.4%</u>	<u>41.0%</u>	<u>42.5%</u>	<u>40.5%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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⁾	<u>37.9%</u>	<u>38.9%</u>	<u>38.1%</u>	<u>39.6%</u>	<u>40.7%</u>	<u>39.1%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
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⁾		Common Stock Traded	Value Line Beta
		Moody's	S&P		
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
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		<u>A3</u>	<u>BBB+</u>		<u>0.90</u>

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		
	Amount Outstanding (\$000)	Capital Structure Ratios Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding (\$000)	Capital Structure Ratios Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding (\$000)	Capital Structure Ratios Incl. S-T Debt	Excl. S-T Debt
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

<u>Series</u>	<u>Date of Maturity</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
<u>First and Refunding Mortgage Bonds</u>					
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%
<u>Trust Preferred Capital Securities</u>					
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		<u>\$ 5,383,554,609</u>			
Annualized Cost		\$ 227,222,465			
Adjustment for Tenders and Calls on Reacquired Debt		<u>341,000</u>			
Total Cost		<u>\$ 227,563,465</u>			<u>4.23%</u>

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

<u>Series</u>	<u>Date of Maturity</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
<u>First and Refunding Mortgage Bonds</u>					
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%
<u>Trust Preferred Capital Securities</u>					
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		<u>\$ 5,958,829,609</u>			
Annualized Cost		\$ 259,830,651			
Adjustment for Tenders and Calls on Reacquired Debt		<u>68,000</u>			
Total Cost		<u>\$ 259,898,651</u>			<u>4.36%</u>

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

<u>Series</u>	<u>Date of Maturity</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
<u>First and Refunding Mortgage Bonds</u>					
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%
<u>Trust Preferred Capital Securities</u>					
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		<u>\$ 6,583,897,609</u>			
Annualized Cost		\$ 301,566,372			
Adjustment for Tenders and Calls on Reacquired Debt		<u>68,000</u>			
Total Cost		<u>\$ 301,634,372</u>			<u>4.58%</u>

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⁾
<u>First and Refunding Mortgage Bonds</u>								
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%
<u>Trust Preferred Capital Securities</u>								
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**

<u>Company</u>	<u>Jan-23</u>	<u>Feb-23</u>	<u>Mar-23</u>	<u>Apr-23</u>	<u>May-23</u>	<u>Jun-23</u>	<u>Jul-23</u>	<u>Aug-23</u>	<u>Sep-23</u>	<u>Oct-23</u>	<u>Nov-23</u>	<u>Dec-23</u>	<u>12-Month Average</u>	<u>6-Month Average</u>	<u>3-Month Average</u>
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)	<u>4.01%</u>	<u>4.13%</u>	<u>4.12%</u>	<u>4.28%</u>	<u>4.51%</u>	<u>4.55%</u>	<u>4.56%</u>	<u>4.99%</u>	<u>5.11%</u>	<u>5.47%</u>	<u>5.01%</u>	<u>4.86%</u>			
Average	<u>3.23%</u>	<u>3.30%</u>	<u>3.30%</u>	<u>3.42%</u>	<u>3.49%</u>	<u>3.49%</u>	<u>3.47%</u>	<u>3.72%</u>	<u>3.92%</u>	<u>4.15%</u>	<u>4.04%</u>	<u>3.82%</u>	<u>3.61%</u>	<u>3.85%</u>	<u>4.00%</u>

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	$K = \frac{D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^2 + D_0(1+g)^3}{P_0} + g$
		3.85%	1.033750	3.98%	
	Discrete	D_0/P_0	Adj.	D_1/P_0	$K = \frac{D_0(1+g)^{25} + D_0(1+g)^{50} + D_0(1+g)^{75} + D_0(1+g)^{100}}{P_0} + g$
		3.85%	1.041843	4.01%	
	Quarterly	D_0/P_0	Adj.	D_1/P_0	$K = \left[\left(1 + \frac{D_0(1+g)^{25}}{P_0} \right)^4 - 1 \right] + g$
		0.9625%	1.016464	3.97%	
	Average			3.99%	
	Growth rate			<u>6.75%</u>	
	K			<u>10.74%</u>	

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	Dividends Per Share	Book Value Per Share	Cash Flow Per Share	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 Corporator	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	<u>5.87%</u>	<u>5.69%</u>	<u>7.31%</u>	<u>5.25%</u>	<u>5.69%</u>	<u>6.38%</u>	<u>4.19%</u>

Source of Information : Yahoo Finance, January 17, 2024
 Zacks, January 17, 2024
 Value Line Investment Survey, November 24, 2023

Gas Group
Financial Risk Adjustment

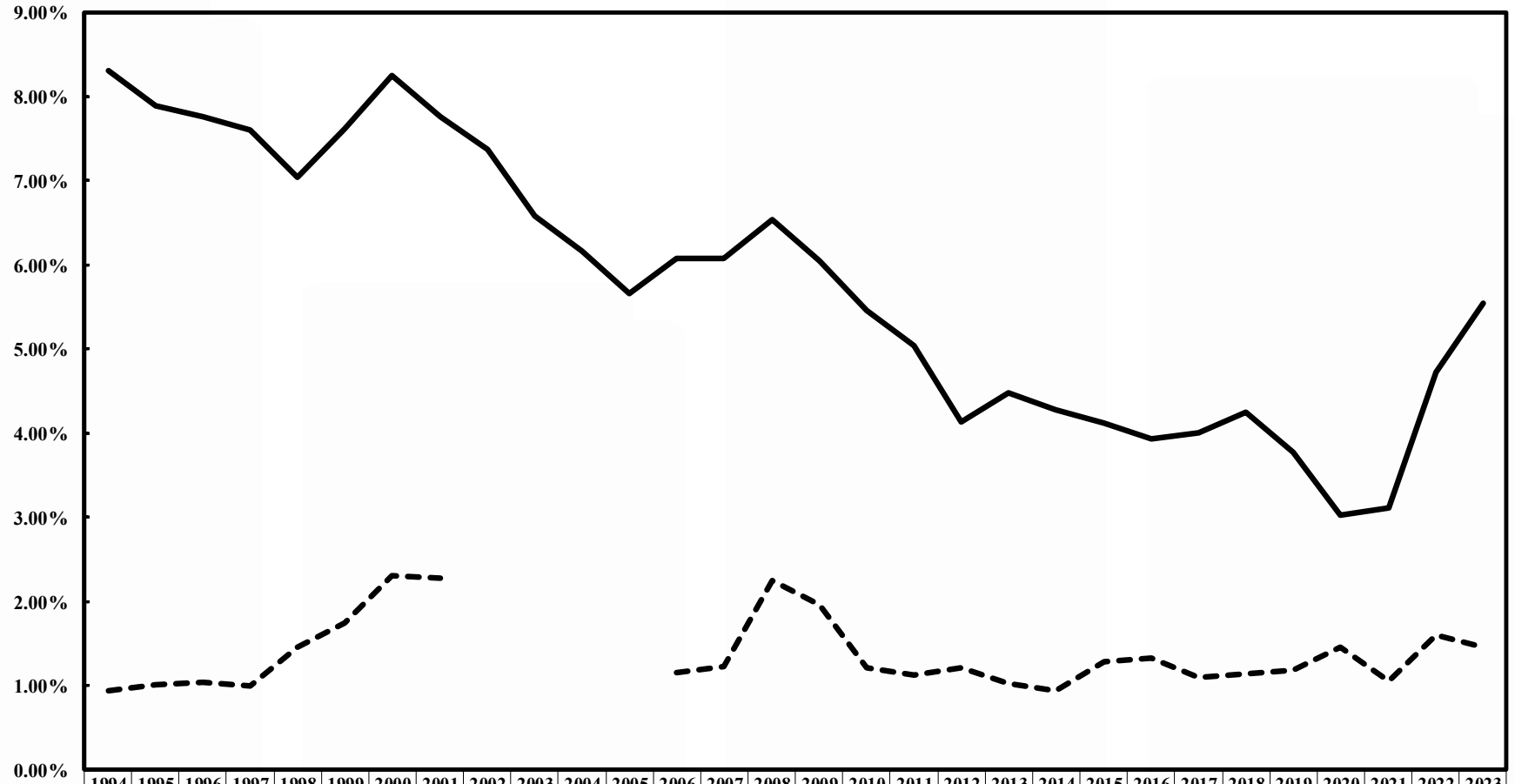
	ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	Southwest Gas (SWX)	Spire Inc. (NYSE:SR)	Average
Fiscal Year	09/30/23	12/31/22	09/30/23	12/31/22	12/31/22	12/31/22	12/31/22	09/30/23	
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									
BI	=	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									
BI	=	0.58	[1+	(1 - t)	D/E	+	P/E	]	
BI	=	0.58	[1+	0.79	1.0934	+	0.0337	]	
BI	=	0.58	1.8975						
BI	=	1.10							
M&M									
ku	=	ke	-	((	ku	-	i	)	
9.09%	=	10.74%	-	((	9.09%	-	5.78%	)	
9.09%	=	10.74%	-	((	3.31%	-		)	
9.09%	=	10.74%	-	((	2.61%	-		)	
9.09%	=	10.74%	-		1.57%	-			
M&M									
ke	=	ku	+	((	ku	-	i	)	
12.05%	=	9.09%	+	((	9.09%	-	5.78%	)	
12.05%	=	9.09%	+	((	3.31%	-		)	
12.05%	=	9.09%	+	((	2.61%	-		)	
12.05%	=	9.09%	+		2.85%	-			

**Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2017-2022
and the Twelve Months Ended December 2023**

<u>Years</u>	<u>Aa Rated</u>	<u>A Rated</u>	<u>Baa Rated</u>	<u>Average</u>
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	<u>3.60%</u>	<u>3.77%</u>	<u>4.13%</u>	<u>3.84%</u>
<u>Months</u>				
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	<u>5.39%</u>	<u>5.54%</u>	<u>5.84%</u>	<u>5.59%</u>
Six-Month Average	<u>5.65%</u>	<u>5.78%</u>	<u>6.08%</u>	<u>5.83%</u>
Three-Month Average	<u>5.76%</u>	<u>5.91%</u>	<u>6.16%</u>	<u>5.94%</u>

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		Year	A-rated Public Utility	30-Year Treasuries		Year	A-rated Public Utility	30-Year Treasuries		Year	A-rated Public Utility	30-Year Treasuries	
		Yield	Spread			Yield	Spread			Yield	Spread			Yield	Spread
Jan-99	6.97%	5.16%	1.81%	Jan-06	5.75%			Jan-13	4.15%	3.08%	1.07%	Jan-19	4.35%	3.04%	1.31%
Feb-99	7.09%	5.37%	1.72%	Feb-06	5.82%	4.54%	1.28%	Feb-13	4.18%	3.17%	1.01%	Feb-19	4.25%	3.02%	1.23%
Mar-99	7.26%	5.58%	1.68%	Mar-06	5.98%	4.73%	1.25%	Mar-13	4.20%	3.16%	1.04%	Mar-19	4.16%	2.98%	1.18%
Apr-99	7.22%	5.55%	1.67%	Apr-06	6.29%	5.06%	1.23%	Apr-13	4.00%	2.93%	1.07%	Apr-19	4.08%	2.94%	1.14%
May-99	7.47%	5.81%	1.66%	May-06	6.42%	5.20%	1.22%	May-13	4.17%	3.11%	1.06%	May-19	3.98%	2.82%	1.16%
Jun-99	7.74%	6.04%	1.70%	Jun-06	6.40%	5.15%	1.25%	Jun-13	4.53%	3.40%	1.13%	Jun-19	3.82%	2.57%	1.25%
Jul-99	7.71%	5.98%	1.73%	Jul-06	6.37%	5.13%	1.24%	Jul-13	4.68%	3.61%	1.07%	Jul-19	3.69%	2.57%	1.12%
Aug-99	7.91%	6.07%	1.84%	Aug-06	6.20%	5.00%	1.20%	Aug-13	4.73%	3.76%	0.97%	Aug-19	3.29%	2.12%	1.17%
Sep-99	7.93%	6.07%	1.86%	Sep-06	6.00%	4.85%	1.15%	Sep-13	4.80%	3.79%	1.01%	Sep-19	3.37%	2.16%	1.21%
Oct-99	8.06%	6.26%	1.80%	Oct-06	5.98%	4.85%	1.13%	Oct-13	4.70%	3.68%	1.02%	Oct-19	3.39%	2.19%	1.20%
Nov-99	7.94%	6.15%	1.79%	Nov-06	5.80%	4.69%	1.11%	Nov-13	4.77%	3.80%	0.97%	Nov-19	3.43%	2.28%	1.15%
Dec-99	8.14%	6.35%	1.79%	Dec-06	5.81%	4.68%	1.13%	Dec-13	4.81%	3.89%	0.92%	Dec-19	3.40%	2.30%	1.10%
Jan-00	8.35%	6.63%	1.72%	Jan-07	5.96%	4.85%	1.11%	Jan-14	4.63%	3.77%	0.86%	Jan-20	3.29%	2.22%	1.07%
Feb-00	8.25%	6.23%	2.02%	Feb-07	5.90%	4.82%	1.08%	Feb-14	4.53%	3.66%	0.87%	Feb-20	3.11%	1.97%	1.14%
Mar-00	8.28%	6.05%	2.23%	Mar-07	5.85%	4.72%	1.13%	Mar-14	4.51%	3.62%	0.89%	Mar-20	3.50%	1.46%	2.04%
Apr-00	8.29%	5.85%	2.44%	Apr-07	5.97%	4.87%	1.10%	Apr-14	4.41%	3.52%	0.89%	Apr-20	3.19%	1.27%	1.92%
May-00	8.70%	6.15%	2.55%	May-07	5.99%	4.90%	1.09%	May-14	4.26%	3.39%	0.87%	May-20	3.14%	1.38%	1.76%
Jun-00	8.36%	5.93%	2.43%	Jun-07	6.30%	5.20%	1.10%	Jun-14	4.29%	3.42%	0.87%	Jun-20	3.07%	1.49%	1.58%
Jul-00	8.25%	5.85%	2.40%	Jul-07	6.25%	5.11%	1.14%	Jul-14	4.23%	3.33%	0.90%	Jul-20	2.74%	1.31%	1.43%
Aug-00	8.13%	5.72%	2.41%	Aug-07	6.24%	4.93%	1.31%	Aug-14	4.13%	3.20%	0.93%	Aug-20	2.73%	1.36%	1.37%
Sep-00	8.23%	5.83%	2.40%	Sep-07	6.18%	4.79%	1.39%	Sep-14	4.24%	3.26%	0.98%	Sep-20	2.84%	1.42%	1.42%
Oct-00	8.14%	5.80%	2.34%	Oct-07	6.11%	4.77%	1.34%	Oct-14	4.06%	3.04%	1.02%	Oct-20	2.95%	1.57%	1.38%
Nov-00	8.11%	5.78%	2.33%	Nov-07	5.97%	4.52%	1.45%	Nov-14	4.09%	3.04%	1.05%	Nov-20	2.85%	1.62%	1.23%
Dec-00	7.84%	5.49%	2.35%	Dec-07	6.16%	4.53%	1.63%	Dec-14	3.95%	2.83%	1.12%	Dec-20	2.77%	1.67%	1.10%
Jan-01	7.80%	5.54%	2.26%	Jan-08	6.02%	4.33%	1.69%	Jan-15	3.58%	2.46%	1.12%	Jan-21	2.91%	1.82%	1.09%
Feb-01	7.74%	5.45%	2.29%	Feb-08	6.21%	4.52%	1.69%	Feb-15	3.67%	2.57%	1.10%	Feb-21	3.09%	2.04%	1.05%
Mar-01	7.68%	5.34%	2.34%	Mar-08	6.21%	4.39%	1.82%	Mar-15	3.74%	2.63%	1.11%	Mar-21	3.44%	2.34%	1.10%
Apr-01	7.94%	5.65%	2.29%	Apr-08	6.29%	4.44%	1.85%	Apr-15	3.75%	2.59%	1.16%	Apr-21	3.30%	2.30%	1.00%
May-01	7.99%	5.78%	2.21%	May-08	6.28%	4.60%	1.68%	May-15	4.17%	2.96%	1.21%	May-21	3.33%	2.32%	1.01%
Jun-01	7.85%	5.67%	2.18%	Jun-08	6.38%	4.69%	1.69%	Jun-15	3.79%	3.11%	1.28%	Jun-21	3.16%	2.16%	1.00%
Jul-01	7.78%	5.61%	2.17%	Jul-08	6.40%	4.57%	1.83%	Jul-15	4.40%	3.07%	1.33%	Jul-21	2.95%	1.94%	1.01%
Aug-01	7.59%	5.48%	2.11%	Aug-08	6.37%	4.50%	1.87%	Aug-15	4.25%	2.86%	1.39%	Aug-21	2.95%	1.92%	1.03%
Sep-01	7.75%	5.48%	2.27%	Sep-08	6.49%	4.27%	2.22%	Sep-15	4.39%	2.95%	1.44%	Sep-21	2.96%	1.94%	1.02%
Oct-01	7.63%	5.32%	2.31%	Oct-08	7.56%	4.17%	3.39%	Oct-15	4.29%	2.89%	1.40%	Oct-21	3.09%	2.06%	1.03%
Nov-01	7.57%	5.12%	2.45%	Nov-08	7.60%	4.00%	3.60%	Nov-15	4.40%	3.03%	1.37%	Nov-21	3.02%	1.94%	1.08%
Dec-01	7.83%	5.48%	2.35%	Dec-08	6.52%	2.87%	3.65%	Dec-15	4.35%	2.97%	1.38%	Dec-21	3.13%	1.85%	1.28%
Jan-02	7.66%	5.45%	2.21%	Jan-09	6.39%	3.13%	3.26%	Jan-16	4.27%	2.86%	1.41%	Jan-22	3.33%	2.10%	1.23%
Feb-02	7.54%	5.40%	2.14%	Feb-09	6.30%	3.59%	2.71%	Feb-16	4.11%	2.62%	1.49%	Feb-22	3.68%	2.25%	1.43%
Mar-02	7.76%			Mar-09	6.42%	3.64%	2.78%	Mar-16	4.16%	2.68%	1.48%	Mar-22	3.98%	2.41%	1.57%
Apr-02	7.57%			Apr-09	6.48%	3.76%	2.72%	Apr-16	4.00%	2.62%	1.38%	Apr-22	4.32%	2.81%	1.51%
May-02	7.52%			May-09	6.49%	4.23%	2.26%	May-16	3.93%	2.63%	1.30%	May-22	4.75%	3.07%	1.68%
Jun-02	7.42%			Jun-09	6.20%	4.52%	1.68%	Jun-16	3.78%	2.45%	1.33%	Jun-22	4.86%	3.25%	1.61%
Jul-02	7.31%			Jul-09	5.97%	4.41%	1.56%	Jul-16	3.57%	2.23%	1.34%	Jul-22	4.78%	3.10%	1.68%
Aug-02	7.17%			Aug-09	5.71%	4.37%	1.34%	Aug-16	3.59%	2.26%	1.33%	Aug-22	4.76%	3.13%	1.63%
Sep-02	7.08%			Sep-09	5.53%	4.19%	1.34%	Sep-16	3.66%	2.35%	1.31%	Sep-22	5.28%	3.56%	1.72%
Oct-02	7.23%			Oct-09	5.55%	4.19%	1.36%	Oct-16	3.77%	2.50%	1.27%	Oct-22	5.88%	4.04%	1.84%
Nov-02	7.14%			Nov-09	5.64%	4.31%	1.33%	Nov-16	4.08%	2.86%	1.22%	Nov-22	5.75%	4.00%	1.75%
Dec-02	7.07%			Dec-09	5.79%	4.49%	1.30%	Dec-16	4.27%	3.11%	1.16%	Dec-22	5.28%	3.66%	1.62%
Jan-03	7.07%			Jan-10	5.77%	4.60%	1.17%	Jan-16	4.27%	2.86%	1.41%	Jan-23	5.20%	3.66%	1.54%
Feb-03	6.93%			Feb-10	5.87%	4.62%	1.25%	Feb-16	4.11%	2.62%	1.49%	Feb-23	5.29%	3.80%	1.49%
Mar-03	6.79%			Mar-10	5.84%	4.64%	1.20%	Mar-16	4.16%	2.68%	1.48%	Mar-23	5.39%	3.77%	1.62%
Apr-03	6.64%			Apr-10	5.81%	4.69%	1.12%	Apr-16	4.00%	2.62%	1.38%	Apr-23	5.13%	3.68%	1.45%
May-03	6.36%			May-10	5.50%	4.29%	1.21%	May-16	3.93%	2.63%	1.30%	May-23	5.36%	3.86%	1.50%
Jun-03	6.21%			Jun-10	5.46%	4.13%	1.33%	Jun-16	3.78%	2.45%	1.33%	Jun-23	5.38%	3.87%	1.51%
Jul-03	6.57%			Jul-10	5.26%	3.99%	1.27%	Jul-16	3.57%	2.23%	1.34%	Jul-23	5.41%	3.96%	1.45%
Aug-03	6.78%			Aug-10	5.01%	3.80%	1.21%	Aug-16	3.59%	2.26%	1.33%	Aug-23	5.71%	4.28%	1.43%
Sep-03	6.56%			Sep-10	5.01%	3.77%	1.24%	Sep-16	3.66%	2.35%	1.31%	Sep-23	5.86%	4.47%	1.39%
Oct-03	6.43%			Oct-10	5.10%	3.87%	1.23%	Oct-16	3.77%	2.50%	1.27%	Oct-23	6.34%	4.95%	1.39%
Nov-03	6.37%			Nov-10	5.37%	4.19%	1.18%	Nov-16	4.08%	2.86%	1.22%	Nov-23	5.96%	4.66%	1.30%
Dec-03	6.27%			Dec-10	5.56%	4.42%	1.14%	Dec-16	4.27%	3.11%	1.16%	Dec-23	5.42%	4.14%	1.28%
Jan-04	6.15%			Jan-11	5.57%	4.52%	1.05%	Jan-17	4.14%	3.02%	1.12%	Recent Average: 12-months: 1.45% 6-months: 1.37% 3-months: 1.32%			
Feb-04	6.15%			Feb-11	5.68%	4.65%	1.03%	Feb-17	4.18%	3.03%	1.15%				
Mar-04	5.97%			Mar-11	5.56%	4.51%	1.05%	Mar-17	4.23%	3.08%	1.15%				
Apr-04	6.35%			Apr-11	5.55%	4.50%	1.05%	Apr-17	4.12%	2.94%	1.18%				
May-04	6.62%			May-11	5.32%	4.29%	1.03%	May-17	4.12%	2.96%	1.16%				
Jun-04	6.46%			Jun-11	5.26%	4.23%	1.03%	Jun-17	3.94%	2.80%	1.14%				
Jul-04	6.27%			Jul-11	5.27%	4.27%	1.00%	Jul-17	3.99%	2.88%	1.11%				
Aug-04	6.14%			Aug-11	4.69%	3.65%	1.04%	Aug-17	3.86%	2.80%	1.06%				
Sep-04	5.98%			Sep-11	4.48%	3.18%	1.30%	Sep-17	3.87%	2.78%	1.09%				
Oct-04	5.94%			Oct-11	4.52%	3.13%	1.39%	Oct-17	3.91%	2.88%	1.03%				
Nov-04	5.97%			Nov-11	4.25%	3.02%	1.23%	Nov-17	3.83%	2.80%	1.03%				
Dec-04	5.92%			Dec-11	4.33%	2.98%	1.35%	Dec-17	3.79%	2.77%	1.02%				
Jan-05	5.78%			Jan-12	4.34%	3.03%	1.31%	Jan-18	3.86%	2.88%	0.98%				
Feb-05	5.61%			Feb-12	4.36%	3.11%	1.25%	Feb-18	4.09%	3.13%	0.96%				
Mar-05	5.83%			Mar-12	4.48%	3.28%	1.20%	Mar-18	4.13%	3.09%	1.04%				
Apr-05	5.64%			Apr-12	4.40%	3.18%	1.22%	Apr-18	4.17%	3.07%	1.10%				
May-05	5.53%			May-12	4.20%	2.93%	1.27%	May-18	4.28%	3.13%	1.15%				
Jun-05	5.40%			Jun-12	4.08%	2.70%	1.38%	Jun-18	4.27%	3.05%	1.22%				
Jul-05	5.51%			Jul-12	3.93%	2.59%	1.34%	Jul-18	4.27%	3.01%	1.26%				
Aug-05	5.50%			Aug-12	4.00%	2.77%	1.23%	Aug-18	4.26%	3.04%	1.22%				
Sep-05	5.52%			Sep-12	4.02%	2.88%	1.14%	Sep-18	4.32%	3.15%	1.17%				
Oct-05	5.79%			Oct-12	3.91%	2.90%	1.01%	Oct-18	4.45%	3.34%	1.11%				
Nov-05	5.88%			Nov-12	3.84%	2.80%	1.04%	Nov-18	4.52%	3.36%	1.16%				
Dec-05	5.80%														

Common Equity Risk Premiums
Years 1926-2022

	<u>Large Common Stocks</u>	<u>Long- Term Corp. Bonds</u>	<u>Equity Risk Premium</u>	<u>Long- Term Govt. Bonds Yields</u>
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**

<u>Years</u>	<u>1-Year</u>	<u>2-Year</u>	<u>3-Year</u>	<u>5-Year</u>	<u>7-Year</u>	<u>10-Year</u>	<u>20-Year</u>	<u>30-Year</u>
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	<u>1.53%</u>	<u>1.63%</u>	<u>1.70%</u>	<u>1.82%</u>	<u>1.97%</u>	<u>2.07%</u>	<u>2.41%</u>	<u>2.48%</u>
<u>Months</u>								
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	<u>5.08%</u>	<u>4.58%</u>	<u>4.30%</u>	<u>4.06%</u>	<u>4.02%</u>	<u>3.96%</u>	<u>4.25%</u>	<u>4.09%</u>
Six-Month Average	<u>5.31%</u>	<u>4.86%</u>	<u>4.59%</u>	<u>4.37%</u>	<u>4.36%</u>	<u>4.30%</u>	<u>4.59%</u>	<u>4.41%</u>
Three-Month Average	<u>5.22%</u>	<u>4.80%</u>	<u>4.57%</u>	<u>4.42%</u>	<u>4.46%</u>	<u>4.44%</u>	<u>4.76%</u>	<u>4.58%</u>

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

Year	Quarter	Treasury					Corporate	
		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
Stapan 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 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

TABLE OF CONTENTS

	Page
I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. BACKGROUND INFORMATION AND SUMMARY OF COST-OF-SERVICE STUDY RESULTS	3
III. PECO’S CLASS COST-OF-SERVICE STUDY	5
IV. DEVELOPMENT OF RATE CLASS REVENUE REQUIREMENT	24
V. RESULTS OF THE COST-OF-SERVICE STUDY	25
VI. CONCLUSION	29

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1 requirement modeling and analyses for regulatory initiatives, cost-of-service
2 studies, and base rate case filings.

3 **5. Q. Please describe the purpose of your testimony.**

4 A. I will explain the cost-of-service principles underlying the unbundled, fully
5 allocated class cost-of-service study (“COSS”) that I performed, the methods and
6 procedures employed to perform such study, and the results produced by the
7 COSS.

8 **6. Q. Have you prepared any exhibits to accompany your testimony?**

9 A. Yes. PECO Exhibits JD-1 through JD-7 were prepared by me or under my
10 supervision and are described in detail in my testimony.

11 **7. Q. How is your testimony organized?**

12 A. My testimony is divided into five parts. First, I introduce my testimony and
13 explain its purpose. Second, I provide some background information, identify the
14 exhibits that I am sponsoring, and summarize the results of the COSS. Third, I
15 introduce and discuss the COSS methodology. Fourth, I explain the development
16 of the revenue requirement for each rate class. Fifth, I present the results of the
17 COSS in detail and discuss the contents of the exhibits.

18 **8. Q. Please identify the exhibits that are included with your testimony.**

19 A. The following exhibits are included with my testimony. They are discussed in
20 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

1 through the Gas Procurement Charge (“GPC”) (line 126), a component of
2 the PGC. While the rate increases shown on line 140 are those necessary
3 to move each rate class to the system average rate of return, the Company
4 is not proposing rates that will take all classes to their indicated cost-of-
5 service at this time, as explained in the direct testimony of Mr. Joseph A.
6 Bisti (PECO Statement No. 7).

7 III. PECO’S CLASS COST-OF-SERVICE STUDY

8 **12. Q. Briefly describe the purpose of a class COSS.**

9 A. The purpose of a COSS is to determine the cost to serve, expressed as revenue
10 requirement, for each rate class served by a utility. The revenue requirement for a
11 rate class is that portion of a utility’s total cost of service attributed to that rate
12 class in accordance with principles of cost causation. In a COSS, all of the
13 utility’s costs of providing service must be analyzed and assigned or allocated
14 among the rate classes. A COSS is used, along with other factors, as discussed in
15 more detail by Mr. Bisti, to design rates that fully recover the utility’s costs.

16 **13. Q. What are the guiding principles for performing a class COSS?**

17 A. The central element in performing a COSS is the determination of allocation
18 factors based on causal relationships between, on the one hand, customer
19 demands, load profiles, and usage characteristics, and, on the other hand, the costs
20 incurred by the Company to meet customers’ service requirements imposed by
21 those demands, load profiles, and usage characteristics. The primary goals in
22 selecting allocation factors are: (1) the appropriate recognition of cost causality;
23 (2) the stability of study methods and their consistent application over time, so

1 that trends in the direction of class revenues relative to cost of service can be
2 discerned properly from case to case; and (3) completeness, such that the COSS
3 captures all of the costs that each class imposes on the distribution system.

4 **14. Q. Please summarize the approach you used in preparing PECO's COSS.**

5 A. As I previously explained, the most critical task in performing any COSS is
6 establishing relationships between customer demands, load profiles, and usage
7 characteristics, and the costs incurred to meet those customer requirements. This
8 requires an understanding of the design of the utility's distribution system how
9 that design relates to the characteristics of the customers it is designed to serve.

10 PECO, like most gas utilities, designs its gas distribution system to meet three
11 primary objectives:

- 12 (1) Extend distribution service to all customers;
- 13 (2) Meet the aggregate design peak day capacity requirements of all
14 customers entitled to receive service on the design peak day; and
- 15 (3) Deliver volumes of natural gas to those customers either on a sales or
16 transportation service basis.

17 The allocation methods used in a COSS must take into account the objectives that
18 the distribution system is designed to achieve so that the allocation of plant
19 investment and operating expenses properly aligns with cost-causation factors.

20 Other factors, such as incentives to influence customer behavior (e.g.,
21 conservation or demand reduction) or to temper the impact on customers of rate
22 changes, are more appropriately considered in the revenue allocation and rate
23 design phase.

1 The PECO COSS performed uses the proprietary Gas Cost-of-Service Model
2 (“Model”) developed by Management Applications Consulting, Inc., which
3 employs a Microsoft Excel platform. The Model facilitates the preparation of the
4 COSS, accelerates computations, and develops appropriate documentation. The
5 Model uses a three-step process to allocate or assign costs to rate classes, in
6 accordance with general cost of service principles. These three steps consist of:
7 (1) functionalizing rate base, purchased gas supply costs, and expenses to
8 determine the particular rate schedules that should share responsibility for each of
9 those assets and costs; (2) classifying functionalized costs into demand-related,
10 commodity-related, and customer-related cost categories to facilitate allocating
11 such costs to rate schedules in accordance with identifiable characteristics; and (3)
12 allocating the functionalized, classified costs among rate classes. The Model
13 provides functionalized, classified cost information by rate class, develops
14 unbundled revenue requirements by functional classification and in total for each
15 rate class, and calculates unit costs.

16 **15. Q. Please identify the rate classes that are included in the COSS.**

17 A. The following nine rate classes are included: (1) GR - General Service -
18 Residential; (2) GC - General Service - Commercial and Industrial; (3) L - Large
19 High Load Factor Service; (4) MV-F - Motor Vehicle Service-Firm; (5) MV-I -
20 Motor Vehicle Service-Interruptible; (6) IS - Interruptible Service; (7) TCS -
21 Temperature Controlled Service; (8) TS-F - Gas Transportation Service-Firm; and
22 (9) TS-I - Gas Transportation Service-Interruptible. In the COSS, the rate class in
23 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

1 allocation phase takes into account the design of the utility system and how it is
2 operated; cost data derived from the utility's accounting records; and usage and
3 load data both for the system overall and for specific customer classes. Based on
4 analyses of the relationship between costs and the factors driving the need to incur
5 such costs, each component of the revenue requirement is either directly assigned
6 to a rate class or an allocator is selected to apportion that component among rate
7 classes.

8 **20. Q. Please explain the term "direct assignment."**

9 A. The term "direct assignment" means identifying specific plant investments or
10 specific expenses incurred exclusively to serve a specific customer or group of
11 customers. Direct assignments reflect a direct causal connection between costs to
12 serve and the customers being served. Therefore, if data are available to make a
13 direct assignment, it is generally the preferred approach.

14 **21. Q. Can significant portions of a utility's assets and expenses generally be**
15 **directly assigned in a COSS?**

16 A. No, most costs must be allocated. Utility service is generally provided to
17 customers by facilities that are used, and expenses that are incurred in common by
18 all, or many, classes of customers. In addition, even in instances where it might
19 be possible to associate specific physical facilities with particular customers, the
20 detailed cost information needed to make a direct assignment may not be
21 reasonably available.

1 **22. Q. Please explain how allocation factors are determined.**

2 A. External and internal allocation factors are typically used to perform a COSS and,
3 consequently, were employed in the Model.

4 An external allocation factor is a factor that is developed from an external source,
5 outside the cost-of-service model. Examples of external allocators are number of
6 customers (CUST) and estimated design day send-out (DPKDAY). PECO
7 Exhibit JD-6 shows the development of the external allocators.

8 An internal allocation factor is one that is developed within the cost-of-service
9 model using other allocated line items. Internal allocators are based on some
10 combination of external allocators, directly assigned costs and other internal
11 allocators. For example, the allocator for property insurance costs is based on
12 plant investment amounts assigned to components of the rate base. It is necessary
13 to compute the rate base before property insurance costs can be assigned.

14 Other examples of internal allocation factors include total operation and
15 maintenance salaries and wages expense (SALWGES) and total gross gas
16 distribution plant (DISTPLT). PECO Exhibit JD-2, pages 18 to 22, shows the
17 internally developed allocation factors.

18 **23. Q. Has PECO changed any of the allocation methods used in PECO's 2022 gas**
19 **base rate proceeding?**

20 A. No, PECO is using the same basic allocation methods that the Company
21 employed in the 2022 proceeding.

1 **24. Q. Turning to the components of PECO’s revenue requirement that are**
2 **assigned or allocated in the COSS, please explain what rate base consists of**
3 **and how it affects the COSS.**

4 A. The rate base is the cost, net of accumulated depreciation, of PECO’s investment
5 in plant and other assets used to serve customers.

6 **25. Q. What is the source of the total rate base amount being allocated or assigned**
7 **to customer classes in the PECO COSS?**

8 A. The total rate base amount employed in the COSS is \$3.52 billion (PECO Exhibit
9 JD-1, line 46) and is derived from PECO Exhibit MJT-1, page 1.

10 **26. Q. What are the major components of PECO’s rate base?**

11 A. For purposes of discussing how I functionalized, classified, and allocated the rate
12 base in the COSS and treated major rate base categories, I will refer to the
13 following groupings of rate base items: production plant, storage plant,
14 distribution plant, general plant, depreciation reserve, other rate base items and
15 cash working capital.

16 **Production plant** represents the investment in LPG production assets which are
17 used to meet design peak day and short-term needs of firm sales customers.

18 These assets have been functionalized to Production, classified to demand, and
19 allocated among rate classes based on design peak day send-out.

20 **Storage plant** represents the investment in LNG facilities which are used to meet
21 design peak day and short-term needs of firm sales customers. These assets have
22

1 been functionalized to Storage, classified to demand, and allocated among rate
2 classes based on design peak day send-out.

3 **Distribution plant** comprises mains, services, meters and meter installation, and
4 other distribution plant. A description of each of those components is as follows:

- 5 • **Mains** were functionalized to Distribution and classified as capacity. A
6 portion of mains costs was directly assigned. The balance of mains costs
7 (approximately 99% of the total) was classified and allocated using the
8 Average and Excess Demand method. In that method, the portion of
9 mains costs equal to the system average load factor is allocated among the
10 rate classes based on their average daily deliveries (annual deliveries
11 divided by 365 days). The balance of mains costs is allocated based on
12 excess demand, which is the excess of design peak demand over average
13 demand. The excess demand is allocated among rate classes in
14 proportion to each class's peak demand over its average demand (PECO
15 Exhibit JD-6, page 5). This method was used by PECO in its 2022 gas
16 base rate case (Docket R-2022-3031113), was recently approved by the
17 Commission in PECO's 2020 gas base rate case (Docket R-2020-
18 3018929), and has been recognized as an acceptable method by the
19 American Gas Association's Gas Rate Fundamentals, 1987 Edition.
- 20 • **Services** are functionalized to their own category, classified as customer-
21 related costs, and allocated among rate classes based on cost per unit

1 (“CPU”) calculations and related ratios by class, as shown in PECO
2 Exhibit JD-6 at page 8.

- 3 • **Meters and meter installation** includes assets that have been
4 functionalized to their own category and classified as customer-related
5 costs. A portion of meter and meter installation costs was directly
6 assigned. The balance of meter and meter installation costs
7 (approximately 99% of the total) was allocated among rate classes based
8 on the average cost of meters of each type for each rate class, as
9 determined from the Company’s records (PECO Exhibit JD-6, pages 7
10 and 9).

- 11 • **Other distribution plant** comprises primarily: (1) measuring and
12 regulating station equipment (“M&R”), a portion of which was directly
13 assigned, and the balance of which was functionalized to Distribution,
14 classified as demand-related, and allocated among the rate classes based
15 on the mains allocation; and (2) land and land rights and structures and
16 improvements, which were functionalized to Distribution, classified as
17 demand-related, and allocated among rate classes based on distribution
18 plant (mains and measuring and regulating station equipment).

19 **General plant** includes primarily structures and improvements, tools and shop
20 and garage equipment. These assets were functionalized, classified, and allocated
21 among rate classes based on direct labor content of operating expenses, reflecting
22 the nature of the assets and common cost-of-service practice.

1 **Depreciation reserve** was based on each asset account. Each component of the
2 depreciation reserve items was functionalized, classified, and allocated among
3 rate classes in the same ratio as the related assets.

4 **Other rate base items** include primarily gas storage inventory, accumulated
5 deferred income taxes (“ADIT”), common plant, customer deposits, customer
6 advances, cash working capital and pension, which are discussed below.

- 7 • **Gas storage inventories** are used to support the planned winter heating
8 requirements of the Company’s sales customers and the daily balancing
9 requirements of all its customers. Gas storage inventories were
10 functionalized and classified to commodity. The Company has identified
11 1.78%¹ of its storage activity that relates to the daily balancing of its
12 transportation service customers (PECO Exhibit JD-6, page 6).
13 Therefore, 1.78% of PECO’s gas storage inventory costs were allocated
14 among its transportation rate classes based on their annual volumes. The
15 remainder of the Company’s storage activity was allocated among the
16 firm sales rate classes based on the average excess of their winter
17 (November-March) gas volumes over their average annual volumes.
- 18 • **ADIT** refers to tax liabilities that are deferred as a result of accelerated
19 depreciation and includes “excess” ADIT that has been removed from the
20 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.

1 **32. Q. What do PECO's customer accounts and customer service expenses include**
2 **and how were those expenses functionalized, classified, and allocated among**
3 **the rate classes?**

4 A. PECO's customer accounts and customer service costs include meter reading
5 expenses, customer records and collection expenses, uncollectible accounts
6 expense, miscellaneous customer accounts expense, customer assistance expense,
7 and demonstrating and selling expense.

8 • **Meter reading expenses** were functionalized to Customer Accounts,
9 classified to the customer category, and allocated among rate classes based on
10 the number of customers.

11 • **Customer records and collection expenses** include activities for billing, call
12 center, payments processing, recoveries, and support for CAP customers.
13 These costs were functionalized to Customer Accounts and classified to the
14 customer category. The account was analyzed in detail to identify the
15 activities included and each activity was allocated among the rate classes
16 using an appropriate basis. For example, the costs of bill activities were
17 allocated based on customer counts, and call center costs were allocated based
18 on a study of calls over a twelve-month period (PECO Exhibit JD-6, page 10).
19 A single customer allocation could not be used because some costs are
20 specific to residential customers while others are specific to commercial and
21 industrial customers. Therefore, a weighted allocator, based upon the analysis
22 discussed above, was used for this account.

1 • **Uncollectible accounts expense**, or bad debt expense, was classified to the
2 customer category. The expense was allocated among rate classes based on
3 the Company’s write-off experience over a historical five-year period (2019-
4 2023) (PECO Exhibit JD-6, page 13).

5 • **Miscellaneous customer accounts expenses** were functionalized to Customer
6 Accounts and classified to the customer category. These expenses include
7 primarily IT support costs and communication and marketing costs. Those
8 costs were allocated among rate classes based on number of customers.

9 • **Customer assistance expense** comprises expenses incurred for the Low
10 Income Usage Reduction Program (“LIURP”). The associated costs were
11 directly assigned to residential customers (PECO Exhibit JD-6, page 11).

12 • **Demonstrating and selling expense** includes expenses incurred in
13 demonstrating activities. The expense was functionalized to Customer
14 Accounts, classified to the customer category, and directly assigned to
15 different customer classes based on the Company’s records (PECO Exhibit
16 JD-6, page 11).

17 **33. Q. How were administrative and general expenses functionalized, classified, and**
18 **allocated among rate classes?**

19 A. Administrative and general (“A&G”) costs include administrative and general
20 salaries, office supplies and expenses, outside services, injuries and damages,
21 employee benefits, property insurance costs, regulatory commission expenses,
22 miscellaneous general expenses, and maintenance of general plant.

1 Except for items discussed immediately below, A&G costs are related to labor
2 costs and therefore were functionalized, classified, and allocated among rate
3 classes in the same ratio as direct labor content.

4 • **Property insurance costs** were functionalized, classified, and allocated
5 among rate classes in the same ratio as plant in service.

6 • **Regulatory commission expenses** were functionalized, classified, and
7 allocated among rate classes in proportion to claimed revenue.

8 • **Maintenance of general plant expenses** were functionalized, classified, and
9 allocated among rate classes in the same ratio as general plant in service.

10 **34. Q. How was depreciation expense functionalized, classified, and allocated**
11 **among the rate classes?**

12 A. Depreciation and amortization expenses were derived from PECO Exhibit CF-3,
13 sponsored by Company witness. Caroline Fulginiti, and PECO Exhibit No. MJT-
14 1, sponsored by Mr. Trzaska, which show depreciation expense by plant account.
15 Each component of depreciation and amortization expense was functionalized,
16 classified, and allocated among rate classes in the same ratio as the related assets.

17 **35. Q. How was Manufactured Gas Plant remediation expense functionalized,**
18 **classified, and allocated among the rate classes?**

19 A. Manufactured Gas Plant (“MGP”) expense is the normalized level of expense for
20 remediating former MGP sites in the Company’s service territory. This cost was
21 allocated among rate classes based on annual gas throughput volumes.

1 **36. Q. How were taxes other than income taxes functionalized, classified, and**
2 **allocated among the rate classes?**

3 A. Taxes other than income tax include payroll-related taxes, Public Utility Realty
4 Tax Act (“PURTA”) taxes, local use taxes, and real estate taxes. Payroll-related
5 taxes were functionalized, classified, and allocated among rate classes based on
6 direct labor expenses. PURTA taxes and real estate taxes were allocated based on
7 total plant in service, and local use taxes based on claimed revenue.

8 **37. Q. How was income tax expense functionalized, classified, and allocated among**
9 **rate classes?**

10 A. Income tax expense was calculated based on revenue at present rates using the
11 same methodology employed by Mr. Trzaska in PECO Exhibit MJT-1, Schedule
12 D-18. Income tax expense was functionalized, classified, and allocated among
13 rate classes based on plant other than Regulatory Asset Programs M-1, which was
14 functionalized, classified and allocated among rate classes based on salaries and
15 wages expense.

16 **38. Q. How were PECO’s revenues at present rates computed and assigned among**
17 **rate classes?**

18 A. The revenues were computed and assigned as follows:

- 19 • **Distribution revenue** at present rates is shown in PECO Exhibit MJT-1,
20 Schedule D-5, and in the proof of revenues set forth in PECO Exhibit JAB-4.
21 The total was assigned to the rate classes based on the same revenue
22 requirement exhibit and the proof of revenues. Distribution revenue at present
23 rates for each rate class is shown on line 5 of PECO Exhibit JD-1.

- 1 • **Purchased gas revenue** consists of revenues collected under the applicable
2 PGC tariff provisions for commodity and balancing service. Commodity
3 revenue and balancing service revenue are determined and assigned based
4 upon PECO's budget. For each rate class, and in total, purchased gas revenue
5 equals the sum of the commodity cost, the balancing service cost, and the
6 revenue requirement for cash working capital.
- 7 • **Forfeited discount revenue** is determined from PECO's budget and was
8 allocated among the rate classes based on an analysis of forfeited discount over
9 a historical three-year period (2021-2023) (PECO Exhibit JD-6, page 14).
- 10 • **Other gas revenue** consists of reimbursement revenues from contracting
11 companies for their employees to conduct necessary operator qualification
12 testing to work on PECO's system and was allocated among the rate classes
13 based on salaries and wages expense.

14 **39. Q. Apart from the COSS being presented in this case, did the Company prepare**
15 **any additional cost of service calculations?**

16 A. Yes. In the Commission-approved Settlement of PECO's 2022 gas base rate
17 proceeding (Docket No. R-2022-3031113), the Company agreed to provide, in its
18 next gas base rate case filing, a good-faith calculation of the costs (both directly
19 assigned and allocated) to serve Negotiated Gas Service ("NGS") customers. The
20 Company's calculations specific to NGS customers are presented in PECO
21 Exhibit JD-7. PECO applied the same cost of service methodology to develop the

1 NGS calculations as was utilized in the COSS proposed by the Company in this
2 case.

3 **IV. DEVELOPMENT OF RATE CLASS**
4 **REVENUE REQUIREMENT**

5 **40. Q. How did you develop the revenue requirement for each class?**

6 A. The revenue requirement for each rate class was calculated using the same
7 method employed by Mr. Trzaska to compute the overall revenue requirement for
8 the FPFTY. Thus, the revenue requirement for each rate class is the sum of that
9 class's forecasted revenue at present rates and change in revenue. The change in
10 revenue for each rate class was computed by multiplying the change in operating
11 income by a gross revenue conversion factor. The change in operating income for
12 each rate class was computed by multiplying the rate class' rate base by the
13 difference between the proposed system average rate of return, which is the same
14 for all rate classes, and the present rate of return. PECO Exhibit JD-1, line 133,
15 shows the total revenue requirement by rate class reflecting the fully allocated
16 distribution cost-of-service at the proposed system average rate of return. PECO
17 Exhibit JD-1, line 81, shows the portion of the total revenue requirement PECO
18 proposes to collect in distribution rates.

19 **41. Q. How did you determine the increase or decrease in revenue needed for each**
20 **class to produce the system average rate of return?**

21 A. The increase or decrease needed for each rate class was calculated by comparing
22 the revenue requirements for each rate class to the forecasted revenue at present
23 rates for that class for the FPFTY. This is the same method used by Mr. Trzaska

1 in PECO Exhibit MJT-1, Schedule A-1, with respect to the overall revenue
2 requirement and revenue deficiency. The increases or (decreases) in rate class
3 revenue needed to produce a rate of return equal to the Company's proposed
4 overall rate of return are shown in PECO Exhibit JD-1 at line 141, which total
5 \$111.17 million. In addition, forfeited discounts (i.e., late payment charges) are
6 expected to increase by \$0.18 million as a result of the increase in distribution
7 revenue (PECO Exhibit JD-1 at line 63). The increases in class distribution
8 revenue are shown on line 83, which total \$110.28 million. The increase in
9 purchased gas revenue of \$1.07 million under the PGC is shown on line 126.

10 **V. RESULTS OF THE COST-OF-SERVICE STUDY**

11 **42. Q. Please describe what is shown on PECO Exhibit JD-1.**

12 A. PECO Exhibit JD-1, which sets forth the substance of the COSS, compares the
13 revenue at current rates by rate class to the revenue requirement allocated on a
14 cost-of-service basis to each rate class. Net income at present rates, shown on line
15 17, is computed by subtracting operating expenses, depreciation and amortization,
16 taxes other than income taxes, and income taxes (lines 10 to 14) from revenue at
17 present rates (line 7). The return on rate base at present rates for each rate class is
18 shown on line 26, and the relative rates of return are shown on line 27.

19 Line 133 shows each rate class's revenue requirement (including revenue from
20 distribution charges and purchased gas) at the proposed overall rate of return.

21 Line 68 shows operating expenses, and line 69 shows depreciation and
22 amortization expense. Lines 79 and 122 show operating income assuming each
23 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.

1 For example, capacity and commodity related cost are divided by Mcf and
2 customer-related cost is divided by number of customers. The unit cost is
3 provided by classification and functional area.

4 **46. Q. Which costs were considered in developing the proposed customer charges?**

5 A. The proposed customer charges are based on the specific customer-classified
6 costs in the COSS that are approved by the Commission for recovery in customer
7 charges. Customer related costs include all costs incurred to attach a customer to
8 the distribution system, for meter usage, and to maintain the customer's account.
9 They include: (1) capital costs associated with services and meters, and general
10 plant supporting the functions identified above; (2) operating and maintenance
11 expenses related to those assets described in (1); and (3) associated administrative
12 and general expense, metering and billing expenses, customer service and account
13 expenses, appropriate pensions and benefits, payroll taxes that are part of the
14 applicable labor expenses, and working capital. Total customer costs by rate class
15 for the FPFTY are shown in PECO Exhibit JD-4, in the unit cost analysis. PECO
16 Exhibit JD-5 provides a summary and each element of measures of value of
17 customer charges.

18 **47. Q. Please describe the information shown on PECO Exhibit JD-6.**

19 A. PECO Exhibit JD-6 presents the development of the main external allocators that
20 are described below and used in the COSS. Except where noted, all data are for
21 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												
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	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 RUPCHASED 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	DPKDAYP	16	11	5	0	0	0	0	0	0	0
RBP	17	361-Structures and Improvements	DPKDAYP	14,932	10,067	4,832	4	30	0	0	0	0	0
RBP	18	362-Gas Holders.	DPKDAYP	7,084	4,775	2,292	2	14	0	0	0	0	0
RBP	19	363-Purification Equipment	DPKDAYP	0	0	0	0	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYP	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		
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		
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		
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		
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												
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												
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
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)
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												

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)
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	ETHRPUTF	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	ETHRPUTF	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

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)
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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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
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)
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	DPKDAYP	363	245	117	0	1	0	0	0	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYP	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	DPKDAYP	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											

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)
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											

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)
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

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)
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												

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)
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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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 - Accts 840-841	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	TOTAL STORAGE 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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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	GENPLT	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	DPKDAYP	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												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AF	19												
AF	20	<u>CAPACITY - DISTRIBUTION RELATED (Non-Coincident Peak Capacity)</u>											
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		
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		
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	<u>ALLOCATION FACTOR TABLE CONTINUED</u>											
AF	52	<u>EXTERNALLY DEVELOPED ALLOCATION FACTORS</u>											
AF	53												
AF	54	<u>COMMODITY</u>											
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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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		
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	CMETRDRG	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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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		
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		
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 Industrial	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	0	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	<u>Production Expense Related</u>											
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_PROD	137	92	44	0	0	0	0	0	0	0
AF	159	Manufactured Gas Production Maintenance Expense	MX_PROD	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												

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)
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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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		(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	<u>Salaries and Wages Expense Related</u>											
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												
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AF	245												
AF	246												
AF	247												
AF	248												
AF	249												
AF	250												
AF	251	<u>REVENUES AND BILLING DETERMINANTS</u>											
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 Industrial	SREVC	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

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)
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	<u>PRESENT REVENUES FROM SALES INPUT</u>											
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	<u>BILLING DETERMINE INPUTS</u>											
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	<u>RATE OF RETURN</u>											
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	<u>ALLOCATION PROPORTIONS TABLE</u>											
AP	2	<u>EXTERNALLY DEVELOPED ALLOCATION FACTORS</u>											
AP	3												
AP	4	<u>CAPACITY</u>											
AP	5	<u>CAPACITY - PRODUCTION RELATED (LPG)</u>											
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

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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		(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	DPKDAY	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		
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		
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											

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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		(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		
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	CMETRDRG	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											

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)
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 Average	PLT_376GA	1.00000	0.50880	0.27666	0.00024	0.00583	0.00001	0.00019	0.00150		
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		
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 Industrial	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												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
AP	151	ALLOCATION PROPORTIONS TABLE CONTINUED											
AP	152	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>											
AP	153												
AP	154	<u>Production Expense Related</u>											
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	<u>Storage Expense Related</u>											
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	<u>Transmission Expense Related</u>											
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	<u>Distribution Expense Related</u>											
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												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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	<u>Customer Distribution Expense Related</u>											
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	<u>Salaries and Wages Expense Related</u>											
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												
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AP	245												
AP	246												

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

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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 Industrial	SREVC	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												

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)
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 Industrial	SREVC	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 Industrial	SREVC	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 Industrial	SREVC	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
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	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 Industrial	SREVC	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 Industrial	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		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
		NO.	(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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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
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	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
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)	(i)	(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 REVENUE		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
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)
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 REVENUE		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
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)	(i)	(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 RUPCHASED 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										

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)
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 PURCHASED 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
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)	(i)	(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	DPKDAYP	16	16	0	0	0	16	0	0
RBP	17	361-Structures and Improvements	DPKDAYP	14,932	14,932	0	0	0	14,932	0	0
RBP	18	362-Gas Holders.	DPKDAYP	7,084	7,084	0	0	0	7,084	0	0
RBP	19	363-Purification Equipment	DPKDAYP	0	0	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYP	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

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)
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	DPKDAYP	0	0	0	0	0	0
RBP	17	361-Structures and Improvements	DPKDAYP	0	0	0	0	0	0
RBP	18	362-Gas Holders.	DPKDAYP	0	0	0	0	0	0
RBP	19	363-Purification Equipment	DPKDAYP	0	0	0	0	0	0
RBP	20	363-1 Liquefaction Equipment	DPKDAYP	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)	(i)	(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
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)	(i)	(k)
RBP	96										
RBP	97										
RBP	98										
RBP	99										
RBP	100										
RBD	1	LESS: ACCUMULATED DEPRECIATION									
RBD	2										
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATION INTPLT		8,018	4,706	0	3,312	27	340	4,338	0
RBD	4										
RBD	5	PRODUCTION PLANT ACCUMULATED DEPRECIATION 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 DEPRECIATION 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	DAMAINSDA	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	CMETINSTDA	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 GENPLT		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
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	96								
RBP	97								
RBP	98								
RBP	99								
RBP	100								
RBD	1	LESS: ACCUMULATED DEPRECIATION							
RBD	2								
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATION INTPLT		0	2,472	821	8	1	10
RBD	4								
RBD	5	PRODUCTION PLANT ACCUMULATED DEPRECIATION 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 DEPRECIATION 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	DAMAINSDA	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	CMETINSTDA	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
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)	(i)	(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
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)	(i)	(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	ETHRPUTF	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	ETHRPUTF	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	ETHRPUTF	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	ETHRPUTF	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)	(i)	(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)	(i)	(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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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	DPKDAYP	363	363	0	0	0	363	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYP	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	DPKDAYP	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
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	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	DPKDAYP	0	0	0	0	0	0
E	27	841-Operation Labor & Expenses - Training	DPKDAYP	0	0	0	0	0	0
E	28	Total Operation		0	0	0	0	0	0
E	29	Maintenance							
E	30	843-Maintenance Expense	DPKDAYP	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
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	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)	(i)	(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)	(i)	(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)	(i)	(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 TAXABLE 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 TAXABLE 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)	(i)	(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 TAXABLE 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
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	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 TAXABLE 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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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	TOTAL STORAGE 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
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)
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	TOTAL STORAGE 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)	(i)	(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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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	DPKDAYP	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
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	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	DPKDAYP						
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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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	<u>EXTERNALLY DEVELOPED ALLOCATION FACTORS</u>							
AF	53								
AF	54	<u>COMMODITY</u>							
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	<u>CUSTOMER</u>							
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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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	<u>Plant Related</u>									
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
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	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	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>							
AF	103	<u>Plant Related</u>							
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
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)	(i)	(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 Industrial	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	<u>Production Expense Related</u>									
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	<u>Storage Expense Related</u>									
AF	164	Storage Operation Expense	OX_STOR	1,292							
AF	165	Storage Maintenance Expense	MX_STOR	5,043							
AF	166										
AF	167										
AF	168	<u>Transmission Expense Related</u>									
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	<u>Distribution Expense Related</u>									
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 Industrial	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	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>							
AF	153								
AF	154	<u>Production Expense Related</u>							
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	<u>Storage Expense Related</u>							
AF	164	Storage Operation Expense	OX_STOR						
AF	165	Storage Maintenance Expense	MX_STOR						
AF	166								
AF	167								
AF	168	<u>Transmission Expense Related</u>							
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	<u>Distribution Expense Related</u>							
AF	176	Account 874	OX_874						
AF	177	Account 875	OX_875						
AF	178	Account 878	OX_878						

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)	(i)	(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	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>									
AF	203										
AF	204	<u>Customer Distribution Expense Related</u>									
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	<u>Salaries and Wages Expense Related</u>									
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							

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	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	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>							
AF	203								
AF	204	<u>Customer Distribution Expense Related</u>							
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	<u>Salaries and Wages Expense Related</u>							
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						

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)	(i)	(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	<u>REVENUES AND BILLING DETERMINANTS</u>									
AF	252										
AF	253	Base Rate Sales Revenue	SALESREV	481,982							
AF	254										
AF	255	Residential	SREVRES	327,766							
AF	256	Small Commercial and Industrial	SREVC	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	<u>PRESENT REVENUES FROM SALES INPUT</u>									
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
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	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	<u>REVENUES AND BILLING DETERMINANTS</u>							
AF	252								
AF	253	Base Rate Sales Revenue	SALESREV						
AF	254								
AF	255	Residential	SREVRES						
AF	256	Small Commercial and Industrial	SREVC						
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	<u>PRESENT REVENUES FROM SALES INPUT</u>							
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
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)	(i)	(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	<u>BILLING DETERMINATE INPUTS</u>									
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	<u>RATE OF RETURN</u>									
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	<u>ALLOCATION PROPORTIONS TABLE</u>									
AP	2	<u>EXTERNALLY DEVELOPED ALLOCATION FACTOR</u>									
AP	3										
AP	4	<u>CAPACITY</u>									
AP	5	<u>CAPACITY - PRODUCTION RELATED (LPG)</u>									
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	<u>CAPACITY - STORAGE RELATED (LNG)</u>									
AP	10	Capacity Storage - Design Peak Day Sendout	DPKDAY	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	11										
AP	12										
AP	13										
AP	14	<u>CAPACITY - TRANSMISSION RELATED</u>									
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	<u>CAPACITY - DISTRIBUTION RELATED (Non-Coinciding)</u>									
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

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	277	Sales of Gas Revenues - BSC							
AF	278								
AF	279								
AF	280	Sales of Gas Revenues - Transmission							
AF	281								
AF	282								
AF	283	<u>BILLING DETERMINE INPUTS</u>							
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	<u>RATE OF RETURN</u>							
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	<u>ALLOCATION PROPORTIONS TABLE</u>							
AP	2	<u>EXTERNALLY DEVELOPED ALLOCATION FACTOR</u>							
AP	3								
AP	4	<u>CAPACITY</u>							
AP	5	<u>CAPACITY - PRODUCTION RELATED (LPG)</u>							
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	<u>CAPACITY - STORAGE RELATED (LNG)</u>							
AP	10	Capacity Storage - Design Peak Day Sendout	DPKDAY	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	11								
AP	12								
AP	13								
AP	14	<u>CAPACITY - TRANSMISSION RELATED</u>							
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	<u>CAPACITY - DISTRIBUTION RELATED (Non-Coinciding)</u>							
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

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)	(i)	(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

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)
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

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)	(i)	(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	<u>Plant Related</u>									
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

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)
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	<u>Plant Related</u>							
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

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)	(i)	(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 Industrial	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	<u>Production Expense Related</u>									
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	<u>Storage Expense Related</u>									
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	<u>Transmission Expense Related</u>									
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

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)
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 Industrial	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	<u>Production Expense Related</u>							
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	<u>Storage Expense Related</u>							
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	<u>Transmission Expense Related</u>							
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
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)	(i)	(k)
AP	173										
AP	174										
AP	175	<u>Distribution Expense Related</u>									
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	<u>ALLOCATION PROPORTIONS TABLE CONTINUED</u>									
AP	202	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>									
AP	203										
AP	204	<u>Customer Distribution Expense Related</u>									
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
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	173								
AP	174								
AP	175	<u>Distribution Expense Related</u>							
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	<u>ALLOCATION PROPORTIONS TABLE CONTINUED</u>							
AP	202	<u>INTERNALLY DEVELOPED ALLOCATION FACTORS</u>							
AP	203								
AP	204	<u>Customer Distribution Expense Related</u>							
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								

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)	(i)	(k)
AP	222										
AP	223	<u>Salaries and Wages Expense Related</u>									
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 Industrial	SREVC	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
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	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 Industrial	SREVC	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
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)	(i)	(k)
AP	271										
AP	272	<u>PRESENT REVENUES FROM SALES INPUT</u>									
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 Industrial	SREVC	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
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	271								
AP	272	<u>PRESENT REVENUES FROM SALES INPUT</u>							
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 Industrial	SREVC	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)	(i)	(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 Industrial	SREVC	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 Industrial	SREVC	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 Industrial	SREVC	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 Industrial	SREVC	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 Industrial	SREVC	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 Industrial	SREVC	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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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 Industrial	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 Industrial	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			PRODUCTION	STORAGE	DISTRIBUTION	COMPGAS
					CAPACITY	COMMODITY	CUSTOMER				
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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												
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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	<u>\$/Mcf</u>											
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	<u>\$/MONTH/CUSTOMER</u>											
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
31												
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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
30												
31												
32												
33												
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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	<u>\$/Mcf</u>											
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	<u>\$/MONTH/CUSTOMER</u>											
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)

LINE	SCH	NO.	DESCRIPTION	RESIDENTIAL CUSTOMER RELATED COSTS						GC CUSTOMER RELATED COSTS					
			(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
			(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
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)
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
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
			(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
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

LINE			RESIDENTIAL CUSTOMER RELATED COSTS					GC CUSTOMER RELATED COSTS						
SCH	NO.	DESCRIPTION	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
			(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
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
			(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
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)
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	(21)	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
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	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
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)
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

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)
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													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

LINE SCH 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													

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)
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													

PECO Energy Company
Gas Class Cost of Service Study
For Fully Projected Future Test Year Ended December 31, 2025 (\$000'S)

LINE SCH 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
			(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)

LINE SCH	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

Table of External Allocators

Schedule	Allocators	Page
	Table of External Allocators	1
1	Summary of External Allocator Values by Class	2
2	Gas Deliveries Allocator	3
3	Customers Allocator	4
4	Demand Allocators	5
5	Storage Allocator	6
6	Mains, M&R and Meter Direct Assignments	7
7	Service Investment Allocator	8
8	Meter Investment Allocator	9
9	Customer Records and Collection Expenses (Account 903) Allocator	10
10	Accounts 908-916 Allocator	11
11	Accounts Receivable Over 60-Day Allocator	12
12	Write-Offs Allocator	13
13	Deposits, Interest, Advances, Forfeited Discounts, EE, GPC, MFC/POR	14
14	Purchased Gas Cost (PGC)	15
15	Balancing Service Cost (BSC)	16
16	Purchase of Receivables (POR)	17
17	Design Day Demand	18
18	Base Customer Charges	19

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)

<u>Class</u>	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

<u>Class</u>	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 (A)	Peak_Mains (B)	Daily_Del-Excl. Dir (C)	Peaks_NCP (D) Max of (B) or (C)	Excess Demand Allocation Basis	Ratio of Excess Demand Allocation Basis	Excess Demand (G) (B) - (C)	Excess Demand by Class (H) (F) * (G)	Average & Excess Demand (I) (C) + (H)	Ratio of Average & Excess Demand (J)
					NCP vs. Daily_Del- Excl. Dir (E) (D) - (C)	NCP vs. Daily_Del- Excl. Dir (F)				
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

<u>Class</u>	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 (mcf/d)	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

	<u>Class</u>	<u>Service</u>	<u>Average Service Cost (\$)</u>	<u>Average Customer Numbers</u>	<u>Investments (\$000s)</u>	<u>Ratio</u>
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%

	Services Costs	Residential			C&I		
		<u>Dollars</u>	<u>Services</u>	<u>Average</u>	<u>Dollars</u>	<u>Services</u>	<u>Average</u>
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

<u>Class</u>	<u>Average Cost (\$) (a)</u>	<u>Average Customers</u> <u>Excl. Dir (b)</u>	<u>Cost (\$000s)</u>	<u>Ratio</u>
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											
<u>Customer Records & Collection- Account 903</u>		<u>Percentage (%)</u>	<u>Dollars (\$000s)</u>	<u>Sub-Allocator</u>	<u>Description</u>						
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								
	<u>Amount</u>	<u>Residential</u>	<u>GC</u>	<u>Large</u>	<u>MV Firm</u>	<u>MV Interr</u>	<u>Interr</u>	<u>Temperature</u>	<u>Trans Firm</u>	<u>Trans Interr</u>	
13	Cust_Avg	7,645	7,013	624	0	0	0	0	5	3	
14	Call Center	3,413	3,157	253	0	2	0	0	0	0	
15	AR Over60-Day	1,944	1,444	413	1	2	0	0	52	30	
16	Cust_Res	832	832	0	0	0	0	0	0	0	
17	Cust_Excl. Ind	662	608	54	0	0	0	0	0	0	
18	Cust_Ind	561	0	0	7	0	0	1	357	195	
19		15,057	13,054	1,344	8	4	0	1	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											
<u>Customer Service & Informational Expenses</u>		<u>Percentage (%)</u>	<u>Dollars (\$000s)</u>	<u>Sub-Allocator</u>	<u>Description</u>						
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								
		<u>Amount</u>	<u>Residential</u>	<u>GC</u>	<u>Large</u>	<u>MV Firm</u>	<u>MV Interr</u>	<u>Interr</u>	<u>Temperature</u>	<u>Trans Firm</u>	<u>Trans Interr</u>
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

	<u>Class</u>	<u>Average Over 2 Months (\$000)</u>	<u>Over60-Day Allocator</u>
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%

	<u>Class</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>Write-Off Allocator - Average</u>
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

<u>Class</u>	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)

	<u>Class</u>	<u>PGC (\$000s)</u>
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)

	<u>Class</u>	<u>BSC (\$000s)</u>
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)

	<u>Class</u>	<u>POR (\$000)</u>
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) = Line 7 + 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

<u>Class</u>	<u>(\$000s)</u>
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)

LINE		ALLOCATION	TOTAL GAS				MOTOR VEHICLE	MOTOR VEHICLE	INTER	TEMP	
SCH	NO.	DESCRIPTION	BASIS	DIVISION	RESID	GC	LARGE	FIRM	INTER	SERV	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	<u>TOTAL RATE CASE (DISTRIBUTION PLUS PURCHASED GAS)</u>									
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										
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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										
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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 RUPCHASED 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 PURCHASED 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 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

TABLE OF CONTENTS

	Page
I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. REVENUE ALLOCATION	3
III. RATE DESIGN	6
IV. CUSTOMER ASSISTANCE PROGRAM (“CAP”) COST RECOVERY	15
V. REVENUE EFFECT BY RATE SCHEDULE, PROOF OF REVENUES, AND SCALE-BACK	17
VI. NEGOTIATED GAS CONTRACTS	19
VII. CONCLUSION	21

1 **DIRECT TESTIMONY**
2 **OF**
3 **JOSEPH A. BISTI**

4 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

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

6 A. My name is Joseph A. Bisti. My business address is PECO Energy Company,
7 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

9 A. I am employed by PECO Energy Company (“PECO” or the “Company”) as a
10 Manager of Rate Analysts. I am responsible for retail tariff administration,
11 project management and regulatory affairs relating to PECO’s gas and electric
12 operations.

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

14 A. I received a Bachelor of Science in Economics from The College of New Jersey
15 in 2000, a Master of Science in Training and Organizational Development from
16 Saint Joseph’s University in 2009, and a Graduate Certificate in Utility
17 Management from Willamette University in 2012. In 2015, I earned a
18 certification as a Project Management Institute Professional in Business Analysis.
19 In September of 2022, I was promoted to my current position. My professional
20 experience includes various roles involving business analysis, project leadership,
21 and regulatory compliance within PECO’s Retail Rates, Energy Acquisition, and
22 Information Technology departments.

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

24 A. The purpose of my testimony is to describe: (1) how PECO proposes to allocate

1 its claimed revenue increase among rate classes and the principles that guided
2 PECO in developing its proposed revenue allocation; and (2) the changes PECO
3 is proposing in the rate design for certain rate classes, why PECO is proposing
4 these changes, and how the proposed new rates were developed. In addition, I
5 will also describe the Company's negotiated gas rate customers that have all had
6 their competitive alternatives verified within five years of the filing date of this
7 proceeding in accordance with Commission requirements.¹

8 **5. Q. Please identify the exhibits you are sponsoring.**

9 A. I am sponsoring the following exhibits:

10 Exhibit JAB-1	Proposed Revenue Allocation, Proposed Increases by Class 11 and Class Rates of Return and Relative Rates of Return 12 under Proposed Rates
13 Exhibit JAB-2	Relevant Gas Service Tariff Pages (Blacklined to Show 14 Changes)
15 Exhibit JAB-3	Comparison of Residential Customer Charges for 16 Pennsylvania Natural Gas Distribution Utilities
17 Exhibit JAB-4	Proof of Revenues at Present and Proposed Rates
18 Exhibit JAB-5	Calculation Methodology for Differentiated Rate GC 19 Customer Charges By Tier
20 Exhibit JAB-6	Modified Base Rate Recovery of CAP Revenues in USFC

21
22
23
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25
26

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.

1 **II. REVENUE ALLOCATION**

2 **6. Q. Please state the principles that guided PECO in developing its proposed**
3 **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:

- 7 1. The results of the class cost-of-service study (“COSS”) prepared by
8 Company witness Jiang Ding and discussed in PECO Statement No. 6
9 should be used as a guide in allocating the proposed revenue increase among
0 rate classes;
- 1
- 2 2. The overall proposed revenue allocation should produce reasonable
3 movement toward the cost of service indicated by the COSS; and
4
- 5 3. Customer impacts should be considered, and PECO should attempt to avoid
6 increases in revenue for major rate classes that, on a percentage basis,
7 exceed two times the proposed system average increase.

8 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,

1 while the results of the Company's COSS are an important guide in evaluating its
2 proposed revenue allocation, they are not the only factor that must be considered.

3 **8. Q. Please discuss the principle of gradualism and how it influenced PECO's**
4 **proposed revenue allocation.**

5 A. The ratemaking principle of gradualism, as traditionally applied in Pennsylvania,
6 guides utilities to avoid abruptly increasing rates in favor of slower adjustments
7 that incrementally move rates toward the actual cost of service over time.
8 PECO's proposed revenue allocation in this case attempts to balance gradualism
9 and other ratemaking principles, and at the same time, also more closely align the
10 class rates of return with the proposed system average rate of return while
11 recognizing the degree to which rates for other classes diverge from their
12 indicated cost of service. Under PECO's proposed revenue allocation and rate
13 structure, the maximum increase for any rate class is 2.0 times the system average
14 to prevent rate shock.

15 **9. Q. What is the revenue allocation that PECO determined to be appropriate in**
16 **this case?**

17 A. PECO's proposed revenue allocation is presented in PECO Exhibit JAB-1.

18 **10. Q. Why is the proposed revenue allocation reasonable?**

19 A. The proposed revenue allocation in PECO Exhibit JAB-1 is reasonable because it
20 appropriately reflects the principles discussed previously:

- 21 1. The COSS prepared by Ms. Ding guided its development;
- 22 2. It produces reasonable movement of rate classes closer to their indicated
23 cost of service; and
- 24 3. It moderates the impact on each major rate class and supports the principle
25 of gradualism by avoiding rate increases exceeding two times the

proposed system average increase.

The class rates of return and relative rates of return² 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.

1 are providing revenues higher or lower than their indicated cost of service.

2 III. RATE DESIGN

3 **12. Q. Explain in general how PECO proposes to change the charges within each**
4 **rate schedule to recover the revenue allocated to each rate class.**

5 A. PECO proposes to increase or decrease each of the charges within each rate
6 schedule in proportion to the revenue increase or decrease allocated to that rate
7 class, subject to certain rate design changes, discussed below. PECO Exhibit
8 JAB-2 is a copy of the Company's Tariff Gas-Pa. P.U.C. No. 6 ("Tariff No. 6")
9 that shows, by strike-out and blacklining, the proposed rate changes I discuss
10 below, as well as the proposed changes in rules, regulations, rate schedules and
11 riders discussed by Ms. Megan A. McDevitt in PECO Statement No. 8. Tariff
12 No. 6 is being filed with the Secretary of the Pennsylvania Public Utility
13 Commission ("PUC" or the "Commission") as part of PECO's base rate filing.

14 Currently, service is provided under the Company's Tariff Gas-Pa. P.U.C. No. 5
15 ("Tariff No. 5") and associated supplements. It is anticipated that Tariff No. 6,
16 which was filed as part of this case on 60 days' notice, will be suspended by
17 operation of Section 1308(d) of the Public Utility Code pending an investigation
18 by the Commission. Because it is possible and, in fact, likely, that changes will
19 be made, via subsequently filed supplements, to Tariff No. 5 during the period
20 Tariff No. 6 is suspended, any provisions of the current tariff that will continue
21 beyond the end of the suspension period and have not already been incorporated
22 in Tariff No. 6 will be merged into the tariff that will be filed as part of PECO's
23 compliance filing at the conclusion of this proceeding.

1 **13. Q. Why is PECO proposing to increase customer charges for several rate classes**
2 **by a greater percentage than the proposed overall revenue increase for those**
3 **classes?**

4 A. PECO is proposing to increase customer charges in this manner to reduce the
5 disparity between its current customer charges and the customer-related costs that
6 should properly be recovered by those customer charges as reflected by Ms. Ding
7 in PECO Exhibit JD-4 at page 4, line 25.

8 A summary of the proposed customer charge increases is shown in Table 2 below.
9 These changes are intended to align customer charges more closely with the
10 Company's customer-classified costs. In most cases, the proposed modified
11 customer charges will be closer to, but still less than, the customer charges
12 warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit
13 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.

1 so would make the recovery of customer-related costs a function of customers'
2 usage, which they are not. More accurate price signals also offer greater
3 transparency to customers about the fixed costs incurred to connect them to the
4 Company's system.

5 Misplacing customer costs in variable distribution charges has adverse
6 consequences. First, it can create inappropriate intra-class subsidies because
7 some customers will pay more than their share of customer-classified costs and
8 others less, based on their relative levels of usage each month. Second, because
9 customer costs, which are a fixed amount per customer, would be recovered in a
10 charge that applies to usage, which varies, the Company could recover either too
11 little or too much of its customer-related costs as a consequence of variations in
12 customer usage.

13 In summary, putting customer costs in the wrong element of a rate can be unfair
14 to both customers and the utility. For these reasons, among others, customer-
15 related costs in a utility's cost of service should be charged to customers in a
16 manner that appropriately reflects the nature of the costs incurred subject to
17 consideration of the principle of gradualism.

18 **15. Q. What residential rate change is PECO proposing?**

19 A. PECO is proposing a residential customer charge of \$19.38 per month. This
20 customer charge will be closer to, but still less than, the customer charge
21 warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit
22 JD-4. The revenue to be recovered from this customer charge was deducted from
23 the total revenue target for the residential class to determine the revenue to be

1 recovered in the variable distribution service charge. The variable distribution
2 service charge was changed to recover the balance of the residential class revenue
3 not recovered by the customer charge.

4 **16. Q. Please summarize PECO's proposed changes to Rate Schedule GC – General**
5 **Service - Commercial and Industrial ("Rate GC") in the context of PECO's**
6 **related 2022 gas rate case settlement commitment.**

7 A. In the settlement of its 2022 gas base rate case at Docket No. R-2022-3031113
8 ("2022 rate case settlement"), the Company agreed to present a cost analysis and
9 rate design proposal for Rate GC in its next base rate case that would evaluate (a)
10 the potential for differentiated customer charges and (b) the cost basis for any
11 declining block commodity charge differentials proposed.

12 PECO's proposal for the Rate GC customer charge in this case is intended to
13 justify differentiated customer charges for small and large customers, while also
14 eliminating the declining block structure for the variable distribution charge.

15 **17. Q. Please describe PECO's customer charge proposal for Rate GC.**

16 A. PECO's customer charge proposal is intended to more reasonably allocate the
17 recovery of meter-related customer costs to smaller and larger GC customers,
18 given that many smaller Rate GC customers have the same meter-related costs as
19 an average residential customer and therefore must not unreasonably subsidize
20 similar costs for larger Rate GC customers.

21 Effective January 1, 2026, PECO proposes to implement two customer charges
22 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

1 the average meter-related cost per customer for each tier. The proof of revenues
2 for Rate GC in Exhibit JAB-4 displays both the single customer charge proposed
3 for the FPFTY as well as the proposed differentiated customer charges for each
4 tier, demonstrating that PECO intends to collect the same amount of customer-
5 related revenue in each case. PECO Exhibit JAB-5 describes the methodology
6 used to calculate the differentiated customer charges effective for 2026 in more
7 detail, citing relevant supporting COSS data submitted by Ms. Ding.

8 **18. Q. Please describe PECO's variable distribution charge proposal for Rate GC.**

9 A. PECO proposes to eliminate the current declining block structure for the Rate GC
10 variable distribution charge and implement a single variable distribution charge
11 with no declining block charge differentials or thresholds. This single charge
12 would apply to all Rate GC distribution customers regardless of their proposed
13 GC tier assignment. The revenue to be recovered from the customer charge
14 during the FPFTY, or alternatively from the differentiated customer charges after
15 the FPFTY, was deducted from the total revenue target for the Rate GC class to
16 determine the revenue to be recovered by this single variable distribution service
17 charge.

18 Eliminating the declining block structure for Rate GC requires PECO to modify
19 related terms in flexible rate classes MV-I – Motor Vehicle Interruptible – and
20 TCS – Temperature-Controlled Service. The current MV-I and TCS tariffs cap
21 the maximum variable distribution charge per month based on calculations that
22 include the current end block of the Rate GC variable distribution charge. PECO
23 therefore is proposing to modify the terms of both the MV-I and TCS tariffs by

1 replacing the use of the end block with the use of the proposed single variable
2 distribution charge for Rate GC.

3 **19. Q. Please explain the proposed volumetric rate differentials for the TS-F and**
4 **TS-I rate classes in the context of PECO's related 2022 rate case settlement**
5 **commitment.**

6 A. In the 2022 rate case settlement, the Company agreed to undertake the load factor
7 analysis for TS-F customers originally performed by the Pennsylvania Office of
8 Small Business Advocate ("OSBA") during that proceeding as part of the
9 Company's next gas base rate case. Load factor is the ratio of average demand to
10 peak day demand. The OSBA's stated intent of its analysis at that time was to
11 evaluate whether the differentials between the Company's proposed variable
12 distribution charges for Rate TS-F customers with annual usage above and below
13 18,000 Mcf yield correlations between load factor and customer size, reasoning
14 that demand-related costs for customers with higher load factors should be lower
15 on a per-mcf basis. The OSBA also suggested that this load factor analysis is not
16 relevant to the Company's existing volumetric rate differentials for Rate TS-I
17 customers because, as explained by Company witness Ms. Ding in her testimony,
18 the Company's Cost Of Service Study assigns demand-related costs to the Rate
19 TS-I class based entirely on average volumes rather than peak demand.

20 A summary of PECO's load factor analysis results for Rate TS-F customers is
21 presented in Tables 3 and 4 below, based on Rate TS-F customer gas data from
22 November of 2022 through October of 2023. To ensure that this analysis aligns
23 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

1 to one. The Company's proposed volumetric rates for TS-F in PECO Exhibit
2 JAB-4 are therefore designed to reduce this differential to a level consistent with
3 these results by setting the differential to the ratio of 1.49 shown above in Table
4 4.

5 Given that the above analysis is not relevant for Rate TS-I customers, the
6 Company proposes to phase out the Rate TS-I volumetric rate differentials over
7 multiple proceedings, beginning with this proceeding. As shown in PECO
8 Exhibit JAB-4, the Company is proposing to maintain the existing TS-I variable
9 base rate for customers below 18,000 Mcf annually while increasing the TS-I
10 variable base rate to the extent necessary to maintain the desired level of TS-I
11 rate revenues. Doing so initially reduces the TS-I volumetric rate differential
12 from 1.88 to 1.67.

13 **IV. CUSTOMER ASSISTANCE PROGRAM ("CAP") COST RECOVERY**

14 **20. Q. Mr. Bisti, please provide an overview of PECO's existing Universal Service**
15 **Fund Charge ("USFC").**

16 A. The USFC is PECO's Commission-approved rate mechanism for recovery of the
17 costs of PECO's universal service programs that are not included in base rates.
18 The USFC is an automatically adjusted surcharge created pursuant to Section
19 1307(a) of the Pennsylvania Public Utility Code.

20 USFC costs are reconciled on an annual basis using actual costs for a historic
21 twelve-month period ("E-Factor") and projected costs for a future twelve month
22 period ("C-Factor"). Interest accrues from the month in which over/under

1 collection of USFC costs occurs to the midpoint of the collection period, the sum
2 of which results in a credit or charge to customers if costs are over- or under-
3 collected, respectively. The cumulative amount (either positive or negative) at the
4 end of the reconciliation period determines the E-Factor to be included in
5 calculation of the next USFC for the subsequent period. PECO normally files its
6 USFC reconciliation and annual rate adjustment in September of each year, with
7 the new USFC rate becoming effective on the following December 1.

8 **21. Q. Please describe the CAP “shortfall”.**

9 A. As explained by Company witness Jacqueline F. Golden in PECO Statement No.
10 10, PECO’s CAP uses a percentage-of-income-based approach to provide bill
11 credits to qualifying low-income residential customers. A portion of the cost of
12 the aggregate benefits provided through PECO’s gas CAP rider is recovered
13 through base rates paid by residential distribution service customers.

14 As explained by Ms. Golden, the CAP “shortfall” refers to the amount of
15 aggregate bill credits (in dollars) provided to CAP customers each year that is not
16 included in base rates. This shortfall is recovered from or refunded to PECO’s
17 residential customers on an ongoing basis through the USFC, with annual
18 reconciliation of any over/under collections as described above. The USFC is
19 currently adjusted so that residential customers pay 73% of the total CAP shortfall
20 amount. The remaining 27% of the CAP shortfall is absorbed by PECO to account
21 for the estimated impact to bad debt expense and working capital.

1 **22. Q. Is PECO proposing to increase the amount of gas CAP bill credits included**
2 **in its base rates in this proceeding?**

3 A. Yes. As explained by Ms. Golden, PECO is proposing to increase the aggregate
4 value of bill credits provided to gas CAP customer currently included in its base
5 rates from \$11 million to \$13.7 million and to change the offset factor applied to
6 reconcilable CAP costs reflected in the USFC formula from 27% to 10.5%.
7 PECO Exhibit JAB-6 illustrates the impact of these changes on the C-Factor and
8 E-Factor calculations for PECO's USFC.

9 **V. REVENUE EFFECT BY RATE SCHEDULE,**
10 **PROOF OF REVENUES, AND SCALE-BACK**

11 **23. Q. Have you prepared a summary of distribution revenues at present and**
12 **proposed rates for each rate class?**

13 A. Yes. PECO Exhibit JAB-1 shows revenue at both present rates and proposed
14 rates as well as the percentage increases each class will receive on an overall
15 basis.

16 **24. Q. Have you prepared proofs of revenue with respect to PECO's present and**
17 **proposed rates?**

18 A. Yes. PECO Exhibit JAB-4 is a proof of revenue with respect to PECO's present
19 and proposed rates, based on pro forma billing determinants for the FPFTY. This
20 exhibit is tied to the portion of PECO Exhibit JAB-1 that addresses the increased
21 revenue that would be required.

1 **25. Q. Please explain the adjustment made to the proof of revenues at present rates**
2 **for the Company’s Distribution System Improvement Charge (“DSIC”).**

3 A. The DSIC is a rate adjustment mechanism that permits PECO to recover the fixed
4 costs of DSIC-eligible property between base rate cases through a separate,
5 reconcilable charge established pursuant to Section 1353 of the Public Utility
6 Code. The Commission approved PECO’s establishment of a DSIC by its final
7 order entered October 22, 2015, at Docket No. P-2015-2471423. PECO began to
8 charge a DSIC effective with bills rendered on or after July 1 of 2018.

9 As required by the terms of the DSIC and Section 1358(b) of the Public Utility
10 Code, PECO is currently charging a DSIC of 0.0%, having reset the DSIC to zero
11 as of January 1, 2023 – the effective date of new base rates established by the
12 Commission’s Final Order in PECO’s 2022 rate case at Docket R-2022-3031113.
13 PECO has filed a DSIC charge of 0.07% effective with bills rendered on or after
14 April 1, 2024 and intends to reset its DSIC charge at zero on the effective date of
15 new rates established through this proceeding. (PECO may file a DSIC charge to
16 be effective January 1, 2025 or later for the sole of reconciling residual over and
17 under-collections experienced before the end of 2024.) The fixed costs of DSIC-
18 eligible property that PECO will continue to recover through the effective date of
19 its new base rates have been included in the Company’s claimed rate base and
20 reflected in the revenue requirement used to establish its proposed rates.
21 Consequently, to properly compare PECO’s revenues at present rates to revenues

1 at its proposed base rates, PECO's proof of revenue at present rates has been
2 adjusted by customer class to include the revenues billed under its DSIC.

3 **26. Q. How does PECO propose to scale-back the proposed rates if it is granted less**
4 **than the revenue increase it requested?**

5 A. In the event PECO is granted less than its requested increase, PECO proposes
6 that:

- 7 (1) the revenue increases proposed for all rate classes will be reduced in
8 proportion to the proposed increase for each class; and
9 (2) the customer charges for all rate classes remain as proposed, and all other
10 rates and charges for all rate schedules be reduced proportionately to
11 produce the revenue target for each rate class.

12 **VI. NEGOTIATED GAS CONTRACTS**

13 **27. Q. Please describe PECO's Negotiated Gas Service ("NGS") rate.**

14 A. The Commission approved the addition of Rate NGS to the Company's tariff in
15 2001 under the consolidated Docket Nos. of R-00016200 and R-00016366. Rate
16 NGS permits the Company to offer negotiated, or discounted, gas service to
17 customers who: (1) either have a history of at least 18,000 Mcf of annual billed
18 gas usage or, if a new customer, establish that the facilities to be served are likely
19 to consume at least 18,000 Mcf of annual gas usage; (2) document a viable,
20 currently available competitive alternative to service under rates GC, L, TS-F, or
21 TS-I; and (3) execute an NGS agreement that agrees with all provisions set forth
22 in rate NGS.

23 The Company requires customers to document their competitive alternative when
24 customers seek service under Rate NGS. A customer's competitive alternative

1 could be an alternative fuel source, a direct connection to a pipeline or producer
2 that bypasses the Company's distribution system, relocation of customer facilities
3 outside of PECO's service territory, or a shutdown of customer facilities. PECO
4 and its customers generally evaluate the potential benefits of a Rate NGS service
5 agreement over a period that is long enough to adequately analyze the impact of
6 the economic conditions that drive the competitive alternative, which can be ten
7 years or more in the case of bypass or facility relocation alternatives.

8 In the Company's 2020 Gas Rate Case Order, the Commission directed PECO to
9 update the competitive alternative analysis for negotiated gas contracts that have
10 not had their competitive alternative verified for a period of five years or more
11 upon PECO's filing of a new base rate case.

12 **28. Q. How many customers currently receive service under negotiated rates?**

13 A. Three customers currently receive service under negotiated rate contracts, and
14 PECO has verified the competitive alternative for each of those customers within
15 the last five years.⁴ Consistent with its commitments in the Company's 2022 base
16 rate case proceeding, on April 1, 2023, PECO entered into a new contract with
17 one of these customers under the terms of PECO's Rate NGS at a reduced
18 discount, allowing Customer 1's variable distribution rate to remain lower than
19 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.

1 **VII. CONCLUSION**

2 **29. Q. Please summarize your conclusions.**

3 A. PECO's proposed rates reflect a reasonable allocation of the Company's proposed
4 revenue increase and a reasonable rate design for each rate schedule. The
5 proposed rate design changes are consistent with relevant terms of the 2022 rate
6 case settlement, the results of the COSS identified by Ms. Ding, and applicable
7 principles of rate structure and rate design, including gradualism.

8 **30. Q. Does this conclude your direct testimony?**

9 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

	(1)	(2)	(3)	(4)	(5)
	Current Distribution	Proposed	(2) - (1)	(3) / (1)	Increase vs.
Rate	Revenue	Distribution Revenue	Revenue Ask	% Increase	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%	

	(7)	(8)	(9)	(10)
	Present	(8) / Average of (8)	Proposed	(9) / Average of (9)
Rate	Rate of Return	Present Relative Rate of Return	Rate of Return	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.

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PECO Energy Company

Gas-Pa. P.U.C. No. 6
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TABLE OF CONTENTS

Index of Communities Served.....	3
How to Use Loose-Leaf Tariff.....	4
Definition of Terms and Explanation of Abbreviations.....	5, 6, 7
RULES AND REGULATIONS:	
1. The Gas Service Tariff.....	8
2. Service Specifications.....	9
3. Customer's Installation.....	10
4. Application for Service.....	11
5. Credit.....	12
6. Service-Supply Facilities.....	13
7. Extensions.....	13
8. Rights-of-Way.....	15
9. Introduction of Service.....	15
10. Company Equipment.....	16
11. Tariff Options on Applications for Service.....	17
12. Service Continuity.....	18
13. Customer's Use of Service.....	22
14. Measurement.....	22
15. Tests.....	24
16. Payment Terms.....	25
17. Termination by the Company.....	27
18. Unfulfilled Contracts.....	27
19. Cancellation by Customer.....	28
20. General.....	28
21. Gas Choice Program Enrollment and/or Switching.....	29
22. Usage Data.....	29
23. Affiliated Marketer Standards of Conduct.....	30
24. Requests for Energy Efficiency Information.....	33
25. Creditworthiness of Natural Gas Supplier (NGS) Serving High Volume Transportation Customers.....	33
26. Gas Quality Standards.....	36, 37, 38, 39
STATE TAX ADJUSTMENT CLAUSE.....	40
UNIVERSAL SERVICE COST RECOVERY MECHANISM.....	41
SALES SERVICE COSTS - ("SSC") Section 1307(f).....	42, 43, 44
GAS PROCUREMENT CHARGE.....	45
MERCHANT FUNCTION CHARGE.....	46, 47
BALANCING SERVICE COSTS ("BSC").....	48, 49
CONSUMER EDUCATION CHARGE (CEC).....	50
DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC).....	51, 52, 53, 54, 55, 56
RATES:	
Rate GR General Service - Residential.....	57
Rate GC General Service - Commercial and Industrial.....	58, 58A
Rate OL Outdoor Lighting.....	59
Rate L Large High Load Factor Service.....	60
Rate MV-F Motor Vehicle Service-Firm.....	62
Rate MV-I Motor Vehicle Service-Interruptible.....	63
Rate IS-Interruptible Service.....	65
Rate TCS-Temperature Controlled Service.....	67
Gas Transportation Service - General Terms and Conditions.....	69, 70, 71, 72, 73
Rate TS-I Gas Transportation Service - Interruptible.....	74
Rate TS-F Gas Transportation Service-Firm.....	75
Rate NGS - Negotiated Gas Service.....	76
RIDERS:	
Applicability Index of Riders.....	78
Casualty Rider.....	79
Construction Rider.....	79
Neighborhood Gas Pilot Rider.....	80
Receivership Rider.....	82
Temporary Service Rider.....	82
Customer Assistance Program (CAP) Rider.....	83
WEATHER NORMALIZED ADJUSTMENT (WNA).....	84

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Gas-Pa. P.U.C. No. 6
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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, Pennel, 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, Colwyn, 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, Whitmarsh, Whitpain, Worcester.

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January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company**Gas-Pa. P.U.C. No. 6**
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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) 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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Gas-Pa. P.U.C. No. ~~6~~
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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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Gas-Pa. P.U.C. No. 6
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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, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company's employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company's ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location 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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 11

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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 restoration. 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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Gas-Pa. P.U.C. No. 6
Original Page No. 12

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 13

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 14

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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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Gas-Pa. P.U.C. No. ~~6~~
Original Page No. 15

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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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Gas-Pa. P.U.C. No. **6**
Original Page No. 16

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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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Gas-Pa. P.U.C. No. 6
Original Page No. 17

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 18

Deleted: 5

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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Deleted: 5

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.

Issued March 28, 2024

Effective May 27, 2024

Deleted: 1

Deleted: issued November 16,
2022 Effective January 1, 2023

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.

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 21

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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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Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 22

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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:

Issued March 28, 2024

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Deleted: Issued November 16, 2022
Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. 23

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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.

Issued March 28, 2024

Effective May 27, 2024

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Effective January 1, 2023¶

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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.

Deleted: Issued November 16, 2022
Effective January 1, 2023¶

PECO Energy

Gas-Pa. P.U.C. No. 6
Original Page No. 25

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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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. 26

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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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Effective May 27, 2024

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Effective January 1, 2023¶
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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

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.

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 28

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 29

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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.

Issued March 28, 2024

Effective May 27, 2024

Deleted: Issued November 16, 2022
Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 30

Deleted: 5

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.

Issued March 28, 2024

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Effective January 1, 2023

PECO Energy Company**Gas-Pa. P.U.C. No. 6,
Original Page No. 31****Deleted: 5**

- (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

Issued March 28, 2024**Effective May 27, 2024****Deleted: Issued November 16, 2022
Effective January 1, 2023**

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 32

Deleted: 5

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.

Issued March 28, 2024

Effective May 27, 2024

Deleted: Issued November 16, 2022
Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 33

Deleted: 5

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.

Issued March 28, 2024

Effective May 27, 2024

Deleted: Issued November 16, 2022
Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 34

Deleted: 5

RULES AND REGULATIONS – Continued

- (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.

Issued March 28, 2024

Effective May 27, 2024

Deleted: Issued November 16, 2022
Effective January 1, 2023

RULES AND REGULATIONS – Continued

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.

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 36

Deleted: 5

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° 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° F) or above one hundred and twenty degrees Fahrenheit (120° 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 (CS₂), 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 (CO₂), not more than 3% by volume of nitrogen (N₂), and shall contain no more than 5% by volume of combined nonhydrocarbon gases including, but not limited to, CO₂, N₂, and O₂.

(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.

Issued March 28, 2024

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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 37

Deleted: 5

RULES AND REGULATIONS – Continued

(x) **Hydrocarbons:** The RNG hydrocarbon dew point is not to exceed forty-five degrees Fahrenheit (45° 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/m ³
Hydrogen	H ₂	0.1	% vol
Ammonia	NH ₃	0.00%	Mol%
Mercury	Hg	0.08	mg/m ³
Arsenic	As	0.19	mg/m ³
Copper	Cu	0.6	mg/m ³
Oxygen	O ₂	0.3	% vol
Propane	C ₃ H ₈	20	% vol
Nitrogen	N ₂	3	% vol
Methane	CH ₄	95	% vol
Hydrogen Sulfide	H ₂ S	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 ₂ O	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/ft³ and shall not have a maximum Wobbe Number greater than 1375 Btu/ft³.

(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.

Issued March 28, 2024

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Effective January 1, 2023

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 38

Deleted: 5

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. Retesting 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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 39

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 40

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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PECO Energy CompanyGas-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:

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

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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PECO Energy Company
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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.¶

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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. ~~42~~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 ~~\$4,419.9~~ per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, ~~\$4,406.2~~ per Mcf for Rate Schedules GC and ~~\$4,399.6~~ 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:

$$CC = (CC1 + \frac{O + C1}{S1 \ S2} \times \frac{1}{(1-T)}) + GPC + MFC$$

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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PECO Energy Company**Gas-Pa. P.U.C. No. 6**
Original Page No. 43

"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 & 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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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-Pa. P.U.C. No. ~~6~~
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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~~.

The GPC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC").

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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:

$$GPC = GPCC/S \times 1/(1-T)$$

"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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. ~~46~~**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:

$$\text{MFC} = \text{Write-Off Factor} \times \text{CCEMFC} \times 1 / (1 - T)$$

"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

Commodity Charge excluding GPC and MFC

Gas Cost Adjustment

Gas Procurement Charge

Merchant Function Charge

Price to Compare

RATES GR and CAP

\$4.3632 per Mcf

(\$0.0468) per Mcf

\$0.0360 per Mcf

~~\$0.0207~~ per Mcf

\$4.3731 per Mcf

COMPONENT

Commodity Charge excluding GPC and MFC

Gas Cost Adjustment

Gas Procurement Charge

Merchant Function Charge

Price to Compare

RATES GC

\$4.3632 per Mcf

(\$0.0468) per Mcf

\$0.0360 per Mcf

~~\$0.0070~~ per Mcf

\$4.3594 per Mcf

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PECO Energy Company

COMPONENT

Commodity Charge excluding GPC
and MFC
Gas Cost Adjustment
Gas Procurement Charge
Merchant Function Charge
Price to Compare

RATES OL, L and MV-F

\$4.3632 per Mcf
(\$0.0468) per Mcf
\$0.0360 per Mcf
\$0.0004 per Mcf
\$4.3528 per Mcf

Gas-Pa. P.U.C. No. 6
Original Page No. 47

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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. ~~48~~**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.

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:

$$BSC = (CC1 + \frac{Q}{S1} + \frac{C1 - E}{S2} \times \frac{1}{S1}) \times \frac{1}{(1 - T)}$$

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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 50Consumer 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.

COMPUTATION OF CEC

The CEC per MCF shall be calculated on an annual basis using the following formula:

$$\frac{CEC(n) = (C+E+I)}{S(n)}$$

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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

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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.

PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 53

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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 54**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:

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

Where:

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

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

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax
[Note that a utility may elect to include STFT calculation in the PTRR component].

Dep = Depreciation expense related to DSIC-eligible property.

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

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

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

Revenue shall be based on one-fourth of the projected annual revenues.

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

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PECO Energy Company

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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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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.

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: \$7.0866 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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 58

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

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VARIABLE DISTRIBUTION CHARGE: \$5.4413 per Mcf

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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.

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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.

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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.

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	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.

Standard.

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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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.

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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.
Standard.

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PECO Energy Company

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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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(TCJA) VOLUNTARY SURCHARGE**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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Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

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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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Effective January 1, 2023¶

PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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.

Standard.

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Gas-Pa. P.U.C. No. 6
Original Page No. 67

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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.

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.

"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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(TCJA) VOLUNTARY SURCHARGE

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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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PECO Energy Company

Gas-Pa. P.U.C. No. 6
Original Page No. 69**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.

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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. ~~70~~**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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
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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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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.

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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.

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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.

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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.

Standard.

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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.

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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 \$ ~~1,552.9~~ per Mcf.

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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.

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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 ~~313.8~~ per Mcf.

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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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VOLUNTARY SURCHARGE**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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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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PECO ENERGY COMPANYGas-Pa. P.U.C. No. 6
Original Page No. 77

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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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PECO Energy Company

Gas-Pa. P.U.C. No. ~~6~~
Original Page No. ~~78~~

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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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Gas-Pa. P.U.C. No. **6**
Original Page No. **79**

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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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Gas-Pa. P.U.C. No. ~~6~~
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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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Gas-Pa. P.U.C. No. 6
Original Page No. 81

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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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Gas-Pa. P.U.C. No. 6
Original Page No. 82

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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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Gas Pa. P.U.C. No. **6**
Original Page No. **83**

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.

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.

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.

MINIMUM CHARGE.

The minimum charge per month will be \$20.

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:

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

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

$$\text{WNA} = \text{WNAC} \times \text{VDC}(n)$$

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.

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Gas-Pa. P.U.C. No. 6
Original Page No. 85

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

<u>Company</u>	<u>Current Residential Customer Charge</u>
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	
		<u>Bills</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
1	Customer Charge					
2	Base Rate	6,151,911	\$ 14.25	\$ 87,664,732	\$ 19.38	\$ 119,224,035
3						
4	Total Customer Charge Revenue			<u>\$ 87,664,732</u>		<u>\$ 119,224,035</u>
5						
6	Variable Distribution Charges	<u>mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
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			<u>\$ 237,831,012</u>		<u>\$ 284,609,394</u>
14						
15	Annualization			\$ 1,185,491		\$ 1,470,806
16						
17	Adjusted Total Distribution Revenue			<u><u>\$ 326,681,235</u></u>		<u><u>\$ 405,304,235</u></u>

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	
		Bills	Rate	Revenue	Rate	Revenue
1	Customer Charge					
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	
	Manufacturer-Rated Input to Lighting Devices (lamp-based)	Units	Rate	Revenue	Rate	Revenue
1	When <u>NOT</u> in Conjunction With Service Under Other Gas Rates					
2						
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	
			Rate	Revenue	Rate	Revenue
1	Customer Charge	Bills				
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	
			Rate	Revenue	Rate	Revenue
1	Customer Charge	<u>Bills</u>				
2	Base Rate	180	\$ 49.84	\$ 8,971	\$ 67.80	\$ 12,204
3						
4	Total Customer Charge Revenue			<u>\$ 8,971</u>		<u>\$ 12,204</u>
5						
6	Variable Distribution Charges	<u>mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
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			<u>\$ 603,315</u>		<u>\$ 686,025</u>
12						
13	Annualization			\$ 405		\$ 462
14						
15	Adjusted Total Distribution Revenue			<u><u>\$ 612,691</u></u>		<u><u>\$ 698,691</u></u>

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	
			Rate	Revenue	Rate	Revenue
1	Customer Charge	Bills				
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	<i>*Flex Rate fluctuates month-to-month based on the cost of alternative fuels</i>					

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	
			Rate	Revenue	Rate	Revenue
1	Customer Charge	Bills				
2	Base Rate	12	\$ 217.89	\$ 2,615	\$ 297.41	\$ 3,569
3						
4	Total Customer Charge Revenue			<u>\$ 2,615</u>		<u>\$ 3,569</u>
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			<u>\$ 63,197</u>		<u>\$ 62,243</u>
12						
13	Total Distribution Revenue			<u><u>\$ 65,812</u></u>		<u><u>\$ 65,812</u></u>
14						
15	<i>*Flex Rate fluctuates month-to-month based on the cost of alternative fuels</i>					

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	
		<u>Bills</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
1	Customer Charge					
2	Base Rate	237	\$ 125.00	\$ 29,625	\$ 170.00	\$ 40,290
3						
4	Total Customer Charge Revenue			<u>\$ 29,625</u>		<u>\$ 40,290</u>
5						
6	Variable Distribution Charges	<u>mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
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			<u>\$ 694,096</u>		<u>\$ 683,431</u>
12						
13	Annualization			\$ (26,474)		\$ (26,474)
14						
15	Adjusted Total Distribution Revenue			<u><u>\$ 697,247</u></u>		<u><u>\$ 697,247</u></u>
16						
17	<i>*Flex Rate fluctuates month-to-month based on the cost of alternative fuels</i>					

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	
		Bills	Rate	Revenue	Rate	Revenue
1	Customer Charges					
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	
		mcf	Rate	Revenue	Rate	Revenue
39						
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			<u>\$ 9,815,394</u>		<u>\$ 9,575,087</u>
54						
55	Adjusted Total Distribution Revenue			<u><u>\$ 10,848,053</u></u>		<u><u>\$ 10,848,053</u></u>

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	
			Rate	Revenue	Rate	Revenue
1	Customer Charges	Bills				
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			<u>\$ 1,438,297</u>		<u>\$ 2,033,960</u>
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			<u>\$ 17,682,388</u>		<u>\$ 21,294,725</u>
19						
20	Adjusted Total Distribution Revenue			<u><u>\$ 19,120,685</u></u>		<u><u>\$ 23,328,685</u></u>

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:

$$\$36.38 * \$69.07/85.59 = \mathbf{\$29.36}$$

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:

$$\$36.38 \text{ Cust Charge} * 547,071 \text{ Bills} = \$19,902,443 \text{ (Total GC Cust Rev)}$$

Resulting Proposed GC Tier Customer Charge Revenues:

$$\$29.36 \text{ Small GC Cust Charge} * 205,656 \text{ Small GC Bills} = \$6,038,060 \text{ (Small GC Cust Rev)}$$

$$\$19,902,443 \text{ GC Cust Rev} - \$6,038,060 \text{ Small GC Cust Rev} = \$13,864,383 \text{ (Large GC Cust Rev)}$$

$$\$13,864,383 \text{ Large GC Cust Rev} / 341,415 \text{ Large GC Bills} = \mathbf{\$40.61} \text{ (Large GC Cust Charge)}$$

PECO Exhibit JAB-6:

Modified Base Rate Recovery of CAP Revenues in Gas USFC

PECO - Gas
Modified Base Rate Recovery of CAP Revenues for USFC

C-Factor Period	Estimated CAP Credits (\$)	Estimated GR Sales (a) (MCF)	Estimated Shortfall Recovered in Base Rates (b) (3) = (2) * \$0.2656 thru 12/31/2024 (3) = (2) * \$0.3123 as of 1/1/2025	Shortfall o/(u) Base Recovery (4) = (1) - (3)	Shortfall o/(u) Base Recovery (c) (5) = (4) * 0.73 thru 12/31/2024 (5) = (4) * 0.895 as of 1/1/2025
	(1)	(2)			
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) (3) = (2) * \$0.2656 thru 12/31/2024 (3) = (2) * \$0.3123 as of 1/1/2025	Base Recovery o/(u) Actual (4) = (3) - (1)	Base Recovery o/(u) Actual (d) (5) = (4) * 0.73 thru 12/31/2024 (5) = (4) * 0.895 as of 1/1/2025	C-Factor Revenue (6) = (2) * (.1398)	C-Factor Over/(Under) Recovery (7) = (5) + (6)
	(1)	(2)					
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 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

TABLE OF CONTENTS

	Page
I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. TARIFF RATES AND RIDERS	2
III. SECTION 1307 SURCHARGES	3
IV. MISCELLANEOUS REVISIONS	12
V. CONCLUSION.....	13

1 **DIRECT TESTIMONY**
2 **OF**
3 **MEGAN A. MCDEVITT**

4 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

5 **1. Q. Please state your name and business address.**

6 A. My name is Megan A. McDevitt. My business address is PECO Energy
7 Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

9 A. I am employed by PECO Energy Company (“PECO” or the “Company”) as
10 Senior Manager, Retail Rates. In that capacity, I am responsible for the
11 management and oversight of PECO’s electric and gas retail and supplier service
12 tariffs and oversee numerous filings with the Pennsylvania Public Utility
13 Commission (the “Commission”).

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

15 A. I earned a Bachelor of Science degree in Accounting from DeSales University in
16 2001. In 2006, I became a Certified Public Accountant in Pennsylvania. In March
17 of 2022, I was promoted to my current position in PECO’s Regulatory Policy and
18 Strategy department, following roles of increasing responsibility within
19 Accounting, Finance, Energy Acquisition, and Gas Supply and Transportation
20 since joining PECO in September of 2004.

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

22 A. My testimony will explain proposed revisions to PECO’s Tariff Gas – Pa. P.U.C.
23 No. 5 that have been incorporated in the Company’s proposed Tariff Gas – Pa.
24 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.

1 **7. Q. Please describe the revisions that PECO is proposing to the Neighborhood**
2 **Gas Pilot Rider (“NGPR”).**

3 A. As explained by Company witness Doreen L. Masalta in PECO Statement No. 9,
4 the Company is proposing to continue the gas main extension pilot program for an
5 additional five years (January 1, 2025 to December 31, 2029). During the five-
6 year pilot extension, the Company’s total investment would not exceed \$40
7 million.

8 **III. SECTION 1307 SURCHARGES**

9 **8. Q. What is a Section 1307 surcharge mechanism?**

10 A. Section 1307 of the Public Utility Code, 66 Pa.C.S. § 1307, authorizes utilities to
11 establish automatic adjustment clauses that allow them to recover, outside of a
12 base rate proceeding, specific, designated categories of costs. Cost recovery is
13 subject to annual review and reconciliation, such that over- or under-recoveries of
14 actual costs are refunded to customers or recouped, as applicable. The operation
15 of Section 1307 clauses is also subject to annual public hearings and periodic
16 audits by the Commission.

17 **9. Q. Is PECO proposing changes to any of its existing Section 1307 surcharge**
18 **mechanisms?**

19 A. Yes, the Company is proposing to revise its Universal Service Fund Charge
20 (“USFC”), GPC, MFC and Distribution System Improvement Charge (“DSIC”).

21 **10. Q. Please describe the changes PECO is proposing to the USFC.**

22 A. The USFC, among other things, is a mechanism by which the Company reflects
23 the aggregate bill credits (in dollars) provided to low-income customers through

1 PECO’s gas Customer Assistance Program (“CAP”) rider each year that are not
2 included in base rates (the “CAP shortfall”). The USFC also returns funds to
3 customers for the cost of energy efficiency programs that were collected in base
4 rates but were not expended.

5 With respect to CAP costs, the current USFC is adjusted so that non-CAP
6 residential customers pay 73% of the total CAP shortfall amount. The remaining
7 27% of the CAP shortfall is absorbed by PECO to account for the estimated
8 impact to bad debt expense and cash working capital arising from incremental
9 changes to the level of CAP bill credits reflected in base rates. In this proceeding,
10 as explained by Company witness Jacqueline F. Golden in PECO Statement No.
11 10, the Company is proposing to increase the aggregate value of bill credits
12 provided to electric CAP customers included in its base rates and to change the
13 offset factor applied to reconcilable CAP costs in the USFC formula from 27% to
14 10.5%.

15 With regard to residential natural gas energy efficiency and conservation
16 (“EE&C”) programs, PECO currently collects \$2,727,500 through base rates each
17 year.¹ If the Company expends less than that amount annually, a credit is
18 provided to residential customers through the USFC. As explained by Ms.
19 Masalta in PECO Statement No. 9, the Company also proposes changes to its
20 residential natural gas EE&C programs and to increase its annual expenditures by
21 \$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.

1 **14. Q. What are the total annual gas procurement costs PECO has included for**
2 **recovery in the Company’s proposed GPC?**

3 A. As summarized on PECO Exhibit MAM-1, p. 1, the total annual non-fuel
4 procurement costs included in the Company’s GPC are \$1,742,000 for labor and
5 benefits, outside legal costs, GasStar costs and CWC costs. These annual non-
6 fuel procurement costs are also eliminated from distribution costs in PECO
7 Exhibit MJT-1, Schedule D-15 by an associated reduction in distribution revenue
8 requirement.

9 **15. Q. How did you determine the GPC and the associated reduction in distribution**
10 **base revenue requirement?**

11 A. The revised GPC was calculated by dividing the non-fuel procurement costs of
12 \$1,742,000 by the projected default service volumes of 48,351,926 Mcf for the
13 fully projected future test year ending December 31, 2025 (“FPFTY”) for Rate
14 Schedules GR, CAP, GC, OL, L and MV-F (PECO Exhibit MAM-1, p. 1). The
15 resulting GPC rate is \$0.0360 per Mcf. Consistent with the Commission
16 regulation and current practice, the GPC rate will be included in the Company’s
17 PGC rate (PECO Exhibit JAB-2) and will remain constant until PECO’s next gas
18 distribution base rate proceeding. The updated tariff page reflecting this GPC is
19 in PECO Exhibit JAB-2, p. 45.

20 The purpose of the distribution revenue requirement reduction is to eliminate
21 from distribution rates the procurement-related costs included in the GPC rate.
22 The associated distribution base rate reduction of \$0.0255 per Mcf for non-fuel
23 procurement costs was determined by dividing the annual gas procurement costs

1 of \$1,742,000 by the projected distribution sales volumes of 68,243,939 Mcf for
2 FPPTY, as shown on PECO Exhibit MAM-1, p. 1. The resulting distribution rate
3 reduction of \$0.0255 per Mcf is shown on PECO MAM-1, p. 1.

4 The annual distribution revenue requirement reduction is determined by applying
5 the distribution base rate reduction of \$0.0255 per Mcf to the associated projected
6 distribution service volumes for the applicable classes of service. As noted above,
7 the overall reduction is \$1,742,000, as applied to the classes of service shown in
8 PECO Exhibit MAM-1, p. 7. This reduction in annual distribution revenue
9 requirement is factored into PECO Exhibit MJT-1, Schedule D-15, page 69 and
10 discussed by Company witness Michael J. Trzaska in PECO Statement No. 3.

11 **16. Q. Please describe the update PECO is proposing to the MFC.**

12 A. The MFC recovers charge-offs of uncollectible PGC commodity charge revenues
13 billed to sales service (default) customers. The MFC is calculated separately for
14 three groups of customers consisting of: (1) Rate Schedules GR and CAP; (2)
15 Rate Schedule GC; and (3) Rate Schedules L, OL and MV-F. The current write-
16 off factors used to calculate the quarterly MFC rates were determined in PECO's
17 2022 gas base rate case (0.42% for Rate Schedule GR including CAP; 0.13% for
18 Rate Schedule GC; and 0.04% for Rate Schedules L, OL and MV-F). PECO is
19 proposing to update the write-off factors in this proceeding based on current costs
20 and use those factors to calculate the update to the MFC, as it did in its previous
21 2022 gas distribution base rate case.

1 **17. Q. What are the updated write-off factors from this proceeding that are used to**
2 **calculate the proposed MFC and the natural gas suppliers' Purchase of**
3 **Receivables ("POR") discount rates?**

4 A. The updated write-off factors are 0.47% for Rate Schedule GR including CAP;
5 0.16% for Rate Schedule GC; and 0.01% for Rate Schedules L, OL and MV-F.
6 These factors are based on a three-year weighted average of charge-offs (2021-
7 2023) expressed as a percentage of billed revenues. Refer to PECO Exhibit
8 MAM-2, p. 1, for the derivation of these factors. These factors will remain
9 constant until the Company's next gas distribution base rate proceeding.

10 **18. Q. How is the MFC determined?**

11 A. Write-off factors for each of the applicable groups of rate schedules are multiplied
12 by the Commodity Charge portion of the Company's projected PGC rate to
13 determine the MFC. Upon completion of this proceeding, the approved write-off
14 factors will be applied to the then-existing applicable Commodity Charge portion
15 of the PGC rate, including the updated GPC from this proceeding, to determine
16 the MFC. Thereafter, the MFC will be updated quarterly as the Commodity
17 Charge rate portion of the PGC rate changes, while the approved write-off factors
18 and GPC will remain constant until the Company's next gas distribution base rate
19 proceeding.

1 **19. Q. What is the relationship between the costs for charge-offs of uncollectible**
2 **accounts included in the MFC and the POR discount rates and the expense**
3 **for uncollectible accounts included for recovery in PECO's gas distribution**
4 **base rates?**

5 A. In accordance with existing practices, the costs for uncollectible charge-offs for
6 sales service (default) customers reflected in the MFC will be included in the
7 PGC rate as part of the Commodity Charge portion of the PGC. In addition, the
8 costs for uncollectible charge-offs for natural gas suppliers are included as part of
9 the POR discount rates. Therefore, these costs will not be included in PECO's
10 gas distribution base rates.

11 **20. Q. What is the MFC PECO proposes in this proceeding?**

12 A. As shown in PECO Exhibit MAM-2, p. 2, the proposed MFC for Rate Schedule
13 GR including CAP is \$0.0227 per Mcf; for Rate Schedule GC is \$0.0077 per Mcf;
14 and for Rate Schedules L, OL and MV-F is \$0.0005 per Mcf. These rates are
15 based on data included in the distribution base rate case from PECO Exhibit MJT-
16 1. As previously discussed, once the write-off factors from this proceeding are
17 approved, they will be applied to the applicable commodity charge portion of the
18 PGC rate in effect, including the updated GPC from this proceeding to determine
19 applicable MFC values. Using the current PGC No. 40 Q1 effective March 1,
20 2024, the updated MFC values with the updated write-off factors and GPC from
21 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.

1 **23. Q. How is the distribution base rate revenue adjusted to account for costs**
2 **associated with uncollectible charge-offs recovered through the POR**
3 **discount rates from natural gas suppliers for customers who shop for their**
4 **natural gas?**

5 A. PECO Exhibit MAM-2, p. 3, shows the reduction to overall distribution revenue
6 requirements associated with the POR discount rates for shopping customers.
7 These rates, which are equal to the write-off factors at this time, are applied to
8 natural gas supplier revenues to determine the reduction in distribution revenue
9 requirement as a result of costs recovered through the POR discount rate. The
10 associated annual revenue requirement that will be deducted from the overall
11 distribution revenue requirement is \$281,000, as shown in PECO Exhibit MAM-
12 2, p. 3 and included in PECO Exhibit MJT-1, Schedule D-15, page 69 and
13 discussed by Mr. Trzaska in PECO Statement No. 3. The MFC reduction, when
14 combined with the annual revenue requirement of \$919,000, results in a total
15 MFC and POR reduction in distribution annual revenue requirement of
16 \$1,200,000.

17 **24. Q. Please describe the revision that PECO is proposing to its DSIC in**
18 **conjunction with this gas distribution rate case.**

19 A. In accordance with the “New Base Rate” section of PECO’s DSIC, which was
20 approved by the Commission’s Order at Docket No. P-2015-2471423 entered on
21 October 22, 2015, PECO is required to reset the DSIC to 0% upon the effective
22 date of Commission-approved base rates. PECO’s DSIC charge will be set to

1 zero effective January 1, 2025, as shown in the proposed DSIC. *See* PECO
2 Exhibit JAB-2.

3 **25. Q. Are there any other matters relating to Section 1307 mechanisms in PECO's**
4 **Gas Tariff that you wish to address?**

5 A. Yes, I would like to address PECO's temporary Tax Cuts and Jobs Act ("TCJA")
6 Voluntary Surcharge, which is a rate adjustment mechanism to refund the
7 estimated TCJA savings to customers. The TCJA Voluntary Surcharge became
8 effective on July 1, 2018 pursuant to the Commission's Order entered on May 17,
9 2018 at Docket R-2018-3000512 (the "2018 Order").

10 From 2018 through 2023, PECO made several additional TCJA Voluntary
11 Surcharge filings to continue to reconcile the final balances for residential, small
12 commercial, large commercial and industrial customers, eventually resetting the
13 TCJA to 0% for all rate classes effective March 1, 2023. The remaining balance
14 as of May 31, 2023 is an undercollection of \$62,667. As explained by Mr.
15 Trzaska in PECO Statement No. 3, PECO proposes to collect the small under-
16 recovery from customers through a distribution revenue requirement addition.
17 Accordingly, PECO has fully satisfied the requirement of the 2018 Order.

18 **IV. MISCELLANEOUS REVISIONS**

19 **26. Q. What miscellaneous revisions are being proposed by PECO and reflected in**
20 **the proposed tariff?**

21 A. PECO is proposing two miscellaneous revisions. First, PECO is proposing to
22 revise the definition of "Holidays" to remove the term "Company" to align

1 language with PECO's electric service tariff and add the new Federal holiday of
2 Juneteenth to the list of holidays.

3 Second, PECO is proposing to revise the Availability section of Rate IS –
4 Interruptible Service to reflect the summer months of April through October.
5 This change will align the summer months with other sections of the tariff.

6 **V. CONCLUSION**

7 **27. Q. Does this complete your direct testimony at this time?**

8 **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\$)

PECO Exhibit MAM-1
Page 1

<u>LABOR AND BENEFITS</u>	<u>Costs</u>	<u>Source</u>
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	<u>\$82</u>	PECO Exhibit MAM-1, Page 2
<i>Total Labor and Benefits</i>	\$848	PECO Exhibit MAM-1, Page 2
<i>Outside Legal Costs</i>	\$60	PECO Exhibit MAM-1, Page 4
<i>GasStar Related Costs</i>	\$62	PECO Exhibit MAM-1, Page 5
<i>Working Capital</i>	<u>\$772</u>	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\$)

PECO Exhibit MAM-1
Page 2

	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	<u>778.8</u>	\$105.01	<u>\$82</u>
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	<u>\$1,008</u>	<u>\$1.49</u>
 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\$)

	<u>Costs</u>	<u>Source</u>
Outside Legal Expenses	\$60	Company Records

PECO-Gas Operations
Annual Expenses for GasStar
January 1, 2025 through December 31, 2025
(Thousand\$)

PECO Exhibit MAM-1
Page 5

	<u>Costs</u>	<u>Source</u>
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\$)

PECO Exhibit MAM-1
Page 6

			<u>Source</u>
Revenue Lag	48.86	days	PECO Exhibit MJT-1, Schedule C-4, Page 23
Purchased Gas Costs Lag	<u>33.24</u>	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)

	<u>Capital Structure</u>	<u>Return</u>	<u>Weighted Return</u>	<u>After-Tax Return</u>
Debt	46.60%	4.58%	2.13%	1.55%
Common	<u>53.40%</u>	11.15%	<u>5.95%</u>	<u>5.95%</u>
	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\$)

PECO Exhibit MAM-1
Page 7

Rate Schedule	Distribution Mcf <u>Sales</u>	Distribution Charge Rate Reduction <u>\$ per Mcf (a)</u>	Distribution Revenue Reduction <u>Reduction</u>
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	<u>503,183</u>	0.0255	<u>\$13</u>
 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

PECO Exhibit MAM-2

Page 1

	12 months ended December 31, 2021	12 months ended December 31, 2022	12 months ended December 31, 2023	
Residential	Charge-Off Analysis	Charge-Off Analysis	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

PECO Exhibit MAM-2
Page 2

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\$)

Rate Schedules	<u>Default Customers</u>					<u>Shopping Customers</u>			<u>Total</u>
	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	<u>273,306</u>	<u>\$0</u>	0.01%	<u>\$626</u>	<u>\$0</u>	<u>\$0</u>
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

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

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ISSUED BY:
Michael A. Innocenzo, President & CEO
PECO Energy Distribution Company
2301 Market Street
Philadelphia, PA. 19103

NOTICE.

PECO Energy Company

Supplement No. ~~x~~ To
Tariff Gas PaPUC No. 2S
~~x~~ Revised Page No. 1
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.

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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.¶

Issued ~~March 28~~, 2024

Effective ~~May 27~~, 2024

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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 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.
- 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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Issued March 28, 2024

Effective May 27, 2024

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

TABLE OF CONTENTS

	Page
I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. PECO’S RESIDENTIAL NATURAL GAS EE&C PROGRAMS.....	3
A. Current Programs	3
B. Proposed Revisions To The Overall Residential Natural Gas EE&C Budget and SEHP Administration	12
III. PECO’S NEIGHBORHOOD GAS PILOT	19
IV. CONCLUSION.....	25

1 **DIRECT TESTIMONY**
2 **OF**
3 **DOREEN L. MASALTA**

4 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

5 **1. Q. Please state your name and business address.**

6 A. My name is Doreen L. Masalta. My business address is PECO Energy Company,
7 2301 Market Street, Philadelphia, PA 19103.

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

9 A. I am employed by PECO Energy Company ("PECO" or the "Company") as
10 Director of Energy and Marketing Services. In that capacity, I have responsibility
11 for the suite of energy efficiency programs offered by PECO to the Company's
12 residential, commercial, and industrial customers. My team provides the
13 marketing and promotions for these programs to encourage all customers to
14 reduce their energy usage and save money on their bills.

15 **3. Q. Please describe your educational background.**

16 A. I have a Bachelor of Arts in Organizational Dynamics from Immaculata
17 University.

18 **4. Q. Please describe your professional experience.**

19 A. I began my career owning and operating Arbor Tree Specialist, a private tree
20 contracting business out of Pittsburgh, Pennsylvania. I then moved into the utility
21 line clearance industry in 1994 with Asplundh Tree Expert Company where I held
22 various positions including climber, foreperson, estimator, and emergent work
23 coordinator. I joined PECO in 1998 as a project lead in the Vegetation

1 Management Department and transitioned to program manager in 2000.
2 Beginning in 2002, I had responsibility for the Vegetation Management Programs
3 at both PECO and one of the Company's utility affiliates, Commonwealth Edison
4 Company. In 2007, I was named Director of PECO's Project, Contract &
5 Vegetation Management Department. In late 2009, I became the Director of
6 Operations in the Bucks & Montgomery County Regions and then transitioned in
7 2013 to the City of Philadelphia and PECO Underground. Finally, in 2019, I was
8 promoted to my current position of Director of Energy and Marketing Services.

9 **5. Q. What is the purpose of your testimony?**

10 A. The purpose of my testimony is to: (1) describe PECO's existing residential
11 natural gas energy efficiency and conservation ("EE&C") programs and the
12 Company's proposals to enhance residential natural gas EE&C offerings and add
13 flexibility to the administration of the Safe and Efficient Heating Program
14 ("SEHP") for income-eligible customers; and (2) describe PECO's neighborhood
15 gas pilot and the Company's proposal to extend the pilot with a programmatic
16 change based on implementation experience.

17 **6. Q. Please identify the exhibits you are sponsoring.**

18 A. I am sponsoring PECO Exhibits DLM-1 and DLM-2 which relate to the
19 Company's natural gas EE&C programs. In addition, I will refer to certain tariff
20 changes contained in PECO Exhibit JAB-2 (sponsored by Company witness
21 Joseph A. Bisti in PECO Statement No. 7).

1 **II. PECO’S RESIDENTIAL NATURAL GAS EE&C PROGRAMS**

2 **A. Current Programs**

3 **7. Q. Please describe PECO’s existing residential natural gas EE&C programs.**

4 A. PECO currently offers its residential customers a mix of rebates to encourage
5 them to upgrade to high-efficiency furnaces, boilers and water heaters, direct
6 install measures, as well as discounts on smart thermostats purchased through
7 PECO’s online marketplace. In addition, SEHP provides qualifying low-income
8 customers no-cost direct installation measures through the Low-Income Usage
9 Reduction Program (“LIURP”) and as part of free home energy assessments to
10 improve the efficiency and safety of natural gas heating and water heating in their
11 homes. SEHP also provides program recipients education on maintenance and
12 energy efficiency tips at no cost. The Company has a total Pennsylvania Public
13 Utility Commission (“Commission”) approved residential natural gas EE&C
14 budget of \$2.727 million and has allocated \$719,000 of that budget to the SEHP.¹

15 **8. Q. What natural gas equipment rebates are currently offered to PECO’s**
16 **residential customers?**

17 A. As shown in the Table 1 below, PECO offers residential customers the following
18 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”).

1
2

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 $\geq 97\%$ annual fuel utilization efficiency (“AFUE”) and $\leq 2\%$ 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 $\leq 2\%$ 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 $\geq 94\%$ 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

3 *New measure to be implemented in Q2 of 2024.

1 **9. Q. What direct install measures does PECO offer to residential natural gas**
2 **customers?**

3 A. For PECO natural gas residential customers who use natural gas to heat their
4 water, PECO offers low flow showerheads, insulation/wrap for hot water pipes,
5 thermostatic shower restriction valves and low-flow faucet aerators at no cost to
6 the customer. In the second quarter of 2024, PECO will add two new direct
7 installation home weatherization measures — outlet gaskets and weatherstripping
8 — for customers who heat their homes with natural gas from PECO’s distribution
9 system. All installations are funded through PECO’s natural gas EE&C programs
10 and performed as part of the Energy Assessment Program included in PECO’s
11 Phase IV Act 129 EE&C Plan (“Phase IV Plan”). The SEHP, which is discussed
12 later in my testimony, also offers certain direct install measures to income-eligible
13 customers.

14 **10. Q. How does PECO offer natural gas customers discounts on smart**
15 **thermostats?**

16 A. Eligible natural gas customers can purchase discounted smart thermostats using
17 PECO’s online marketplace.² Eligibility is determined by the customer’s heating
18 and cooling source that will be connected to the smart thermostat.³

19 **11. Q. How has PECO informed its customers about these rebates?**

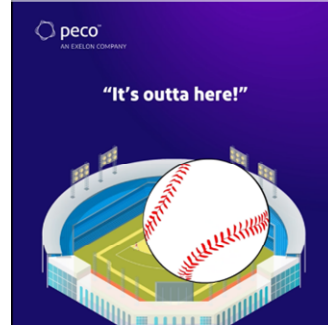
20 A. PECO has used several channels to promote customer rebate opportunities,

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>.

1 including the Company's website, trade-ally networks, newsletters, and bill
2 inserts. In addition, PECO has utilized targeted digital promotions to build
3 residential customer awareness of the Company's natural gas energy efficiency
4 offerings. Below are examples of the Company's digital efforts to promote
5 natural gas energy efficiency awareness.

6 ***Social Media Campaigns.*** Digital ads, such as those shown below, are designed
7 to reach PECO customers on social media platforms to deliver brief, relatable
8 animations around the importance of Energy Efficiency. The ads provide a direct
9 link for customers to learn about PECO's programs online, including how to
10 apply. In addition to the digital ads, PECO often sends corresponding emails
11 using similar messaging and imagery.

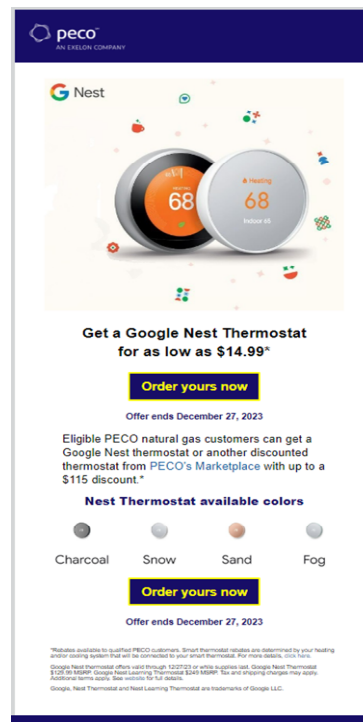
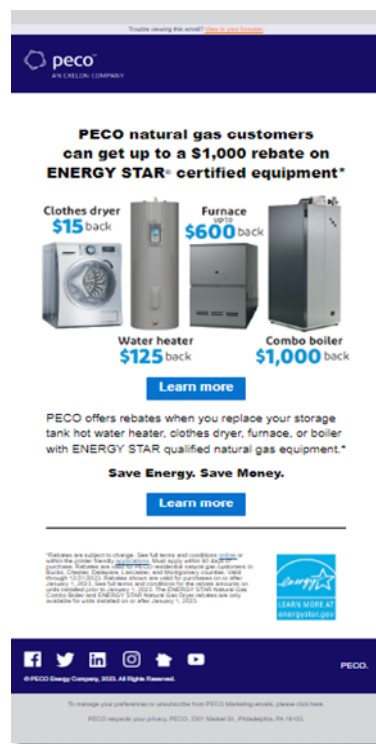


12 The above-referenced social media and email campaign ran in November 2023.
13
14 During this time, PECO saw an average of over 600 unique visitors per day to the
15 Gas Energy Efficiency webpage⁴ versus an average of 30 unique visitors per day
16 during months when there were no campaigns. In the month following the
17 campaign (December of 2023), PECO saw a 55% increase in rebates issued
18

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

1 Company spends less than \$2.727 million, then the difference is credited to
2 customers through the Universal Service Fund Charge (“USFC”).

3 **15. Q. In the Commission-approved settlement of PECO’s most recent gas base rate**
4 **proceeding,⁸ PECO committed to perform an analysis of residential and**
5 **small commercial natural gas EE&C measures. Did PECO fulfill this**
6 **commitment?**

7 A. Yes. In 2023, PECO engaged two vendors familiar with the PECO’s natural gas
8 EE&C programs to perform an analysis of the residential and small commercial
9 natural gas EE&C measures (the “Measure Study”). The Measure Study includes
10 both: (1) an evaluation of the cost effectiveness of the residential (non-SEHP) and
11 small commercial portfolio based on implementation data from 2021 and 2022;
12 and (2) a residential measure adoption rate analysis and forecast of measure
13 performance for 2024 and 2025. The Measure Study also included some
14 recommendations derived from the above-described analyses.

15 Overall, for the 2021-2022 period evaluated, the Measure Study concluded that
16 the portfolio of natural gas EE&C programs was cost-effective. *See* DLM-1 at
17 PDF p. 10. In response to recommendations in the Measure Study, the Company
18 has made some changes to the residential natural gas EE&C portfolio. First, the
19 Company is implementing two new direct install measures in 2024: (1) weather
20 stripping; and (2) outlet gaskets. These two measures will help support the
21 program’s cost effectiveness by implementing weatherization measures through

⁸ *See* Docket No. R-2022-3031113.

1 the direct install portion of the program. Second, beginning in 2024, the
2 Company plans to adjust education efforts to promote the highest efficiency
3 furnaces, boilers, and water heaters and direct install measures to maximize
4 energy savings. Finally, the Company will continue to explore opportunities to
5 implement additional rebate and direct install measures such as hybrid heat
6 pumps, additional home weatherization measures and building optimization.⁹

7 I will discuss how the Company believes that additional funding will help to
8 ensure the program can support projected growth in participation later in my
9 testimony.

10 **16. Q. Does PECO plan to continue evaluating its natural gas EE&C portfolio to**
11 **ensure customers are provided reasons measures that reduce natural gas**
12 **usage?**

13 A. Yes. Consistent with the Company's statement in its most recent base rate
14 proceeding,¹⁰ the Company will perform an evaluation, measurement and
15 verification ("EM&V") study in 2024 to evaluate program years 2021-2023. The
16 Company will perform the next EM&V study in 2027, evaluating program years
17 2024-2026 and will retain the ability to determine the necessity, cadence and
18 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>.

1 **B. Proposed Revisions To The Overall Residential Natural Gas EE&C Budget**
2 **and SEHP Administration**

3 17. **Q. Is the Company proposing to revise the existing budget for PECO's**
4 **residential natural gas EE&C programs?**

5 A. Yes. The Company is requesting to increase the current residential natural gas
6 EE&C budget of \$2.727 million by an additional \$350,000. As shown in Exhibit
7 DLM-2, Table 1, the Company expended 94% of the residential budget in 2023.¹¹
8 The additional \$350,000 would support the projected growth in customer
9 participation from 2023 levels and support future EM&V and customer education
10 activities. Exhibit DLM-2, Tables 1 and 2, provide additional information about
11 forecasted customer participation, energy savings, and costs. As outlined in
12 DLM-2 Table-2, the Company forecasts a 8% growth in energy savings between
13 program years 2024 and 2025 and a 7%-8% growth in energy savings year-over-
14 year through 2027.

15 18. **Q. Why is the Company forecasting continued growth in customer participation**
16 **above 2023 levels?**

17 A. PECO has made great strides in customer participation as a result of increases to
18 customer education efforts and an increasing number of measures. Since 2022,
19 the Company has added four new rebate measures, six direct install measures,
20 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. $(\$2,556,703 \text{ (Spend)} \div \$2,727,500 \text{ (budget)}) = 94\%$.

1 marketing efforts and continue to enhance the portfolio of measures available to
2 customers. Some recent and anticipated highlights include the following:

3 ***Addition of Tankless Water Heater Measures.*** PECO evaluated this measure in
4 response to 2023 ENERGY STAR changes to tank water heater criteria that
5 sharply reduced the number of models that would be eligible for a rebate (from
6 over 400 to less than 40). With the addition of a tankless water heater measure,
7 PECO customers can receive a rebate on over 200 different models of ENERGY
8 STAR-certified water heaters. The \$400 rebate level for tankless water heaters
9 was set to be consistent with similar programs in the region.¹² Based on the
10 findings in the Measure Study, the Company could see an adoption of up to 300
11 rebates per year, which represents a substantial increase to the incentive cost
12 budget.¹³

13 ***New Direct Installation Measures.*** As described earlier, the Company began
14 planning for the implementation of weatherstripping and outlet gaskets measures
15 in 2023, to be made available in 2024, based on findings in the 2023 Measure
16 Study.¹⁴ These new measures require an increase in incentive costs based on the
17 Company's current spend for direct install measures.¹⁵

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.

1 ***Increased Education & Strategy.*** Since 2021, the Company has increased
2 customer education substantially to include social media and email campaigns, as
3 previously described in my testimony. The success of these campaigns warrants
4 increasing the education budget to support continued growth. Additionally, the
5 Company intends to target education efforts towards measures which have a high
6 savings yield and cost effectiveness, through the use of more costly digital
7 advertising such as social media. By highlighting the highest efficiency natural
8 gas equipment and direct install measures, the Company can drive participation
9 for residential measures (non-SEHP) that help achieve overall portfolio cost
10 effectiveness in future program years.

11 **19. Q. Is the Company recommending any changes to the SEHP?**

12 A. Yes, the Company has identified a few programmatic changes which would allow
13 the Company to adapt the SEHP to meet the needs of customers, including
14 adjusting heating system replacement criteria and adding flexibility to adjust
15 customer eligibility requirements and SEHP funding.

16 ***Heating System Replacement Criteria.*** The SEHP is currently focused on
17 replacing heating systems based on age as noted earlier in my testimony, with
18 occasional exceptions made for customers who require replacements due to
19 system failures under the age requirements. The Company proposes to remove
20 the age requirements for eligible customer heating systems and evaluate
21 equipment based on a range of criteria including age, end-of-life, safety, ability to
22 repair and system efficiency. This flexibility would allow the Company to
23 properly manage replacement activity based on field conditions, rather than solely

1 age requirements.

2 ***Customer Eligibility Requirements.*** The Company is requesting the ability to
3 adjust eligibility requirements as follows:

- 4 • Adjust eligibility to up to 200% of the Federal Poverty Level for
5 homeowners and renters.
- 6 • Adjust winter monthly usage requirements.

7
8 This flexibility would allow the Company to adjust the program based on changes
9 to other low-income programs or to align the program with the needs of income-
10 eligible customers within PECO's service territory. For example, if the Company
11 is trending towards a reduced spend within the SEHP budget, the Company could
12 use this flexibility to reach more customers. There are no plans to change
13 eligibility requirements at this time, and any future changes would be reported
14 during the quarterly Universal Service Advisory Committee ("USAC") meetings.

15 ***SEHP Budget Flexibility.*** In the event that the SEHP requires additional funds
16 within a program year, the Company is proposing to have the ability to move
17 funding within the total proposed \$3.078 million budget for residential natural gas
18 EE&C programs to meet the needs of SEHP customers. The Company would
19 limit annual budget transfers to 50% of the allocated SEHP budget.¹⁶ The
20 Company would have sole discretion on moving funding into the SEHP and will
21 notify stakeholders of plans to move funding at quarterly USAC meetings,
22 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. ($\$719,000 * 50\% = \$359,500$).

1 participation. This flexibility would allow the Company to continue to effectively
2 manage the residential natural gas EE&C budget at the program level, by
3 expanding the flexibility to shift funding towards the SEHP. This flexibility
4 would align with the Company's current ability to adjust non-SEHP program
5 budgets within the overall budget for residential natural gas EE&C programs to
6 support growth, increase education or support program evaluation.

7 **20. Q. Exhibit DLM-2, Table 2, shows the programs will underspend the increased**
8 **budget in program year ("PY") 2025 and 2026, please explain.**

9 A. The forecast shown in Exhibit DLM-2 Table 1 shows the estimated PY's 2025
10 and 2026 spending based on expected participation. As shown, the Company
11 would manage spending within 93% and 97% of the overall residential natural gas
12 EE&C budget respectively, if the increase is approved. The underspend is simply
13 a result of the Company's participation forecasting and would still be available for
14 use within the programs, including the SEHP if the aforementioned budget
15 flexibility is approved. Nonetheless, any overall underspend would be refunded
16 to rate payers through the USFC mechanism.

17 **21. Q. What is the projected annual cost of the expanded residential natural gas**
18 **EE&C programs?**

19 A. The projected annual cost of the residential natural gas EE&C programs is \$3.078
20 million, which reflects a \$350,000 increase from the current budget to support
21 increased participation from the Company's efforts to expand the program since
22 2022. The projected annual breakdown of costs by program is provided in
23 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 Study¹⁷, 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.

1 Moving forward, the education budget will be more strongly focused on more
2 cost effective and highly efficient measures, such as the direct install measures
3 and furnace rebates offered through the Company. PECO would still build
4 awareness around the entire natural gas EE&C portfolio through channels such as
5 the Company newsletters, website and email campaigns. More costly targeted
6 channels, such as direct mail or digital advertising, would be focused on helping
7 the program achieve cost effectiveness. Additionally, the Company would
8 continue to evaluate new measures to help with cost effectiveness.

9 **25. Q. How is PECO proposing to recover the costs of the residential natural gas**
10 **EE&C programs?**

11 A. PECO is proposing to recover \$3.078 million through residential gas distribution
12 base rates. If less than \$3.078 million is spent, the difference would be credited to
13 the following year's USFC, as is currently PECO's practice. PECO Exhibit JAB-
14 2 shows the proposed changes to the USFC to incorporate the \$3.078 million
15 annual spending amount.

16 **III. PECO'S NEIGHBORHOOD GAS PILOT**

17 **26. Q. Please describe PECO's Neighborhood Gas Pilot Rider.**

18 A. The Commission approved PECO's Neighborhood Gas Pilot Rider ("NGPR") on
19 October 1, 2015.¹⁹ The NGPR was designed to study two coordinated strategies
20 to increase access to natural gas service by: (1) allowing a customer to pay a
21 contribution in aid of construction ("CIAC") for a gas main extension through a

¹⁹ See Docket No. P-2014-2451772.

1 fixed monthly surcharge instead of requiring an upfront, lump-sum payment; and
2 (2) calculating the required CIAC by taking into account the revenue (including
3 the fixed monthly CIAC payment) expected from the applicant or applicants
4 requesting service and from prospective customers located along the proposed
5 main extension who are expected to connect to the main in the future.

6 The NGPR is available to PECO residential customers who will receive natural
7 gas service under Rate GR, including customers on the Customer Assistance
8 Program (“CAP”) Rider. Certain cost and customer interest thresholds must be
9 met to qualify for the pilot (e.g., the proposed extension must be greater than
10 \$15,000 and at least 20% of eligible customers must execute contracts for gas
11 service). Customers may pay for the main extension in either one upfront
12 payment or a fixed monthly fee with interest on their PECO bill.

13 The NGPR originally had a three-year term and the Company’s investment was
14 limited to no more than: (1) \$10 million over three years; and (2) \$4 million for
15 any particular year. On January 17, 2019, the Commission approved extending the
16 pilot from three to five years (ending March 31, 2021) and the overall pilot
17 investment limit was increased from \$10 million to \$25 million.²⁰ In the 2020
18 Gas Order, the Commission approved a five-year pilot extension (now ending
19 June 30, 2026) with an additional investment of \$25 million. The Commission
20 further approved PECO’s proposal to provide the first forty feet of gas main
21 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).

1 within the project. On July 13, 2023, the Commission approved PECO's petition
2 to remove the \$5 million annual spending limitation.²¹

3 **27. Q. How many main extension projects have been funded under the NGPR?**

4 A. Since the program launched with modifications on July 1, 2021, through
5 December 31, 2023, 99 projects encompassing over 2,048 homes have been
6 funded through the NGPR with a total design estimate cost of \$25 million. Due to
7 overwhelming customer demand and funding limitations, PECO stopped
8 accepting new NGPR projects in August 2022. Many more potential gas main
9 extension projects were analyzed by the Company before August of 2022, but
10 either did not garner sufficient neighborhood interest to move forward or had not
11 advanced sufficiently to proceed prior to funding limitations.

12 **28. Q. Please describe the Company's proposed NGPR revision.**

13 A. The Company is proposing to extend the pilot with a programmatic change to
14 facilitate access to natural gas service in more communities. The revised NGPR
15 would be implemented for a five-year term beginning January 1, 2025, through
16 December 31, 2029.

17 PECO's proposed programmatic change is to modify the percentage of customers
18 the Company models will convert in the first year of a neighborhood project from
19 66% to 50% to more accurately reflect the percentages that we have seen in the
20 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).

1 completion of the project. The revised NGPR would continue to apply to any
2 existing premise that is not located along an existing PECO gas main and where
3 there is an application for natural gas service within the Company's natural gas
4 service territory under Rate Schedule GR, including the CAP Rider. Consistent
5 with the existing pilot, a main extension project must meet the following criteria
6 to qualify for the revised NGPR:

- 7 (1) The project area must contain at least two prospective premises;
- 8 (2) The cost of the project must equal or exceed \$15,000;
- 9 (3) A minimum of twenty percent (20%) of the existing residences located
10 along the proposed main extension must commit to receive natural gas
11 service by signing an agreement prior to the start of construction;
- 12 (4) The Company must have adequate system capacity to serve the
13 customers that are eligible to receive natural gas service from the
14 proposed main extension; and
- 15 (5) The project must be consistent with the overall spending cap for the
16 revised pilot.

17 The limited tariff changes required to implement the revised NGPR are discussed
18 by Company witness Megan A. McDevitt in PECO Statement No. 8 and shown in
19 PECO Exhibit JAB-2.

20 **29. Q. Why is it appropriate to extend the term of the NGPR?**

21 A. The Company continues to see strong demand for natural gas conversion from
22 potential customers. Since PECO stopped accepting new NGPR projects in
23 August 2022 because of fully contracting the \$25 million program budget, there
24 have been over 800 customer inquiries about extending natural gas into new
25 neighborhoods. Potential cost savings from oil or propane conversion to natural
26 gas is typically a driver of interest from customers. As of March 2024, PECO's

1 natural gas prices, including distribution costs, are approximately 63% less than
2 fuel oil and approximately 69% less than propane prices.²²

3 **30. Q. Please explain further why the Company is proposing to update its modeling**
4 **to reflect a 50% conversion in the first year.**

5 A. PECO is proposing to update the Net Present Value (“NPV”) model to reflect
6 50% of customers in a neighborhood converting in the first year to more
7 accurately reflect recent implementation experience. Under the most recent
8 iteration of the pilot, approximately 45% of customers have signed contracts prior
9 to installation. It is not uncommon for additional contracts to be signed within a
10 week or two of the beginning of installation activities.

11 **31. Q. What is the projected cost of the five-year revised NGPR?**

12 A. The Company is proposing to invest a maximum of \$40 million in capital over the
13 five-year term of the revised NGPR. PECO has reviewed customer demand, the
14 number of potential jobs that go through various stages of the process, and
15 updated installation costs, among other factors to determine the proposed capital
16 request.

17 The projected spend in Table 4 below is an estimate of annual costs. The
18 Company is not proposing annual spending restrictions but would instead manage
19 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.

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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 Natural Gas Energy Efficiency Programs

2023 Measure Study

Prepared by: PECO Marketing Department, Strategic Programs

Prepared in partnership with:



CLEAResult[®]

Contents

Section 1: Introduction, Background and Scope	3
<i>2022 Gas Rate Case Settlement Term</i>	3
Background & Scope	3
Section 2: Measure Study Partners.....	4
Measure Study Partners	4
Guidehouse	4
CLEAResult Inc.....	4
Section 3: Guidehouse Analysis	5
Section 4: CLEAResult Program and Adoption Analysis.....	18

Section 1: Introduction, Background and Scope

In accordance with PECO's Base Rate Filing Docket R-2022-3031113¹, 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 Term²

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 2024³. 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.

Guidehouse⁵

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 Investigation¹ 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 TRM³. 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 boilers⁴ 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\(e\)\(2\)\(iii\)](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\(a\)](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 than 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 ($\geq 95\%$ AFUE)	6,203	41,221	37,997	79,218
ENERGY STAR Boiler ($\geq 90\%$ AFUE)	422	1,770	2,151	3,921
ENERGY STAR Furnace ($\geq 97\%$ 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 ($\geq 95\%$ AFUE)	38	226	69	295
ENERGY STAR Boiler < 300 kBTU/h ($\geq 90\%$ 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 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 ($\geq$ 95% AFUE)	\$350.00	\$529	21
	ENERGY STAR Furnace ($\geq$ 97% AFUE)	\$600.00	\$649	21
	ENERGY STAR Boiler ($\geq$ 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 ($\leq$ 1.5 GPM)*	Direct Install	\$11.61	10
	Low Flow Showerhead ($\leq$ 2.0 GPM)*	Direct Install	\$21.00	10
Commercial	ENERGY STAR Furnace <225 kBTU/h ($\geq$ 90% AFUE)	\$300.00	\$433	20
	ENERGY STAR Boiler <300 kBTU/h ($\geq$ 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 PECO's 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 PECO's 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 PECO's 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 PECO's 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 DOE's 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 PECO's 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 conduct 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

Measure Name - TRM	Measure Name - Plan Design	Program	Quantity	Verified Savings (Ex-Post)				Reported Savings (Ex-Ante)	
				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 (Philadelphia value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelphia value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacities 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	Verified and Reported Ratios (Per Unit)	Verified Savings (Ex-Post)				
				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 (Philadelphia value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelphia value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacities 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	<i>Design plan measure characterization unavailable</i>
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 (Philadelphia value from 2021 PA TRM; MD average from MD TRM v11)
2. Commercial HVAC EFLH is 456.5 (average of Philadelphia value of retail and office value per 2021 PA TRM)
3. Smart thermostats are weather normalized for Philadelphia
4. BTU capacities 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

A photograph of three people (two men and one woman) looking intently at a screen, likely a laptop or tablet. The woman in the center is wearing a bright yellow top. The man on the left is wearing a blue shirt. The man on the right is wearing a dark blue jacket over a white shirt. The image is partially obscured by a large red diagonal shape on the right side.

We change the way
people use energy™

PECO Gas Measure Analysis

December 8, 2023

Prepared By
CLEAResult

Prepared For
PECO

Table of Contents

ADOPTION RATE ANALYSIS: RESIDENTIAL SIZE MEASURES	3
Defining the Market.....	3
Benchmark PECO Performance.....	7
A Shifting Market?	8
Measure Forecast	9
New Opportunities	9
Anticipated Program Performance 2024-2025	10
NEW MEASURE EVALUATION	10
Evaluation of Existing and New Gas Measures	10
New Measures	12
REGULATORY CHANGES	13
Federal Standards	13
ENERGY STAR	13
Electrification	14
EMERGING GAS TECHNOLOGY OPPORTUNITIES AND CHALLENGES.....	14
APPENDIX.....	16
Exhibit A: Source for Historical Performance of other Natural Gas Rebate Programs	16
Exhibit B: Measure List.....	17

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

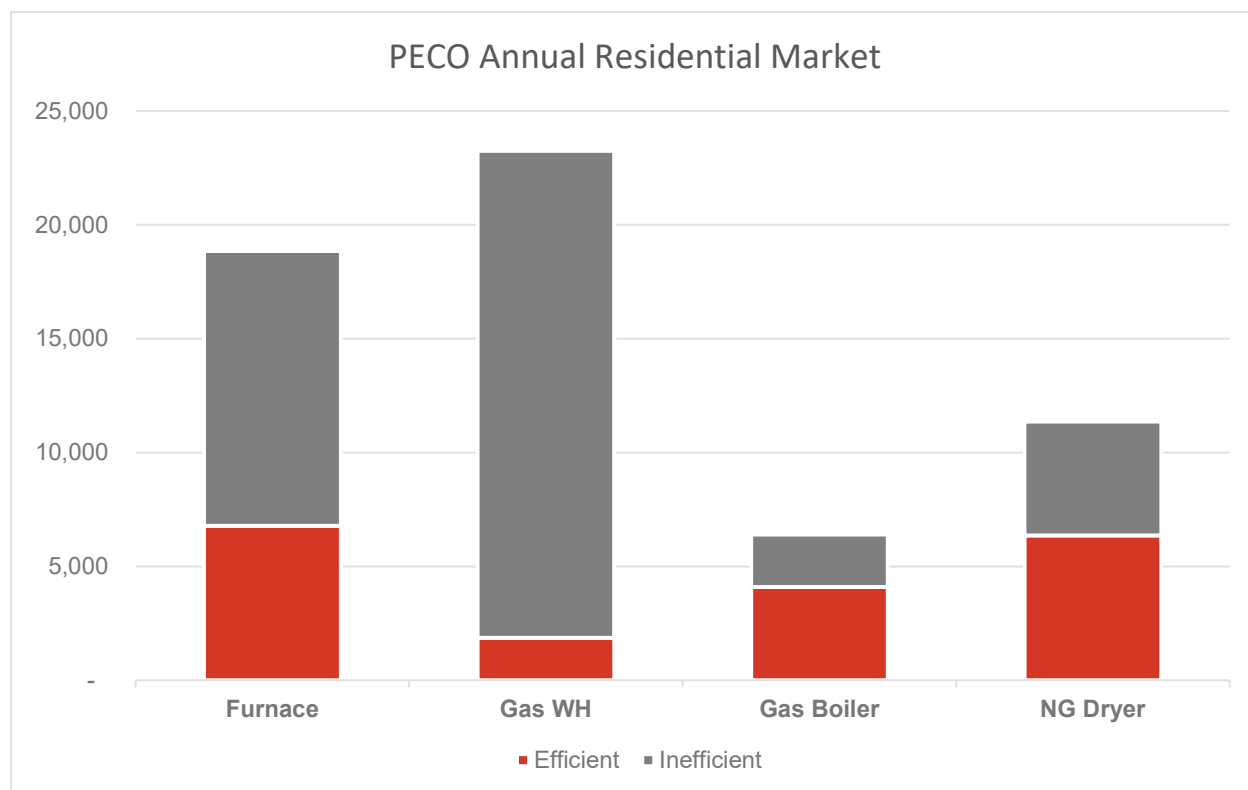
Rebates Paid in PECO Territory

	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%

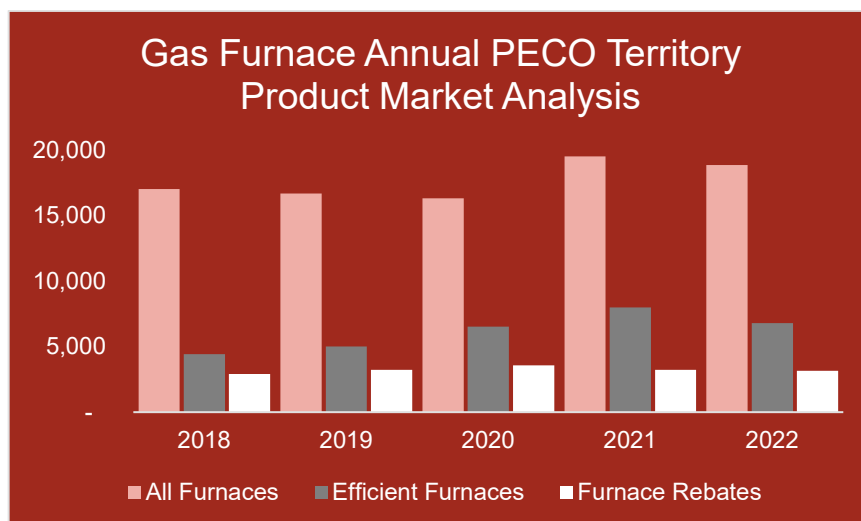
2022 PECO natural gas furnace rebate capture rate efficient market: 3,160/6,786 = 47%

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.

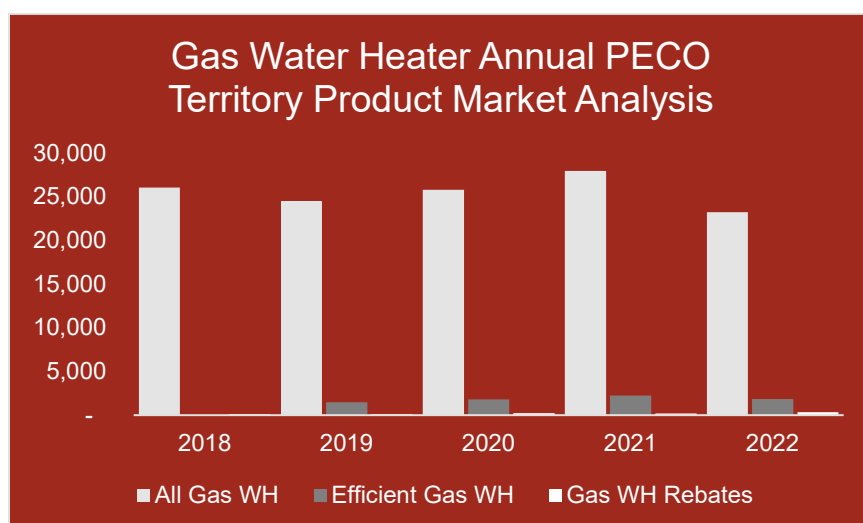


The first equipment type analyzed are natural gas furnaces. The furnace market is the only equipment type where a strong rebate capture rate was found per industry standards, with an efficient market capture rate averaging out at 54%. This is the measure that PECO has been most successfully influencing the market with the rebate offering, though there remains some opportunity to push more rebates.

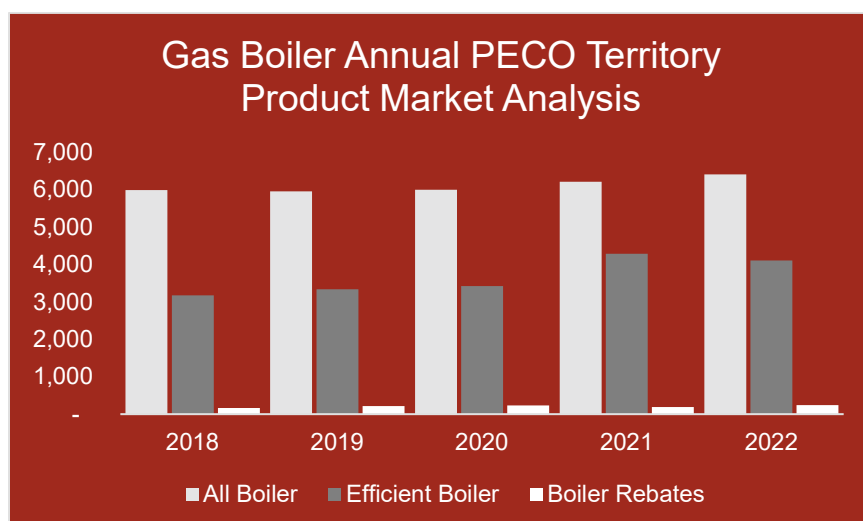
The next graph and table analyze natural gas storage tank water heaters. As noted earlier, this measure has a very low ENERGY STAR market penetration, resulting in a small efficient market opportunity within the territory. The PECO rebate program has not been able to successfully capture this limited 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.



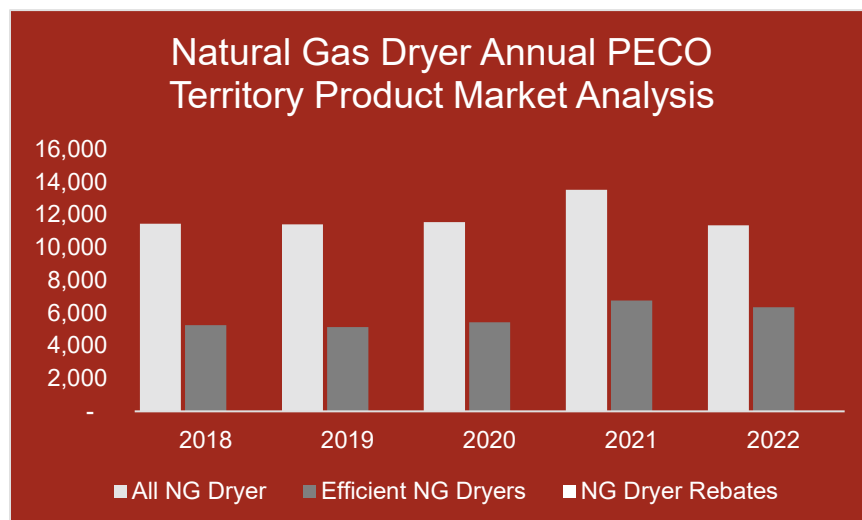
Rebate Capture Rate		
	Whole Market	Efficient Market
2018	17%	54%
2019	19%	65%
2020	22%	55%
2021	17%	41%
2022	17%	47%



Rebate Capture Rate		
	Whole Market	Efficient Market
2018	0%	0%
2019	1%	8%
2020	1%	12%
2021	1%	9%
2022	1%	18%



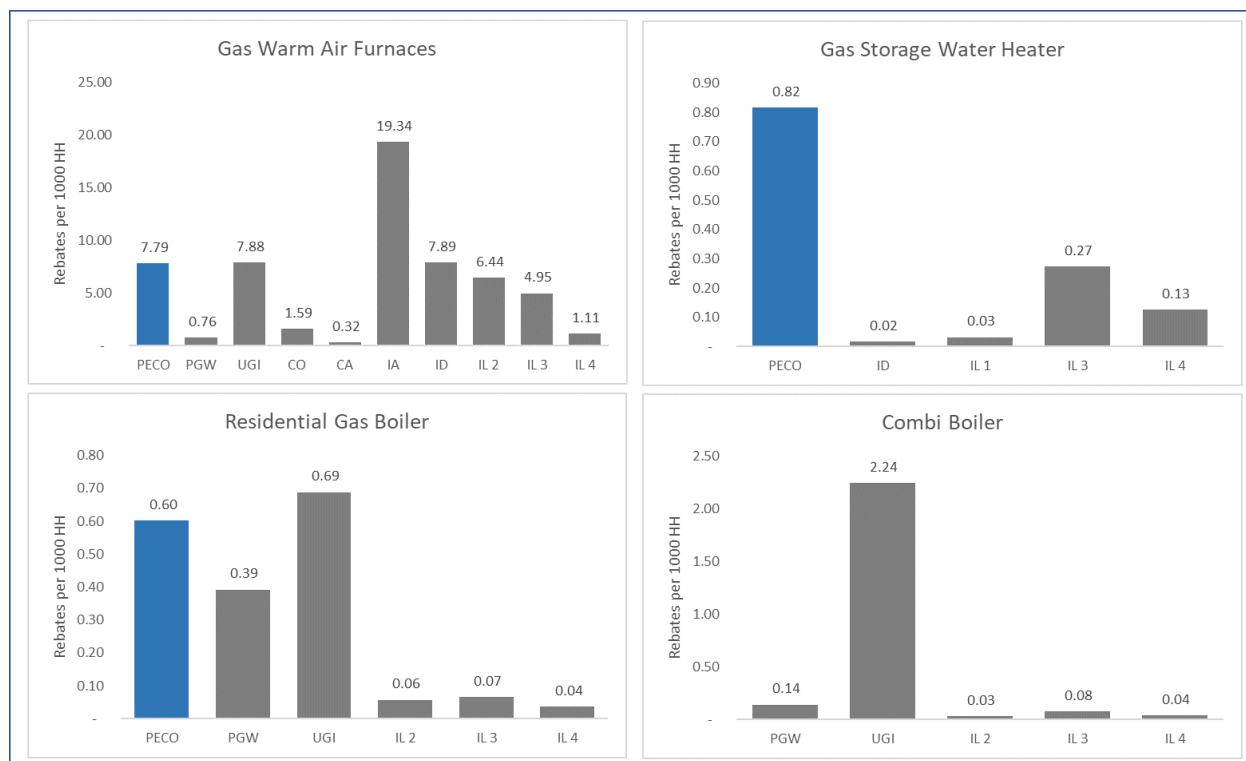
Rebate Capture Rate		
	Whole Market	Efficient Market
2018	3%	5%
2019	4%	7%
2020	4%	7%
2021	3%	4%
2022	4%	6%



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](#)

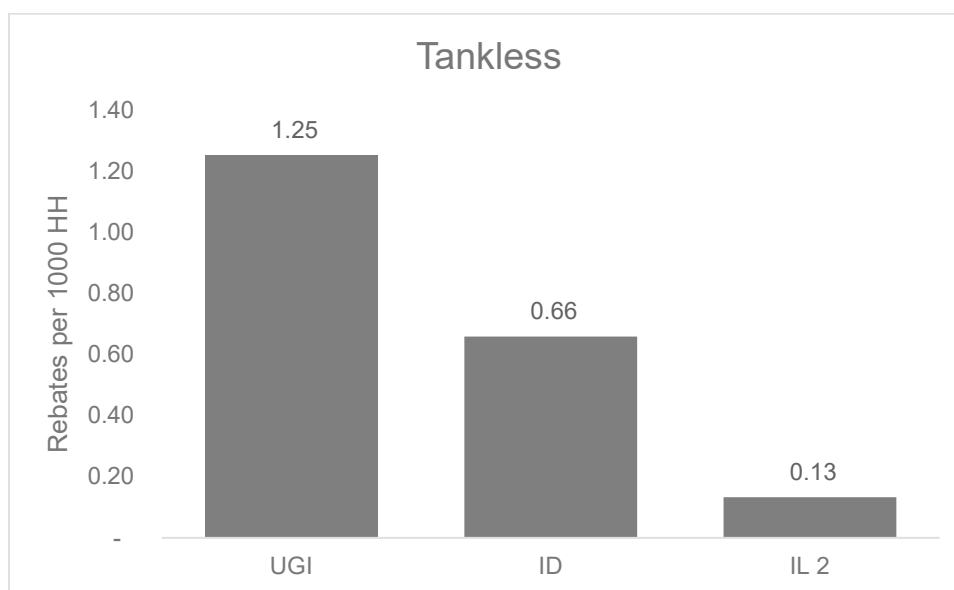
Measure Forecast

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. Forecasted 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
<u>Existing Measures</u>				
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 sunseting 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 sunseting 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® <i>Natural Gas Clothes Dryer</i> **	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® <i>Smart Thermostat Discounts</i>	Residential	Instant Discount	Market Rate
ENERGY STAR® <i>Commercial Gas Furnace Rebate >=95%</i>	Commercial**	Downstream Rebate	Market Rate
ENERGY STAR® <i>Commercial Gas Boiler >= 90% AFUE</i>	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

Participation & Savings 2023-2027	2023 Program Year		2024 Program Year			2025 Program Year		2026 Program Year		2027 Program Year	
	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	\$350K Budget Increase	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		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 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

TABLE OF CONTENTS

	Page
I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. RECOVERY OF CUSTOMER ASSISTANCE PROGRAM (“CAP”) COSTS.....	2
III. OTHER UNIVERSAL SERVICE PROGRAMS	7
IV. REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND.....	8
V. REVISIONS TO THE SMALL BUSINESS GRANT PROGRAM	10
VI. REVISIONS TO THE GAS CUSTOMER SAFETY PROGRAM.....	13
VII. CONCLUSION.....	16

**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.

1 **5. Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to describe: (1) PECO’s proposal for the recovery
3 of Customer Assistance Program (“CAP”) costs; (2) PECO’s existing universal
4 service programs in addition to CAP; (3) PECO’s proposed revisions to its
5 Matching Energy Assistance Fund (“MEAF”); (4) PECO’s proposed revisions to its
6 Small Business Grant Program; and (5) PECO’s proposed revisions to the Gas
7 Customer Safety Program.

8 **II. RECOVERY OF CUSTOMER ASSISTANCE PROGRAM (“CAP”) COSTS**

9 **6. Q. Ms. Golden, please describe PECO’s current CAP for gas customers.**

10 A. In accordance with the universal service obligations set forth in the Public Utility
11 Code, PECO’s CAP assists low-income customers in its service territory through
12 discounted energy bills. PECO’s CAP is a special rate rider for customers with an
13 annual household gross income level at or below 150% of the federal poverty level
14 (“FPL”) as established by the US Department of Health and Human Services. As of
15 December 31, 2023, approximately 23,000 residential gas customers in PECO’s
16 service territory – around 4.5% of PECO residential gas customers – were
17 participating in CAP.

18 The structure of PECO’s CAP discount has evolved over time. Most recently, in
19 December 2022, PECO implemented a new CAP Percentage of Income Payment
20 Plan (“PIPP”), approved by the Commission in Docket No. M-2018-3005795, to

1 provide a percentage of income-based benefit to CAP customers.¹ The PIPP design
2 provides eligible customers with a fixed maximum monthly bill equal to what the
3 CAP customer can afford to pay for utility service. The fixed bill amount is
4 determined by applying an energy burden percentage² to the customer's annual
5 income. CAP bill credits are applied to reduce the customer's monthly
6 undiscounted bill to the monthly PIPP bill amount. For billing purposes, PECO
7 applies the lesser of the CAP PIPP bill or actual charges. Bills issued under the
8 CAP PIPP are subject to monthly minimum bill amounts.

9 Prior to employing a PIPP design, the Company utilized a Fixed Credit Option
10 ("FCO") design (from October 2016 to December 2022) and a tiered rate discount
11 CAP structure (prior to October 2016).

12 **7. Q. What was the dollar amount of the aggregate PIPP bill credits provided to**
13 **CAP customers in 2023 and how were those costs recovered?**

14 A. The value of the CAP bill credits provided to low-income customers through
15 PECO's gas CAP was approximately \$10.9 million in 2023. These costs are
16 recovered through a combination of base rates and a surcharge mechanism under
17 Section 1307 of the Public Utility Code. In the settlement of PECO's 2010 gas base
18 rate case ("2010 Settlement"), the parties agreed that PECO's base rates would
19 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.

1 income customers.³ Since that time, PECO has implemented several CAP
2 enhancements to provide more affordable monthly bills to low-income customers
3 based on the Commission’s energy burden levels set forth in its CAP Policy
4 Statement, which have caused the cost of the CAP program to increase
5 substantially.⁴

6 The CAP “shortfall” refers to the amount of aggregate bill credits (in dollars)
7 provided to CAP customers each year that is not reflected in base rates. This
8 shortfall is recovered from or refunded to PECO’s residential customers on an
9 ongoing basis through PECO’s Universal Service Fund Charge (“USFC”), with
10 annual reconciliation of any over/under collections. Pursuant to the Commission-
11 approved settlement of PECO’s first default service proceeding (the “DSP
12 Settlement”), the USFC is adjusted so that residential customers pay 73% of the
13 total CAP shortfall amount.⁵ The remaining 27% of the CAP shortfall is absorbed
14 by PECO to account for the estimated impact to PECO’s uncollectible expense
15 (22%) and cash working capital requirements (5%). At that time, the 27% factor
16 was associated with CAP program enhancements agreed to in the DSP Settlement,
17 which would be implemented at the same time as base rates established in PECO’s
18 2010 gas rate case.

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).*

1 **8. Q. Is PECO proposing to increase the amount of electric CAP bill credits**
2 **included in its base rates in this proceeding?**

3 A. Yes. The Commission’s CAP Policy Statement was amended effective March 21,
4 2020, which, among other things, established lower recommended maximum
5 energy burden targets for electric and gas CAP bills.⁶ In accordance with the
6 USECP Order, PECO’s energy burdens were updated in late July 2022. As
7 previously noted, in December 2022, PECO implemented its PIPP – providing
8 eligible customers with a maximum monthly bill amount that is determined by
9 applying an energy burden percentage to the customer’s annual income. These two
10 changes greatly increased the value of the bill credits provided to CAP customers.

11 In the fully projected future test year (“FPFTY”), the total estimated amount of
12 PIPP bill credits for customers projected to be enrolled in CAP as of December 31,
13 2025 will be approximately \$13.7 million. As explained by Company witness
14 Joseph A. Bisti in PECO Statement No. 7, PECO proposes to update its base rate
15 recovery to reflect this amount. Annual reconciliation of any over/under collections
16 will continue to be via the USFC.

17 **9. Q. Ms. Golden, is PECO proposing to change the 27% offset percentage applied**
18 **to the CAP shortfall, which is recovered through the USFC?**

19 A. Yes. PECO proposes to change the offset factor applied to reconcilable CAP costs
20 recovered through the USFC from 27% to 10.5%. When additional low-income
21 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).

1 costs attributable to those customers because those costs will be collected from all
2 residential customers through the USFC. PECO currently applies a 22% offset
3 factor to reconcilable CAP costs in the USFC formula to reflect uncollectible
4 expense increases or savings associated with incremental changes in the level of
5 CAP bill credits embedded in PECO's base rates. PECO also applies a 5% USFC
6 offset factor for cash working capital.

7 In light of the increase in value of CAP bill credits provided under the Company's
8 PIPP, PECO has evaluated its recent uncollectible trends for CAP and all residential
9 non-CAP customers to assess the remaining potential improvement in charge-offs.
10 Based on that analysis, PECO is proposing to lower the uncollectible offset
11 percentage to 5.5%.⁷

12 As explained by Company witness Michael J. Trzaska in PECO Statement No. 3,
13 PECO calculated its claim for uncollectible accounts expense using a three-year
14 historic average ratio of net charge-offs as a percentage of billed revenues. As
15 shown in the table below, the uncollectible accounts rate for CAP customers was
16 calculated in the same manner by using the Company's actual charge-off experience
17 for 2021 through 2023 divided by PECO's total billed revenues for the same three
18 years. The offset percentage of 5.5% represents the difference between the
19 uncollectible accounts rate for CAP customers (6.6%) and all residential non-CAP
20 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	3-Year Average	2021	2022	2023	3-Year Average
Annual Billings (\$M)	\$109.3	\$118.7	\$94.3		\$2,387.2	\$2,861.1	\$2,868.7	
Net Charge-Offs (\$M)*	\$3.3	\$10.3	\$7.7		\$22.9	\$28.9	\$34.2	
Ratio (%)	3.0%	8.7%	8.2%		1.0%	1.0%	1.2%	

*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.

1 PECO has a Customer Assistance Referral and Evaluation Service (“CARES”) team
2 that provides referral and information services to assist special-needs, low-income
3 customers who have financial hardships.

4 PECO also has a hardship program – MEAF – that provides customers at or below
5 200% of the FPL whose service is in threat of termination or has been terminated
6 for non-payment with a grant to cure arrears. As discussed below, PECO is
7 proposing a modification to its MEAF program as part of this filing to allow more
8 customers to qualify for these grants.⁸

9 In addition to these universal service programs, PECO’s Safe and Efficient Heating
10 Program (“SEHP”) offers eligible low-income customers no-cost: (1) tune-ups and
11 repairs of natural gas furnaces, boilers and water heaters; (2) replacement of
12 qualifying natural gas furnaces, boilers and water heaters; and (3) direct installation
13 of energy savings measures.⁹

14 **IV. REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND**

15 **11. Q. Please describe the MEAF established by PECO.**

16 A. MEAF is a hardship program funded through donations¹⁰ and matching PECO
17 shareholder contributions. The program is administered in coordination with local
18 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 approved¹¹ 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.

1 **18. Q. What programmatic changes is the Company proposing to the Small**
2 **Business Grant Program?**

3 A. The Company intends to make changes to improve grant accessibility for our small
4 business customers. We found that the requirement of a \$500 arrearage balance on
5 the account at the time of application was a significant barrier. In 2023, 83% of
6 small business customers who applied to the Grant Program were ineligible
7 primarily due to failure to meet the \$500 arrearage requirement. Consequently,
8 PECO is proposing to remove that requirement and utilize the following criteria:
9 PECO will continue to require applicants to:

- 10 • Have an active PECO gas account on or before March 31, 2020;
- 11 • Take service under Rate GC;
- 12 • Attest to a financial hardship; and
- 13 • Attest (via completion of the application) to having fewer than 25
14 employees.

15 PECO will newly require applicants to:

- 16 • Have an average arrearage balance of at least \$150 over the prior 18-
17 month period directly preceding application;
- 18 • Have previously had an arrearage balance on their account at least four
19 times in that same 18-month period; and
- 20 • Have no deposit on hold for poor payment history.

21 Based on account information from the fourth quarter of 2023, approximately 2,477
22 small business customers would be eligible under the revised criteria. Following
23 approval, eligible small business customers would receive a \$200 grant applied as a
24 credit to the active PECO account on a first come, first serve basis.

1 **19. Q. How will the Company encourage applications to the updated Grant**
2 **Program?**

3 A. To advertise and encourage applications, the Company will utilize current customer
4 contact information to send out a blast email notification about the Small Business
5 Grant to eligible small business customers. Additionally, the Small Business
6 Account Managers will employ a new strategy to make specific outreach to eligible
7 small business customers starting with those who have the highest average
8 arrearage amount in the applicable 18-month timespan and the highest number of
9 previous arrearage balance instances on their account (with at least 4 instances
10 being the threshold) in the same applicable 18-month period. The goals of the
11 specific outreach are to: (1) make the customer aware of their eligibility; (2) discuss
12 options for helping the customer manage their energy costs; and (3) encourage the
13 customer to apply for a grant.

14 **VI. REVISIONS TO THE GAS CUSTOMER SAFETY PROGRAM**

15 **20. Q. Does PECO currently offer a Gas Customer Safety Program?**

16 A. Yes. In 2023, PECO launched a Program with an annual budget of \$400,000 that
17 utilizes a two-pronged approach to deliver gas safety materials to residential
18 customers.¹³ First, all new residential gas customers who move into an existing
19 home and sign up for gas service along an existing gas main (referred to as “gas
20 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.

1 educational materials and a gas safety device.¹⁴ The educational materials include,
2 at a minimum: (1) mercaptan “scratch n sniff” information so that customers
3 understand how to recognize natural gas odor leaks; and (2) pamphlets or brochures
4 illustrating where gas detectors should be placed in the home and explaining the
5 importance of installing and maintaining smoke detectors in the home.

6 Second, all residential customers who receive a gas odor response visit (i.e., a home
7 visit in response to a gas odor complaint) are provided with the educational material
8 component of the Safety Package. There are approximately 20,000 gas odor
9 complaints made each year that require a formal gas odor response by PECO.

10 **21. Q. Is PECO proposing to continue this Program?**

11 A. Yes, with some modifications. First, PECO intends to incorporate gas safety
12 advertising as a new component of the Program. In addition, the Company plans to
13 modify the delivery channel for gas safety devices to new “gas along the main”
14 customers and provide a magnet to new residential along with educational
15 materials. The revised Program would operate as follows:

16 **New Residential Gas Customers.** New “gas along the main” customers would
17 receive safety literature, a refrigerator magnet about responding to gas emergencies,
18 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).

1 device and gas safety literature distribution, the Company will engage a fulfillment
2 vendor. New construction customers would receive safety literature and the
3 magnet.

4 **Gas Odor Response.** All residential customers who receive a gas odor response
5 visit would continue to be provided with gas safety literature consistent with the
6 existing program.

7 **Gas Safety Advertising.** PECO would provide enhanced gas safety advertising
8 across multiple channels, including but not limited to digital, video, radio, out of
9 home (e.g. signage, billboards, transit shelters), and social media. The advertising
10 that is currently focused in late September through October and mid-November
11 through December would be expanded to additional time periods throughout the
12 year. On average, PECO currently spends \$300,000 to \$400,000 each year on
13 natural gas safety advertising. In 2023, the Company's advertising provided 30
14 million impressions and approximately 38,000 clicks to our natural gas safety
15 webpage. PECO is proposing to repurpose approximately \$250,000 of the existing
16 Gas Customer Safety Program budget towards enhanced advertising, bringing the
17 Company's total annual gas safety advertising budget to approximately \$650,000.
18 This increased level of spending would facilitate expanded advertising and will
19 increase the number of impressions and visits to the gas safety webpage.

1 **22. Q. With these changes, does PECO expect to spend the full \$400,000 Program**
2 **budget?**

3 A. Yes. PECO notes that if the annual budget is exhausted prior to the end of a
4 Program year, the Company would stop distributing gas safety device vouchers.

5 **VII. CONCLUSION**

6 **23. Q. Does this conclude your direct testimony at this time?**

7 A. Yes, it does.