



pecoSM

AN EXELON COMPANY

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May 30, 2025

Via E-Filing

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

SUBJECT: PECO Purchased Gas Cost No. 42, Effective December 1, 2025
Docket No. R-2025-3054868, Supplement No. 5 to Gas Service Tariff No. 6

Dear Secretary Homsher:

This letter transmits for filing with the Pennsylvania Public Utility Commission (the "Commission") the Purchased Gas Cost ("PGC") No. 42 filing of PECO Energy Company, consisting of the following:

1. Statement No. 1 – Direct Testimony of Suzette E. Adams
2. Statement No. 2 – Direct Testimony of Scott J. Hughes (including exhibit)
3. Statement No. 3 – Direct Testimony of Blerina Gaba-Teme (including exhibits)
4. Statement No. 4 – Direct Testimony of Anthony P. DiFelice (including exhibits)

As required by Commission Order entered December 6, 1985, at Docket No. P-850081, the Company has begun the advance public notice of the proposed gas rate changes contained in the PGC No. 42 filing through bill inserts and newspaper advertisements.

Additionally, this package is being served only via email to those on the Certificate of Service, per their requests for electronic service only.

Matthew Homsher, Secretary
May 30, 2025
Page 2

All correspondence, pleadings and other documents should be sent electronically to the attention of:

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Sincerely,

A handwritten signature in black ink, appearing to read "R.G.W." followed by a long horizontal flourish.

Richard G. Webster, Jr
Vice President
Regulatory Policy & Strategy

cc: K. Hafner, Director, Office of Special Assistants (via e-mail only)
P. T. Diskin, Director, Bureau of Technical Utility Services (via e-mail only)
C. Yother, Director, Bureau of Audits (via e-mail only)

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY
COMMISSION**

v.

PECO ENERGY COMPANY

:
:
:
:
:
:

Docket No. R-2025-3054868

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of PECO's Annual 1037(f) Purchased Gas Cost Filing upon the participants listed below in accordance with the requirements of 52 Pa. Code Section 1.54 (relating to service by a participant).

Via E-File

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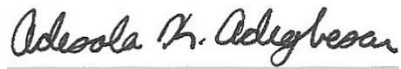
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Dated: May 30, 2025



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**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY**

Docket No. R-2025-3054868

**DIRECT TESTIMONY
OF
SUZETTE E. ADAMS**

PECO STATEMENT NO. 1

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1 Center, and served as the Chief of Staff to the Chief Customer Officer (CCO) in
2 Customer Operations.

3 **5. Q. Please identify your current job responsibilities.**

4 A. In May 2022, I became the Senior Manager of PECO’s Gas Supply &
5 Transportation Department. In this position, I manage all aspects of PECO’s natural
6 gas supply acquisition portfolio including contract negotiation, administration and
7 accounting, gas supply procurement, risk management, off-system sales and
8 capacity release, and long and short-term supply planning. This includes
9 management and optimization of upstream pipeline storage assets and pipeline
10 transportation, as well as decisions on hedging strategies for future supplies. I am
11 also responsible for reviewing all gas supply and capacity costs and providing
12 testimony regarding all gas acquisition activities in the annual Pennsylvania Public
13 Utility Commission (the “Commission”) Purchased Gas Cost Proceedings. In
14 addition, I am also responsible for oversight of the high-volume transportation
15 program and management of Federal Energy Regulatory issues impacting PECO
16 Gas and its customers.

17 **II. PURPOSE OF TESTIMONY**

18 **6. Q. What is the purpose of your Direct Testimony in this proceeding?**

19 A. The purpose of my Direct Testimony is to present the information required in
20 Section 1317(a) of the Pennsylvania Public Utility Code (the “Code”) (*See* 66 Pa.
21 C.S.A. § 1317(a)) so that the Commission may make the findings required by
22 Section 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that
23 PECO’s PGC rates and charges for the historic period (April 1, 2024 through March
24 31, 2025), the estimated period (April 1, 2025 through November 30, 2025) and the

1 PGC application period (December 1, 2025 through November 30, 2026) are just
2 and reasonable. To that end, I am sponsoring the information previously filed by
3 the Company on April 30, 2025 (the “Advance Filing Information”) in support of
4 this year’s purchased gas cost proceeding (“PGC 42”). Additionally, I will describe
5 the Company’s natural gas purchase policies and practices, including PECO’s use
6 of natural gas pipeline transportation and storage contracts, and set forth its plans
7 for evaluating and continuing to incorporate Marcellus Shale production into its
8 supply portfolio.

9 **7. Q. Are you sponsoring any exhibits?**

10 A. No, I am not sponsoring any exhibits. However, as previously mentioned, I am
11 sponsoring the Advance Filing Information, which has been separated into Sections
12 1 through 22, and which correspond, generally, to the PGC filing requirements set
13 forth in 66 Pa. C.S.A § 1317.

14 **8. Q. Please provide a general description of PECO’s natural gas system.**

15 A. PECO’s natural gas system is located in Southeastern Pennsylvania and serves the
16 four-county area surrounding, but not including, the City of Philadelphia and a
17 portion of Lancaster County. Because this is not a natural gas-producing region,
18 PECO and its natural gas customers depend on the interstate natural gas pipeline
19 system to deliver natural gas into PECO’s distribution system. This dependency
20 applies to all natural gas supplies, storage, and interstate transportation services,
21 except for PECO’s two on-system peak-shaving facilities. For a schematic of
22 PECO’s natural gas system, please refer to Section 13 of the Advance Filing
23 Information.

1 **9. Q. Please identify PECO’s interstate transmission suppliers.**

2 A. Texas Eastern Transmission, LP (“Texas Eastern”), Transcontinental Gas Pipeline
3 Corporation (“Transco”), Eastern Shore Natural Gas Company (“Eastern Shore”),
4 and Adelfia Gateway are the four interstate natural gas pipelines that deliver
5 natural gas directly to PECO’s city gates. In addition, Eastern Gas Transmission
6 and Storage, Inc. (“EGTS”), Texas Eastern, and Transco also provide natural gas
7 storage services, which PECO uses to meet winter daily and peaking requirements.
8 In the case of EGTS’ storage service, intermediate transportation service from
9 Texas Eastern is required to deliver the natural gas to PECO’s city gate.

10 **III. HISTORIC AND PROJECTED NATURAL GAS PURCHASES**

11 **10. Q. Please describe the information provided in Section 1 of the Advance Filing**
12 **Information.**

13 A. The information provided in Section 1 of the Advance Filing Information accounts
14 for all of the Company’s purchased natural gas costs during the period from January
15 1, 2024 through March 31, 2025, and includes the source of the natural gas, the
16 price and the associated volumes. This information also includes applicable rates,
17 demand components, and incremental purchased natural gas costs associated with
18 contracted interstate pipeline transportation and storage services. All costs detailed
19 in Section 1 result from applying the Company’s policy to purchase natural gas on
20 a basis that ensures system reliability at the least-cost.

1 **11. Q. During the past 12 months, did PECO purchase natural gas from any affiliated**
2 **interest?**

3 A. No, PECO did not purchase natural gas from any affiliated interest during the past
4 12 months.

5 **12. Q. Has PECO withheld or caused to be withheld from the market any natural gas**
6 **supplies which should have been utilized as part of a least-cost fuel**
7 **procurement policy?**

8 A. No. Because PECO is neither a natural gas producer nor a wholesale market
9 participant of significant size or scope, it could not benefit from withholding any
10 natural gas supplies from the market. For these same reasons, PECO has no market
11 power in the pipeline capacity market. PECO only engages in purchases related to
12 providing natural gas service to its retail customers and a small amount of off-
13 system sales from which its retail customers derive substantial benefit.

14 **13. Q. Has PECO included in its PGC rates any purchased natural gas costs that**
15 **should be charged to transportation customers?**

16 A. No. When a transportation customer uses PECO's purchased natural gas under Rate
17 IS ("Interruptible Service"), these fuel costs are excluded from costs to be recovered
18 from PECO's PGC customers. In addition, PECO provides Standby Sales Service
19 for firm and interruptible transportation customers whereby those customers may
20 purchase natural gas from the Company at the standard retail rate should a
21 customer's supplier fail to deliver gas. The demand charge revenues derived from
22 Standby Sales Service are credited toward recovery of purchased natural gas costs
23 through the Section 1307(f) mechanism. If a firm transportation ("FT") customer

1 fails to elect Standby Sales Service and nevertheless uses PECO's purchased
2 natural gas to make up for deficient supplier deliveries, or if an interruptible
3 customer consumes unauthorized volumes, the customer is charged tariff rates for
4 the natural gas used and assessed a penalty for the delivery deficiency. These
5 penalty revenues are also credited to PECO's PGC customers.

6 **14. Q. Please describe the information provided in Sections 6 and 7 of the Advance**
7 **Filing Information.**

8 A. Sections 6 and 7 of the Advance Filing Information provide the projected cost of
9 purchasing natural gas for the estimated period (April 1, 2025 through November
10 30, 2025) and the PGC application period (December 1, 2025 through November
11 30, 2026), respectively. This information includes the expected source of the
12 natural gas, the price, and the associated volumes. The projected purchases reflect
13 the Company's policy to purchase natural gas on a basis that ensures system
14 reliability at the least-cost. Sections 6 and 7 of the Advance Filing Information
15 include all projected interstate pipeline costs, storage demand costs, variable
16 storage and fuel-related costs, and commodity costs for the relevant time periods.
17 As shown in Section 6 of the Advance Filing Information, the total projected cost
18 applicable to the PGC for the estimated period is approximately \$178.390 million.
19 As shown in Section 7 of the Advance Filing Information, the total projected cost
20 applicable to the PGC for the application period is approximately \$416.639 million.

1 **IV. DESIGN DAY REQUIREMENTS**

2 **15. Q. Have you provided an overview of the methodology the Company employs to**
3 **determine design day requirements?**

4 A. Yes. Details of PECO's design day methodology and a description of its 2025-2026
5 winter design day requirements are included in Section 16 of the Advance Filing
6 Information. As described in Section 16, PECO's supply resources, combined with
7 peaking and delivered supply, will satisfy the Company's design day requirement
8 of 904,404 Mcf for the 2025-2026 winter season.

9 **16. Q. Is PECO proposing a change to its design day as a result of its experience**
10 **during the 2024-2025 winter season?**

11 A. No. PECO's design day methodology, as well as system performance this past
12 winter, supports the continued use of a zero degree design day.

13 **V. PECO'S NATURAL GAS PURCHASE POLICIES AND PRACTICES**

14 **17. Q. Does PECO pursue a least-cost procurement policy?**

15 A. Yes, it does.

16 **18. Q. Please describe PECO's least-cost procurement policy.**

17 A. PECO's natural gas procurement policy is designed to achieve a reasonable balance
18 of long- and short-term natural gas purchases under different pricing approaches,
19 in order to achieve system supply reliability at the least-cost. As previously
20 discussed, the details of PECO's actual natural gas purchases for the fifteen (15)
21 months ending March 31, 2025 and its estimated purchases through November 30,
22 2026, are presented in the Advance Filing Information (Sections 1, 6 and 7). PECO
23 utilizes its interstate transportation and storage entitlements to obtain and deliver
24 market-priced supplies to the PECO natural gas distribution system.

1 **19. Q. Please explain the practical implementation of the policy.**

2 A. PECO manages its least-cost procurement strategy through purchases made under
3 long-term (more than one month), such as purchases made in conjunction with the
4 Ratable Hedging Program, and short-term (one month or less) contracts, and on the
5 daily spot market. Purchases made under long- and short-term contracts generally
6 use two pricing mechanisms: (1) daily or first-of-the-month indices; and (2)
7 adjusted New York Mercantile Exchange (“NYMEX”) futures pricing. Index-
8 based pricing refers to the use of either a first-of-the-month index at a particular
9 location, such as the index published in the *Inside FERC Gas Market Report*, or a
10 daily index at a particular location, such as those published in *Gas Daily*. NYMEX
11 futures pricing refers to the use of a selection of monthly natural gas futures prices
12 from a NYMEX futures contract pricing screen, or a monthly NYMEX settlement
13 price, plus or minus a negotiated locational basis. PECO receives bids from
14 suppliers for the lowest basis numbers, which, when added to the applicable
15 NYMEX futures price or NYMEX settlement price, affords PECO the least-cost
16 natural gas price at its city gate.

17 Spot purchases are made at either a daily index or a fixed price. PECO also
18 uses Requests for Proposals (“RFPs”) to obtain least-cost bids for natural gas
19 supplies. In this process, the bids may or may not contain a premium or discount
20 depending on the market and time of year.

21 Additionally, PECO continued and extended its Ratable Hedging Program
22 as authorized by the Joint Petition for Complete Settlement in last year’s PGC
23 proceeding at Docket No. R-2024-3048767.

1 **20. Q. Why does PECO employ a variety of pricing approaches rather than just one?**

2 A. PECO uses different pricing approaches to reduce the price volatility risk associated
3 with using only one approach. The flexibility of using different pricing methods
4 has enabled PECO to diversify its natural gas-purchasing portfolio. By employing
5 these various options, PECO reasonably limits its exposure to intra-month, monthly
6 and seasonal pricing volatility.

7 **21. Q. What other methods does PECO use to mitigate its exposure to price**
8 **volatility?**

9 A. One additional method PECO uses to mitigate its exposure to price volatility is to
10 use its interstate transportation contracts for supply purchases from geographically
11 diverse locations that have substantial liquidity. This allows PECO the flexibility
12 to analyze the market and optimize its purchases to reduce the price of natural gas
13 delivered to its city gate, considering both commodity and transportation costs.
14 PECO’s interstate transportation capacity ensures access to supplies from the Gulf
15 of Mexico, mid-continent, and the Appalachian region, which includes Marcellus
16 Shale natural gas supplies from Pennsylvania and other Marcellus Shale natural
17 gas-producing areas.

18 PECO also mitigates its exposure to price volatility by using its interstate
19 pipeline storage entitlements. In addition to providing a source of wintertime
20 deliverability, access to pipeline storage allows PECO to purchase natural gas
21 during the summer period. The natural gas procured in the summer period can be
22 redelivered during periods of strong demand, when prices could potentially be

1 higher (typically, the winter period). However, summer prices for natural gas are
2 not always predictably lower than winter prices.

3 **22. Q. Does storage provide PECO with a substantial source of supply?**

4 A. Yes. As shown in Sections 16 and 22 of the Advance Filing Information, 26.48%
5 of the Company's required design day supply, which equates to 241,729 Mcf, will
6 be received via delivery from contracted underground storage. In addition, LNG,
7 propane, and delivered peaking services combine to represent about 27.34% of the
8 required design day supply. Accordingly, as shown in Sections 16 and 22 of the
9 Advance Filing Information, 190,000 Mcf are available from LNG, 24,838 Mcf are
10 available from propane, and 34,726 Mcf are available from delivered hedged
11 contracts.¹ Overall, the use of storage and LNG enables PECO to substantially
12 mitigate its exposure to the price volatility that typically occurs during the winter,
13 while ensuring sufficient deliverability to meet firm demand.

14 PECO plans to fill its contracted storage to approximately ninety-five
15 percent (95%) of capacity, in the aggregate, by October 31 of each year. For a
16 typical winter, PECO reduces the inventory of natural gas in its contracted storage
17 to approximately 20% of capacity by March 31 of each year. Additionally, PECO
18 can store 1.2 Bcf of natural gas at its on-system LNG facility, which is filled to
19 capacity during the summer liquefaction season.

¹ For the upcoming 2025-2026 winter, PECO, through its approved hedging program, will enter into fixed price delivered supply contracts equal to 36,000 Dth/day.

1 **23. Q. Are there limitations on PECO’s source of supply from its LNG facility, its**
2 **propane facility, or contracted storage?**

3 A. Yes, there are certain system operational factors the Company must consider when
4 using LNG, propane, or storage supply. The LNG, propane, and contracted
5 underground storage tanks are filled during the summer months, and the natural gas
6 in those tanks must last through the winter months (November – March). The
7 Company closely monitors LNG, propane, and storage inventory, especially from
8 November through January, to ensure our ability to meet customer needs through
9 the winter and early spring.

10 **24. Q. Please explain PECO’s strategy to ensure system reliability.**

11 A. PECO’s reliability strategy is two-fold. First, PECO must ensure that sufficient
12 capacity exists to satisfy design day deliverability requirements. This capacity is
13 diversified into three categories: (1) pipeline FT capacity; (2) pipeline storage
14 capacity; and (3) peaking capacity. Peaking capacity refers to PECO’s LNG
15 facility, propane-air facility, and contracted peaking services with reliable third-
16 party suppliers.

17 Second, PECO must ensure that a firm source of supply exists to utilize the
18 capacity resources described above. PECO ensures the availability of firm supplies
19 through its contractual arrangements with its suppliers. PECO subjects all potential
20 counterparties to a credit analysis. If the credit analysis deems the counterparty
21 acceptable, PECO will negotiate a NAESB Agreement with the counterparty,
22 which enables PECO to procure natural gas at competitive prices for its PGC
23 customers.

1 **25. Q. What was PECO’s experience regarding meeting customer demand this**
 2 **past winter?**

3 A. As illustrated in Table SA-1 below, PECO experienced a winter that was overall,
 4 by degree day, 3.7% warmer than a normal winter. December through February
 5 were colder than normal, and November and March were significantly warmer than
 6 normal which was offset by the colder than normal temperatures in December
 7 through February.² Variations from normal weather by season, month, or day
 8 present balancing challenges. These challenges can be exacerbated by certain
 9 factors. For example, on warmer than normal days, the challenges can be made
 10 worse by the increase in firm supply receipts associated with the LVT Gas Choice
 11 program and the Company’s Ratable Hedging Program, and on colder than normal
 12 days, by exposure to market area price volatility and limited LNG, propane and
 13 underground storage inventory. PECO utilized its balancing assets, such as
 14 contracted storage, as well as its daily load balancing processes to minimize costs
 15 this past winter.

16 **Table SA-1**

Heating Degree Days (HDD)						
	November	December	January	February	March	Total
	2024	2024	2025	2025	2025	
HDD Normal	511	799	952	799	636	3,697
HDD Actual	397	813	1066	809	476	3,561
Difference	-114	14	114	10	-160	-136
HDD vs Normal	-22.3%	1.8%	12.0%	1.3%	25.2%	-3.7%

17
² PECO defines a normal winter as 3,854 heating degree days (“HDD”).

1 **26. Q. Was there any impact on PECO’s contracted supply, or on the operation of**
2 **the Company’s on-system propane or LNG facilities for the duration of the**
3 **winter weather period?**

4 A. No. PECO did not experience any interruptions or reductions in its contracted
5 natural gas deliveries. Although the winter was relatively warm, the Company’s
6 propane and LNG facilities were available to operate in a safe and efficient manner
7 if needed; supplies from those assets remain crucial in allowing the Company to
8 meet the high customer demand experienced during the normal winter weather
9 periods.

10 **27. Q. Did PECO enter into any Off-System Sales during the most recent winter**
11 **season where the purchase price exceeded the sales price? If so, please explain.**

12 A. No.

13 **28. Q. Did the past winter result in any new records for the Company’s natural gas**
14 **system sendouts?**

15 A. Yes. For context, Table SA-2 below provides the top 20 highest sendout days in the
16 Company’s history.

Table SA-2

Rank	System Sendout MCF	Plant Sendout MCF	Date	Airport Temperature	Wind Speed
1	800,927	775,393	Saturday, January 06, 2018	11	13
2	791,455	770,593	Tuesday, January 21, 2025	15	8
3	790,627	763,764	Friday, January 05, 2018	12	21
4	782,361	757,668	Monday, January 21, 2019	16	13
5	779,550	754,130	Thursday, January 31, 2019	15	13
6	778,349	757,766	Sunday, February 15, 2015	10	20
7	776,980	750,804	Sunday, December 31, 2017	12	10
8	773,696	752,455	Wednesday, January 22, 2025	16	3
9	770,605	749,103	Friday, February 01, 2019	15	13
10	767,421	740,109	Thursday, February 19, 2015	11	19
11	766,103	740,745	Wednesday, January 30, 2019	14	13
12	761,932	748,146	Saturday, December 24, 2022	18	19
13	759,549	726,625	Tuesday, January 07, 2014	11	14
14	748,912	730,867	Saturday, January 29, 2022	18	16
15	748,059	722,740	Thursday, January 04, 2018	19	22
16	746,011	727,121	Monday, January 01, 2018	16	13
17	738,801	715,769	Friday, February 20, 2015	14	8
18	736,728	717,743	Monday, January 20, 2025	17	12
19	735,540	714,085	Saturday, January 15, 2022	19	10
20	731,348	707,044	Tuesday, January 02, 2018	20	9

1 **29. Q: Did PECO incur any pipeline penalties this past year?**

2 A. No, PECO did not incur any pipeline penalties this past year.

3 **30. Q. Did PECO's supply contracts perform as required during the winter of 2025-**
4 **2026?**

5 A. Yes. For the winter of 2025-2026, all natural gas scheduled under PECO's supply
6 contracts was delivered to PECO's city gate.

7 **31. Q. Based on its experience in recent winters, is PECO considering any changes to**
8 **its natural gas supply portfolio?**

9 A. Yes. While the Company believes that its current mix of FT, firm storage, propane,
10 LNG, and delivered peaking contracted services provides adequate peaking
11 capacity to ensure the system reliability necessary to meet peak demand in a safe,
12 least-cost manner at present, PECO continues to analyze supply portfolio and on-

1 system LNG solutions to address observations from experiences these past few
2 winters, as well as for peak-day demand projections. Although this past winter was
3 relatively mild, the Company's projected growth in design day and overall demand
4 supports the Company's continuing review of how to best manage its natural gas
5 supply portfolio. To that end, PECO has continued its examination of potential
6 long- and short-term solutions to assist in meeting customer demand during the
7 heating season, including peak-day demand. The results of this examination are
8 discussed below in response to Questions 34 through 36.

9 **32. Q. Please provide an update on the steps the Company took to ensure availability**
10 **of supply for the winter of 2024-2025.**

11 A. As described in the Direct Testimony in PECO's prior PGC proceedings,³ PECO
12 continues to analyze and adopt multiple solutions to procure reliable, least-cost
13 assets for both the short- and long-term peak day supply deficits. To that end, to
14 ensure the availability of winter delivery services for the winter of 2024-2025 (as
15 explained at page 2 of Section 22 of the Advance Filing Information in PGC 41
16 (Docket No. R-2024-3048767)), PECO took the following steps to acquire the
17 25,745 Dth needed:

- 18 • PECO procured 30,000 Dth/day of delivered supply via the Company's
19 approved Ratable Hedging program., leaving us with a surplus of 4,255 Dth

³ See Direct Testimony of Carlos P. Thillet (PGC 35 through 38) and Direct Testimony of Scott J. Hughes (PGC 39).

1 **33. Q. Did PECO purchase any trucked LNG or propane under the aforementioned**
2 **call options and if so, why?**

3 A. No, PECO did not purchase any trucked LNG or propane under the aforementioned
4 call options.

5 **34. Q. How does the Company plan to ensure availability of supply for the winter of**
6 **2025-2026?**

7 A. PECO will utilize both short- and long-term solutions to address its supply needs
8 for the winter of 2025-2026. As to the short-term solutions, similar to previous
9 winters, PECO will depend on delivered supply in order to meet part of its design
10 day requirements.⁴ PECO has taken the following steps to ensure the availability of
11 the 25,215 Dth/day of required delivered supply:

12 • PECO will procure 36,000 Dth/day of delivered supply via the Company's
13 Ratable Hedging program.

14 In addition, PECO will take the following steps to obtain the remainder of
15 the delivered natural gas resources needed:

16 • On or before July 1, 2025, PECO will issue a notice of Additional Capacity
17 Constraints, as explained in the Company's DSO program, which is
18 anticipated to produce a similar yield as in prior years.

19 • PECO will issue an RFP for delivered supply equal to the total winter
20 delivered resources required, less those volumes obtained by the two
21 contracts and DSO program participation listed above.

22 **35. Q. Please describe the actions PECO is pursuing to address the longer term peak**
23 **day requirements through the winter of 2034-2035.**

24 A. To reduce reliance on delivered supply, the Company continues to investigate
25 longer term solutions. The objectives of the longer-term solution are to provide

⁴ PECO's design day requirements can be found at page 2 of Section 22 of the Advance Filing Information.

1 PECO with a least-cost, reliable source of supply enabling the Company to meet its
2 firm demand, eliminate the peak-day supply gap while providing deliveries to
3 PECO gate stations, and further eliminating exposure to market area price volatility.
4 To that end, PECO is currently involved in two projects that will aid it in meeting
5 its long-term supply objectives.

6 First, PECO has continued its evaluation of participation in pipeline open
7 seasons as a way of securing additional cost-effective FT to PECO's City Gate. As
8 discussed below (and also in the Company's response to Question 11, PECO
9 Statement No. 3, the Direct Testimony of Blerina Gaba-Teme), PECO continues to
10 evaluate pipeline open seasons and capacity made available via permanent capacity
11 releases to determine if any new, cost-effective, firm natural gas transportation
12 source to PECO's city gate become available.

13 Second, as discussed in the Direct Testimony of Scott J. Hughes in PGC 39,
14 and in detail in the Direct Testimony of Carlos P. Thillet submitted in PGC 32
15 through PGC 38, PECO has continued its LNG investment and continues to take
16 actions that will lead to increasing LNG Vaporization capability at the Company's
17 West Conshohocken facility from 160,000 Mcf/day to 220,000 Mcf/day, directly
18 reducing reliance on delivered supply. The Natural Gas Reliability Project, of
19 which the increased LNG Vaporization capability is a part, is also discussed in
20 depth in the Direct Testimony of Carlos P. Thillet (PECO Statement No. 2) in
21 Docket No. P-2021-3024328.⁵ In that proceeding, PECO explained the need for the

⁵ PECO filed its Petition for a Finding of Necessity on May 14, 2021. A copy of the Direct Testimony in Docket No. P-2021-3024328, which is confidential, will be made available upon request and execution of a confidentiality agreement acceptable to PECO.

Natural Gas Reliability Project from the standpoint of ensuring the reliability of PECO's natural gas supply to meet design day requirements-

36. Q. How will the actions taken by PECO described above reduce the currently projected deficit between currently contracted-for pipeline storage and FT deliveries, as well as LNG and propane capacity and peak day demand requirements?

A. First, for reference, Table SA-3 provides a comparison of projected design day demand compared to current and planned future assets.

Table SA-3

DESIGN DAY DEMAND VS ASSETS (Dth/D)					
WINTER	DESIGN DAY DEMAND	PROJECTED TOTAL ASSETS	GAP	% GAP	Notes
2025-2026	937,596	946,321	8,725	1%	Assets equal current Pipeline FT and Storage deliveries plus PECO LNG and Propane vaporization assets. Includes Hedged Gas for executed contracts of 36,000 Dth/d.
2026-2027	975,000	946,321	-28,679	-3%	Assets at steady state
2027-2028	985,000	946,321	-38,679	-4%	
2028-2029	1,001,000	946,321	-54,679	-5%	
2029-2030	1,009,000	946,321	-62,679	-6%	
2030-2031	1,010,000	946,321	-63,679	-6%	
2031-2032	1,011,000	946,321	-64,679	-6%	
2032-2033	1,012,000	946,321	-65,679	-6%	
2033-2034	1,013,000	946,321	-66,679	-7%	
2034-2035	1,014,000	946,321	-67,679	-7%	

1 The projected total assets for the winter of 2025-2026 include all of PECO's
2 current firm assets, which increase by 36,000 Dth/day beginning in the winter of
3 2025-2026.

4 The acquisition of these firm assets will result in the elimination of the
5 current firm gap between total assets and design day demand of 1%. By the winter
6 of 2026-2027, PECO is projecting to have a deficit beyond the projected design day
7 of -3%. PECO plans to meet this deficit through the hedging program which may
8 also result in supplemental capacity, which will better enable the Company to serve
9 its customers should future instances occur where any of the interstate pipelines
10 delivering supply to PECO's service area are subjected to equipment failures,
11 integrity concerns, or other obstacles or force majeure events that prevent them
12 from meeting their contracted obligations during periods of high natural gas
13 demand. Supplemental capacity would also provide a degree of flexibility to ensure
14 deliverability and help to lessen exposure to market area price volatility.

15 **VI. REGIONAL AND SUSTAINABLE NATURAL GAS ACQUISITION STRATEGY**

16 **37. Q. Has the Company purchased any natural gas produced in Marcellus Shale**
17 **regions?**

18 A. Yes. PECO has purchased natural gas from Marcellus Shale production areas. Since
19 2010, PECO has incorporated increasing quantities of locally produced Marcellus
20 Shale natural gas into its portfolio of supply assets. The only supply PECO
21 purchases that it presumes is not from the Marcellus production regions are those
22 necessary for injections into its WSS storage contract, located upstream on

1 Transco’s main line.⁶ PECO uses its FT contracts to purchase and transport natural
2 gas primarily from both the Southwestern and the Northeastern/Leidy production
3 areas in Pennsylvania.

4 PECO projects that most of its purchases going forward, other than those
5 needed to refill its Transco WSS storage contract located in the Gulf Area storage,
6 will be made at pooling points inside of Pennsylvania. PECO, however, remains
7 mindful of its obligation to seek the least-cost natural gas for its customers. As such,
8 it retains the ability to adjust its purchase points to coincide with changes to industry
9 fundamentals should those changes affect the cost of natural gas in different
10 locations.

11 **38. Q. Please describe any steps the Company has taken to Acquire Renewable**
12 **Natural Gas (RNG).**

13 A. PECO has continued to pursue a strategy to support the growth of Renewable
14 Natural Gas (“RNG”) production and secure a reliable source of natural gas supply
15 onto PECO’s distribution system at market-based prices. PECO is actively
16 supporting a RNG project being developed by a third party and has completed the
17 appropriate feasibility study to assess whether the project can safely deliver natural
18 gas into PECO’s distribution system. PECO is currently working through the
19 necessary technical and contractual details required to potentially finalize an
20 interconnection agreement. As previously noted in prior PGC filings, while PECO
21 does not intend to pay a premium for, or otherwise acquire, the environmental

⁶ Due to the location of certain purchase receipt points, the Company reasonably assumes they are supported by Marcellus Shale gas produced in Pennsylvania. However, the Company is not privy to pipeline information regarding physical flows to the well head. Nor does the Company’s least-cost obligation to its firm customers require it to request such proof from its counterparties.

1 attributes of the RNG delivered into its system as natural gas, PECO would like
2 maximum flexibility to pursue sources of RNG production that would be most
3 advantageous to PECO's PGC customers.

4 Per the PGC 41 Settlement, if PECO were to acquire RNG, it committed to
5 do so in a manner that is consistent with the Company's least-cost procurement
6 strategy for natural gas, *e.g.*, it would pursue the least cost RNG, and would
7 undertake commercially reasonable efforts to minimize the cost impact to PECO'S
8 PGC customers from the costs associated with purchasing RNG.

9 **VII. CONCLUSION**

10 **39. Q. Does this conclude your Direct Testimony?**

11 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY**

Docket No. R-2025-3054868

**DIRECT TESTIMONY
OF
SCOTT J. HUGHES**

PECO STATEMENT NO. 2

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1 Developers. I joined the Gas Supply Group in 1999 as a Senior Operations
2 Area Analyst, then from 2001 to 2007, I worked as a Senior Natural Gas
3 Analyst, before transitioning to the position of Principal Acquisition Analyst,
4 which I held until May 2019. Over that time, my responsibilities included
5 tracking departmental Key Performance Indicators, supply planning, storage
6 asset management, asset optimization, daily, monthly, seasonal and long-
7 term natural gas purchasing, analyzing and authorizing capacity releases and
8 scheduling natural gas flow on interstate pipelines.

9 **5. Q. Please identify your current job responsibilities.**

10 A. In June 2019, I became the Manager of PECO's Gas Acquisition
11 Department. In this position, I am responsible for the day-to-day
12 management and oversight of the natural gas procurement, short- and long-
13 term planning, the ratable hedging program, asset management agreements,
14 and all natural gas asset optimization functions for PECO.

15 **II. PURPOSE OF TESTIMONY**

16 **6. Q. What is the purpose of your Direct Testimony in this proceeding?**

17 A. The purpose of my Direct Testimony is to present certain of the information
18 required in Section 1317(a) of the Pennsylvania Public Utility Code (the
19 "Code") (*See* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility
20 Commission (the "Commission") may make the findings required by Section
21 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that PECO's
22 PGC rates and charges for the historic period (April 1, 2024 through March
23 31, 2025), the estimated period (April 1, 2025 through November 30, 2025),
24 and the PGC application period (December 1, 2025 through November 30,

1 2026) are just and reasonable. To that end, I will describe the Company's
2 current hedging program. Additionally, I will discuss PECO's off-system
3 sales sharing mechanism. Finally, I will furnish certain information that
4 PECO committed to provide under the terms of the Joint Petition for
5 Complete Settlement in the 2024 PGC proceeding at Docket No. 2024-
6 3048767 ("2024 Joint Petition").

7 **7. Q. Are you sponsoring any exhibits?**

8 A. Yes. I am sponsoring Exhibit SJH-1 which is discussed later in my Direct
9 Testimony.

10 **III. PECO'S HEDGING POLICY**

11 **8. Q. Please describe PECO's hedging policy.**

12 A. PECO employs hedging as an additional tool to purchase natural gas on a
13 basis that reasonably ensures system reliability at the least cost. PECO is
14 required to lock-in (*i.e.*, hedge) the price of a minimum volume of its long-
15 term natural gas purchases. This mechanism is designed to mitigate PECO's
16 exposure to natural gas price volatility by locking-in increments of natural
17 gas by preset deadlines so that PECO is not hedging all of its natural gas at
18 the same time under the same market conditions.

19 **9. Q. Please briefly summarize PECO's current Ratable Hedging Program.**

20 A. In the 2016 Joint Petition for Complete Settlement (PGC 33, Docket No. R-
21 2016-2545925), PECO agreed to implement its current "Ratable Hedging
22 Program," which was extended for additional years in the 2017 Joint Petition
23 for Complete Settlement (PGC 34, Docket No. R-2017-2602611), the 2018
24 Joint Petition for Complete Settlement (PGC 35, Docket No. R-2018-

1 3001568), the 2019 Joint Petition for Complete Settlement (PGC 36, Docket
2 No. R-2019-3009624), the 2020 Joint Petition for Complete Settlement
3 (PGC 37, Docket No. R-2020-3019661), the 2021 Joint Petition for
4 Complete Settlement (PGC 38, Docket No. R-2021-3025629), the 2022 Joint
5 Petition for Complete Settlement (PGC 39, Docket No. R-2022-3032250),
6 the 2023 Joint Petition for Complete Settlement (PGC 40, Docket No. R-
7 2023-3040285) and the 2024 Joint Petition for Complete Settlement (PGC
8 41, Docket No. 2024-3048767)

9 Under this program, PECO hedges approximately 11% of its
10 projected winter purchase volumes. The hedges under the Ratable Hedging
11 Program began in November 2016 and will continue through July 2027. All
12 hedges in this program are made between three (3) and 24 months in advance
13 of the delivery date for the purchased natural gas. In addition, as agreed to in
14 the 2020 Joint Petition for Complete Settlement, PECO no longer engages in
15 hedging for summer purchases. For convenience, I have attached the current
16 Ratable Hedging Program execution schedule to my Direct Testimony as
17 Exhibit SJH-1.

18 Finally, pursuant to Paragraphs 19(c) and (d) of the 2016 Joint
19 Petition, the following conditions are applicable to all hedges under the
20 Ratable Hedging Program:

- 21 1. PECO will not enter into any individual hedge unless
22 there are at least three qualified respondents to the
23 RFP;
- 24 2. Each transaction will be evaluated and compared to
25 current index market indicators, and if the proposed
26 transaction is 10% higher than the indicators, PECO

1 will not conduct the transaction;

2 3. PECO will not purchase any of its hedged gas from
3 Transco Zone 4, nor will it use NYMEX Transco
4 Zone 4 basis contract pricing as a market price
5 indicator; and

6 4. PECO will not make any financial hedges, only
7 hedges of physical gas.

8 **10. Q. Has PECO implemented the Ratable Hedging Program as required? If**
9 **so, please summarize the results thus far.**

10 A. Yes, during the historic period (April 1, 2024 through March 31, 2025),
11 PECO issued RFPs for six (6) execution periods (these periods are
12 highlighted in yellow in Exhibit SJH-1, with all previous executions
13 appearing in blue). As shown in Table SJH-1 below, for the historic period,
14 PECO has purchased approximately 5.44 MMDTH of hedged natural gas
15 under the program at a weighted average cost of \$4.4792 per Dth.

Ratable Hedge Program			
Executed Hedges April 2024 through March 2025			
Execution Month	DTH	\$/DTH	Total \$
July 2024	1,812,000	\$ 3.7400	\$ 6,776,880
November 2024	1,812,000	\$ 4.6775	\$ 8,475,630
March 2025	1,812,000	\$ 5.0200	\$ 9,096,240
Total	5,436,000	\$ 4.4792	\$24,348,750

16 **11. Is PECO proposing any changes to the Ratable Hedging Program?**

17 A. Yes, PECO is proposing that the Ratable Hedging Program be extended for
18 an additional year. Table SJH-2 below provides the proposed hedging
19 schedule for Year 12:

VI. CONCLUSION

1

2

18. Q. Does this conclude your Direct Testimony?

3

A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY**

Docket No. R-2025-3054868

**DIRECT TESTIMONY
OF
BLERINA GABA-TEME**

PECO STATEMENT NO. 3

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1 In addition, I am responsible for capacity releases, gas confirmations, and Federal
2 Energy Regulatory related matters, as well as overseeing the current pipeline and
3 storage contracts and analyzing new opportunities for PECO and its ratepayers.
4 Lastly, I manage the information systems that capture all gas supply, transportation,
5 accounting, and retail operations.

6 **II. PURPOSE OF TESTIMONY**

7 **6. Q. What is the purpose of your Direct Testimony in this proceeding?**

8 A. The purpose of my Direct Testimony is to present certain of the information
9 required in Section 1317(a) of the Pennsylvania Public Utility Code (the “Code”)
10 (*see* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility Commission
11 (the “Commission”) may make the findings required by Section 1318 of the Code
12 (*see* 66 Pa. C.S.A. § 1318) for a determination that PECO’s PGC rates and charges
13 for the historic period (April 1, 2024 through March 31, 2025), the estimated period
14 (April 1, 2025 through November 30, 2025), and the PGC application period
15 (December 1, 2025 through November 30, 2026) are just and reasonable. To that
16 end, I will describe the Company’s natural gas purchase policies and practices,
17 including PECO’s use of natural gas pipeline transportation and storage contracts,
18 and explain its HVT Gas Choice program.

19 **7. Q. Are you sponsoring any exhibits?**

20 A. Yes. I am sponsoring Exhibits BGT-1, BGT-2, and BGT-3, which are discussed
21 later in my Direct Testimony.

1 **III. THE BALANCING CHARGE**

2 **8. Q. Is the Company proposing a change to the balancing charge rate in this case?**

3 A. Yes. Under the terms of the Settlement of the Company’s 2008 Gas Distribution
4 Base Rate Case at Docket No. R-2008-2028394, the Company is required to update
5 the balancing charge as part of its annual 1307(f) filing. Pursuant to the terms of
6 the 2020 Joint Petition for Complete Settlement in the PGC 37 proceeding (Docket
7 No. R-2020-3025629), the balancing charge calculation was revised to include: (i)
8 the costs associated with the interstate pipeline transportation arrangements
9 required to deliver natural gas to and from storage; and (ii) aggregate daily HVT
10 imbalances experienced during the summer months, as opposed to only the winter
11 months as was the historical practice.

12 The Company is proposing two balancing charge options for consideration.
13 The first option, as shown in Exhibit BGT-1, displays the balancing charge
14 calculation used in PGC 41 and in previous years. In Exhibit BGT-1, the Company
15 is proposing a balancing charge of \$0.0203 per Mcf to become effective on
16 December 1, 2025, which is \$0.0022 less per Mcf than the currently effective
17 balancing charge. The second option, as shown in Exhibit BGT-3, shows PECO’s
18 investigation and feasibility study of including applicable storage costs in the
19 calculation of the High Volume Transportation (“HVT”) balancing charge, as set
20 forth in the PGC 41 Testimony of Jerome D. Mierzwa (OCA St. No. 1) pp. 4-6.

21 **9. Q. Why did the balancing charge decrease by \$0.0022 per Mcf?**

22 A. Please refer to Exhibit BGT-2, which provides the calculations used to establish the
23 current balancing charge and the proposed balancing charge, along with a line-by-

1 line comparison showing the changes between the two. The decrease is driven by
2 deviations in several factors, including slightly decreased variable storage costs.

3 **10. Q: Please describe the results of the Company’s feasibility study concerning**
4 **including applicable storage related costs in the calculation of the High**
5 **Volume Transportation (“HVT”) balancing charge?**

6 A. As shown in Exhibit BGT-3, the Company is providing all workpapers and
7 calculations to support including HVT storage related costs. The Company
8 proposes including HVT Storage Injection Costs by multiplying each month’s
9 aggregate daily excess deliveries by a monthly injection weighted average cost of
10 gas (“WACOG”). The Company also proposes including the HVT Storage
11 Withdrawal Costs by multiplying each month’s aggregate daily deficient deliveries
12 by a monthly withdrawal WACOG. The Storage Injection Costs and the Storage
13 Withdrawal Cost will be added to the Fixed Storage Costs included in the balancing
14 charge calculation for a Total Storage Cost. Using this methodology, the 2024
15 Balancing Charge would have been \$0.0260, and the 2025 Balancing Charge would
16 be \$0.0229.

17 **IV. PECO’S NATURAL GAS PURCHASE POLICIES AND PRACTICES**

18 **11. Q. Has PECO continued its evaluation of participation in pipeline open seasons**
19 **as a way of securing additional cost-effective Firm Transportation to PECO’s**
20 **City Gate?**

21 A. Yes. PECO continues to evaluate pipeline open seasons and capacity made
22 available via permanent capacity releases to see if any new, cost-effective, firm
23 natural gas transportation source to PECO’s city gate become available. In general,
24 each opportunity is analyzed to determine whether PECO’s participation in the

1 project is needed to meet projections for increased firm demand, or if the project
2 offers a reliable least-cost alternative to an existing transportation or storage
3 contract approaching its expiration date. In addition, projects are reviewed to
4 determine: (1) their ability to deliver firm natural gas from a reliable, liquid market
5 to PECO; and (2) if they are compatible with PECO’s existing contracts and load
6 profile.

7 The Regional Energy Access (“REA”) project was referred to as Project X
8 in Company Witness Carlos Thillet’s Direct Testimony submitted in support of
9 PECO’s prior PGC proceedings – PGC 36, PGC 37, and PGC 38 – and was also
10 discussed in Company Witness Scott J. Hughes’ Direct Testimony in support of
11 PGC 39 and in Julie S. Drezner’s Direct Testimony in support of PGC 40 and PGC
12 41. On February 10, 2020, PECO executed a Precedent Agreement with Transco
13 for 100,000 Dth/day of REA capacity. The firm transportation capacity will enable
14 PECO to move natural gas from receipt points in the Leidy Pennsylvania Marcellus
15 Shale production area to delivery points on PECO’s distribution system. The initial
16 term is for 15 years. The capacity will provide PECO with a least-cost, reliable,
17 source of supply enabling the Company to meet its firm demand by reducing the
18 delivered supply needed to eliminate the peak-day supply gap, and while providing
19 deliveries to PECO gate stations and further eliminating exposure to market area
20 price volatility. Transco filed its 7(c) FERC Application on March 26, 2021.
21 Subsequently, on April 28, 2021, Exelon Corporation filed comments in support of
22 the REA application. On February 17, 2023, PECO executed a Service Agreement
23 with Transco for 100,000 Dth/day of REA capacity. PECO negotiated an early in-

1 service contract for 32,922 Dth/day of the 100,000 Dth/day REA firm capacity,
2 effective August 1, 2024 for fifteen years.

3 PECO also submitted one non-binding bid on an open season in 2024. On
4 May 29, 2024, Adelphia initiated an open season for 22,500 dth/day FT Adelphia
5 North Zone capacity. PECO participated in the open season and won the non-
6 binding FT capacity. Ultimately, contract negotiations did not continue due to
7 several operational concerns identified in the proposed transaction. Also, due to the
8 current Adelphia rate case, PECO and Adelphia are not in negotiations for this
9 incremental project any longer.

10 PECO also submitted two non-binding bids on open seasons in 2023. PECO
11 submitted one bid for 22,500 Dth/day north-zone capacity on Adelphia for \$0.0864
12 per MMBTU per day on September 19, 2023. PECO submitted the other bid for
13 3,687,492 MSQ in Dth storage capacity on Mississippi Hub for \$0.031 storage
14 reservation charge in \$/Dth/Month on November 9, 2023. The Mississippi Hub bid
15 was an attempt to duplicate WSS storage, as discussed in the response to Question
16 13. Neither of PECO's submitted bids were selected.

17 **12. Q. Did participation in PECO's LVT Gas Choice program continue to grow for**
18 **the 12-month period ending March 31, 2025?**

19 A. As indicated in Table BGT-1 below, PECO's LVT Gas Choice program continues
20 to be robust. The number of customers in the program has typically increased year-
21 over-year; however, for the 12-month period ending March 31, 2025, participation
22 slightly decreased. In addition, the number of suppliers increased during this period
23 from 59 to 63. PECO expects strong participation in this program to continue.

Table BGT-1

12-Month Period Ending March 31	Customers participating in LVT program	YOY Change	Aggregate Daily Delivery Quantity	Aggregate Daily Contract Quantity
2016	81,088	0.80%	46,896	58,573
2017	81,472	0.50%	46,481	60,324
2018	84,161	3.30%	60,951	60,920
2019	95,293	13.20%	66,786	66,760
2020	105,312	10.50%	74,190	74,166
2021	96,625	-8.20%	70,841	70,841
2022	89,563	-7.30%	66,013	66,013
2023	83,504	-6.80%	64,743	64,743
2024	84,024	0.60%	67,178	67,178
2025	83,668	-0.40%	66,499	66,499

1 **V. FIRM INTERSTATE PIPELINE CONTRACTS**

2 **13. Q. Please identify the firm interstate natural gas pipeline service agreements that**
 3 **have been subject to renewal since PECO’s last PGC proceeding (PGC 41) and**
 4 **that remain in effect.**

5 A. Table BGT-2 below lists the storage and transportation service agreements that
 6 were subject to renewal/termination notice during the past year and identifies
 7 whether PECO opted to renew each agreement. All renewed contracts are listed
 8 below. The Early In-Service REA contract was replaced with the full REA 100,000
 9 Dth/day capacity contract as discussed in response to Question 11. The WSS
 10 Storage contract was not renewed and is being replaced by WSS Market Based
 11 Rates (“MBR”). For a description of the WSS MBR proceedings, please see the
 12 response to Question 16.

13 On October 23, 2024, PECO submitted the two-year notice to terminate the
 14 UGI XD contract, effective December 1, 2026. The original purpose of the contract

1 was to ensure distribution service to North Coventry and Upper Pottsgrove
 2 Townships via interconnection with UGI, which helps serve certain HVT
 3 customers. PECO Gas Engineering has since performed distribution system
 4 upgrades, eliminating the need for the UGI capacity feed and interconnections.

5 **Table BGT-2**

Pipeline Contract	Earliest Termination Date	Notice Period	Renewed (Yes or No)
Texas Eastern			
FT-1 Transportation	10/31/2026	24 Months	Yes
CDS Transportation	10/31/2026	24 Months	Yes
FT-1 Phila Lateral	10/31/2029	60 Months	Yes
FT-1 Phila Flex X	10/31/2029	60 Months	Yes
FT-1 Transportation ELA	10/31/2025	12 Months	Yes
FTS-2 Transportation	3/31/2026	12 Months	Yes
FTS-7 Transportation	4/15/2027	24 Months	Yes
FTS-8 Transportation	4/15/2027	24 Months	Yes
FTS Transportation	3/31/2027	24 Months	Yes
SS-1 Storage	4/30/2027	24 Months	Yes
Transco			
FT Transportation	3/31/2028	36 Months	Yes
FT Transportation	7/31/2027	36 Months	Yes
FT - Leidy	10/31/2026	24 Months	Yes
FT - Trenton Woodbury	10/31/2026	24 Months	Yes
WSS Storage	3/31/2025	12 Months	No
WSS Storage MBR	4/1/2035	120 Months	Yes
REA	08/01/2024	180 Months	Yes
S-2 Storage	3/31/2026	12 Months	Yes
Eastern Gas Transmission & Storage, Inc.			
GSS Storage	3/31/2027	24 Months	Yes
UGI			
XD Firm	12/01/2025	12 Months	No

1 **14. Q. Why did PECO choose to allow the contracts identified above to evergreen for**
2 **an additional term?**

3 A. First, PECO continues to require the above-mentioned services primarily to satisfy
4 the temperature-sensitive demands of both its customers and its Gas Choice
5 customers for whom PECO is the supplier of last resort (“SOLR”).

6 Second, each of these agreements is designed to provide satisfactory
7 capacity to transport the natural gas supplies needed to serve the demand of PECO’s
8 customers, especially during the winter period. As the SOLR, PECO also needs
9 these contracts to serve Gas Choice customers that may return to PECO for supply
10 during the winter period. PECO has not yet discovered a more economical
11 alternative to continuing these contracts.

12 Third, consistent with the settlement of PECO’s natural gas restructuring
13 proceeding at Docket No. R-00994787, on June 24, 2024 and November 22, 2024,
14 PECO issued RFPs for its firm storage and transportation contracts. The RFPs were
15 sent to Pennsylvania NGSs, including Gas Choice Suppliers participating in
16 PECO’s Gas Choice programs, interstate pipeline companies and others. In
17 response to the RFPs, interested parties were given the opportunity to provide a
18 contract service as a replacement to service provided by the pipeline supplier. None
19 of the responses received provided a more cost-effective alternative to the contracts
20 listed in Table BGT-2 above.

1 **15. Q. By what means other than the RFP process did PECO try to obtain**
2 **comparable services at a lower cost than the existing services?**

3 A. PECO regularly reviews all pipeline open seasons (see response to Question 11) to
4 assess opportunities for new and replacement services. PECO also entered two open
5 seasons which were not accepted (see response to Question 11). Additionally,
6 PECO regularly contacted pipeline representatives to discuss its supply portfolio
7 needs and to explore potentially less costly options for existing services. Despite
8 these efforts, PECO could not obtain any comparable replacement services at a
9 lower cost than the existing services. Therefore, it is necessary for PECO to retain
10 these agreements as part of its overall capacity portfolio to satisfy the demand
11 requirements of its retail sales and Gas Choice customers.

12 **16. Q. Please explain how PGC customers benefit from PECO's active participation**
13 **in the recent FERC rate case proceedings.**

14 A. Please review Section 5 of the Advance Filing Information for a list of PECO's
15 active involvement in FERC cases. PECO's active participation in the FERC rate
16 case proceedings benefit PECO's PGC customers by achieving settlement rates that
17 are less than the increases sought in the as-filed rates, resulting in smaller rate
18 increases for PECO and its PGC customers. Please see below for a brief explanation
19 of the WSS MBR proceedings.

20 WSS: PECO renewed and extended the WSS contract listed in Table BGT-
21 2. In 2021, Transco filed for MBR authority for Rate Schedule WSS, which as
22 originally proposed, would increase costs for the service by 140% to be effective
23 on April 1, 2025. PECO and the WSS Customer Group protested and challenged

1 Transco’s proposal in Dockets RP21-1143 and RP23-840. Despite the challenges
2 of the WSS Customer Group, in 2022 and upon rehearing in 2023, FERC found the
3 MBR to be just and reasonable. The WSS Customer Group appealed the decisions
4 to the United States Court of Appeals for the District of Columbia Circuit. In 2023,
5 after receiving the decision on the rehearing affirming the MBR from FERC,
6 Transco filed new General Terms and Conditions for the storage service with the
7 Commission.

8 PECO provided data showing that Requests for Proposal were sent out on
9 two occasions (see response to Question 13) trying to replicate the WSS service,
10 but that no licensed supplier in the Commonwealth of Pennsylvania responded.
11 PECO also responded to an Open Season from Mississippi Hub Storage for a
12 Market Based Rate storage equivalent to WSS, as referenced in the response to
13 Question 1. The storage was similarly located to WSS, interconnected with Transco
14 in Zone 4. PECO’s bid was not accepted. PECO also submitted an affidavit as part
15 of the WSS Customer Group protest in Docket RP23-840. FERC determined that
16 these facts along with other issues warranted a Technical Conference on September
17 13, 2023. The parties reached a settlement in the proceeding that would increase
18 WSS rates by 124% over a ten-year period and allow market-based rates.

19 PECO performed a cost analysis of the proposal and reviewed the analysis
20 of outside consultants, ultimately finding the 124% cost increase to be a discount
21 compared to the open market for storages interconnected with the Transco system.
22 PECO elected to extend the WSS MBR agreement with the 10-year storage and

1 commodity storage deal, in order to provide the lowest increase in fixed costs to
2 PGC customers.

3 TETCO initiated a pre-filing for a Section 4 Rate Case settlement in lieu of
4 a Section 4 Rate Case. PECO participated in the pre-filing initiative, and the parties
5 reached a settlement for all issues as of May 3, 2024.

6 TETCO's rate case settled in June 2024, and PECO agreed to a two-increase
7 step up. The first increase went into effect on October 1, 2024, which was a 6%
8 increase. The second increase goes into effect January 1, 2026, and accounts for an
9 additional 2.62% increase.

10 Transco filed a Section 4 Rate Case on August 31, 2024. The Section 4 Case
11 included increases in rates as PECO intervened and protested in the filing. These
12 rates were held in abeyance for six months, with an effective date of March 1, 2025,
13 subject to refund due to litigation or settlement. The increase in the filed rates
14 represents over a 40% increase in PECO's demand charges on Transco. Also, on
15 August 31, 2024, Transco filed a Modernization Surcharge tracker for which terms
16 are still being negotiated. If the Modernization Surcharge rates are ultimately
17 approved, they could go into effect during 2026. We have eliminated their costs in
18 Sections 6 and 7 of the PGC 42 Advance Filing Information as the concept has not
19 been approved by the FERC, let alone the rates.

20 Adelphia filed a Section 4 Rate Case on September 30, 2024 for rate
21 increases that will go into effect April 1, 2025, subject to refund. PECO intervened
22 and protested in the filing. At this time, PECO currently only has one contract with

1 Adelphia for a negotiated rate with the original contract terms through October 1,
2 2030, at which time PECO will be subject to cost of service tariff rates.

3 PECO will continue to actively participate in all relevant FERC
4 proceedings to achieve the best possible rates and reliability services for PGC
5 customers.

6 **VI. HVT GAS CHOICE PROGRAM INFORMATION**

7 **17. Q. Please describe the HVT Gas Choice program.**

8 A. Under PECO's HVT Gas Choice program, large commercial and industrial
9 customers may purchase natural gas from an NGS for transport on the PECO
10 system. The rules of the HVT Gas Choice program are set forth in PECO's Natural
11 Gas Service Tariff.

12 **18. Q. Did the Advance Filing Information contain any information regarding the
13 HVT Gas Choice program?**

14 A. Yes, certain information regarding the HVT Gas Choice program was included in
15 Sections 10 through 12 of the Advance Filing Information.

16 **19. Q. What information is contained in Section 10 of the Advance Filing
17 Information?**

18 A. Section 10 of the Advance Filing Information includes a copy of the PECO Gas
19 Transportation Service Agreement form for large commercial and industrial
20 customers electing to participate in the HVT Gas Choice program.

21 **20. Q. What information is provided in Sections 11 and 12 of the Advance Filing
22 Information?**

23 A. Section 11 of the Advance Filing Information includes a report reflecting specific
24 contract information for each HVT Gas Choice customer. Specifically, the

1 following information is provided for each customer: the customer's rate, size
2 category (greater than or less than 18,000 Mcf per year), daily transportation
3 contract quantity, firm stand-by sales quantity, if any, and commodity rate. Section
4 12 of the Advance Filing Information provides the monthly transportation volume
5 for each transportation customer for each month beginning April 1, 2024 and
6 ending March 31, 2025. Specifically, the following information is provided for each
7 customer: the customer's rate; total monthly deliveries in Mcf; and total
8 transportation deliveries. Because this information is voluminous, PECO does not
9 file it with the Advance Filing Information but will provide it upon request.

10 **VII. CONCLUSION**

11 **21. Q. Does this conclude your Direct Testimony?**

12 A. Yes, it does.

2025 Balancing Charges Exhibit BGT-1

Annual Cost for Storage (PECO PGC 41, Section 7, Page 1)						\$ 26,791,000
Aggregate Imbalances for TS Customers						
		Aggregate Daily	Aggregate Daily			
		Excess Deliveries	Deficient Deliveries			
Dec-23		82,053	31,666			
Jan-24		53,818	75,655			
Feb-24		30,929	79,175			
Mar-24		65,138	50,466			
Apr-24		40,858	47,899			
May-24		53,368	27,336			
Jun-24		33,346	89,414			
Jul-24		58,079	81,807			
Aug-24		59,760	36,259			
Sep-24		21,631	58,702			
Oct-24		52,518	46,058			
Nov-24		41,920	55,079			
Total		593,418	679,516			
Total Aggregate 12 Month Daily TS Imbalance in MCF						1,272,934
Projected Annual PGC Volume in MCF						68,895,451
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)						1.85%
Annual Storage Cost Applicable to Transportation Customers						
1.85%	of	\$ 26,791,000				\$ 494,999
Revenue From Excess Delivery Penalty Charge for Dec 23 through Nov 24 in mcf						71,182
			\$ 0.25			\$ 17,795.50
Calculation of the Proposed Adjusted Balancing Charges						
Storage Cost applicable to Transportation Customers						\$ 477,203
Divided by TS MCF Actual Dec 23 through Nov 24						23,564,697
Balancing Charge per MCF						\$ 0.0203

2025 Balancing Charges Exhibit BGT-2			
<u>Annual Cost for Storage (PECO PGC 41, Section 7, Page 1)</u>			
Fixed Storage Costs (includes associated transport)			\$ 26,791,000
Storage Injection Cost			\$ -
Storage Withdrawl Cost			\$ -
Total			\$ 26,791,000
Aggregate Imbalances for TS Customers			
	Aggregate Daily	Aggregate Daily	
	Excess Deliveries	Deficient Deliveries	
Dec-23	82,053	31,666	
Jan-24	53,818	75,655	
Feb-24	30,929	79,175	
Mar-24	65,138	50,466	
Apr-24	40,858	47,899	
May-24	53,368	27,336	
Jun-24	33,346	89,414	
Jul-24	58,079	81,807	
Aug-24	59,760	36,259	
Sep-24	21,631	58,702	
Oct-24	52,518	46,058	
Nov-24	41,920	55,079	
Total	593,418	679,516	
Total Aggregate 12 Month Daily TS Imbalance in MCF			1,272,934
Projected Annual PGC Volume in MCF			68,895,451
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)			1.85%
Annual Storage Cost Applicable to Transportation Customers 1.85% of \$ 26,791,000			\$ 494,999
Revenue From Excess Delivery Penalty Charge for Dec 23 through Nov 24 in mcf	71,182	\$ 0.25	\$ 17,795.50
Calculation of the Proposed Adjusted Balancing Charges			
Storage Cost applicable to Transportation Customers			\$ 477,203
Divided by TS MCF Actual Dec 23 through Nov 24			23,564,697
Balancing Charge per MCF			\$ 0.0203

2024 Balancing Charges Exhibit BGT-2			
<u>Annual Cost for Storage (PECO PGC 40, Section 7, Page 1)</u>			
Fixed Storage Costs (includes associated transport)			\$ 31,570,000
Storage Injection Cost			\$ -
Storage Withdrawl Cost			\$ -
Total			\$ 31,570,000
Aggregate Imbalances for TS Customers			
	Aggregate Daily	Aggregate Daily	
	Excess Deliveries	Deficient Deliveries	
Dec-22	52,041	73,244	
Jan-23	31,278	52,746	
Feb-23	73,799	69,655	
Mar-23	41,223	50,508	
Apr-23	52,378	43,910	
May-23	46,324	34,833	
Jun-23	25,815	40,097	
Jul-23	44,433	45,471	
Aug-23	34,311	56,079	
Sep-23	20,843	71,704	
Oct-23	27,168	69,714	
Nov-23	47,044	87,971	
Total	496,657	695,932	
Total Aggregate 12 Month Daily TS Imbalance in MCF			1,192,589
Projected Annual PGC Volume in MCF			68,253,410
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)			1.75%
Annual Storage Cost Applicable to Transportation Customers 1.75% of \$ 31,570,000			\$ 551,621
Revenue From Excess Delivery Penalty Charge for Dec 22 through Nov 23 in mcf	76,105	\$ 0.25	\$ 19,026.25
Calculation of the Proposed Adjusted Balancing Charges			
Storage Cost applicable to Transportation Customers			\$ 532,595
Divided by TS MCF Actual Dec 22 through Nov 23			23,652,714
Balancing Charge per MCF			\$ 0.0225

2025 Balancing Charges Exhibit BGT-3				
Annual Cost for Storage (PECO PGC 41, Section 7, Page 1)				
Fixed Storage Costs (includes associated transport)				\$ 26,791,000
Storage Injection Cost				\$ 1,276,387
Storage Withdrawal Cost				\$ 2,086,070
Total				\$ 30,153,457
Aggregate Imbalances for TS Customers				
	Aggregate Daily	Injection	Aggregate Daily	Withdrawal
	Excess Deliveries	Wacog	Deficient Deliveries	Wacog
Dec-23	82,053	\$ 3.4524	31,666	\$ 2.8073
Jan-24	53,818	\$ -	75,655	\$ 2.8967
Feb-24	30,929	\$ 2.4098	79,175	\$ 2.7444
Mar-24	65,138	\$ 3.6186	50,466	\$ 2.9224
Apr-24	40,858	\$ 1.4272	47,899	\$ 3.1201
May-24	53,368	\$ 1.4502	27,336	\$ 3.7958
Jun-24	33,346	\$ 1.9404	89,414	\$ 3.7783
Jul-24	58,079	\$ 2.3110	81,807	\$ 3.5542
Aug-24	59,760	\$ 1.4618	36,259	\$ 3.4330
Sep-24	21,631	\$ 1.5372	58,702	\$ 3.4286
Oct-24	52,518	\$ 1.9010	46,058	\$ 2.1768
Nov-24	41,920	\$ 3.0483	55,079	\$ 1.9146
Total	593,418		679,516	
Total Aggregate 12 Month Daily TS Imbalance in MCF				1,272,934
Projected Annual PGC Volume in MCF				68,895,451
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)				1.85%
Annual Storage Cost Applicable to Transportation Customers	1.85%	of	\$ 30,153,457	\$ 557,125
Revenue From Excess Delivery Penalty Charge for Dec 23 through Nov 24 in mcf		71,182	\$ 0.25	\$ 17,795.50
Calculation of the Proposed Adjusted Balancing Charges				
Storage Cost applicable to Transportation Customers				\$ 539,329
Divided by TS MCF Actual Dec 23 through Nov 24				23,564,697
Balancing Charge per MCF				\$ 0.0229

2024 Balancing Charges Exhibit BGT-3				
Annual Cost for Storage (PECO PGC 40, Section 7, Page 1)				
Fixed Storage Costs (includes associated transport)				\$ 31,570,000
Storage Injection Cost				\$ 1,429,671
Storage Withdrawal Cost				\$ 3,266,885
Total				\$ 36,266,556
Aggregate Imbalances for TS Customers				
	Aggregate Daily	Injection	Aggregate Daily	Withdrawal
	Excess Deliveries	Wacog	Deficient Deliveries	Wacog
Dec-22	52,041	\$ 6.2659	73,244	\$ 5.8223
Jan-23	31,278	\$ 4.7129	52,746	\$ 5.8180
Feb-23	73,799	\$ 3.5167	69,655	\$ 5.9332
Mar-23	41,223	\$ 3.6068	50,508	\$ 6.0343
Apr-23	52,378	\$ 1.7667	43,910	\$ 6.1094
May-23	46,324	\$ 1.7156	34,833	\$ 4.3208
Jun-23	25,815	\$ 1.4755	40,097	\$ 4.3208
Jul-23	44,433	\$ 1.5660	45,471	\$ 4.3208
Aug-23	34,311	\$ 1.4203	56,079	\$ 4.3208
Sep-23	20,843	\$ 1.3805	71,704	\$ 4.0454
Oct-23	27,168	\$ 1.6377	69,714	\$ 2.9958
Nov-23	47,044	\$ 3.1096	87,971	\$ 3.2486
Total	496,657		695,932	
Total Aggregate 12 Month Daily TS Imbalance in MCF				1,192,589
Projected Annual PGC Volume in MCF				68,253,410
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)				1.75%
Annual Storage Cost Applicable to Transportation Customers	1.75%	of	\$ 36,266,556	\$ 633,684
Revenue From Excess Delivery Penalty Charge for Dec 22 through Nov 23 in mcf		76,105	\$ 0.25	\$ 19,026.25
Calculation of the Proposed Adjusted Balancing Charges				
Storage Cost applicable to Transportation Customers				\$ 614,658
Divided by TS MCF Actual Dec 22 through Nov 23				23,652,714
Balancing Charge per MCF				\$ 0.0260

PECO STATEMENT NO. 4

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PECO ENERGY COMPANY

DOCKET NO. R-2025-3054868

**DIRECT TESTIMONY
OF
ANTHONY P. DIFELICE**

PECO STATEMENT NO. 4

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DIRECT TESTIMONY OF ANTHONY P. DIFELICE

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I. INTRODUCTION

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

A. My name is Anthony P. DiFelice. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

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

A. I am employed by PECO Energy Company (“PECO” or the “Company”) as a Senior Engineer in the Retail Rates Division.

3. Q. Please describe your educational background.

A. I graduated from the University of Pennsylvania in 1981 with a Bachelor of Applied Science degree from the School of Engineering and Applied Science. I obtained a Master of Business Administration degree with a concentration in Finance from Drexel University in 1989.

4. Q. Please describe your employment history with PECO.

A. I began working for PECO in January of 1982. Since that time, I have been employed in the Rates area of the Company, currently known as Retail Rates. Among other responsibilities, my duties include the calculation of the rate for the Purchased Gas Cost (“PGC”) adjustment.

5. Q. Have you previously submitted testimony in rate proceedings?

A. Yes. I submitted testimony on behalf of the Company in the following proceedings:

- a. PGC No. 18 at Docket No. R-00016366;
- b. PGC No. 19 at Docket No. R-00027391;

- 1 c. PGC No. 20 at Docket No. R-00038409;
- 2 d. PGC No. 21 at Docket No. R-00049423;
- 3 e. PGC No. 22 at Docket No. R-00050537;
- 4 f. PGC No. 23 at Docket No. R-00061501;
- 5 g. PGC No. 24 at Docket No. R-00072331;
- 6 h. PGC No. 26 at Docket No. R-2009-2108705;
- 7 i. PGC No. 27 at Docket No. R-2010-2174034;
- 8 j. PGC No. 28 at Docket No. R-2011-2239263;
- 9 k. PGC No. 29 at Docket No. R-2012-2302784;
- 10 l. PGC No. 30 at Docket No. R-2013-2363227;
- 11 m. PGC No. 31 at Docket No. R-2014-2420283;
- 12 n. PGC No. 32 at Docket No. R-2015-2480969;
- 13 o. PGC No. 33 at Docket No. R-2016-2545925;
- 14 p. PGC No. 34 at Docket No. R-2017-2602611;
- 15 q. PGC No. 35 at Docket No. R-2018-3001568;
- 16 r. PGC No. 36 at Docket No. R-2019-3009624;
- 17 s. PGC No. 37 at Docket No. R-2020-3019661;
- 18 t. PGC No. 38 at Docket No. R-2021-3025629;
- 19 u. PGC No. 39 at Docket No. R-2022-3032250;
- 20 v. PGC No. 40 at Docket No. R-2023-3040285 and
- 21 w. PGC No. 41 at Docket No. R-2024-3048767.

22 In addition, I submitted testimony in the Company’s proceeding regarding
23 the determination of the Gas Procurement Charge (“GPC”), at Docket No. P-2012-
24 2328614, in compliance with the Pennsylvania Public Utility Commission’s (the

1 “Commission”) Order for Promotion of Competitive Retail Markets at Docket No.
2 L-2008-2069114.

3 **II. PURPOSE OF TESTIMONY**

4 **6. Q. What is the purpose of your Direct Testimony?**

5 A. My Direct Testimony will describe and support the development of the PGC rates filed
6 by the Company in this proceeding, PGC No. 42, to become effective December 1,
7 2025. Pursuant to the Company’s Gas Restructuring Settlement, filed and approved at
8 Docket No. R-00994787, the PGC rate is unbundled into the Sales Service Cost
9 (“SSC”) and the Balancing Service Cost (“BSC”). The SSC is a charge to those
10 customers purchasing natural gas supply from PECO. The BSC recovers costs
11 associated with the operations of contract storage facilities and PECO’s peaking
12 services from all of PECO’s low-volume customers, whether they purchase their natural
13 gas supply from PECO or from a competitive natural gas supplier. Low-volume
14 customers are defined as customers taking service under Rate Schedules GR, CAP, GC,
15 OL, L and MV-F.

16 My Direct Testimony also will provide the monthly demand charge for Rate TS
17 (Transportation Service) standby sales service to become effective December 1, 2025.

18 **III. EXHIBITS SPONSORED**

19 **7. Q. Please identify the exhibits you are sponsoring in this proceeding.**

20 A. I am sponsoring the following exhibits:

- 21 • Exhibit APD-1 is a table outlining the proposed PGC No. 42 rates, effective
22 December 1, 2025, in comparison to the Company’s current PGC No. 41 Q2
23 rates, effective on June 1, 2025.
- 24 • Exhibit APD-2 provides the calculation including the GPC and the development
25 of the Merchant Function Charge (“MFC”) for the applicable rate classes for

1 the proposed December 1, 2025 PGC rates, as well as the total PGC rates for
2 the applicable rate classes.

- 3 • Exhibit APD-3 summarizes the computation of the PGC No. 42 SSC
4 adjustment, exclusive of the MFC.
- 5 • Exhibit APD-4 summarizes the computation of the PGC No. 42 BSC
6 adjustment.

7 Also included in my Direct Testimony as Exhibit APD-5 are the following
8 pages, in both regular text and “redlined” versions, of PECO’s proposed Supplement
9 No. 5 to Tariff Gas – Pa. P.U.C. No. 6 (“Supplement No. 5”):

- 10 • Fifth revised Page No. 1 and Fifth revised Page No. 2.
- 11 • Third revised Page Numbers 42 and 48, reflecting a \$0.3492 per Mcf total
12 decrease in the Section 1307(f) rates for Rates GR and CAP, a \$0.3477 per Mcf
13 total decrease for Rate GC and a \$0.3469 per Mcf total decrease for Rates OL,
14 L and MV-F.
- 15 • First revised Page No. 43, extending the Off-System Sales Sharing Mechanism
16 through November 30, 2028.
- 17 • Third revised Page Numbers 46 and 47, reflecting the Merchant Function
18 Charge and the Price to Compare.
- 19 • First revised Page No. 70, reflecting a \$0.0022 per Mcf decrease in the
20 Transportation Balancing Charge to a value of \$0.0203 per Mcf.

21 **IV. PROPOSED PGC RATES**

22 **8. Q. Please identify the specific time periods relevant to this filing.**

23 A. The period December 1, 2024 through April 30, 2025 reflects actual data and the period
24 May 1, 2025 through November 30, 2025 reflects projected data and together comprise
25 the “E” factor period. The “C” factor period, or PGC No. 42 application period, begins
26 December 1, 2025 and ends November 30, 2026.

1 **9. Q. Did you prepare Exhibits APD-1, 2, 3, 4 and 5 identified above?**

2 A. Yes. In addition, the natural gas cost information previously filed by the Company on
3 April 30, 2025 in support of PGC 42 (the “Advance Filing Information”) is sponsored
4 by Company Witness Suzette E. Adams, who is submitting PECO Statement No. 1.
5 Similarly, the proposed extension of the Off-System Sales Sharing Mechanism is
6 sponsored by Company Witness Scott J. Hughes, who is submitting PECO Statement
7 No. 2. Finally, the determination of the Transportation Balancing Charge is sponsored
8 by Company Witness Blerina Gaba-Teme, who is submitting PECO Statement No. 3.

9 **10. Q. Please summarize how the Company recovers its projected cost of purchased**
10 **natural gas and prior period over/under collections through current rates.**

11 A. As set forth in its tariff, the Company recovers the projected cost of purchased natural
12 gas and natural gas procurement charges through the Commodity Charge (“CC”) factor
13 of the SSC and the “C” factor of the BSC. In addition, amounts for prior period
14 over/under collections, refunds, interest and other items are recovered through the GCA
15 of the SSC and the “E” factor of the BSC. In total, under PGC No. 41, which was
16 approved by the Commission at Docket No. R-2024-3048767, the Company began
17 recovering \$5.2258 per Mcf for Rates GR and CAP, \$5.2122 per Mcf for Rate GC and
18 \$5.2080 per Mcf for Rates OL, L and MV-F as the bundled SSC and BSC charges
19 applicable to its retail sales service as of December 1, 2024. An update was made, as a
20 result of the 2024 Gas Distribution Base Rate Case at Docket No. R-2024 3046932
21 effective January 1, 2025, to implement a revised Gas Procurement Charge (“GPC”)
22 and the write-off factors for the Merchant Function Charges (“MFC”). The result was
23 a PGC rate of \$5.2255 per Mcf for Rates GR and CAP, \$5.2110 per Mcf for Rate GC
24 and \$5.2040 per Mcf for Rates OL, L and MV-F. These amounts were updated by a

1 February 27, 2025 filing for PGC No. 41-Q1 that put into effect, as of March 1, 2025,
2 PGC rates of \$6.3145 per Mcf for Rates GR and CAP, \$6.2977 per Mcf for Rate GC
3 and \$6.2896 per Mcf for Rates OL, L and MV-F. Finally, a May 29, 2025 filing,
4 effective June 1, 2025, includes PGC rates of \$7.0067 per Mcf for Rates GR and CAP,
5 \$6.9877 per Mcf for Rate GC and \$6.9785 per Mcf for Rates OL, L and MV-F.

6 **11. Q. Please describe the MFC and its impact on the June 1, 2025 PGC rate.**

7 A. As a result of the Commission’s Order at Docket No. P-2012-2328614,¹ an MFC was
8 created separately for Rates GR and CAP and Rate GC. The charge recovers
9 uncollectible charge-offs related to natural gas supply from PGC customers who
10 procure their natural gas supply from PECO. It is currently based on write-off factors
11 of 0.47% for Rates GR and CAP and 0.16% for Rate GC and 0.01% for Rates OL, L
12 and MV-F. These write-off factors are from the Commission’s Final Order in PECO’s
13 2024 Gas Distribution Base Rate Case at Docket No. R-2024-3046932. The write-off
14 factors are applied to the CC, including the GPC portion of the PGC rate, to produce
15 the applicable MFCs. Subsequently, the MFCs are included in the CC portion of the
16 SSC. The MFC charges initially became effective on June 1, 2015.

17 These MFCs will change with PGC rate changes due to the changing CC,
18 including GPC charges, and are not reconcilable. As a result of the different MFCs and
19 the subsequent different CCs, the PGC rates will have different values depending on
20 the applicable rate classes. Specifically, the June 1, 2025 value of the MFC is \$0.0288
21 per Mcf for Rates GR and CAP, \$0.0098 per Mcf for Rate GC and \$0.0006 per Mcf for

¹ *Petition of PECO Energy Company – Gas Division – Pursuant to 66 Pa. C.S. 1308(a) For Approval of its Proposed Tariff Revisions*, Docket No. P-2012-2328614, Order (Issued April 18, 2013).

1 Rates OL, L and MV-F. This leads to a June 1, 2025 total CC value of \$6.1494 per
2 Mcf for Rates GR and CAP, \$6.1304 per Mcf for Rate GC and \$6.1212 per Mcf for
3 Rates OL, L and MV-F (*see* Table APD-1, below).

1

Table APD-1

	Rates GR and CAP (\$/Mcf)	Rate GC (\$/Mcf)	Rates OL, L and MV-F (\$/Mcf)
CC including GPC	\$6.1206	\$6.1206	\$6.1206
MFC	\$0.0288	\$0.0098	\$0.0006
Total CC including GPC and MFC Effective June 1, 2025	\$6.1494	\$6.1304	\$6.1212

2

The June 1, 2025 GCA value of \$0.4814 per Mcf is the same for Rates GR, CAP, GC, OL, L and MV-F. The June 1, 2025 BSC of \$0.3759 per Mcf is also the same for these rates. The resultant PGC rates are shown below in Table APD-2.

3

4

5

Table APD-2

	Rates GR and CAP (\$/Mcf)	Rate GC (\$/Mcf)	Rates OL, L and MV-F (\$/Mcf)
CC	\$6.1494	\$6.1304	\$6.1212
GCA	\$0.4814	\$0.4814	\$0.4814
BSC	\$0.3759	\$0.3759	\$0.3759
Total PGC Rate Effective June 1, 2025	\$7.0067	\$6.9877	\$6.9785

6

7 **12. Q. How does the MFC impact the December 1, 2025 PGC No. 42 rate?**

8 A. The PGC rates will differ, depending on the applicable tariff rate class. Exhibit APD-
9 2 shows the derivation of the proposed December 1, 2025 PGC rates.

10 The write-off factors for uncollectible charge-offs are applied to the December
11 1, 2025 CC, including the GPC, to yield an MFC (effective December 1, 2025) of
12 \$0.0265 per Mcf for Rates GR and CAP, \$0.0090 per Mcf for Rate GC and \$0.0006
13 per Mcf for Rates OL, L and MV-F. As a result, the total December 1, 2025 CC,

1 including the GPC and MFC, is \$5.6752 per Mcf for Rates GR and CAP, \$5.6577 per
 2 Mcf for Rate GC and \$5.6493 per Mcf for Rates OL, L and MV-F as shown below in
 3 Table APD-3 and in Exhibit APD-2.

4 **Table APD-3**

	Rates GR and CAP (\$/Mcf)	Rate GC (\$/Mcf)	Rates OL, L and MV-F (\$/Mcf)
CC including GPC	\$5.6487	\$5.6487	\$5.6487
MFC	\$0.0265	\$0.0090	\$0.0006
Total CC including GPC and MFC Effective December 1, 2025	\$5.6752	\$5.6577	\$5.6493

5 **13. Q. Please describe the rates proposed for PGC No. 42 effective December 1, 2025.**

6 A. Adding the GCA value of \$0.6032 per Mcf and the BSC of \$0.3791 per Mcf to the
 7 above total CC values produces PGC rates, effective December 1, 2025, of \$6.6575 per
 8 Mcf for Rates GR and CAP, \$6.6400 per Mcf for Rate GC and \$6.6316 per Mcf for
 9 Rates OL, L and MV-F as shown below in Table APD-4 and in Exhibit APD-2.

1

Table APD-4

	Rates GR and CAP (\$/Mcf)	Rate GC (\$/Mcf)	Rates OL, L and MV-F (\$/Mcf)
CC	\$5.6752	\$5.6577	\$5.6493
GCA	\$0.6032	\$0.6032	\$0.6032
BSC	\$0.3791	\$0.3791	\$0.3791
Total PGC Rate Effective December 1, 2025	\$6.6575	\$6.6400	\$6.6316

2

3 **14. Q. Please summarize the differences between the PGC No. 42 and the PGC No. 41-**
4 **Q2 rates.**

5 A. The CC component of the SSC, exclusive of the MFC, is projected to decrease by
6 \$0.4719 per Mcf, from \$6.1206 per Mcf in PGC No. 41-Q2 to \$5.6487 per Mcf in PGC
7 No. 42. The GCA reconciliation component of the SSC will increase from \$0.4814 per
8 Mcf in PGC No. 41-Q2 to a value of \$0.6032 per Mcf in PGC No. 42. Lastly, the BSC
9 will increase from \$0.3759 per Mcf to \$0.3791 per Mcf.

10 **15. Q. Please explain what caused the CC component of the SSC, exclusive of the MFC,**
11 **to decrease from \$6.1206 per Mcf in PGC No. 41-Q2 to \$5.6487 per Mcf in PGC**
12 **No. 42.**

13 A. The \$5.6487 per Mcf value of the CC, exclusive of the MFC, for PGC No. 42 is
14 comprised of two parts. The first component is the projected recoverable fuel cost of
15 \$387.1 million for the period December 1, 2025 through November 30, 2025 divided
16 by twelve-month projected sales of 68,973,172 Mcf's for the same period, which
17 equates to \$5.6127 per Mcf. In addition, a GPC of \$0.0360 per Mcf is included in the
18 CC component. The calculation of the \$6.1206 per Mcf CC rate, exclusive of the MFC,

1 for PGC No. 41-Q2 reflects a value of \$6.0846 per Mcf for the combination of actual
2 and projected fuel costs and certain over/under collection data for the period December
3 1, 2024 through November 30, 2025.² The CC rate also includes the same GPC value
4 of \$0.0386 per Mcf.

5 **16. Q. Please explain what caused the GCA rate to increase from a value of \$0.4814 per**
6 **Mcf in PGC No. 41-Q2 to a value of \$0.6032 per Mcf in PGC No. 42.**

7 A. The \$0.1218 per Mcf increase in the GCA rate is due to three factors. First, there was
8 a change in the over/under collection component for the commodity cost, from a \$26.1
9 million under-collection balance as of November 30, 2024, reflected in the PGC No.
10 41-Q2 rate, to a projected \$28.5 million under-collection balance as of November 30,
11 2025, which is to be collected from customers during the PGC No. 42 application
12 period.

13 Second, there was a change in the accompanying interest balance from a \$1.4
14 million under-collection balance as of November 30, 2024, reflected in the PGC No.
15 41-Q2 rate, to a projected \$2.0 million under-collection balance as of November 30,
16 2025, which is to be recovered from customers during the PGC No. 42 application
17 period.

18 Finally, there was a decrease in the balance for supplier refunds, including
19 interest, from an over-collection balance of \$3.9 million as of November 30, 2024,
20 reflected in the PGC 41-Q2 rate, to a projected under-collection balance of \$68,595 as

² This was calculated in accordance with the PGC quarterly calculation methodology approved in the Company's PGC No. 20 proceeding at Docket No. R-00038409.

1 of November 30, 2025. The changes in the commodity cost under-collection, interest
2 and supplier refunds act to increase the GCA rate.

3 **17. Q. Please explain what caused the BSC rate to increase from \$0.3759 per Mcf in PGC**
4 **No. 41-Q2 to \$0.3791 per Mcf for PGC No. 42.**

5 A. The portion of the total BSC rate for PGC No. 42 associated with contract storage and
6 peaking services of \$0.4221 per Mcf is based on a projected recoverable cost of \$29.1
7 million for the period December 1, 2025 through November 30, 2025, divided by
8 twelve-month projected sales of 68,973,172 Mcf's for the same period. The associated
9 value of \$0.4073 per Mcf for PGC No. 41-Q2 reflects a combination of actual and
10 projected costs and certain over/under-collection data for the period December 1, 2024
11 through November 30, 2025.³ This change caused an increase of \$0.0148 per Mcf in
12 the BSC rate for PGC No. 42.

13 The combination of changes for over/under-collection balances for various
14 items of the BSC rate act to decrease the BSC rate by \$0.0016 per Mcf. The over/under-
15 collection balance associated with contract storage and peaking services changed from
16 a \$0.4 million over-collection balance as of November 30, 2024, to a projected under-
17 collection balance of \$1.0 million as of November 30, 2025. In addition, the
18 over/under-collection balance for miscellaneous surcharge monies increased from a
19 \$1.2 million over-collection balance as of December 1, 2024, to a projected over-
20 collection balance of \$3.7 million as of November 30, 2025. Lastly, the net interest

³ This was calculated in accordance with the PGC quarterly calculation methodology approved in the Company's PGC No. 20 proceeding at Docket No. R-00038409.

1 balance changed from an over-collection balance of \$0.5 million as of November 30,
2 2024, to a projected over-collection balance of \$0.3 million as of November 30, 2025.

3 **V. SALES SERVICE COST COMPONENTS**

4 **18. Q. Please describe the information shown in Exhibit APD-1.**

5 A. Exhibit APD-1 is a single sheet titled “Proposed Changes in PGC Rate Prices Effective
6 December 1, 2025.” This sheet consists of three columns, the first of which shows the
7 unbundled rates effective June 1, 2025, from PGC No. 41-Q2. The second column
8 shows the proposed changes to the PGC No. 41-Q2 rates. The third column is the sum
9 of Columns 1 and 2 and shows the PGC No. 42 proposed rates set forth in Supplement
10 No. 5, which are to become effective on December 1, 2025. Exhibit APD-1 shows a
11 total decrease of \$0.3492 per Mcf between the proposed PGC No. 42 rates and current
12 PGC No. 41-Q2 rates for Rates GR and CAP, a total decrease of \$0.3477 per Mcf for
13 Rate GC and a total decrease of \$0.3469 per Mcf for Rates OL, L and MV-F.

14 **19. Q. Please describe the information shown in Exhibit APD-2.**

15 A. Exhibit APD-2 provides the development of the MFC and its effect on the CC by rate
16 class for the PGC No. 42 rate to be effective December 1, 2025. In addition, the GCA
17 and BSC are included to determine the total PGC No. 42 rates by rate class to be
18 effective December 1, 2025.

1 **20. Q. Please describe the information shown on page 1 of Exhibit APD-3, which**
2 **develops the SSC, exclusive of the MFC, for PGC No. 42 to be effective December**
3 **1, 2025.**

4 A. Exhibit APD-3, page 1, summarizes the projected cost of natural gas, the GPC and
5 details of the experienced net under-collection (“E” factor or GCA). Page 1, line 1,
6 shows the allocated projection of the commodity cost of natural gas of \$387,126.866
7 and the associated rate of \$5.6127 per Mcf.

8 In addition, as a result of the Commission’s Order at Docket No. R-2024-
9 3046932, the Company’s 2024 gas distribution base rate case, a GPC of \$0.0360 per
10 Mcf, to recover procurement-related costs including labor, pensions, benefits, outside
11 legal, information technology and working capital, is shown on page 1, line 1. It is
12 applied to PGC customers who obtain natural gas supply from PECO. This charge is
13 included in the calculation of the CC portion of the SSC for PGC No. 41-Q2 and the
14 proposed PGC No. 42. The charge is not reconcilable and will remain constant until
15 the next distribution base rate case.

16 Summing the components of the projected cost of natural gas of \$5.6127 per
17 Mcf and the GPC of \$0.0360 per Mcf, results in a CC, exclusive of the MFC, of \$5.6487
18 per Mcf.

19 Lines 2.a. - d. summarize the items used to develop the GCA factor. This sheet
20 shows a net amount of approximately \$30.6 million in under-collections, Rate IS
21 profits, supplier refunds and interest to be returned to customers through the GCA factor
22 during the PGC No. 42 application period.

23 **21. Q. Please explain the basis for the approximately \$30.6 million net under-collection**
24 **to be recovered from customers through the GCA factor.**

1 A. Four items determine the net amount. They are set forth below:

2 **Item 1: Over/(Under) Collections (Exhibit APD-3, Pages 2-4)**

3 The recoverable cost of natural gas is subtracted from the CC revenues received,
4 including the adjustment for the prior period reconciliation and excluding GPC and
5 MFC revenues. As of November 30, 2025, the estimated total under-collection balance
6 after reconciliation is expected to be \$28,504,872. That figure is brought forward from
7 page 2 to page 1.

8 **Item 2: Rate IS Profit (Exhibit APD-3, Page 5)**

9 The difference between revenues received and costs comprises “profit” from Rate IS
10 customers. As a result of the compliance filing of the 2020 Gas Base Rate Case at
11 Docket No. R-2020-3018929, and later implemented on the effective date of December
12 1, 2021 for PGC No. 38 at Docket No. R-2021-3025629, future profits are incorporated
13 in distribution base rates. The remaining balance of profits through November 30,
14 2025, of \$1,219, will be returned to customers and is determined by reconciling prior
15 refunds/recoveries of profits through November 30, 2025.

16 **Item 3: Net Interest on Item 1 (Exhibit APD-3, Page 6)**

17 The current period over/under-collection for the SSC is determined monthly. The
18 current interest is calculated by applying an annual interest rate to these over/under
19 collections which is then multiplied by a factor based on an equivalent payback to the
20 midpoint of the PGC No. 42 application period.

21 Effective December 1, 2016, as a result of PA Act 47 as reflected in the
22 Company’s PGC No. 33 Compliance Filing at Docket No. R-2016-2545925, the
23 interest rate used to determine monthly interest for current period under-collections and

1 over-collections is the prime rate for commercial borrowing in effect sixty (60) days
2 prior to the tariff filing in accordance with Section 1307(f).

3 In accordance with Paragraph 24 of the 2024 Joint Petition for Complete
4 Settlement in the PGC No. 41 Proceeding at Docket No. R-2024-3048767, the
5 Company used the prime rate effective sixty (60) days prior to the date of this filing,
6 which was 7.50%, or the period December 2024 through November 2025. Based on
7 this interest rate, the current interest for the period December 2024 through November
8 2025 to be recovered from customers for the GCA during the PGC No. 42 application
9 period amounts to \$1,581,745.

10 Combining the under-collection balance of \$1,400,060 as of November 30,
11 2024, the current interest to be recovered from customers for the December 2024
12 through November 2025 time period of \$1,581,745 and the estimated recovery from
13 customers of \$955,714 from December 1, 2024 through November 30, 2025 (Exhibit
14 APD-3, page 6), the total interest balance at November 30, 2025, for the GCA to be
15 recovered from customers during the PGC No. 42 application period has an estimated
16 value of \$2,026,091.

17 **Item 4: Supplier Refunds (Including Interest) (Exhibit APD-3, Page 8)**

18 This item is comprised of the actual refunds returned to the Company by suppliers after
19 July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 42
20 application period less the amount expected to be recovered from customers through
21 November 30, 2025. The net result is an estimated amount of \$69,693 to be recovered
22 from customers as of November 30, 2025. This value is prior to the PAPUC Bureau
23 of Audits adjustment described below.

1 Also included in the November 30, 2025 supplier refunds balance is an
2 adjustment of \$1,368 to be returned to customers as determined by the PAPUC
3 Bureau of Audits in its finding at Docket No. D-2023-3044009 associated with
4 interest for supplier refunds. This adjustment is included in Exhibit APD-3, page 8,
5 column 9. Thus, the total supplier refunds including interest balance as of November
6 30, 2025 to be recovered from customers is \$68,595.

7 **VI. BALANCING SERVICE COST COMPONENTS**

8 **22. Q. Please describe the information shown on page 1 of Exhibit APD-4, which**
9 **develops the BSC for PGC No. 42 to be effective December 1, 2025.**

10 A. Exhibit APD-4, page 1, summarizes the projected cost that PECO will incur under
11 natural gas storage and peaking agreements with various interstate pipeline and natural
12 gas marketing companies and details the experienced net over/under-collection balance.
13 Page 1, line 1, shows the projected costs for contract storage and peaking services.
14 Lines 2 a. - d. summarize the items used to develop the “E” factor. This sheet shows
15 that the projected recoverable cost for contract storage and peaking services is \$29.1
16 million for the period December 1, 2025 through November 30, 2026. There is also a
17 projected over-collection balance of \$3.0 million as of November 30, 2025. This
18 amount includes over-collections, refunds, interest, and miscellaneous surcharge
19 monies to be returned to customers during the PGC No. 42 application period. Page 1,
20 line 3 shows the \$26.1 million net amount to be recovered from customers.

21 **23. Q. Please explain the basis for the \$26.1 million net amount to be recovered from**
22 **customers.**

23 A. Five items determine the net amount. They are set forth below:

1 **Item 1: Projected Cost of Gas (Exhibit APD-4, Page 1)**

2 The projected recoverable cost for contract storage facilities and peaking services is
3 \$29,111,155 as shown on Exhibit APD-4, page 1.

4 **Item 2: Over/(Under) Collections (Exhibit APD-4, Pages 2-4)**

5 The recoverable cost of natural gas is subtracted from the BSC revenues received,
6 including the adjustment for the prior period reconciliation. The resulting balance is an
7 estimated under-collection of \$983,755 as of November 30, 2025, which is brought
8 forward from page 2 to page 1.

9 **Item 3: Miscellaneous Surcharge Monies (Exhibit APD-4, Page 5)**

10 Transportation balancing surcharges and penalties applied to transportation, Rate TCS
11 and Rate IS customers are returned to firm service customers through the BSC. After
12 reconciling refunds of prior balances and adding current surcharge monies, a projected
13 balance of \$3,659,163 as of November 30, 2025, is expected to be returned to
14 customers.

15 **Item 4: Net Interest on Item 2 (Exhibit APD-4, Page 6)**

16 The current period over/under-collections for the BSC are determined monthly.
17 Current interest for the over/under-collections for the BSC is calculated in the same
18 manner as current period interest on over/under-collections for the SSC as described
19 above.

20 As a result, the current interest for the period December 2024 through
21 November 2025 to be returned to customers for the BSC during the PGC No. 42
22 application period amounts to \$309,161. The current interest is based on the 7.50%
23 interest rate previously described above for the SSC.

1 Combining the current interest to be returned to customers of \$309,161 for the
2 period December 2024 through November 2025 with the over-collected balance of prior
3 period interest of \$498,194 as of December 1, 2024, and including the amount returned
4 to customers of \$519,830 during the December 1, 2024 through November 30, 2025
5 period results in an estimated interest balance for the BSC of \$287,525 to be returned
6 to customers during the PGC No. 42 application period.

7 **Item 5: Supplier Refunds (Including Interest) (Exhibit APD-4, Page 7)**

8 This item is comprised of the actual refunds returned to the Company by suppliers on
9 or before July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC
10 No. 42 application period, less the amount expected to be returned to customers through
11 November 30, 2025. The net result is an estimated amount of \$2,041 as of November
12 30, 2025, to be returned to customers.

13 **VII. OTHER RATES**

14 **24. Q. Does the Company propose to update the monthly demand charge for Rate TS**
15 **standby sales service?**

16 Yes. The updated monthly demand charge for Rate TS standby sales service will be
17 \$22.72 per Mcf.

18 **VIII. CONCLUSION**

19 **25. Q. Does this conclude your Direct Testimony?**

20 A. Yes, it does.

Exhibit APD-1

Proposed Changes in PGC Rate Prices Effective December 1, 2025

**Rates GR, CAP, GC, L, OL and MV-F
(Values in \$ per Mcf)**

		<u>06/01/25</u> Unbundled <u>Rates</u>	Change in <u>Rates</u>	<u>12/01/25</u> Unbundled <u>Rates</u>
<u>Rates GR and CAP</u>				
	CC	\$6.1494	(\$0.4742)	\$5.6752
	GCA	\$0.4814	\$0.1218	\$0.6032
	BSC	<u>\$0.3759</u>	<u>\$0.0032</u>	<u>\$0.3791</u>
	Total	\$7.0067	(\$0.3492)	\$6.6575
<u>Rates GC</u>				
	CC	\$6.1304	(\$0.4727)	\$5.6577
	GCA	\$0.4814	\$0.1218	\$0.6032
	BSC	<u>\$0.3759</u>	<u>\$0.0032</u>	<u>\$0.3791</u>
	Total	\$6.9877	(\$0.3477)	\$6.6400
<u>Rates OL, L and MV-F</u>				
	CC	\$6.1212	(\$0.4719)	\$5.6493
	GCA	\$0.4814	\$0.1218	\$0.6032
	BSC	<u>\$0.3759</u>	<u>\$0.0032</u>	<u>\$0.3791</u>
	Total	\$6.9785	(\$0.3469)	\$6.6316
Rate OL				
	(1.5 MCF)	CC \$9.1818	(\$0.7078)	\$8.4740
	(1.7 MCF)	\$10.4060	(\$0.8022)	\$9.6038
	(2.1 MCF)	\$12.8545	(\$0.9910)	\$11.8635
	(2.4 MCF)	\$14.6909	(\$1.1326)	\$13.5583
	(1.5 MCF)	GCA \$0.7221	\$0.1827	\$0.9048
	(1.7 MCF)	\$0.8184	\$0.2070	\$1.0254
	(2.1 MCF)	\$1.0109	\$0.2558	\$1.2667
	(2.4 MCF)	\$1.1554	\$0.2923	\$1.4477
	(1.5 MCF)	BSC \$0.5639	\$0.0048	\$0.5687
	(1.7 MCF)	\$0.6390	\$0.0055	\$0.6445
	(2.1 MCF)	\$0.7894	\$0.0067	\$0.7961
	(2.4 MCF)	\$0.9022	\$0.0076	\$0.9098
Rate L				
	First 50% of Usage	CC \$6.1212	(\$0.4719)	\$5.6493
	Additional Use	\$6.1212	(\$0.4719)	\$5.6493
	First 50% of Usage	GCA \$0.4814	\$0.1218	\$0.6032
	Additional Use	\$0.4814	\$0.1218	\$0.6032
	First 50% of Usage	BSC \$0.3759	\$0.0032	\$0.3791
	Additional Use	\$0.3759	\$0.0032	\$0.3791
Standby Sales Demand Charge Under Rate TS-F		\$24.13	(\$1.4100)	\$22.72
Unit Credit for Rate TS-F Standby Sales Purchases		\$0.79	(\$0.0400)	\$0.75
Balancing Charge-Transportation		\$0.0225	(\$0.0022)	\$0.0203

Exhibit APD-2

Exhibit APD-2

PGC No. 42 Calculation Including Gas Procurement Charge (GPC) and Merchant Function Charge (MFC)

Application Period : December 1, 2025 through November 30, 2026

Computation Period : December 1, 2025 through November 30, 2026

\$/Mcf

		<u>Rates GR and CAP</u>	<u>Rate GC</u>	<u>Rates OL, L and MV-F</u>
CC Including GPC	Exhibit APD-3, Page 1	\$5.6487	\$5.6487	\$5.6487
x				
Write-Off Factor (a)		0.47%	0.16%	0.01%
=				
MFC		<u>\$0.0265</u>	<u>\$0.0090</u>	<u>\$0.0006</u>
CC Including GPC and MFC		\$5.6752	\$5.6577	\$5.6493
GCA	Exhibit APD-3, Page 1	\$0.6032	\$0.6032	\$0.6032
BSC	Exhibit APD-4, Page 1	<u>\$0.3791</u>	<u>\$0.3791</u>	<u>\$0.3791</u>
Total PGC		\$6.6575	\$6.6400	\$6.6316

(a) From Docket No. R-2024-3046932, the 2024 PECO Gas Distribution Base Rate Case

Exhibit APD-3

Computation of Sales Service Cost Adjustment No. 42
Application and Computation Period : 12 Months
December 1, 2025 Through November 30, 2026

1. Projected Commodity Charge Excluding Gas Procurement Charge (GPC)	\$387,126,866	Pg. 2	\$5.6127 /Mcf
GPC From Docket No. R-2024-3046932			<u>\$0.0360</u> /Mcf
Total CC = Commodity Charge Including GPC			\$5.6487 /Mcf
2. E = Experienced and Estimated Net Over/(Under)			
a. Commodity Cost Over / (Under)	(\$28,504,872)	Pg. 2	(\$0.5620) /Mcf
b. Rate IS Profit Monies	\$1,219	Pg. 5	\$0.0000 /Mcf
c. Net Interest on Item a.	(\$2,026,091)	Pg. 6	(\$0.0399) /Mcf
d. Supplier Refunds (Including Interest)	<u>(\$68,595)</u>	Pg. 8	<u>(\$0.0013)</u> /Mcf
Experienced Net Over/Under Collections - GCA	(\$30,598,339)		(\$0.6032) /Mcf
3. S = Projected Sales for Computation Period CC	68,973,172	mcf	
4. S = Projected Sales for Computation Period GCA	50,722,578	mcf	
GCA Charge / (Credit) to Customers	\$0.6032		/Mcf

Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)	CC/GCA Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance - Nov. 30, 2023								(\$13,820,712)
Dec	\$27,676,820	\$76,582	\$27,600,238	0.99958747	\$27,588,852	\$29,411,516	\$1,822,664	(\$11,998,048)
Jan '24	\$46,944,004	\$51,701	\$46,892,303	0.99918483	\$46,854,078	\$33,209,325	(\$13,644,753)	(\$25,642,801)
Feb	\$29,338,682	\$44,380	\$29,294,302	1.00000000	\$29,294,302	\$29,334,453	\$40,151	(\$25,602,650)
March	\$21,574,284	\$216	\$21,574,068	0.99926522	\$21,558,216	\$28,715,078	\$7,156,862	(\$18,445,788)
April	\$10,044,184	\$86	\$10,044,098	0.99909284	\$10,034,986	\$19,200,728	\$9,165,742	(\$9,280,046)
May	\$6,705,335	\$78	\$6,705,257	0.99990398	\$6,704,613	\$10,371,685	\$3,667,072	(\$5,612,974)
June	\$6,280,969	\$36	\$6,280,933	0.99982530	\$6,279,836	\$5,007,351	(\$1,272,485)	(\$6,885,459)
July	\$5,762,566	\$17,093	\$5,745,473	0.99992937	\$5,745,067	\$4,216,612	(\$1,528,455)	(\$8,413,914)
Aug	\$6,989,592	\$18	\$6,989,574	0.99990927	\$6,988,940	\$4,000,434	(\$2,988,506)	(\$11,402,420)
Sept	\$7,174,320	\$882	\$7,173,438	0.99984822	\$7,172,349	\$4,090,430	(\$3,081,919)	(\$14,484,339)
Oct	\$9,314,015	\$72,258	\$9,241,757	0.99954754	\$9,237,575	\$6,174,077	(\$3,063,498)	(\$17,547,837)
Nov	\$19,189,086	\$2,446	\$19,186,640	0.99936116	\$19,174,383	\$10,628,439	(\$8,545,944)	(\$26,093,781)
12 Months	\$196,993,857	\$265,776	\$196,728,081		\$196,633,197	\$184,360,128	(\$12,273,069)	
12 Months -Nov 30, 2025	\$299,175,069	\$246,839	\$298,928,230		\$298,805,735			

Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)	CC/GCA Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance - Nov. 30, 2024								(\$26,093,781)
Dec	\$32,803,213	\$220	\$32,802,993	0.99907242	\$32,772,566	\$29,353,282	(\$3,419,284)	(\$29,513,065)
Jan '25	\$56,422,535	\$304	\$56,422,231	0.99922613	\$56,378,567	\$45,214,557	(\$11,164,010)	(\$40,677,075)
Feb	\$39,594,072	\$265	\$39,593,807	0.99963796	\$39,579,472	\$41,845,716	\$2,266,244	(\$38,410,831)
March	\$23,349,274	(\$30,827)	\$23,380,101	0.99971813	\$23,373,511	\$39,747,331	\$16,373,820	(\$22,037,011)
April	\$14,973,975	\$31,262	\$14,942,713	0.99931196	\$14,932,432	\$24,187,360	\$9,254,928	(\$12,782,083)
May (est)	\$18,621,000	\$50,990	\$18,570,010	0.99992381	\$18,568,595	\$16,025,260	(\$2,543,335)	(\$15,325,418)
June (est)	\$15,252,000	\$40,811	\$15,211,189	0.99989273	\$15,209,557	\$10,662,046	(\$4,547,511)	(\$19,872,929)
July (est)	\$15,115,000	\$26,528	\$15,088,472	0.99995831	\$15,087,843	\$9,912,723	(\$5,175,120)	(\$25,048,049)
Aug (est)	\$14,986,000	\$26,852	\$14,959,148	0.99994775	\$14,958,366	\$9,619,388	(\$5,338,978)	(\$30,387,027)
Sept (est)	\$14,466,000	\$24,255	\$14,441,745	0.99991569	\$14,440,527	\$10,048,777	(\$4,391,750)	(\$34,778,777)
Oct (est)	\$19,377,000	\$25,679	\$19,351,321	0.99980386	\$19,347,525	\$19,225,187	(\$122,338)	(\$34,901,115)
Nov (est)	\$34,215,000	\$50,500	\$34,164,500	0.99977385	\$34,156,774	\$40,553,017	\$6,396,243	(\$28,504,872)
12 Months	\$299,175,069	\$246,839	\$298,928,230		\$298,805,735	\$296,394,644	(\$2,411,091)	
12 Months -Nov 30, 2026	\$387,972,600	\$721,921	\$387,250,679		\$387,126,866			

Exclusions							
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	\$0	\$32,285	\$0	\$44,107	\$190	\$0	\$76,582
Jan '24	\$0	\$13,622	\$0	\$37,669	\$410	\$0	\$51,701
Feb	\$0	\$22,174	\$0	\$22,092	\$114	\$0	\$44,380
March	\$0	\$0	\$0	\$0	\$216	\$0	\$216
April	\$0	\$0	\$0	\$0	\$86	\$0	\$86
May	\$0	\$0	\$0	\$0	\$78	\$0	\$78
June	\$0	\$0	\$0	\$0	\$36	\$0	\$36
July	\$0	\$626	\$0	\$16,465	\$2	\$0	\$17,093
Aug	\$0	\$0	\$0	\$7	\$11	\$0	\$18
Sept	\$0	\$0	\$0	\$869	\$13	\$0	\$882
Oct	\$0	\$0	\$0	\$72,127	\$131	\$0	\$72,258
Nov	\$0	\$0	\$0	\$2,446	\$0	\$0	\$2,446
12 Months	\$0	\$68,707	\$0	\$195,782	\$1,287	\$0	\$265,776
12 Months -Nov 30, 2025	\$0	\$20,057	\$0	\$224,777	\$2,005	\$0	\$246,839

Allocation Factor Calculation					
Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	2,517	6,098,923	6,101,440	0.99958747	6,098,923
Jan '24	6,562	8,043,336	8,049,898	0.99918483	8,043,336
Feb	0	7,107,764	7,107,764	1.00000000	7,107,764
March	4,858	6,606,635	6,611,493	0.99926522	6,606,635
April	3,746	4,125,640	4,129,386	0.99909284	4,125,640
May	214	2,228,553	2,228,767	0.99990398	2,228,553
June	188	1,075,924	1,076,112	0.99982530	1,075,924
July	64	906,019	906,083	0.99992937	906,019
Aug	78	859,569	859,647	0.99990927	859,569
Sept	131	862,978	863,109	0.99984822	862,978
Oct	580	1,281,301	1,281,881	0.99954754	1,281,301
Nov	1,410	2,205,711	2,207,121	0.99936116	2,205,711
12 Months	20,348	41,402,353	41,422,701		41,402,353
12 Months -Nov 30, 2025	\$23,574	\$53,886,446	\$53,910,020		\$48,943,886

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge

Exclusions							
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	\$0	\$0	\$0	\$0	\$220	\$0	\$220
Jan '25	\$0	\$0	\$0	\$0	\$304	\$0	\$304
Feb	\$0	\$0	\$0	\$0	\$265	\$0	\$265
March	\$0	\$0	\$0	(\$31,086)	\$259	\$0	(\$30,827)
April	\$0	\$0	\$0	\$31,041	\$221	\$0	\$31,262
May (est)	\$0	\$2,608	\$0	\$48,290	\$92	\$0	\$50,990
June (est)	\$0	\$2,796	\$0	\$37,913	\$102	\$0	\$40,811
July (est)	\$0	\$3,018	\$0	\$23,406	\$104	\$0	\$26,528
Aug (est)	\$0	\$3,042	\$0	\$23,699	\$111	\$0	\$26,852
Sept (est)	\$0	\$2,780	\$0	\$21,371	\$104	\$0	\$24,255
Oct (est)	\$0	\$2,681	\$0	\$22,899	\$99	\$0	\$25,679
Nov (est)	\$0	\$3,132	\$0	\$47,244	\$124	\$0	\$50,500
12 Months	\$0	\$20,057	\$0	\$224,777	\$2,005	\$0	\$246,839
12 Months -Nov 30, 2026	\$0	\$34,471	\$0	\$686,181	\$1,269	\$0	\$721,921

Allocation Factor Calculation					
Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	5,641	6,075,805	6,081,446	0.99907242	6,075,805
Jan '25	7,232	9,337,992	9,345,224	0.99922613	9,337,992
Feb	3,130	8,642,238	8,645,368	0.99963796	8,642,238
March	2,088	7,405,461	7,407,549	0.99971813	7,405,461
April	2,818	4,092,893	4,095,711	0.99931196	4,092,893
May (est)	214	2,808,496	2,808,710	0.99992381	1,767,676
June (est)	188	1,752,480	1,752,668	0.99989273	1,178,067
July (est)	64	1,534,958	1,535,022	0.9995831	1,075,066
Aug (est)	78	1,492,605	1,492,683	0.99994775	1,008,217
Sept (est)	131	1,553,580	1,553,711	0.99991569	1,117,734
Oct (est)	580	2,956,501	2,957,081	0.99980386	2,318,628
Nov (est)	1,410	6,233,438	6,234,848	0.99977385	4,924,110
12 Months	23,574	53,886,446	53,910,020		48,943,886
12 Months -Nov 30, 2026	23,574	68,973,172	68,996,746		50,722,578

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge

(b) TCS Sales Volume x (Commodity Price Excl TOP + TCS Fixed Commodity Cost Component)

(c) Demand portion based on Rate CGS Firm Reservation Supply Charge / 30.41 x NGS Sales Volume,

Commodity portion based on Weighted Average Commodity Cost of Gas x NGS Sales Volume

SSC Revenues

Exhibit APD-3

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	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)	GCA Appl. Sales In Month (4)	Prior Pd. O/(U) Adjust. Rate (5)	Prior Pd. O/(U) Adjust. Revenue (6) = (4) x (5)	Total Revenues Recovered In Base Rates (7) = (3) + (6)
Dec bef 12/1	3,497,732	\$4.7174	\$16,500,201	3,497,732	\$0.6221	\$2,175,939	\$18,676,140
Dec aft 12/1	2,601,191	\$4.2347	\$11,015,264	2,601,191	(\$0.1076)	(\$279,888)	\$10,735,376
Jan '24 bef 12/1	-	\$4.7174	\$0		\$0.6221	\$0	\$0
Jan '24 aft 12/1	8,043,336	\$4.2354	\$34,066,745	8,043,336	(\$0.1066)	(\$857,420)	\$33,209,325
Feb	7,107,764	\$4.2347	\$30,099,248	7,107,764	(\$0.1076)	(\$764,795)	\$29,334,453
March	6,606,635	\$4.2882	\$28,330,572	6,606,635	\$0.0582	\$384,506	\$28,715,078
April	4,125,640	\$4.3632	\$18,000,992	4,125,640	\$0.2908	\$1,199,736	\$19,200,728
May	2,228,553	\$4.3632	\$9,723,622	2,228,553	\$0.2908	\$648,063	\$10,371,685
June	1,075,924	\$4.3632	\$4,694,472	1,075,924	\$0.2908	\$312,879	\$5,007,351
July	906,019	\$4.3632	\$3,953,142	906,019	\$0.2908	\$263,470	\$4,216,612
Aug	859,569	\$4.3632	\$3,750,471	859,569	\$0.2908	\$249,963	\$4,000,434
Sept	862,978	\$4.4462	\$3,836,973	862,978	\$0.2937	\$253,457	\$4,090,430
Oct	1,281,301	\$4.5222	\$5,794,299	1,281,301	\$0.2964	\$379,778	\$6,174,077
Nov	2,205,711	\$4.5222	\$9,974,666	2,205,711	\$0.2964	\$653,773	\$10,628,439
12 Months	41,402,353		\$179,740,667	41,402,353		\$4,619,461	\$184,360,128

SSC Revenues

Exhibit APD-3

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	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)	GCA Appl. Sales In Month (4)	Prior Pd. O/(U) Adjust. Rate (5)	Prior Pd. O/(U) Adjust. Revenue (6) = (4) x (5)	Total Revenues Recovered In Base Rates (7) = (3) + (6)
Dec bef 12/1	2,810,485	\$4.5222	\$12,709,575	2,810,485	\$0.2964	\$833,028	\$13,542,603
Dec aft 12/1	3,265,320	\$4.6542	\$15,197,452	3,265,320	\$0.1878	\$613,227	\$15,810,679
Jan '25 bef 12/1	-	\$4.5222	\$0		\$0.2964	\$0	\$0
Jan '25 aft 12/1	9,337,992	\$4.6542	\$43,460,882	9,337,992	\$0.1878	\$1,753,675	\$45,214,557
Feb	8,642,238	\$4.6542	\$40,222,704	8,642,238	\$0.1878	\$1,623,012	\$41,845,716
March	7,405,461	\$5.0016	\$37,039,154	7,405,461	\$0.3657	\$2,708,177	\$39,747,331
April	4,092,893	\$5.3602	\$21,938,725	4,092,893	\$0.5494	\$2,248,635	\$24,187,360
May (est)	2,808,496	\$5.3602	\$15,054,099	1,767,676	\$0.5494	\$971,161	\$16,025,260
June (est)	1,752,480	\$5.7201	\$10,024,359	1,178,067	\$0.5413	\$637,687	\$10,662,046
July (est)	1,534,958	\$6.0846	\$9,339,605	1,075,066	\$0.5331	\$573,118	\$9,912,723
Aug (est)	1,492,605	\$6.0846	\$9,081,907	1,008,217	\$0.5331	\$537,481	\$9,619,388
Sept (est)	1,553,580	\$6.0846	\$9,452,913	1,117,734	\$0.5331	\$595,864	\$10,048,777
Oct (est)	2,956,501	\$6.0846	\$17,989,126	2,318,628	\$0.5331	\$1,236,061	\$19,225,187
Nov (est)	6,233,438	\$6.0846	\$37,927,974	4,924,110	\$0.5331	\$2,625,043	\$40,553,017
12 Months	53,886,446		\$279,438,475	48,943,886		\$16,956,169	\$296,394,644

IS Profits

	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue (4) = (1)-(2)-(3)	Reg IS Sales Mcf (5)	Commodity Cost/Mcf (6)	Total Reg IS Cost of Gas (7) = (5) x (6)	Increase In Taxable Income (8) = (4) - (7)	Profit to Be Returned To Customers (9) = (8) x 0% (a)	Applicable GCA Sales (10)	IS Profit Return Rate (11)	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
Balance - Nov. 30, 2023													\$869
Dec bef 12/1										3,497,732	(\$0.0001)	(\$350)	\$1,219
Dec aft 12/1	\$85,443	\$0	\$0	\$85,443	10,012	\$3,2246	\$32,285	\$53,158	\$0	2,601,191	\$0.0000	\$0	\$1,219
Jan '24 bef 12/1										0	(\$0.0001)	\$0	\$1,219
Jan '24 aft 12/1	\$7,095	\$0	\$0	\$7,095	931	\$14,6321	\$13,622	(\$6,527)	\$0	8,043,336	\$0.0000	\$0	\$1,219
Feb	\$35,935	\$0	\$0	\$35,935	5,054	\$4,3875	\$22,174	\$13,761	\$0	7,107,764	\$0.0000	\$0	\$1,219
March	\$0	\$0	\$0	\$0	0	\$3,4775	\$0	\$0	\$0	6,606,635	\$0.0000	\$0	\$1,219
April	\$0	\$0	\$0	\$0	0	\$2,1930	\$0	\$0	\$0	4,125,640	\$0.0000	\$0	\$1,219
May	\$0	\$0	\$0	\$0	0	\$1,5840	\$0	\$0	\$0	2,228,553	\$0.0000	\$0	\$1,219
June	\$0	\$0	\$0	\$0	0	\$2,2762	\$0	\$0	\$0	1,075,924	\$0.0000	\$0	\$1,219
July	\$2,909	\$0	\$0	\$2,909	315	\$1,9874	\$626	\$2,283	\$0	906,019	\$0.0000	\$0	\$1,219
Aug	\$0	\$0	\$0	\$0	0	\$1,7854	\$0	\$0	\$0	859,569	\$0.0000	\$0	\$1,219
Sept	\$197	\$0	\$0	\$197	0	\$1,9026	\$0	\$197	\$0	862,978	\$0.0000	\$0	\$1,219
Oct	\$0	\$0	\$0	\$0	0	\$2,0824	\$0	\$0	\$0	1,281,301	\$0.0000	\$0	\$1,219
Nov	\$0	\$0	\$0	\$0	0	\$3,3266	\$0	\$0	\$0	2,205,711	\$0.0000	\$0	\$1,219
12 Months	\$131,579	\$0	\$0	\$131,579	16,312		\$68,707	\$62,872	\$0	41,402,353		(\$350)	\$350
Balance at Nov 30, 2024													\$1,219

(a) From Docket No. R-2020-3018929 and Docket No. R-2021-3025629

IS Profits

	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue (4) = (1)-(2)-(3)	Reg IS Sales Mcf (5)	Commodity Cost/Mcf (6)	Total Reg IS Cost of Gas (7) = (5) x (6)	Increase In Taxable Income (8) = (4) - (7)	Profit to Be Returned To Customers (9) = (8) x 0% (a)	Applicable GCA Sales (10)	IS Profit Return Rate (11)	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
Balance - Nov. 30, 2024													\$1,219
Dec bef 12/1										2,810,485	\$0.0000	\$0	\$1,219
Dec aft 12/1	\$0	\$0	\$0	\$0	0	\$4,1453	\$0	\$0	\$0	3,265,320	\$0.0000	\$0	\$1,219
Jan '25 bef 12/1										0	\$0.0000	\$0	\$1,219
Jan '25 aft 12/1	\$0	\$0	\$0	\$0	0	\$7,7850	\$0	\$0	\$0	9,337,992	\$0.0000	\$0	\$1,219
Feb	\$0	\$0	\$0	\$0	0	\$9,1508	\$0	\$0	\$0	8,642,238	\$0.0000	\$0	\$1,219
March	\$0	\$0	\$0	\$0	0	\$4,1775	\$0	\$0	\$0	7,405,461	\$0.0000	\$0	\$1,219
April	\$0	\$0	\$0	\$0	0	\$3,8775	\$0	\$0	\$0	4,092,893	\$0.0000	\$0	\$1,219
May (est)	\$4,901	\$0	\$0	\$4,901	820	\$3,1800	\$2,608	\$2,293	\$0	1,767,676	\$0.0000	\$0	\$1,219
June (est)	\$5,090	\$0	\$0	\$5,090	820	\$3,4100	\$2,796	\$2,294	\$0	1,178,067	\$0.0000	\$0	\$1,219
July (est)	\$5,311	\$0	\$0	\$5,311	820	\$3,6800	\$3,018	\$2,293	\$0	1,075,066	\$0.0000	\$0	\$1,219
Aug (est)	\$5,336	\$0	\$0	\$5,336	820	\$3,7100	\$3,042	\$2,294	\$0	1,008,217	\$0.0000	\$0	\$1,219
Sept (est)	\$5,074	\$0	\$0	\$5,074	820	\$3,3900	\$2,780	\$2,294	\$0	1,117,734	\$0.0000	\$0	\$1,219
Oct (est)	\$4,975	\$0	\$0	\$4,975	820	\$3,2700	\$2,681	\$2,294	\$0	2,318,628	\$0.0000	\$0	\$1,219
Nov (est)	\$5,426	\$0	\$0	\$5,426	820	\$3,8200	\$3,132	\$2,294	\$0	4,924,110	\$0.0000	\$0	\$1,219
12 Months	\$36,114	\$0	\$0	\$36,114	5,740		\$20,057	\$16,057	\$0	48,943,886		\$0	\$0
Balance at Nov 30, 2025													\$1,219

(a) From Docket No. R-2020-3018929 and Docket No. R-2021-3025629

PUC Adjustment plus Interest

Exhibit APD-3

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Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance				(\$1,311)
- Nov. 30, 2023				
Dec bef 12/1	3,497,732	\$0.0000	\$0	(\$1,311)
Dec aft 12/1	2,601,191	\$0.0000	\$0	(\$1,311)
Jan '24 bef 12/1	-	\$0.0000	\$0	(\$1,311)
Jan '24 aft 12/1	8,043,336	\$0.0000	\$0	(\$1,311)
Feb	7,107,764	\$0.0000	\$0	(\$1,311)
March	6,606,635	\$0.0000	\$0	(\$1,311)
April	4,125,640	\$0.0000	\$0	(\$1,311)
May	2,228,553	\$0.0000	\$0	(\$1,311)
June	1,075,924	\$0.0000	\$0	(\$1,311)
July	906,019	\$0.0000	\$0	(\$1,311)
Aug	859,569	\$0.0000	\$0	(\$1,311)
Sept	862,978	\$0.0000	\$0	(\$1,311)
Oct	1,281,301	\$0.0000	\$0	(\$1,311)
Nov	2,205,711	\$0.0000	\$0	(\$1,311)
12 Months	41,402,353		\$0	
Balance at Nov 30, 2024				(\$1,311)

PUC Adjustment plus Interest

Exhibit APD-3

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Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance				(\$1,311)
- Nov. 30, 2024				
Dec bef 12/1	2,810,485	\$0.0000	\$0	(\$1,311)
Dec aft 12/1	3,265,320	\$0.0000	\$0	(\$1,311)
Jan '25 bef 12/1	-	\$0.0000	\$0	(\$1,311)
Jan '25 aft 12/1	9,337,992	\$0.0000	\$0	(\$1,311)
Feb	8,642,238	\$0.0000	\$0	(\$1,311)
March	7,405,461	\$0.0000	\$0	(\$1,311)
April	4,092,893	\$0.0000	\$0	(\$1,311)
May (est)	1,767,676	\$0.0000	\$0	(\$1,311)
June (est)	1,178,067	\$0.0000	\$0	(\$1,311)
July (est)	1,075,066	\$0.0000	\$0	(\$1,311)
Aug (est)	1,008,217	\$0.0000	\$0	(\$1,311)
Sept (est)	1,117,734	\$0.0000	\$0	(\$1,311)
Oct (est)	2,318,628	\$0.0000	\$0	(\$1,311)
Nov (est)	4,924,110	\$0.0000	\$0	(\$1,311)
12 Months	48,943,886		\$0	
Balance at Nov 30, 2025				(\$1,311)

Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)
Balance					
- Nov. 30, 2025					
Dec (est)	\$52,470,550	\$85,578	\$52,384,972	0.99945689	\$52,356,521
Jan '26 (est)	\$68,893,550	\$129,995	\$68,763,555	0.99945499	\$68,726,078
Feb (est)	\$60,589,300	\$119,949	\$60,469,351	0.99973170	\$60,453,127
March (est)	\$48,906,800	\$97,027	\$48,809,773	0.99978575	\$48,799,315
April (est)	\$28,199,300	\$59,830	\$28,139,470	0.99947509	\$28,124,699
May (est)	\$19,022,300	\$50,357	\$18,971,943	0.99992453	\$18,970,511
June (est)	\$15,145,300	\$38,321	\$15,106,979	0.99989411	\$15,105,379
July (est)	\$14,865,300	\$24,414	\$14,840,886	0.99995890	\$14,840,276
Aug (est)	\$14,631,300	\$24,352	\$14,606,948	0.99994846	\$14,606,195
Sept (est)	\$14,044,300	\$21,792	\$14,022,508	0.99991680	\$14,021,341
Oct (est)	\$18,697,300	\$23,509	\$18,673,791	0.99980611	\$18,670,170
Nov (est)	\$32,507,300	\$46,797	\$32,460,503	0.99977667	\$32,453,254
12 Months	\$387,972,600	\$721,921	\$387,250,679		\$387,126,866

SSC Revenues

Exhibit APD-3 Page 10

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)
Dec bef 12/1 (est)	5,444,150	\$6.0846	\$33,125,475
Dec aft 12/1 (est)	4,936,732	\$5.6127	\$27,708,398
Jan '26 bef 12/1 (est)	-	\$6.0846	\$0
Jan '26 aft 12/1 (est)	13,262,171	\$5.6127	\$74,436,588
Feb (est)	11,662,785	\$5.6127	\$65,459,713
March (est)	9,743,478	\$5.6127	\$54,687,218
April (est)	5,365,672	\$5.6127	\$30,115,906
May (est)	2,835,172	\$5.6127	\$15,912,967
June (est)	1,775,157	\$5.6127	\$9,963,424
July (est)	1,557,208	\$5.6127	\$8,740,141
Aug (est)	1,513,355	\$5.6127	\$8,494,010
Sept (est)	1,574,365	\$5.6127	\$8,836,436
Oct (est)	2,990,757	\$5.6127	\$16,786,223
Nov (est)	6,312,171	\$5.6127	\$35,428,320
12 Months	68,973,172		\$389,694,819

Interest on Moneys Owed to Customers - Summary

Exhibit APD-3 Page 11

Month	CC Portion of SSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)
Balance - Nov. 30, 2025			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	\$60,833,873	\$52,356,521	\$8,477,352
Jan '26 bef 12/1 (est)			
Jan '26 aft 12/1 (est)	\$74,436,588	\$68,726,078	\$5,710,510
Feb (est)	\$65,459,713	\$60,453,127	\$5,006,586
March (est)	\$54,687,218	\$48,799,315	\$5,887,903
April (est)	\$30,115,906	\$28,124,699	\$1,991,207
May (est)	\$15,912,967	\$18,970,511	(\$3,057,544)
June (est)	\$9,963,424	\$15,105,379	(\$5,141,955)
July (est)	\$8,740,141	\$14,840,276	(\$6,100,135)
Aug (est)	\$8,494,010	\$14,606,195	(\$6,112,185)
Sept (est)	\$8,836,436	\$14,021,341	(\$5,184,905)
Oct (est)	\$16,786,223	\$18,670,170	(\$1,883,947)
Nov (est)	\$35,428,320	\$32,453,254	\$2,975,066
12 Months	\$389,694,819	\$387,126,866	\$2,567,953

Exhibit APD-4

Computation of Balancing Service Cost Adjustment No. 42
Application and Computation Period : 12 Months
December 1, 2025 Through November 30, 2026

1. C = Projected Cost of Gas for Application Period	\$29,111,155	Pg. 2	\$0.4221 /Mcf
2. E = Experienced and Estimated Net Over/(Under)			
a. Balancing Over / (Under)	(\$983,755)	Pg. 2	(\$0.0143) /Mcf
b. Miscellaneous Surcharge Monies	\$3,659,163	Pg. 5	\$0.0531 /Mcf
c. Net Interest on Item a.	\$287,525	Pg. 6	\$0.0042 /Mcf
d. Supplier Refunds (Including Interest)	<u>\$2,041</u>	Pg. 7	<u>\$0.0000</u> /Mcf
Experienced Net Over/(Under) Collections	\$2,964,974		\$0.0430 /Mcf
3. C - E	\$26,146,181		\$0.3791 /Mcf
4. S = Projected Sales for Computation Period	68,973,172	mcf	
Charge / (Credit) to Customers			\$0.3791 /Mcf

Over/(Under) Collections

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2023							\$2,304,054
Dec	\$2,101,934	\$26,721	\$2,075,213	0.99970230	\$2,074,595	\$3,110,210	\$1,035,615	\$3,339,669
Jan '24	\$2,176,115	\$24,632	\$2,151,483	0.99940813	\$2,150,210	\$4,601,633	\$2,451,423	\$5,791,092
Feb	\$2,217,872	\$20,892	\$2,196,980	1.00000000	\$2,196,980	\$4,076,411	\$1,879,431	\$7,670,523
March	\$2,168,234	\$16,983	\$2,151,251	0.99947034	\$2,150,112	\$3,802,513	\$1,652,401	\$9,322,924
April	\$2,179,705	\$16,899	\$2,162,806	0.99936098	\$2,161,424	\$2,425,372	\$263,948	\$9,586,872
May	\$2,141,802	\$17,759	\$2,124,043	0.99993455	\$2,123,904	\$1,353,520	(\$770,384)	\$8,816,488
June	\$2,110,910	\$28,118	\$2,082,792	0.99988610	\$2,082,555	\$683,240	(\$1,399,315)	\$7,417,173
July	\$2,117,091	\$33,980	\$2,083,111	0.99995315	\$2,083,013	\$565,487	(\$1,517,526)	\$5,899,647
Aug	\$2,135,950	\$21,217	\$2,114,733	0.99994197	\$2,114,610	\$556,398	(\$1,558,212)	\$4,341,435
Sept	\$2,130,722	\$20,209	\$2,110,513	0.99989915	\$2,110,300	\$499,138	(\$1,611,162)	\$2,730,273
Oct	\$2,126,356	\$31,796	\$2,094,560	0.99969788	\$2,093,927	\$685,337	(\$1,408,590)	\$1,321,683
Nov	\$2,197,195	\$20,846	\$2,176,349	0.99959903	\$2,175,476	\$1,255,220	(\$920,256)	\$401,427
12 Months	\$25,803,886	\$280,052	\$25,523,834		\$25,517,106	\$23,614,479	(\$1,902,627)	
12 Months -Nov 30, 2025	\$28,367,456	\$285,904	\$28,081,552		\$28,074,747			

Over/(Under) Collections

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2024							\$401,427
Dec	\$2,216,757	\$24,265	\$2,192,492	0.99932650	\$2,191,015	\$3,132,432	\$941,417	\$1,342,844
Jan '25	\$2,251,466	\$26,692	\$2,224,774	0.99943232	\$2,223,511	\$4,952,906	\$2,729,395	\$4,072,239
Feb	\$2,290,785	\$26,834	\$2,263,951	0.99973298	\$2,263,346	\$4,558,613	\$2,295,267	\$6,367,506
March	\$2,241,138	\$24,383	\$2,216,755	0.99979540	\$2,216,301	\$4,139,334	\$1,923,033	\$8,290,539
April	\$2,322,310	\$26,318	\$2,295,992	0.99951755	\$2,294,884	\$2,469,581	\$174,697	\$8,465,236
May (est)	\$2,436,000	\$23,396	\$2,412,604	0.99992381	\$2,412,420	\$1,187,993	(\$1,224,427)	\$7,240,809
June (est)	\$2,406,000	\$21,530	\$2,384,470	0.99989273	\$2,384,214	\$722,372	(\$1,661,842)	\$5,578,967
July (est)	\$2,436,000	\$21,281	\$2,414,719	0.99995831	\$2,414,618	\$615,978	(\$1,798,640)	\$3,780,327
Aug (est)	\$2,436,000	\$20,640	\$2,415,360	0.99994775	\$2,415,234	\$598,982	(\$1,816,252)	\$1,964,075
Sept (est)	\$2,406,000	\$19,952	\$2,386,048	0.99991569	\$2,385,847	\$623,452	(\$1,762,395)	\$201,680
Oct (est)	\$2,436,000	\$22,939	\$2,413,061	0.99980386	\$2,412,588	\$1,186,444	(\$1,226,144)	(\$1,024,464)
Nov (est)	\$2,489,000	\$27,674	\$2,461,326	0.99977385	\$2,460,769	\$2,501,478	\$40,709	(\$983,755)
12 Months	\$28,367,456	\$285,904	\$28,081,552		\$28,074,747	\$26,689,565	(\$1,385,182)	
12 Months -Nov 30, 2026	\$29,442,000	\$323,843	\$29,118,157		\$29,111,155			

Exclusions					Allocation Factor Calculation				
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	
Dec	\$21,914	\$4,807	\$0	\$26,721	Dec	2,517	8,452,307	8,454,824	0.99970230
Jan '24	\$21,062	\$3,570	\$0	\$24,632	Jan '24	6,562	11,080,263	11,086,825	0.99940813
Feb	\$18,333	\$2,559	\$0	\$20,892	Feb	0	9,813,218	9,813,218	1.00000000
March	\$16,983	\$0	\$0	\$16,983	March	4,858	9,167,098	9,171,956	0.99947034
April	\$16,899	\$0	\$0	\$16,899	April	3,746	5,858,386	5,862,132	0.99936098
May	\$17,759	\$0	\$0	\$17,759	May	214	3,269,373	3,269,587	0.99993455
June	\$28,118	\$0	\$0	\$28,118	June	188	1,650,337	1,650,525	0.99988610
July	\$31,461	\$2,519	\$0	\$33,980	July	64	1,365,911	1,365,975	0.99995315
Aug	\$21,216	\$1	\$0	\$21,217	Aug	78	1,343,957	1,344,035	0.99994197
Sept	\$20,045	\$164	\$0	\$20,209	Sept	131	1,298,824	1,298,955	0.99989915
Oct	\$19,888	\$11,908	\$0	\$31,796	Oct	580	1,919,174	1,919,754	0.99969788
Nov	\$20,551	\$295	\$0	\$20,846	Nov	1,410	3,515,039	3,516,449	0.99959903
12 Months	\$254,229	\$25,823	\$0	\$280,052	12 Months	20,348	58,733,887	58,754,235	
12 Months -Nov 30, 2025	\$267,393	\$18,511	\$0	\$285,904					(a) TCS Sales Volume x TCS Fixed Cost Storage Component (b) Based on C factor portion of Balancing Service Charge (BSC) x NGS Sales Volume

Exclusions					Allocation Factor Calculation				
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	
Dec	\$24,265	\$0	\$0	\$24,265	Dec	5,641	8,370,023	8,375,664	0.99932650
Jan '25	\$26,692	\$0	\$0	\$26,692	Jan '25	7,232	12,732,406	12,739,638	0.99943232
Feb	\$26,834	\$0	\$0	\$26,834	Feb	3,130	11,718,799	11,721,929	0.99973298
March	\$26,904	(\$2,521)	\$0	\$24,383	March	2,088	10,202,942	10,205,030	0.99979540
April	\$23,562	\$2,756	\$0	\$26,318	April	2,818	5,838,253	5,841,071	0.99951755
May (est)	\$19,225	\$4,171	\$0	\$23,396	May (est)	214	2,808,496	2,808,710	0.99992381
June (est)	\$18,406	\$3,124	\$0	\$21,530	June (est)	188	1,752,480	1,752,668	0.99989273
July (est)	\$19,451	\$1,830	\$0	\$21,281	July (est)	64	1,534,958	1,535,022	0.99995831
Aug (est)	\$18,797	\$1,843	\$0	\$20,640	Aug (est)	78	1,492,605	1,492,683	0.99994775
Sept (est)	\$18,184	\$1,768	\$0	\$19,952	Sept (est)	131	1,553,580	1,553,711	0.99991569
Oct (est)	\$20,998	\$1,941	\$0	\$22,939	Oct (est)	580	2,956,501	2,957,081	0.99980386
Nov (est)	\$24,075	\$3,599	\$0	\$27,674	Nov (est)	1,410	6,233,438	6,234,848	0.99977385
12 Months	\$267,393	\$18,511	\$0	\$285,904	12 Months	23,574	67,194,480	67,218,054	
12 Months -Nov 30, 2026	\$268,339	\$55,504	\$0	\$323,843		23,574	68,973,172	68,996,746	

BSC Revenues

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)	Prior Pd. O/(U) Adjust. Rate (4)	Prior Pd. O/(U) Adjust. Revenue (5) = (1) x (4)	Total Revenues Recovered In Base Rates (6) = (3) + (5)
Dec bef 12/1	4,847,398	\$0.3180	\$1,541,473	\$0.0147	\$71,257	\$1,612,730
Dec aft 12/1	3,604,909	\$0.4605	\$1,660,061	(\$0.0451)	(\$162,581)	\$1,497,480
Jan '24 bef 12/1	-	\$0.3180	\$0	\$0.0147	\$0	\$0
Jan '24 aft 12/1	11,080,263	\$0.4603	\$5,100,245	(\$0.0450)	(\$498,612)	\$4,601,633
Feb	9,813,218	\$0.4605	\$4,518,987	(\$0.0451)	(\$442,576)	\$4,076,411
March	9,167,098	\$0.4560	\$4,180,197	(\$0.0412)	(\$377,684)	\$3,802,513
April	5,858,386	\$0.4498	\$2,635,102	(\$0.0358)	(\$209,730)	\$2,425,372
May	3,269,373	\$0.4498	\$1,470,564	(\$0.0358)	(\$117,044)	\$1,353,520
June	1,650,337	\$0.4498	\$742,322	(\$0.0358)	(\$59,082)	\$683,240
July	1,365,911	\$0.4498	\$614,387	(\$0.0358)	(\$48,900)	\$565,487
Aug	1,343,957	\$0.4498	\$604,512	(\$0.0358)	(\$48,114)	\$556,398
Sept	1,298,824	\$0.4203	\$545,896	(\$0.0360)	(\$46,758)	\$499,138
Oct	1,919,174	\$0.3932	\$754,619	(\$0.0361)	(\$69,282)	\$685,337
Nov	3,515,039	\$0.3932	\$1,382,113	(\$0.0361)	(\$126,893)	\$1,255,220
12 Months	58,733,887		\$25,750,478		(\$2,135,999)	\$23,614,479

BSC Revenues

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)	Prior Pd. O/(U) Adjust. Rate (4)	Prior Pd. O/(U) Adjust. Revenue (5) = (1) x (4)	Total Revenues Recovered In Base Rates (6) = (3) + (5)
Dec bef 12/1	3,871,722	\$0.3932	\$1,522,361	(\$0.0361)	(\$139,769)	\$1,382,592
Dec aft 12/1	4,498,301	\$0.4117	\$1,851,951	(\$0.0227)	(\$102,111)	\$1,749,840
Jan '25 bef 12/1	-	\$0.3932	\$0	(\$0.0361)	\$0	\$0
Jan '25 aft 12/1	12,732,406	\$0.4117	\$5,241,932	(\$0.0227)	(\$289,026)	\$4,952,906
Feb	11,718,799	\$0.4117	\$4,824,630	(\$0.0227)	(\$266,017)	\$4,558,613
March	10,202,942	\$0.4203	\$4,288,297	(\$0.0146)	(\$148,963)	\$4,139,334
April	5,838,253	\$0.4292	\$2,505,778	(\$0.0062)	(\$36,197)	\$2,469,581
May (est)	2,808,496	\$0.4292	\$1,205,406	(\$0.0062)	(\$17,413)	\$1,187,993
June (est)	1,752,480	\$0.4183	\$733,062	(\$0.0061)	(\$10,690)	\$722,372
July (est)	1,534,958	\$0.4073	\$625,188	(\$0.0060)	(\$9,210)	\$615,978
Aug (est)	1,492,605	\$0.4073	\$607,938	(\$0.0060)	(\$8,956)	\$598,982
Sept (est)	1,553,580	\$0.4073	\$632,773	(\$0.0060)	(\$9,321)	\$623,452
Oct (est)	2,956,501	\$0.4073	\$1,204,183	(\$0.0060)	(\$17,739)	\$1,186,444
Nov (est)	6,233,438	\$0.4073	\$2,538,879	(\$0.0060)	(\$37,401)	\$2,501,478
12 Months	67,194,480		\$27,782,378		(\$1,092,813)	\$26,689,565

Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			Cumulative Total (9) = (5)-(8)
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	
Balance	-Nov 30, 2023								\$2,041
Dec bef 12/1						4,847,398	\$0.0000	\$0	\$2,041
Dec aft 12/1	\$0	6.00%	18/12	\$0	\$0	3,604,909	\$0.0000	\$0	\$2,041
Jan '24 bef 12/1						-	\$0.0000	\$0	\$2,041
Jan '24 aft 12/1	\$0	6.00%	17/12	\$0	\$0	11,080,263	\$0.0000	\$0	\$2,041
Feb	\$0	6.00%	16/12	\$0	\$0	9,813,218	\$0.0000	\$0	\$2,041
March	\$0	6.00%	15/12	\$0	\$0	9,167,098	\$0.0000	\$0	\$2,041
April	\$0	6.00%	14/12	\$0	\$0	5,858,386	\$0.0000	\$0	\$2,041
May	\$0	6.00%	13/12	\$0	\$0	3,269,373	\$0.0000	\$0	\$2,041
June	\$0	6.00%	12/12	\$0	\$0	1,650,337	\$0.0000	\$0	\$2,041
July	\$0	6.00%	11/12	\$0	\$0	1,365,911	\$0.0000	\$0	\$2,041
Aug	\$0	6.00%	10/12	\$0	\$0	1,343,957	\$0.0000	\$0	\$2,041
Sept	\$0	6.00%	9/12	\$0	\$0	1,298,824	\$0.0000	\$0	\$2,041
Oct	\$0	6.00%	8/12	\$0	\$0	1,919,174	\$0.0000	\$0	\$2,041
Nov	\$0	6.00%	7/12	\$0	\$0	3,515,039	\$0.0000	\$0	\$2,041
12 Months	\$0			\$0	\$0	58,733,887		\$0	\$0
Balance	at Nov 30, 2024								\$2,041

Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			Cumulative Total (9) = (5)-(8)
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	
Balance	-Nov 30, 2024								\$2,041
Dec bef 12/1						3,871,722	\$0.0000	\$0	\$2,041
Dec aft 12/1	\$0	6.00%	18/12	\$0	\$0	4,498,301	\$0.0000	\$0	\$2,041
Jan '25 bef 12/1						-	\$0.0000	\$0	\$2,041
Jan '25 aft 12/1	\$0	6.00%	17/12	\$0	\$0	12,732,406	\$0.0000	\$0	\$2,041
Feb	\$0	6.00%	16/12	\$0	\$0	11,718,799	\$0.0000	\$0	\$2,041
March	\$0	6.00%	15/12	\$0	\$0	10,202,942	\$0.0000	\$0	\$2,041
April	\$0	6.00%	14/12	\$0	\$0	5,838,253	\$0.0000	\$0	\$2,041
May (est)	\$0	6.00%	13/12	\$0	\$0	2,808,496	\$0.0000	\$0	\$2,041
June (est)	\$0	6.00%	12/12	\$0	\$0	1,752,480	\$0.0000	\$0	\$2,041
July (est)	\$0	6.00%	11/12	\$0	\$0	1,534,958	\$0.0000	\$0	\$2,041
Aug (est)	\$0	6.00%	10/12	\$0	\$0	1,492,605	\$0.0000	\$0	\$2,041
Sept (est)	\$0	6.00%	9/12	\$0	\$0	1,553,580	\$0.0000	\$0	\$2,041
Oct (est)	\$0	6.00%	8/12	\$0	\$0	2,956,501	\$0.0000	\$0	\$2,041
Nov (est)	\$0	6.00%	7/12	\$0	\$0	6,233,438	\$0.0000	\$0	\$2,041
12 Months	\$0			\$0	\$0	67,194,480		\$0	\$0
Balance	at Nov 30, 2025								\$2,041

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)
Balance	-Nov 30, 2025				
Dec (est)	\$2,519,000	\$33,483	\$2,485,517	0.99945689	\$2,484,167
Jan '26 (est)	\$2,519,000	\$37,648	\$2,481,352	0.99945499	\$2,480,000
Feb (est)	\$2,434,000	\$34,737	\$2,399,263	0.99973170	\$2,398,619
March (est)	\$2,519,000	\$34,237	\$2,484,763	0.99978575	\$2,484,231
April (est)	\$2,406,000	\$26,319	\$2,379,681	0.99947509	\$2,378,432
May (est)	\$2,436,000	\$23,430	\$2,412,570	0.99992453	\$2,412,388
June (est)	\$2,406,000	\$21,530	\$2,384,470	0.99989411	\$2,384,217
July (est)	\$2,436,000	\$21,285	\$2,414,715	0.99995890	\$2,414,616
Aug (est)	\$2,436,000	\$20,681	\$2,415,319	0.99994846	\$2,415,195
Sept (est)	\$2,406,000	\$19,872	\$2,386,128	0.99991680	\$2,385,929
Oct (est)	\$2,436,000	\$22,918	\$2,413,082	0.99980611	\$2,412,614
Nov (est)	\$2,489,000	\$27,703	\$2,461,297	0.99977667	\$2,460,747
12 Months	\$29,442,000	\$323,843	\$29,118,157		\$29,111,155

BSC Revenues

Exhibit APD-4 Page 9

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)
Dec bef 12/1 (est)	5,444,150	\$0.4073	\$2,217,402
Dec aft 12/1 (est)	4,936,732	\$0.4221	\$2,083,795
Jan '26 bef 12/1 (est)	-	\$0.4073	\$0
Jan '26 aft 12/1 (est)	13,262,171	\$0.4221	\$5,597,962
Feb (est)	11,662,785	\$0.4221	\$4,922,862
March (est)	9,743,478	\$0.4221	\$4,112,722
April (est)	5,365,672	\$0.4221	\$2,264,850
May (est)	2,835,172	\$0.4221	\$1,196,726
June (est)	1,775,157	\$0.4221	\$749,294
July (est)	1,557,208	\$0.4221	\$657,297
Aug (est)	1,513,355	\$0.4221	\$638,787
Sept (est)	1,574,365	\$0.4221	\$664,539
Oct (est)	2,990,757	\$0.4221	\$1,262,399
Nov (est)	6,312,171	\$0.4221	\$2,664,367
12 Months	68,973,172		\$29,033,002

Month	CC Portion of BSC Revenue	Recoverable Cost of Gas	Current Over/(Under) Collection for Interest (3) = (1) - (2)
	(1)	(2)	
Balance			
-Nov 30, 2025			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	\$4,301,197	\$2,484,167	\$1,817,030
Jan '26 bef 12/1 (est)			
Jan '26 aft 12/1 (est)	\$5,597,962	\$2,480,000	\$3,117,962
Feb (est)	\$4,922,862	\$2,398,619	\$2,524,243
March (est)	\$4,112,722	\$2,484,231	\$1,628,491
April (est)	\$2,264,850	\$2,378,432	(\$113,582)
May (est)	\$1,196,726	\$2,412,388	(\$1,215,662)
June (est)	\$749,294	\$2,384,217	(\$1,634,923)
July (est)	\$657,297	\$2,414,616	(\$1,757,319)
Aug (est)	\$638,787	\$2,415,195	(\$1,776,408)
Sept (est)	\$664,539	\$2,385,929	(\$1,721,390)
Oct (est)	\$1,262,399	\$2,412,614	(\$1,150,215)
Nov (est)	\$2,664,367	\$2,460,747	\$203,620
12 Months	\$29,033,002	\$29,111,155	(\$78,153)

Exhibit APD-5

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street
Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 30, 2025

Effective December 1, 2025

ISSUED BY: DAVID M. VELAZQUEZ - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 3rd Revised Page No. 42

The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

SALES SERVICE COST (SSC) – 1st Revised Page No. 43

The Off-System Sales Sharing Mechanism is extended through November 30, 2028.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 3rd Revised Page No. 46 and 3rd Revised Page No. 47

The Merchant Function Charges are decreased. The Prices to Compare are decreased.

BALANCING SERVICE COSTS (BSC) – 3rd Revised Page No. 48

The Balancing Service Cost is increased.

GAS TRANSPORTATION SERVICE – GENERAL TERMS AND CONDITIONS – 1st Revised Page No. 70

The Balancing Charge is decreased.

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SALES SERVICE COSTS (SSC) - Section 1307(f)

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **\$5.6752** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **\$5.6577** per Mcf for Rate Schedules GC and **\$5.6493** 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 **\$0.6032** 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. (D) (I)

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.

(I) Denotes Increase
(D) Denotes Decrease

PECO Energy Company

"GPC" – Gas Procurement Charge determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

"MFC" – Merchant Function Charge determined to the nearest one hundredth cent (0.01¢) to be charged for each Mcf of Sales Services gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous 1307(f) GCA.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle

"S" projected Mcf of gas to be billed to Customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L & and MV-F during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve month mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F.

"S2" – defined as mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F and for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"Purchased Gas Costs" - Include the direct costs paid by the Company for the purchase and delivery of natural gas (which also includes liquefied natural gas, synthetic natural gas, and natural gas substitutes, excluding propane, the cost of which is included in the Balancing Service Costs) to its system to supply its Customers (plus such portion of the Company's used and unaccounted for gas as the Commission permits), including costs paid under agreements to purchase natural gas from sellers; costs paid for transporting natural gas to its system; all charges, fees, taxes and rates paid in connection with such purchases, pipeline gathering, and transportation; and costs paid for employing futures, options and other risk management tools.

QUARTERLY UPDATES

The Company's rates for recovery of gas costs related to Sales Service are also subject to quarterly adjustments under procedures set forth in Section 1307 (f) of the Public Utility Code and in the Commission's regulations. Such updates shall reflect, adjustments for under or overcollections and, adjustments to the projected cost of gas related to Sales Service based upon more current versions of the same sources of data and using the same methods to project the gas costs related to Sales Service approved by the Commission in the Company's most recent annual proceeding for recovery of gas costs related to Sales Service under section 1307 (f).

OFF-SYSTEM SALES SHARING MECHANISM

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first \$3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over \$3.5 million. Subsequently, effective March 31, 2008 through November 30, 2028 and thereafter, until terminated or otherwise revised by Final Order (C)

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.

(C) Denotes Change

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 **\$0.0265** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **\$0.0090** per Mcf for Rate Schedule GC and at **\$0.0006** 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. (D)

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:

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

"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.

"CCMFC" – 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:

<u>COMPONENT</u>	<u>RATES GR and CAP</u>	
Commodity Charge excluding GPC and MFC	\$5.6127 per Mcf	(D)
Gas Cost Adjustment	\$0.6032 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0265</u> per Mcf	(D)
Price to Compare	\$6.2784 per Mcf	(D)

<u>COMPONENT</u>	<u>RATES GC</u>	
Commodity Charge excluding GPC and MFC	\$5.6127 per Mcf	(D)
Gas Cost Adjustment	\$0.6032 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0090</u> per Mcf	(D)
Price to Compare	\$6.2609 per Mcf	(D)

(I) Denotes Increase

(D) Denotes Decrease

PECO Energy Company

<u>COMPONENT</u>	<u>RATES OL, L and MV-F</u>	
Commodity Charge excluding GPC and MFC	\$5.6127 per Mcf	(D)
Gas Cost Adjustment	\$0.6032 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0006</u> per Mcf	
Price to Compare	\$6.2525 per Mcf	(D)

(I) Denotes Increase

(D) Denotes Decrease

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 **\$0.3791** 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. (I)

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:

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

Projected Balancing Service Costs, so computed, shall be charged to Customers for all gas delivered pursuant to the rate schedules identified above. The amount of those costs, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Balancing Service Costs, per Mcf, pursuant to the formula above, the following definitions shall apply:

"BSC" - Balancing Service Costs determined to the nearest one-hundredth cent (0.01¢) to be charged to each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: for all types of storage and related services, project the cost for the projected period when rates will be in effect.

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1" - defined as the rate associated with "C" effective December 1 of the current PGC period.

"O" - defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by storage and related services revenues less associated storage and related services costs from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

"E" - the net overcollection or undercollection of Balancing Service Costs.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

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

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle.

As otherwise described in the Sales Service Costs section "Off-System Sales Sharing Mechanisms", the portion of margin revenue attributable to certain balancing assets shall be included in the calculation of "E".

Supplier refunds received prior to July 1, 2001 will be included in the calculation of "E" with interest added at the annual rate of six per cent (6%) beginning with the month such refund is received by the Company.

"S" - projected Mcf of gas to be delivered to Customers during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve months of mcf of gas to be delivered to customers.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"S2" - defined as mcf sales delivered to customers for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

Balancing Service Costs - fixed and variable storage costs and the cost of propane to be charged to all customers served under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

QUARTERLY UPDATES

The Company's rates for recovery of Balancing Service Costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code 53.64 (1) (5). Such updates shall reflect adjustments for under or over collections and adjustments to the projected cost of Balancing Services based upon more current versions of the same sources of data and using the same methods to project the Balancing Service Costs approved by the Commission in the Company's most annual proceeding for recovery of Balancing Service Costs under section 1307 (f) of the Public Utility Code.

(I) Denotes Increase

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 **\$0.0203** 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) **(D)**

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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PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street
Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May ~~30~~, 2025

Effective ~~December~~ 1, 2025

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ISSUED BY: DAVID M. VELAZQUEZ - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

Supplement No. 5 to
Gas-Pa. P.U.C. No. 6

Fifth Revised Page No. 1

Supersedes Fourth Revised Page No. 1

PECO Energy Company

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 3rd Revised Page No. 42

The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

SALES SERVICE COST (SSC) – 1st Revised Page No. 43

The Off-System Sales Sharing Mechanism is extended through November 30, 2028.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 3rd Revised Page No. 46 and 3rd Revised Page No. 47

The Merchant Function Charges are decreased. The Prices to Compare are decreased.

BALANCING SERVICE COSTS (BSC) – 3rd Revised Page No. 48

The Balancing Service Cost is increased.

GAS TRANSPORTATION SERVICE – GENERAL TERMS AND CONDITIONS – 1st Revised Page No. 70

The Balancing Charge is decreased.

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SALES SERVICE COSTS (SSC) - Section 1307(f)

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at \$5.6752 per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, \$5.6577 per Mcf for Rate Schedules GC and \$5.6493 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 \$0.6032 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:

$$CC = \frac{(C)}{(S)} \times \frac{1}{(1-T)} + GPC + MFC ; \text{ and}$$

$$GCA = \frac{(E)}{(S)} \times \frac{1}{(1-T)}$$

For March 1, June 1 and September 1 quarterly updates, CC is revised to:

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

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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"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, 2023, and thereafter, until terminated or otherwise revised by Final Order (C)

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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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Issued May 30, 2025

Effective December 1, 2025

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 ~~\$0.0265~~ per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at ~~\$0.0090~~ per Mcf for Rate Schedule GC and at ~~\$0.0006~~ per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2024-3046932. The MFC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC") and shall be updated quarterly in conjunction with the calculation of the CC.

COMPUTATION OF MERCHANT FUNCTION CHARGE

The MFC shall include uncollectible charge-offs incurred by the Company on behalf of its Sales Service customers and calculated for Rate Schedules GR, CAP, GC, OL, L and MV-F. The MFC shall be computed as follows:

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

"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

~~\$5.6127~~ per Mcf (D)
~~\$0.6032~~ per Mcf (I)
 \$0.0360 per Mcf
~~\$0.0265~~ per Mcf (D)
~~\$6.2784~~ per Mcf (D)

COMPONENT

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

RATES GC

~~\$5.6127~~ per Mcf (D)
~~\$0.6032~~ per Mcf (I)
 \$0.0360 per Mcf
~~\$0.0090~~ per Mcf (D)
~~\$6.2609~~ per Mcf (D)

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PECO Energy Company

Supplement No. 5
 Gas-Pa. P.U.C. No. 6
Third Revised Page No. 47
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COMPONENT

RATES OL, L and MV-F

Commodity Charge excluding GPC and MFC	\$ <u>5.6127</u> per Mcf	(D)	
Gas Cost Adjustment	\$ <u>0.6032</u> per Mcf	(I)	
Gas Procurement Charge	\$ <u>0.0360</u> per Mcf		
Merchant Function Charge	\$ <u>0.0006</u> per Mcf		
Price to Compare	\$ <u>6.2525</u> per Mcf	(D)	

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BALANCING SERVICE COSTS (BSC)- Section 1307(f)

PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at **\$0.3791** 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:

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

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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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 \$0.0203 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) **(D)**

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.

(D) Denotes Decrease

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