

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY :
COMMISSION :
 : **Docket No. R-2025-3054868**
v. :
 :
PECO ENERGY COMPANY :

JOINT PETITION FOR COMPLETE SETTLEMENT

TO ADMINISTRATIVE LAW JUDGE F. JOSEPH BRADY:

I. INTRODUCTION

PECO Energy Company (“PECO” or the “Company”) and the Office of Consumer Advocate (“OCA”) (hereinafter referred to individually as “Party” or collectively as “Settling Parties”),¹ hereby submit this Joint Petition for Complete Settlement (“Joint Petition” or “Settlement”)² and respectfully request that:

1. Administrative Law Judge F. Joseph Brady (the “ALJ” or “ALJ Brady”) recommend that the Pennsylvania Public Utility Commission (“Commission”) approve this Settlement and all of its terms and conditions, and that the Commission grant such approval, without modification;

2. ALJ Brady recommend that the Commission authorize PECO to file a tariff supplement to reflect rates and terms consistent with this Settlement applicable to the Section 1307(f) Purchased Gas Cost rate investigation at Docket No. R-2025-3054868 to be effective for

¹ The Philadelphia Area Industrial Energy Users Group (“PAIEUG”), the Commission’s Bureau of Investigation and Enforcement (“I&E”), and the Office of the Small Business Advocate (“OSBA”) also participated in this proceeding and have authorized the Settling Parties to represent their non-opposition to this Joint Petition for Complete Settlement. PAIEUG, I&E, and the OSBA have each indicated they will file a letter of non-opposition to the Settlement.

² PECO’s Statement in Support is attached as Appendix D and the OCA’s Statement in Support is attached as Appendix E.

service rendered on and after December 1, 2025, subject to quarterly adjustments as permitted by the Commission's regulations and that the Commission grant such authorization;

3. Based on the data and testimony submitted in this case, ALJ Brady recommend, and the Commission make, the Findings of Fact and Conclusions of Law proposed at Sections IV and V, respectively, below; and

4. The Commission terminate its investigation at Docket No. R-2025-3054868, including dismissal of the Complaint filed by OCA at Docket No. C-2025-3055065.

II. BACKGROUND

5. On April 30, 2025³, pursuant to 66 Pa. C.S. § 1307(f) and 52 Pa. Code § 53.64, PECO submitted data, as required by the Commission's regulations, in advance of its annual Purchased Gas Cost rate filing ("Advance Filing"). The Advance Filing consisted of Sections 1 through 22, which respond to information requests in the Commission's regulations at 52 Pa. Code § 53.64.

6. On May 5, 2025, I&E entered its appearance in this case.

7. On May 8, 2024, OCA entered its appearance in this case and also filed a Formal Complaint and Public Statement (Docket No. C-2025-3055065).

8. On May 27, 2024, PAIEUG filed a Petition to Intervene, which was unopposed, and which ALJ Brady granted during the telephonic pre-hearing conference on June 24, 2025.

9. On May 28, 2025, OSBA entered its appearance in this case.

10. On May 30, 2025, PECO filed its Purchased Gas Cost No. 42 rate to become effective for service rendered on and after December 1, 2025 ("PGC 42 Filing"). PECO made the

³ The Advance Information was filed on April 30, 2025. However, due to issues during the e-filing process, it was refiled with proper formatting on May 2, 2025.

PGC 42 Filing pursuant to 66 Pa. C.S. § 1307(f), which authorizes certain natural gas distribution companies to make annual purchased gas cost filings with the Commission to reflect increases or decreases in their natural gas costs. Pursuant to 66 Pa. C.S. § 1307(f)(3), the Company's PGC 42 Filing included a reconciliation of expenses previously incurred and revenues received. In support of its PGC 42 Filing, PECO submitted supporting data and information, including the Direct Testimony of witnesses: Suzette E. Adams (PECO Statement No. 1); Scott J. Hughes (PECO Statement No. 2); Blerina Gaba-Teme (PECO Statement No. 3); and Anthony P. DiFelice (PECO Statement No. 4), along with accompanying exhibits.

11. As required by 52 Pa. Code § 53.68, PECO provided public notice of the proposed PGC No. 42 rate through bill inserts and newspaper publications in PECO's service territory.

12. On June 19, 2025, the Company filed updated Sections 15, 16, 17, and 22, as well as the updated testimony of Suzette E. Adams.

13. On June 24, 2025, a telephonic prehearing conference was held before ALJ Brady whereby the Parties agreed to a procedural schedule for the submission of further written testimony and conducting evidentiary hearings, as set forth in the Prehearing Order, which ALJ Brady issued on June 30, 2025.

14. The Parties engaged in discovery issued by OCA and I&E. PECO responded to multiple formal, written data requests, many with multiple subparts, and also responded to informal data and information requests.

15. On July 8, 2025, OCA filed the Direct Testimony of Jerome D. Mierzwa (OCA Statement No. 1).

16. No other party filed any direct testimony.

17. The Settling Parties were able to reach a settlement to resolve all issues in this proceeding on or about July 15, 2025. As part of the Settlement, the Settling Parties agreed to waive cross-examination of all witnesses and to move for the admission of testimony and exhibits by stipulation, as set forth in Paragraph 26, *infra*.

III. SETTLEMENT

The terms of the Settlement are as follows:

18. **Purchased Gas Cost Rates**

(a) Attached as Appendix A to this Joint Petition are the rates and underlying cost data resulting from the Settlement that are applicable to the Commodity Charge (“CC”), the Gas Cost Adjustment Charge (“GCA”), the Balancing Charge (“BC”), and the Balancing Service Charge (“BSC”). These rates are predicated on the Company’s current gas cost projections and are the same as originally filed in this proceeding, with the BC updated to reflect the value from Paragraph 19(b) of the Joint Petition. To the extent that actual experience and changes in forecasted natural gas prices and demand would alter the CC, GCA and the BSC rates, PECO reserves the right to file quarterly adjustments to be effective September 1, 2025, December 1, 2025, and thereafter in accordance with 52 Pa. Code § 53.64.⁴

(b) PECO reserves the right to update the Rate Transportation Service-Firm (“TS-F”) standby sales service demand charge, as shown in Appendix A, Exhibit APD-1, to be effective December 1, 2025, to the extent that actual experience and changes in forecasted natural gas prices and demand may alter these rates.

⁴ Pursuant to the terms of the settlement of the Company’s gas base rate case at Docket No. R-2008-2028394 (the “2008 Gas Base Rate Case”), the BC may be updated and revised only as part of PECO’s annual PGC filing.

19. Balancing Charge Rate

(a) Under the terms of the 2008 Gas Base Rate Case Settlement, PECO is required to update the BC as part of its annual Section 1307(f) filing. As set forth on Page 3 of PECO Statement No. 3, the Direct Testimony of Blerina Gaba-Teme in the PGC 42 Filing (and also included in Appendix A), PECO proposed two BC options: the first option was \$0.0203 per MCF. The second option was \$0.0229 per Mcf. Both options had a proposed effective date of December 1, 2025. The second option was included as part of PECO's commitment to investigate the feasibility of including applicable fixed storage costs in the calculation of the High Volume Transportation ("HVT") BC. (PECO St. No. 3, p. 3).

(b) The Settling Parties have agreed to adopt the second of PECO's as-filed BC options. Accordingly, the BC, effective December 1, 2025, will be \$0.0229 per Mcf. The associated tariff pages are included in Appendix A.

20. Retainage Rate

(a) In accordance with Paragraph 19 of the 2024 Joint Petition for Complete Settlement,⁵ the retainage volume adjustment for transportation service customers for the 12 months beginning December 1, 2024 and ending November 30, 2025 is 3.4%, which was calculated based on the weighted three-year average of LUGF plus the portion of Company-use gas attributable to preheater gate station usage for the period ending June 30, 2024.

(b) PECO also agreed that the retainage volume adjustment for the twelve-month period ending November 30, 2026 would be calculated based on the weighted three-

⁵ See *Pennsylvania Pub. Util. Comm'n. v. PECO Energy Co.*, Docket No. R-2024-3048767, Order Adopting Joint Petition for Complete Settlement, dated October 10, 2024 (hereinafter referred to as the "2024 Joint Petition").

year average of LUG plus the portion of Company-use natural gas attributable to preheater gate station usage for the period ending June 30, 2025.

(c) The Settling Parties have agreed to adopt the retainage rate of 3.3%, which was calculated in accordance with the requirements in the 2024 Joint Petition (as shown below), for the period ending November 30, 2026. Attached as Appendix B are the associated tariff pages.

Adjusted Retainage Calculation for 2025 PGC - Pre-Heater Company Use Added Back In				
	Sendout in MCF + Pre- Heater Fuel	Billed Sales in MCF	Retainage Rate	Pre-Heater Company Use
36 months ending 6/30/2025	244,344,775	236,332,255	3.3%	311,265

21. Gas Price Hedging

(a) PECO has complied with the terms of the Ratable Hedging Program for all hedges made through April 2025 and will continue to do so. Pursuant to the Ratable Hedging Program’s execution schedule and since the Company’s reporting in last year’s PGC proceeding, PECO issued Requests for Proposals (“RFPs”) for six execution periods through March 2025 (these periods appear in yellow highlight in Exhibit SJH-1 accompanying PECO Statement No. 2, the Direct Testimony of Scott J. Hughes, in the PGC 42 Filing, whereas those periods highlighted in blue reflect the same information as reported in prior years’ PGC proceedings). PECO entered into transactions with the respondents who could provide supply at the lowest cost for the specified volumes on a fixed price basis.⁶ For the period April 2024 through March 2025, PECO purchased 5.44 MMDth of hedged gas under the program at a weighted

⁶ There is an execution period shown on Exhibit SJH-1 highlighted in grey. This simply reflects that for the Year 6 Summer, August 2020, execution period, PECO did not receive the requisite three respondents to its RFP, and therefore did not make the hedges for that period. The additional dark grey highlighting indicates summer months during which PECO no longer hedges gas.

average cost of \$4.4792 per Dth as reflected in the table below (*see* Table SJH-1 in PECO Statement No. 2, the Direct Testimony of Scott J. Hughes, in the PGC 42 Filing).

(b) Accordingly, PECO’s purchases under the Ratable Hedging Program through March 2025 have been in compliance with the Ratable Hedging Program execution schedule.

Ratable Hedging Program Executed Hedges April 2023 through March 2024			
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

(c) In the PGC 42 Filing, PECO requested that the Ratable Hedging Program, as modified in the 2020 Joint Petition, be extended for an additional year, ⁷ whereby hedging associated with summer purchases was eliminated on a going forward basis. Extending the program for an additional year (“Year 12”) will add Winter periods with volumes at the same bifurcated volumetric level, and with execution periods similar to those used in prior years.

(d) Specifically, the Settling Parties have agreed to extend the Ratable Hedging program for an additional year, which will continue with the current winter hedging schedule of 36,000 Dth/day.

(e) The revised Ratable Hedging Program execution schedule is attached as Appendix C.

⁷ See *Pennsylvania Pub. Util. Comm’n. v. PECO Energy Co.*, Docket No. R-2020-019661, Order Adopting Joint Petition for Complete Settlement, dated October 8, 2020 (hereinafter referred to as the “2020 Joint Petition”).

22. Renewable Natural Gas (“RNG”)

(a) PECO will continue pursuing reliable sources of RNG supply via interconnections with RNG producers to bring RNG onto PECO’s gas system.

(b) Should PECO acquire RNG, it will do so in a manner that is consistent with its least-cost procurement strategy for natural gas, *e.g.*, it will pursue the least cost RNG, and will undertake commercially reasonable efforts to minimize the cost impact to PECO’s PGC customers from the costs associated with purchasing RNG.

23. Lost And Unaccounted for Gas (“LUFG”) Monitoring And Reporting

While no further LUFG reporting obligations are required, consistent with its reporting in prior PGC proceedings, in the PGC 41 Filing PECO has voluntarily reported a three-year weighted average for the periods ending March 31, 2025 and June 30, 2025, consistent with the previous reporting mechanism set forth in the 2015 Joint Petition for Complete Settlement.⁸

PECO LUFG Calculation 2023-2025 PGC (3-Year Average)

	<u>Sendout in Mcf</u>	<u>Billed Sales in Mcf</u>	<u>LUFG</u>
<u>12 Months Ending 3/31/23</u>	<u>86,824,606</u>	<u>84,280,413</u>	<u>2.9%</u>
<u>12 Months Ending 3/31/24</u>	<u>84,316,700</u>	<u>84,592,318</u>	<u>2.0%</u>
<u>12 Months Ending 3/31/25</u>	<u>90,830,021</u>	<u>87,215,379</u>	<u>4.0%</u>
<u>36 Months Ending 3/31/25</u>	<u>261,971,327</u>	<u>254,088,109</u>	<u>3.0%</u>

	<u>Sendout in Mcf</u>	<u>Billed Sales in Mcf</u>	<u>LUFG</u>
<u>12 Months Ending 6/30/23</u>	<u>84,884,281</u>	<u>82,956,376</u>	<u>2.3%</u>
<u>12 Months Ending 6/30/24</u>	<u>84,814,048</u>	<u>81,832,437</u>	<u>3.5%</u>
<u>12 Months Ending 6/30/25</u>	<u>91,328,455</u>	<u>88,387,625</u>	<u>3.2%</u>
<u>36 Months Ending 6/30/25</u>	<u>261,026,784</u>	<u>253,176,438</u>	<u>3.0%</u>

⁸ See *Pennsylvania Pub. Util. Comm’n. v. PECO Energy Co.*, Docket No. R-2015-2480969, Order Adopting Joint Petition for Complete Settlement, dated October 22, 2015 (hereinafter referred to as the “2015 Joint Petition”).

24. Off-System Sales/Capacity Release Sharing

Pursuant to the 2024 Joint Petition, the off-system sharing mechanism was extended at the 25% rate through November 30, 2027. In the instant proceeding, the Settling Parties agree that PECO will further extend the off-system sharing mechanism through November 30, 2028.

25. Interest Rate for Over- and Under-Collections

In compliance with Paragraph 24(b) of the 2017 Joint Petition for Complete Settlement,⁹ PECO applied the prime rate in effect sixty (60) days prior to the annual PGC filing date to the monthly over- and under-collections for the PGC period December 1, 2024 through November 30, 2025. Going forward, as previously agreed, PECO will use the prime rate for commercial borrowing in effect 60 days prior to the annual PGC filing (which occurs on or before June 1 of each year) to determine interest on the monthly over- and under-collections through November 30 of the year in which the PGC filing is made.

26. Admission of Evidence

The Parties agree to waive cross-examination of each other's witnesses and that the testimony and exhibits identified in sections (a) and (b) below may be admitted into evidence by stipulation and motion. To that end, the Parties have prepared, and are filing, a separate Motion, with attached Stipulation, requesting that ALJ Brady admit such testimony and exhibits into the record:

(a) PECO's Advance Filing consisting of Sections 1-22, which was filed with the Commission and served on April 30, 2025, as explained in Paragraph No. 5, *supra*;

⁹ See *Pennsylvania Pub. Util. Comm'n. v. PECO Energy Co.*, Docket No. R-2017-2602611, Order Adopting Joint Petition for Complete Settlement, dated October 5, 2017 (hereinafter referred to as the "2017 Joint Petition").

(b) PECO Statement Nos. 1, 2, 3, and 4 with accompanying Exhibits (SJH-1; BGT-1 through BGT-3; and APD-1 through APD-5), which were filed with the Commission and served on May 30, 2025, as explained in Paragraph No. 10, *supra*;

(c) PECO's Updated Sections 15, 16, 17, and 22 and updated testimony of Suzette E. Adams, which were filed with the Commission and served on June 19, 2025, as explained in Paragraph No. 12, *supra*; and

(d) OCA Statement No. 1, which was served on July 8, 2025, as explained in Paragraph No. 15, *supra*.

IV. PROPOSED FINDINGS OF FACT

As a consequence of the Settlement terms and conditions set forth in Section III above and supported by the PGC 42 Filing, exhibits and testimony submitted for admission in the record, the Settling Parties request that the ALJ and the Commission make the following findings of fact and such other findings and conclusions as may be required or appropriate:

27. PECO operates a natural gas distribution system in the southeastern portion of Pennsylvania subject to the jurisdiction of the Commission. (PECO St. 1, p. 3).

28. PECO's gas purchasing policy is designed to achieve a reasonable balance of long and short-term gas purchases that assures system supply reliability at the least cost. (PECO St. 1, p. 7).

29. The details of PECO's actual gas purchases for the twelve months ending March 31, 2025 are presented in Section 1 of PECO's Advance Filing. (PECO Adv. Filing § 1).

30. PECO receives almost all of its gas supply directly into its distribution system from Texas Eastern Transmission, LP ("Texas Eastern"), Transcontinental Gas Pipe Line Corporation ("Transco"), Adelphia Gateway, and Eastern Shore Natural Gas Company. (PECO St. 1, p. 4). Evidence of record shows that firm transportation contracts with these pipelines

provide PECO the ability to purchase gas supplies directly from producers and marketers and to use firm transportation capacity on the pipelines for delivery of the gas to PECO. (PECO St. 1, pp. 4, 7-8; PECO Adv. Filing §§ 2, 3 and 8). PECO also obtains natural gas storage services from Eastern Gas Transmission and Storage, Inc., Texas Eastern, and Transco. (PECO St. 1, p. 4). Evidence of record shows that PECO has purchased all of its requirements on competitive terms. (PECO St. 1, pp. 8-11).

31. PECO participated in significant rulemaking, rate and certificate proceedings before the Federal Energy Regulatory Commission (“FERC”) concerning interstate natural gas pipeline company rates and conditions of service that affect its costs and, therefore, its customers’ costs. PECO also participated in major FERC proceedings of the interstate pipelines from which it receives transportation and storage service. (PECO Adv. Filing § 5). PECO’s efforts in this regard directly reduced costs for its PGC customers (PECO St. 3, pp. 9-11).

32. In the past year, PECO renewed several storage and transportation service agreements, after conducting a process for competitive alternatives (PECO St. 3, pp. 6-8).

33. PECO continued to review pipeline open seasons and capacity to determine whether participation in a project could help PECO meet its projections for increased firm demand or offer a reliable least-cost alternative to an existing transportation or storage contract nearing expiration. (PECO St. 3, p. 9).

34. During the historic period, PECO did not purchase natural gas from any affiliated interest. (PECO St. 1, p. 5).

35. PECO did not withhold supplies or capacity from the market. (PECO St. 1, p. 5).

36. Projected natural gas costs, as reflected in this Settlement, are based on peak-day capacity requirements at a 0-degree design day temperature, as fully set forth in the record. (PECO Adv. Filing § 16; PECO St. 1, p. 7).

V. PROPOSED CONCLUSIONS OF LAW

37. This proceeding is a consolidation of two reviews that the Commission is required to undertake pursuant to Sections 1307(f) and 1318 of the Public Utility Code (66 Pa. C.S. §§ 1307(f) and 1318) (hereinafter, Section 1307(f) and Section 1318, respectively). Specifically, under Section 1307(f), the Commission must determine whether PECO met the standards of Section 1318 with regard to the natural gas costs PECO incurred during an historic twelve-month period. In addition, because PECO filed a tariff proposing a new rate reflecting a change in its natural gas costs, the Commission must determine whether the specific findings of Section 1318 can be made with regard to the period that rates will be in effect (the “Application Period”). This finding is a condition precedent to the Commission’s approval of PECO’s proposed rates. *See* 66 Pa. C.S. § 1318. The provisions of Section 1318(a) are applicable to all gas utilities that recover their natural gas costs pursuant to Section 1307(f).

(a) Historic Reconciliation Period Standards

(i) With respect to PECO’s natural gas purchases and purchasing practices during the twelve-month historic reconciliation period ended March 31, 2025, it is requested that the Commission find that PECO met the standards set out in Section 1318 and required by Section 1307(f)(5) as to all actual purchased natural gas costs in the historic period. It is also requested that the Commission find, pursuant to Section 1307(f)(5) and based upon the evidence presented in this case, that during the twelve months ended March 31, 2025 (1) PECO met the requirements of Section 1318(a) by pursuing a least-cost fuel procurement policy, consistent with its obligation to provide safe, adequate and reliable service to its customers; and

(2) PECO met the requirements of Section 1318(b) relating to its purchases of natural gas, transportation services and storage services from affiliates.

(b) Projected and Interim Period Findings

(i) With respect to the twelve-month period beginning December 1, 2025, which is when the proposed rates agreed to by the Settling Parties in this Settlement would be in effect, it is requested that the Commission make the findings concerning PECO's natural gas purchasing policies and practices required by Section 1318, including those in subsections (a)(1) through (a)(4) and (b)(1) through (b)(3) thereof, based upon information presently available and the evidence of record in this proceeding.

(ii) The Settling Parties agree that PECO's projected natural gas purchases and projected natural gas purchasing policies will comply with the standards of Section 1318 and that their assessment is supported by the evidence of record in this proceeding relating to such projected purchases and natural gas purchasing policies. Nevertheless, it is expressly understood and agreed that the findings relating to the rate to become effective December 1, 2025 are made solely for the purpose of setting prospective rates that shall be subject to the standards of Section 1318 and to further review in an appropriate future proceeding. Paragraph 36(b) of the Joint Petition is not intended to limit or prevent in any way present or future complainants from reviewing, after such projected natural gas purchases actually have been made and natural gas purchasing practices actually have been implemented, whether PECO's natural gas purchases and natural gas purchasing practices have, in fact, complied with the standards of Section 1318. If, in an appropriate future proceeding, natural gas purchases and natural gas purchasing practices relating to the period December 1, 2025 through November 30, 2026 are challenged, the Commission's findings in this Paragraph 36(b) of the Joint Petition shall pose no bar to the

examination of such purchases and practices including, but not limited to, disallowance of, or reductions to, such costs during the one-year period commencing December 1, 2024.

(iii) The Settling Parties agree that future examination of the natural gas costs relating to the period April 1, 2025 through November 30, 2026 shall be permitted to determine whether PECO's experienced and projected natural gas purchases and natural gas purchasing practices complied with the standards set forth in Section 1318 and the terms of prior settlements, and that the Commission's adoption of the findings under this Paragraph 36(b) of the Joint Petition shall not be construed to limit or prevent any disallowance or reduction of such costs that are otherwise permitted.

VI. CONDITIONS OF SETTLEMENT

38. The Settling Parties acknowledge and agree that this Settlement shall have the same force and effect as if the Parties fully litigated this proceeding.

39. This Settlement is conditioned upon the Commission's approval of terms and conditions contained herein without modification. If the Commission modifies the Settlement, any Party may elect to withdraw from this Settlement and may proceed with litigation, and, in such event, this Settlement shall be void and of no effect. Such election to withdraw must be made in writing, filed with the Secretary of the Commission and served upon all Parties within five (5) business days after the entry of an order modifying the Settlement. This Settlement is proposed by the Settling Parties to settle all issues in the instant proceeding and is made without any admission against, or prejudice to, any position that any Party to this Settlement may adopt during any subsequent litigation of this or any other proceeding.

40. If the Commission does not approve the Settlement and the proceedings continue to hearing, the Parties reserve their respective rights to present additional testimony and to conduct full cross-examination, briefing and argument.

41. The Commission's approval of this Settlement shall not be construed to represent approval of any Party's position on any issue, except to the extent required to effectuate the terms and agreements of this Settlement, in this and future proceedings.

42. It is understood and agreed among the Settling Parties that this Settlement is the result of compromises and does not necessarily represent the position(s) that would be advanced by any Party if this proceeding were fully litigated.

43. This Settlement is being presented only in the context of this Section 1307(f) proceeding in an effort to resolve outstanding issues in a manner that is fair and reasonable. The Settlement is the product of compromise. With the exception of matters identified in Sections III and IV as they relate to this proceeding and for the specific time periods set forth therein should the Commission approve this Settlement without modification, this Settlement is presented without prejudice to any position which any of the Parties may have advanced and without prejudice to the position any of the Parties may advance in the future on the merits of the issues.

44. The Settling Parties prepared and attached to this Settlement, as Appendices D-G respectively, statements in support setting forth the bases upon which they believe the Settlement is fair, just and reasonable and is, therefore, in the public interest.

WHEREFORE, the Settling Parties, by their respective counsel, respectfully request that Administrative Law Judge F. Joseph Brady and the Commission approve this Settlement, including all terms and conditions thereof, and that the Commission enter an order consistent with this Settlement resolving and terminating the proceeding and resolving all outstanding complaints.

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Counsel for PECO Energy Company

Dated: August 6, 2025

APPENDIX A

**Rates and Cost Data Applicable To
The Commodity Charge (“CC”),
The Gas Cost Adjustment Charge (“GCA”),
The Balancing Service Charge (“BSC”) and
The Balancing Charge (“BC”)**

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 Rates	Change in Rates	<u>12/01/25</u> Unbundled Rates	
<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	\$0.0004	\$0.0229 (a)	

(a) updated to reflect Joint Petition for Settlement value for Balancing Charge

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

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			

Month	Exclusions						
	cost of cgs gas (a)	Cost of Reg IS Cust. Gas (a)	Cost of Indtpt. IS Gas (a)	Cost of TCS Gas (b)	Cost of MV-I Gas (a)	Rate NGS Exclusion (c)	Total Exclusions (7)
	(1)	(2)	(3)	(4)	(5)	(6)	(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

Month	Allocation Factor Calculation				
	Interdept. Firm Mcf	CC Sales Mcf	Total Applicable Sales Mcf	Allocation Factor	GCA Sales Mcf
	(1)	(2)	(3) = (1) + (2)	(4) = (2)/(3)	(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

Month	Exclusions						
	cost of cgs gas (a)	Cost of Reg IS Cust. Gas (a)	Cost of Indtpt. IS Gas (a)	Cost of TCS Gas (b)	Cost of MV-I Gas (a)	Rate NGS Exclusion (c)	Total Exclusions (7)
	(1)	(2)	(3)	(4)	(5)	(6)	(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

Month	Allocation Factor Calculation				
	Interdept. Firm Mcf	CC Sales Mcf	Total Applicable Sales Mcf	Allocation Factor	GCA Sales Mcf
	(1)	(2)	(3) = (1) + (2)	(4) = (2)/(3)	(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	0.99995831	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	Commodity Cost/Mcf	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	IS Profit Return Rate	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
	(1)	(2)	(3)	(1)-(2)-(3)	(5)	(6)	(5) x (6)	(8) - (7)	(8) x 0% (a)	(10)	(11)	(10) x (11)	(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	Commodity Cost/Mcf	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	IS Profit Return Rate	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
	(1)	(2)	(3)	(1)-(2)-(3)	(5)	(6)	(5) x (6)	(8) - (7)	(8) x 0% (a)	(10)	(11)	(10) x (11)	(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 - Nov. 30, 2023				(\$1,311)
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

Page 7

Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2024				(\$1,311)
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

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

Exclusions				
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)
Dec	\$21,914	\$4,807	\$0	\$26,721
Jan '24	\$21,062	\$3,570	\$0	\$24,632
Feb	\$18,333	\$2,559	\$0	\$20,892
March	\$16,983	\$0	\$0	\$16,983
April	\$16,899	\$0	\$0	\$16,899
May	\$17,759	\$0	\$0	\$17,759
June	\$28,118	\$0	\$0	\$28,118
July	\$31,461	\$2,519	\$0	\$33,980
Aug	\$21,216	\$1	\$0	\$21,217
Sept	\$20,045	\$164	\$0	\$20,209
Oct	\$19,888	\$11,908	\$0	\$31,796
Nov	\$20,551	\$295	\$0	\$20,846
12 Months	\$254,229	\$25,823	\$0	\$280,052
12 Months -Nov 30, 2025	\$267,393	\$18,511	\$0	\$285,904

Allocation Factor Calculation				
Month	Interdept. Firm Mef (1)	BSC Sales Mef (2)	Total Applicable Sales Mef (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	2,517	8,452,307	8,454,824	0.99970230
Jan '24	6,562	11,080,263	11,086,825	0.99940813
Feb	0	9,813,218	9,813,218	1.00000000
March	4,858	9,167,098	9,171,956	0.99947034
April	3,746	5,858,386	5,862,132	0.99936098
May	214	3,269,373	3,269,587	0.99993455
June	188	1,650,337	1,650,525	0.99988610
July	64	1,365,911	1,365,975	0.99995315
Aug	78	1,343,957	1,344,035	0.99994197
Sept	131	1,298,824	1,298,955	0.99989915
Oct	580	1,919,174	1,919,754	0.99969788
Nov	1,410	3,515,039	3,516,449	0.99959903
12 Months	20,348	58,733,887	58,754,235	
12 Months -Nov 30, 2025				(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				
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)
Dec	\$24,265	\$0	\$0	\$24,265
Jan '25	\$26,692	\$0	\$0	\$26,692
Feb	\$26,834	\$0	\$0	\$26,834
March	\$26,904	(\$2,521)	\$0	\$24,383
April	\$23,562	\$2,756	\$0	\$26,318
May (est)	\$19,225	\$4,171	\$0	\$23,396
June (est)	\$18,406	\$3,124	\$0	\$21,530
July (est)	\$19,451	\$1,830	\$0	\$21,281
Aug (est)	\$18,797	\$1,843	\$0	\$20,640
Sept (est)	\$18,184	\$1,768	\$0	\$19,952
Oct (est)	\$20,998	\$1,941	\$0	\$22,939
Nov (est)	\$24,075	\$3,599	\$0	\$27,674
12 Months	\$267,393	\$18,511	\$0	\$285,904
12 Months -Nov 30, 2026	\$268,339	\$55,504	\$0	\$323,843

Allocation Factor Calculation				
Month	Interdept. Firm Mef (1)	BSC Sales Mef (2)	Total Applicable Sales Mef (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	5,641	8,370,023	8,375,664	0.99932650
Jan '25	7,232	12,732,406	12,739,638	0.99943232
Feb	3,130	11,718,799	11,721,929	0.99973298
March	2,088	10,202,942	10,205,030	0.99979540
April	2,818	5,838,253	5,841,071	0.99951755
May (est)	214	2,808,496	2,808,710	0.99992381
June (est)	188	1,752,480	1,752,668	0.99989273
July (est)	64	1,534,958	1,535,022	0.99995831
Aug (est)	78	1,492,605	1,492,683	0.99994775
Sept (est)	131	1,553,580	1,553,711	0.99991569
Oct (est)	580	2,956,501	2,957,081	0.99980386
Nov (est)	1,410	6,233,438	6,234,848	0.99977385
12 Months	23,574	67,194,480	67,218,054	
12 Months -Nov 30, 2026	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	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

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	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

Interest on Revenues to be Returned to Customers

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)

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

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 **\$0.0229** 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) (I)

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.

(I) Denotes Increase

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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 **\$0.0229** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. (U) 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)

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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.

(U) Denotes Increase

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APPENDIX B

Pro Forma Tariff Pages

Retainage Volume Adjustment Rate

PECO Energy Company

Natural Gas Supplier Coordination Tariff – The Tariff, setting forth the basic requirements for interactions and coordination between the Company, as the natural gas distribution company, and Suppliers necessary for maintaining the delivery of Competitive Natural Gas Supply from Suppliers to their Low Volume Transportation Customers under the Company’s Gas Choice program.

Principal Office - The Company’s Main Office Building located at 2301 Market Street, Philadelphia, Pa. 19103.

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

Sales Service Cost (“SSC”) - Cost of commodity and non-storage interstate pipeline firm transportation capacity to delivery such commodity to the city gate for Low Volume Sales Customers.

Rate - The rates are CAP, GR, GC, OL, L, MV-F, MV-I, IS, TCS, TS-I, TS-F, and NGS or the successors thereto.

Separate NGS Billing (“Dual Billing”) – Separate Billing by an NGS of its charges for gas supply service.

Service - The distribution of gas for use by the Customer, including all things done by the Company in connection with such distribution.

Service-Supply Pipe - The pipe extending from the Company’s supply main to a metered delivery point or, in the case of installations comprised exclusively of outdoor gas lights, to the first such light.

Summary Billing Accounts - An aggregate bill prepared at the option of the Company for Customers with multiple accounts that are related within the same partnership, association, corporation or governmental agency.

Supplier of Last Resort Service (“SLR Service” or “Sales Service”) - Natural gas supply service provided by the Company as supplier-of-last-resort to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order (“SMO”) – operational directive issued by the Company in its sole discretion to protect the operational integrity of its systems in terms of line pressure and adequacy of supply, which orders directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer’s natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company’s system.

Tariff – This Gas Service Tariff comprising the rates, rules and regulations that apply to the distribution of natural gas, including all things done by the Company in connection with such distribution and/or the supply of natural gas under Supplier of Last Resort (Sales) Service.

Transportation Service – Natural gas supply service provided to HVT Customers, by an alternative Natural Gas Supplier as further detailed in Rule 1.1 of the Gas Transportation Service General Terms and Conditions Section of this Tariff.

Variable Distribution Service Charge – The variable charges on a Mcf basis for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

Volume Adjustment - the current adjustable factor applied to all rate classes to account for: a) reduction for system losses of 3.3% **(D)** and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company’s system by a reference Btu content of 1,000 Btu per cubic foot.

(D) Denotes Decrease

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and Rate TS-F Gas Transportation Service-Firm.)

1. TRANSPORTATION SERVICE

1.1 GENERAL. Transportation service shall consist of: the receipt of gas on behalf of a Customer; the transportation of gas through the Company's distribution facilities, and the delivery of equivalent quantities of gas to the Customer, adjusted for thermal correction and system losses where applicable.

Transportation service may also include Standby Sales Service to permit purchases of gas under one of the Company's retail sales rate schedules.

1.2 TERMS DEFINED. The following definitions shall apply throughout the transportation portion of this tariff:

RECEIVED/RECEIPT shall refer to gas tendered to the Company for the Customer's account at one or more of the interconnections between the Company and its interstate pipeline suppliers, or other specified location. The normal unit of measurement is the dekatherm or mmBtu.

DELIVERED/DELIVERY shall refer to gas tendered to the Customer by the Company at the Customer's specified location. The normal unit of measurement is the Mcf.

USE/USAGE shall refer to gas actually consumed by the Customer at the specified location as measured by the Company's meter in Mcf.

DEFICIENT DELIVERIES shall refer to occurrences in which the Customer uses more gas than the quantity of transportation gas tendered by the Company for delivery.

EXCESS DELIVERIES shall refer to occurrences in which the Customer uses less than the quantity of gas tendered by the Company for delivery.

1.3 VOLUME ADJUSTMENT. The quantity of transportation gas received into the Company's distribution system for the Customer's account shall be: (a) reduced by 3.3% for system losses; and (b) adjusted for thermal correction determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. Where the transported gas can be delivered directly to the Customer without commingling with other system supplies, no reduction for system losses shall be made, and the thermal correction shall be based on the daily average Btu content of the pipeline to which the Customer is directly connected. (D)

1.4 SUPPLY COST ADJUSTMENT. If the Company incurs any added gas supply cost in order to provide transportation service by displacement, or for other reasons, such additional cost will be charged to the Customer. Displacement occurs when a Customer, who is directly connected to one of the Company's pipeline suppliers, arranges for receipt of transportation gas on another pipeline to which the Customer is not directly connected. Revenues received by the Company in payment for added gas supply cost will be credited to firm sales Customers through the annual Sales Service Costs reconciliation (Section 1307[f]).

1.5 SERVICE AGREEMENT. The Customer will be required to execute a Transportation Service Agreement which will specify an initial Transportation Contract Quantity (TCQ) to be the maximum daily volume of gas, expressed in Mcf net of system losses where applicable, to be transported and delivered to the Customer. The agreement will also specify delivery locations, the election of Standby Sales Service, the commodity charge to be in effect for the term of the agreement, and any special provisions for service. The standard term for a Transportation Service Agreement shall be twelve months, unless the Company and the Customer agree to a shorter or longer term.

The TCQ shall not exceed the lower of (a) the capacity of the Company's metering and regulating equipment at the Customer's location; or (b) 110% of the maximum daily usage of the Customer during the twelve-month period prior to the execution of the Transportation Service Agreement, unless full documentation of new or additional gas usage capability is provided by the Customer. If a Customer chooses to designate an Agent to act on the Customer's behalf for scheduling, dispatching, billing and other administrative aspects of transportation service, such designation shall be made in the Transportation Service Agreement. The designation of an Agent shall not relieve the Customer of ultimate responsibility for payment for service or other obligations incurred under this tariff.

Every November 1 following execution of the Transportation Service Agreement, the Customer's TCQ shall be automatically adjusted by the Company to be 110% of the maximum daily usage of the Customer during the prior twelve-month period if such adjustment would raise or lower the customer TCQ by the higher of either 10 mcf or 10%. The TCQ may also be adjusted by mutual agreement of the Customer and the Company.

(Continued)

(D) Denotes Decrease

Supplier of Last Resort Service (“SLR” or “Sales Service”) - Natural gas supply service provided by the Company to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order (“SMO”) - operational directives issued by the Company in its sole discretion to protect the operational integrity of its system in terms of line pressure and adequacy of supply, which orders will directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer’s natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company’s system

Tariff - this Natural Gas Supplier Coordination Tariff.

Volume Adjustment - the current adjustable factor applied to all rate classes to account

for: a) reduction for system losses of 3.3%; and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company’s system by a reference Btu content of 1,000 Btu per cubic foot.

(D)

(D) Denotes Decrease

PECO Energy Company

Natural Gas Supplier Coordination Tariff – The Tariff, setting forth the basic requirements for interactions and coordination between the Company, as the natural gas distribution company, and Suppliers necessary for maintaining the delivery of Competitive Natural Gas Supply from Suppliers to their Low Volume Transportation Customers under the Company’s Gas Choice program.

Principal Office - The Company’s Main Office Building located at 2301 Market Street, Philadelphia, Pa. 19103.

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

Sales Service Cost (“SSC”) - Cost of commodity and non-storage interstate pipeline firm transportation capacity to delivery such commodity to the city gate for Low Volume Sales Customers.

Rate - The rates are CAP, GR, GC, OL, L, MV-F, MV-I, IS, TCS, TS-I, TS-F, and NGS or the successors thereto.

Separate NGS Billing (“Dual Billing”) – Separate Billing by an NGS of its charges for gas supply service.

Service - The distribution of gas for use by the Customer, including all things done by the Company in connection with such distribution.

Service-Supply Pipe - The pipe extending from the Company’s supply main to a metered delivery point or, in the case of installations comprised exclusively of outdoor gas lights, to the first such light.

Summary Billing Accounts - An aggregate bill prepared at the option of the Company for Customers with multiple accounts that are related within the same partnership, association, corporation or governmental agency.

Supplier of Last Resort Service (“SLR Service” or “Sales Service”) - Natural gas supply service provided by the Company as supplier-of-last-resort to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order (“SMO”) – operational directive issued by the Company in its sole discretion to protect the operational integrity of its systems in terms of line pressure and adequacy of supply, which orders directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer’s natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company’s system.

Tariff – This Gas Service Tariff comprising the rates, rules and regulations that apply to the distribution of natural gas, including all things done by the Company in connection with such distribution and/or the supply of natural gas under Supplier of Last Resort (Sales) Service.

Transportation Service – Natural gas supply service provided to HVT Customers, by an alternative Natural Gas Supplier as further detailed in Rule 1.1 of the Gas Transportation Service General Terms and Conditions Section of this Tariff.

Variable Distribution Service Charge – The variable charges on a Mcf basis for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

Volume Adjustment - the current adjustable factor applied to all rate classes to account for: a) reduction for system losses of 3.3% (D) and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company’s system by a reference Btu content of 1,000 Btu per cubic foot.

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(D) Denotes Decrease

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Effective ~~December~~, 1, 2025

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PECO Energy Company

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and Rate TS-F Gas Transportation Service-Firm.)

1. TRANSPORTATION SERVICE

1.1 GENERAL. Transportation service shall consist of: the receipt of gas on behalf of a Customer; the transportation of gas through the Company's distribution facilities, and the delivery of equivalent quantities of gas to the Customer, adjusted for thermal correction and system losses where applicable.

Transportation service may also include Standby Sales Service to permit purchases of gas under one of the Company's retail sales rate schedules.

1.2 TERMS DEFINED. The following definitions shall apply throughout the transportation portion of this tariff:

RECEIVED/RECEIPT shall refer to gas tendered to the Company for the Customer's account at one or more of the interconnections between the Company and its interstate pipeline suppliers, or other specified location. The normal unit of measurement is the dekatherm or mmBtu.

DELIVERED/DELIVERY shall refer to gas tendered to the Customer by the Company at the Customer's specified location. The normal unit of measurement is the Mcf.

USE/USAGE shall refer to gas actually consumed by the Customer at the specified location as measured by the Company's meter in Mcf.

DEFICIENT DELIVERIES shall refer to occurrences in which the Customer uses more gas than the quantity of transportation gas tendered by the Company for delivery.

EXCESS DELIVERIES shall refer to occurrences in which the Customer uses less than the quantity of gas tendered by the Company for delivery.

1.3 VOLUME ADJUSTMENT. The quantity of transportation gas received into the Company's distribution system for the Customer's account shall be: (a) reduced by 3.3% for system losses; and (b) adjusted for thermal correction determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. Where the transported gas can be delivered directly to the Customer without commingling with other system supplies, no reduction for system losses shall be made, and the thermal correction shall be based on the daily average Btu content of the pipeline to which the Customer is directly connected.

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1.4 SUPPLY COST ADJUSTMENT. If the Company incurs any added gas supply cost in order to provide transportation service by displacement, or for other reasons, such additional cost will be charged to the Customer. Displacement occurs when a Customer, who is directly connected to one of the Company's pipeline suppliers, arranges for receipt of transportation gas on another pipeline to which the Customer is not directly connected. Revenues received by the Company in payment for added gas supply cost will be credited to firm sales Customers through the annual Sales Service Costs reconciliation (Section 1307[f]).

1.5 SERVICE AGREEMENT. The Customer will be required to execute a Transportation Service Agreement which will specify an initial Transportation Contract Quantity (TCQ) to be the maximum daily volume of gas, expressed in Mcf net of system losses where applicable, to be transported and delivered to the Customer. The agreement will also specify delivery locations, the election of Standby Sales Service, the commodity charge to be in effect for the term of the agreement, and any special provisions for service. The standard term for a Transportation Service Agreement shall be twelve months, unless the Company and the Customer agree to a shorter or longer term.

The TCQ shall not exceed the lower of (a) the capacity of the Company's metering and regulating equipment at the Customer's location; or (b) 110% of the maximum daily usage of the Customer during the twelve-month period prior to the execution of the Transportation Service Agreement, unless full documentation of new or additional gas usage capability is provided by the Customer. If a Customer chooses to designate an Agent to act on the Customer's behalf for scheduling, dispatching, billing and other administrative aspects of transportation service, such designation shall be made in the Transportation Service Agreement. The designation of an Agent shall not relieve the Customer of ultimate responsibility for payment for service or other obligations incurred under this tariff.

Every November 1 following execution of the Transportation Service Agreement, the Customer's TCQ shall be automatically adjusted by the Company to be 110% of the maximum daily usage of the Customer during the prior twelve-month period if such adjustment would raise or lower the customer TCQ by the higher of either 10 mcf or 10%. The TCQ may also be adjusted by mutual agreement of the Customer and the Company.

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Issued ~~xxxx,xx~~, 2025.

Effective December 1, 2025

Supplement No. ~~xx~~ to
Tariff Gas Pa PUC No. 2S
~~xxxx~~ Revised Page No. 7
Supersedes ~~xxxx~~ Revised Page No. 7

PECO Energy Company

Supplier of Last Resort Service ("SLR" or "Sales Service") - Natural gas supply service provided by the Company to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order ("SMO") - operational directives issued by the Company in its sole discretion to protect the operational integrity of its system in terms of line pressure and adequacy of supply, which orders will directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer's natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company's system

Tariff - this Natural Gas Supplier Coordination Tariff.

Volume Adjustment - the current adjustable factor applied to all rate classes to account

for: a) reduction for system losses of 3.3%; and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot.

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Issued ~~xxxx~~ xx, 2025

Effective December 1, 2025

APPENDIX C

**Ratable Hedging Program
Execution Schedule**

APPENDIX D

**PECO Energy Company's
Statement in Support**

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2025-3054868
	:	
PECO ENERGY COMPANY	:	

**PECO ENERGY COMPANY’S
STATEMENT IN SUPPORT OF THE
JOINT PETITION FOR COMPLETE SETTLEMENT**

PECO Energy Company (“PECO” or the “Company”) submits this Statement in Support with respect to the unopposed Joint Petition for Complete Settlement (“Joint Petition” or “Settlement”) in the above-captioned proceeding.¹ For the reasons stated herein and in the Joint Petition, PECO believes that the settlement embodied in the Joint Petition is fair and reasonable and in the public interest. PECO also believes that the settlement terms comply with and implement the Commission’s regulations in a just and reasonable manner. Additionally, by resolving all issues raised in this proceeding, this Settlement will avoid the time, expense and uncertainty of litigation. Therefore, PECO requests that Administrative Law Judge F. Joseph Brady and the Commission approve the Joint Petition, without modification, and make the findings required by Sections 1317 and 1318 of the Public Utility Code (66 Pa. C.S.A. §§ 1317 and 1318).

¹ The Joint Petitioners are PECO and the Office of Consumer Advocate (“OCA”) (hereinafter referred to collectively as “Settling Parties”). The Philadelphia Area Industrial Energy Users Group (“PAIEUG”), the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”), and the Office of Small Business Advocate (“OSBA”) are not opposed to the Settlement.

I. BACKGROUND

On April 30, 2025², pursuant to 66 Pa. C. S. § 1307(f) and 52 Pa. Code § 53.64, PECO submitted data, as required by the Commission’s regulations, in advance of its annual Purchased Gas Cost (“PGC”) rate filing (“Advance Filing”). The Advance Filing consists of Sections 1 through 22, which respond to information requests in the Commission’s regulations at 52 Pa. Code § 53.64.

On May 30, 2025, PECO filed its Purchased Gas Cost No. 42 rate to become effective for service rendered on and after December 1, 2025 (“PGC 42 Filing”). PECO made the PGC 42 Filing pursuant to 66 Pa. C.S. § 1307(f), which authorizes certain natural gas distribution companies to make annual purchased gas cost filings with the Commission to reflect increases or decreases in their natural gas costs. Pursuant to 66 Pa. C.S. § 1307(f)(3), the Company’s PGC 42 Filing included a reconciliation of expenses previously incurred and revenues received. In support of its PGC 42 Filing, PECO submitted supporting data and information including the Direct Testimonies of witnesses Suzette E. Adams (PECO Statement No. 1), Scott J. Hughes (PECO Statement No. 2), Blerina Gaba-Teme (PECO Statement No. 3), and Anthony P. DiFelice (PECO Statement No. 4), and accompanying exhibits.

On June 19, 2025, the Company filed updated Sections 15, 16, 17, and 22, as well as the updated testimony of Suzette E. Adams.

A. Direct Testimony of Suzette E. Adams

In its PGC 42 Filing, PECO made the following requests and proposals, in relevant part:

- (i) Historic and Projected Natural Gas Purchases

² The Advance Information was filed on April 30, 2025. However, due to issues during the e-filing process, it was refiled with proper formatting on May 2, 2025.

The PGC 42 Filing proposed to recover the Company’s historic natural gas purchases as set forth in Section 1 of the Advance Information (PECO St. No. 1, pp. 4-6) and the Company’s projected gas purchases as set forth in Sections 6 and 7 of the Advance Information. (PECO St. No. 1, p. 6). According to Section 6 of the Advance Information, the total projected cost applicable to the PGC for the estimated period is \$178.390 million. (PECO St. No. 1, p. 6). According to Section 7 of the Advance Information, the total projected cost applicable to the PGC for the application period is approximately \$416.639 million. (PECO St. No. 1, p. 6).

(ii) Gas Purchase Policies and Practices

The PGC 42 Filing also sought acceptance of the Company’s least-cost procurement policy, which achieves a reasonable balance of long- and short-term natural gas purchases under different pricing approaches (designed to reduce price volatility risk) in order to achieve system supply reliability at the least-cost. (PECO St. No. 1, pp. 7-9). PECO’s procurement policy also incorporates use of its interstate transportation contracts to purchase supplies from geographically diverse locations that have substantial liquidity, and its peaking facilities. (PECO St. No. 1, pp. 9-12).

B. Direct Testimony of Scott J. Hughes

(i) Hedging Policy

Regarding its Ratable Hedging Program, the Company proposed extending the Ratable Hedging Program by an additional year. (PECO St. No. 2, pp. 5-6). In addition, as agreed in the 2020 Joint Petition for Complete Settlement (2020 Joint Petition),³ PECO will no longer engage

³ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2020-3019661, Order Adopting Joint Petition for Complete Settlement, dated October 8, 2020 (hereinafter referred to as the “2020 Joint Petition”).

in hedging for summer purchases but will continue with its current winter hedging schedule. (PECO St. No. 2, p. 4).

(ii) Off-System Sales Sharing Mechanism

The PGC 42 Filing also proposed to extend the Company's existing 25% off-system sales sharing mechanism through November 30, 2028. (PECO St. No. 2, p. 6).

C. Direct Testimony of Blerina Gaba-Teme

(i) The Balancing Charge

The PGC 42 Filing proposed two options for a Balancing Charge. The first option was \$0.0203 per MCF. The second option was \$0.0229 per Mcf. Both options had a proposed effective date of December 1, 2025. The second option was included as part of PECO's commitment to investigate the feasibility of including applicable fixed storage costs in the calculation of the High Volume Transportation ("HVT") Balancing Charge. (PECO St. No. 3, p. 3).

D. Direct Testimony of Anthony P. DiFelice

(i) Proposed PGC Rates

The PGC 42 Filing described the development of the PGC rates to become effective December 1, 2025, and requested approval thereof. (PECO St. No. 4, pp. 4-9). The PGC rate is unbundled into the Sales Service Cost ("SSC") and the Balancing Service Cost ("BSC"). (PECO St. No. 4, p. 9). The SSC is a charge to those customers purchasing gas supply from PECO. (PECO St. No. 4, p. 3). The BSC recovers costs associated with the operation of contract storage facilities and PECO's peaking services from all of PECO's low-volume customers. (PECO St. No. 4, p. 3).

II. SETTLEMENT TERMS

The specific terms detailing the agreement of the Settling Parties is set forth in detail below:

Purchased Gas Cost Rates – PECO’s forecast of purchased natural gas costs and its purchased natural gas cost rates,⁴ as originally filed, are accepted, subject to further adjustment in accordance with the Commission’s quarterly adjustment procedures as set forth in 52 Pa. Code § 53.64.

Balancing Charge Rate – The Company proposed two Balancing Charges in its original filing. Following discussions, the Settling Parties have agreed to a Balancing Charge of \$0.0229 per Mcf to become effective on December 1, 2025 (\$0.0004 per Mcf more than the currently effective Balancing Charge). The Settling Parties have agreed to adopt one of the two as-filed Balancing Charge options PECO proposed. Accordingly, the Balancing Charge, effective December 1, 2025, will be \$0.0229 per Mcf.

Retainage Volume Adjustment Rate – In accordance with Paragraph 19 of the 2024 Joint Petition,⁵ the retainage volume adjustment for transportation service customers for the 12 months beginning December 1, 2024 and ending November 30, 2024 is 3.4%, which was calculated based on the weighted three-year average of LUFG plus the portion of Company-use gas attributable to preheater gate station usage for the period ending June 30, 2024.

The Settling Parties agree that the retainage volume adjustment will be 3.3% for the 12 months beginning December 1, 2025 and ending November 30, 2026, as shown on the tariff pages attached to the Joint Petition as Appendix B.

Gas Price Hedging – The Company has complied with the terms of the Ratable Hedging Program for all hedges made through March 2025 and will continue to do so. In the PGC 42 Filing, PECO requested that the Ratable Hedging Program be extended for an additional year.

⁴ The Company’s PGC Rates are comprised of the Commodity Charge (“CC”), the Gas Cost Adjustment Charge (“GCA”), and the BSC.

⁵ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2024-3048767, Order Adopting Joint Petition for Complete Settlement, dated October 10, 2024 (hereinafter referred to as the 2024 Joint Petition).

Extending the program for an additional year (“Year 12”) will add Winter periods with volumes at the same bifurcated volumetric level, and with execution periods similar to those used in prior years.

Specifically, the Settling Parties have agreed: (i) to extend the Ratable Hedging program for an additional year, which will continue with the current winter hedging schedule of 36,000 Dth/day. The revised Ratable Hedging Program execution schedule is attached to the Joint Petition as Appendix C.

Renewable Natural Gas (“RNG”) – PECO will continue pursuing reliable sources of RNG supply via interconnections with RNG producers to bring RNG onto PECO’s gas system. Based on PECO’s investigation into RNG supply, production, and pricing over the past year, it is anticipated that if PECO can procure RNG the price of bringing RNG onto PECO’s gas system will be higher than market-based pricing for natural gas. Should PECO acquire RNG, it will do so in a manner that is consistent with its least-cost procurement strategy for natural gas, *e.g.*, it will pursue the least cost RNG, and will undertake commercially reasonable efforts to minimize the cost impact to PECO’s PGC customers from the costs associated with purchasing RNG.

Lost And Unaccounted For Gas Monitoring And Reporting – Though not obligated to do so, the Company has voluntarily reported a three-year weighted average for the periods ending March 31, 2025, and June 30, 2025, consistent with the previous reporting mechanism set forth in the 2015 Joint Petition.⁶ The Settling Parties have accepted the Company’s reported lost and unaccounted for gas (“LUFG”) percentages as being reasonable.

⁶ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2015-2480969, Order Adopting Joint Petition for Complete Settlement, dated October 22, 2015 (hereinafter referred to as the 2015 Joint Petition).

Off-System Sales/Capacity Release Sharing – As agreed upon by the Settling Parties, PECO will extend the off-system sharing mechanism at 25% of margin revenues through November 30, 2028.

Interest Rate for Over- and Under-Collections – PECO applied the prime rate in effect for commercial borrowing 60 days prior to the annual PGC filing date to the monthly over- and under-collections for the PGC period December 1, 2024 through November 30, 2025. Going forward, as previously agreed, PECO will use the prime rate for commercial borrowing in effect 60 days prior to the annual PGC filing (which occurs on or before June 1 of each year) to determine interest on the monthly over- and under-collections through November 30 of the year in which the PGC filing is made.

Each of the above-referenced areas is described in further detail below.

Purchased Gas Cost Rates. The reasonableness of the Company's historical gas costs for the 12-month period ending March 31, 2025, is affirmed by the Settlement. (*See* Joint Petition, ¶ 37(a)(i)). Specifically, the Joint Petition concludes that PECO has satisfied the requirements of Section 1318 of the Public Utility Code by pursuing a least-cost fuel procurement policy, consistent with its obligation to provide safe, adequate and reliable natural gas distribution service to its customers, and that PECO has met the requirements of the Public Utility Code relating to affiliate purchases. The Settlement also provides a reasonable basis for calculating and setting the GCA, CC and BSC to become effective December 1, 2025. (*See* Joint Petition, ¶ 18(a) and Appendix A). These rates in dollars per Mcf are as follows:

	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

To the extent that actual experience and changes in forecasted natural gas prices and demand would alter such rates, PECO reserves the right to file quarterly adjustments to be effective September 1, 2025 and December 1, 2025, and thereafter in accordance with 52 Pa. Code § 53.64. For the December 1, 2025 filing, the PGC rates will be updated as noted above. As a result, the Settlement allows the Company to recover a reasonable estimate of its projected period purchased gas costs in a manner that protects the interests of the Company and its customers. Under Paragraph 36(b)(iii) of the Joint Petition, the Commission will continue to have the authority to review the actual costs incurred by the Company in a subsequent audit or Section 1307(f) proceeding.

As agreed in the Joint Petition, PECO reserves the right to update Rate TS-F (Gas Transportation Service-Firm) standby sales service demand charge, as shown in Appendix A of the Joint Petition (PECO St. No. 4, Exhibit APD-1), to become effective December 1, 2025, to the extent that actual experience and changes in forecasted natural gas prices and demand would alter those rates.

Balancing Charge Rate. Under the terms of the 2008 Base Rate Case Settlement, the Company is required to update the Balancing Charge as part of its annual 1307(f) filing. The Company proposed two potential Balancing Charges and the Settling Parties agreed to adopt the second option: a Balancing Charge of \$0.0229 per Mcf to become effective on December 1, 2025,

which is \$0.0004 per Mcf more than the currently effective Balancing Charge. (See Joint Petition, ¶ 19(a) and Appendix A). The Settling Parties have agreed to adopt PECO's as-filed Balancing Charge. Accordingly, the Balancing Charge, effective December 1, 2025, will be \$0.0229 per Mcf.

Retainage. Some portion of the natural gas introduced into PECO's distribution system becomes LUGF. Transportation customers arrange to have natural gas delivered to PECO's "City Gate" for delivery to them through PECO's distribution system. PECO, like all other natural gas distribution companies, has tariff rules applicable to transportation service providing that some portion of the natural gas delivered to its City Gate will be deemed to be LUGF. The portion of the natural gas deemed to be LUGF for transported volumes is considered "retainage" and is expressed as a percentage.

In accordance with Paragraph 19 of the 2024 Joint Petition for Complete Settlement, the retainage volume adjustment for transportation service customers is 3.4% for the 12 months beginning December 1, 2024 and ending November 30, 2025. This figure was calculated based on the weighted three-year average of LUGF plus the portion of Company-use gas attributable to preheater gate station usage for the period ending June 30, 2024. The Company agreed in the 2020 Joint Petition that (i) the retainage volume adjustment for the twelve-month period ending November 30, 2022 would be calculated based on the weighted three-year average of LUGF plus the portion of Company-use natural gas attributable to preheater gate station usage for the period ending June 30, 2021, and (ii) Direct Pipeline customer sendout and volumes delivered would be removed from the retainage rate calculation on a going forward basis.

Accordingly, the retainage volume adjustment will be 3.3% for the 12 months beginning December 1, 2025 and ending November 30, 2026, as shown on the tariff pages attached to the Joint Petition as Appendix B. (Joint Petition, ¶ 20(c)).

Gas Price Hedging. PECO employs hedging as an additional tool to purchase natural gas on a basis that reasonably ensures system reliability at the least cost. (PECO St. No. 2, p. 3). PECO's current hedging program, the Ratable Hedging Program, was approved by the Commission as part of the settlement as set forth in 2016 Joint Petition for Complete Settlement,⁷ and extended for an additional three years as part of the settlements as set forth in the 2017 Joint Petition for Complete Settlement,⁸ 2018 Joint Petition for Complete Settlement,⁹ and 2019 Joint Petition for Complete Settlement.¹⁰ The program was extended further and modified to eliminate summer hedging in the 2020 Joint Petition. The program was extended, adding an additional year in each of the settlements as set forth in the 2021 Joint Petition, 2022 Joint Petition, 2023 Joint Petition, and 2024 Joint Petition.

PECO has complied with the terms of the Ratable Hedging Program for all hedges made through April 2025 and will continue to do so. (Joint Petition, ¶ 21(a)). In its PGC 42 Filing, the Company proposed that the current Ratable Hedging Program be extended for an additional year. The Settling Parties have agreed to extend the Ratable Hedging Program for an additional year, which will continue with the current winter hedging schedule of 36,000 Dth/day. The revised Ratable Hedging Program execution schedule is attached as Appendix C to the Joint Petition.

⁷ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2016-2545925, Order Adopting Joint Petition for Complete Settlement, dated October 6, 2016 (hereinafter referred to as the "2016 Joint Petition").

⁸ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2017-2602611, Order Adopting Joint Petition for Complete Settlement, dated October 5, 2017 (hereinafter referred to as the "2017 Joint Petition").

⁹ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. R-2018-3001568, Order Adopting Joint Petition for Complete Settlement, dated October 4, 2018 (hereinafter referred to as the "2018 Joint Petition").

¹⁰ See *Pennsylvania Public Utility Commission v. PECO Energy Company*, Docket No. 2019-3009624, Order Adopting Joint Petition for Complete Settlement, dated October 3, 2019 (hereinafter referred to as the "2019 Joint Petition").

Renewable Natural Gas (“RNG”). PECO will continue pursuing reliable sources of RNG supply via interconnections with RNG producers to bring RNG onto PECO’s gas system. Based on PECO’s investigation into RNG supply, production, and pricing over the past year, it is anticipated that if PECO can procure RNG the price of bringing RNG onto PECO’s gas system will be higher than market-based pricing for natural gas. Should PECO acquire RNG, it will do so in a manner that is consistent with its least-cost procurement strategy for natural gas, *e.g.*, it will pursue the least cost RNG, and will undertake commercially reasonable efforts to minimize the cost impact to PECO’s PGC customers from the costs associated with purchasing RNG.

Lost and Unaccounted For Gas Monitoring and Reporting. Though not required, PECO has voluntarily provided a three-year weighted average for the periods ending March 31, 2025 and June 30, 2025, consistent with the methodology set forth in Paragraph 20(c) of the 2015 Joint Petition for Complete Settlement, in the following tables:

PECO LUFG Calculation 2023-2025 PGC (3-Year Average)

	<u>Sendout in Mcf</u>	<u>Billed Sales in Mcf</u>	<u>LUFG</u>
12 Months Ending 3/31/23	86,824,606	84,280,413	2.9%
12 Months Ending 3/31/24	84,316,700	84,592,318	2.0%
12 Months Ending 3/31/25	90,830,021	87,215,379	4.0%
36 Months Ending 3/31/25	261,971,327	254,088,109	3.0%

	<u>Sendout in Mcf</u>	<u>Billed Sales in Mcf</u>	<u>LUFG</u>
12 Months Ending 6/30/23	84,884,281	82,956,376	2.3%
12 Months Ending 6/30/24	84,814,048	81,832,437	3.5%
12 Months Ending 6/30/25	91,328,455	88,387,625	3.2%
36 Months Ending 6/30/25	261,026,784	253,176,438	3.0%

Off-System Sales/Capacity Release Sharing. Under its currently approved sharing mechanism, PECO receives 25% of all margin revenues from off-system sales transactions and capacity release transactions (PECO St. 2, p. 7). The Settling Parties have agreed, with respect to this proceeding, that PECO will be permitted to continue to receive 25% of all such margin

revenues stated above through November 30, 2028. (Joint Petition, ¶ 24). This extension, from November 30, 2027 to November 30, 2028, will allow the Company to enter into longer term asset management agreements, which the Company believes, under certain conditions, will potentially provide for a larger reduction in gas costs (PECO St. 2, p. 7).

Interest Rate for Over- and Under-Collections. While PECO files its annual 1307(f) filing on or around June 1 of each year, the Company makes quarterly filings throughout the 12-month period to update rates to reflect actual experience and changes in supply and demand, consistent with 52 Pa. Code § 53.64. In compliance with § 1307(f)(5), 66 Pa. C.S.A. § 1307(f)(5), which requires that “[r]efunds to customers shall be made with and recoveries from customers shall include interest at the prime rate for commercial borrowing in effect 60 days prior to the tariff filing made under paragraph (1) . . . ,” and Paragraph 23(b) of the 2017 Joint Petition, PECO applied the prime rate in effect 60 days prior to the annual PGC filing date to the over- and under-collections for the PGC period December 1, 2024 through November 30, 2025. Going forward, as previously agreed, PECO will use the prime rate for commercial borrowing in effect 60 days prior to the annual PGC filing (which occurs on or before June 1 of each year) to determine interest on the over- and under-collections through November 30 of the year in which the PGC filing is made.

For example, if next year’s PGC filing were made on June 1, 2026, PECO would apply the prime rate for commercial borrowing in effect 60 days in advance of that date to determine the interest to be applied to over- and under-collections from December 1, 2025 through November 30, 2026.

III. CONCLUSION

This Settlement achieves significant positive results, as summarized above. Each of the terms of the Settlement are consistent with PECO’s obligation to provide safe, adequate and

reliable natural gas distribution service to its customers. All of the positive results of this Settlement are achieved without requiring hearings, briefing and time consuming and expensive litigation.

For all of the foregoing reasons, PECO Energy Company supports the Joint Petition and respectfully requests that the Administrative Law Judge and the Commission approve it in its entirety and without modification.

Respectfully submitted,

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Counsel for PECO Energy Company

Dated: August 6, 2025

APPENDIX E

**Office of Consumer Advocate's
Statement in Support**

On May 5, 2025, the Bureau of Investigation and Enforcement (I&E) filed its Notice of Appearance. On May 8, 2025, the OCA filed its Notice of Appearance (docketed at C-2025-3055065). On May 27, 2025, the Philadelphia Area Industrial Energy Users Group (PAIEUG) filed its Petition for Intervention. On May 28, 2025, the OCA filed a Formal Complaint and Public Statement. Also on May 28, 2025, the Office of Small Business Advocate (OSBA) filed its Notice of Appearance. On June 4, 2025, the Pennsylvania Public Utility Commission (Commission) served a notice establishing an initial telephonic prehearing conference for this matter for Tuesday, June 24, 2025, at 10:00 a.m. and assigning ALJ Brady as the presiding officer.

The OCA retained Jerome D. Mierzwa¹ to provide technical assistance and to review the Company's gas purchasing practices and operations. Mr. Mierzwa reviewed the Company's preliminary and definitive filing in this matter. In addition, the OCA served discovery on the Company and reviewed all Company responses.

Subsequently, in accordance with the Commission's Rules and Regulations at 52 Pa. Code Section 5.321, the parties undertook discussions in an attempt to reach settlement. On July 16, 2025, the Joint Petitioners informed the ALJ that they had reached a settlement in principle of all issues in the proceeding. The terms and conditions of the settlement agreement reached by the Joint Petitioners are now embodied in the "Settlement Petition" that accompanies this instant Appendix/Statement in Support. The OCA submits that the Company has met the requirements of 66 Pa. C.S. Sections 1307(f) and 1318, and that the Settlement is in the public interest for the reasons set forth below.

¹ Mr. Mierzwa is a Principal with and Vice President of Exeter Associates, Inc. (Exeter). Since joining Exeter in 1990, he has specialized in evaluating the gas purchasing practices and policies of natural gas distribution companies (NGDCs), utility class cost of service and rate design analysis, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services and the evaluation of customer choice natural gas transportation programs.

II. TERMS AND CONDITIONS OF SETTLEMENT

The Commission encourages parties in contested, on-the-record proceedings to settle cases. *See* 52 Pa. Code § 5.231. A Settlement, by definition, reflects a compromise of the parties' positions. When active parties in a proceeding reach a settlement, the principal issue for Commission consideration is whether the settlement is in the public interest. *Pa. Public Utility Commission v. CS Water and Sewer Associates*, 74 Pa. PUC 767, 711 (1991). When the settling parties submitted their joint settlement petition for approval, the principal issue for the Commission is whether the agreement serves the public interest. *Pa. Public Utility Commission v. Philadelphia Electric Company*, 60 Pa. PUC 1, 21 (1985).

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Under the terms of a 2008 Base Rate Case settlement, PECO is required to update the Balancing Charge as part of its annual Section 1307(f) filing. *Pa. PUC v. PECO*, Docket No. R-2008-2028394, (Oct. 29, 2008) R.D. at 7. PECO provides firm transportation service under which customers arrange with a third-party for the purchase and delivery of the gas supplies needed to meet their daily requirements to the PECO system. OCA St. 1 at 5. The quantity of gas delivered to PECO on a daily basis to serve a transportation customer varies from the quantity of gas used by a transportation customer. *Id.* PECO provides balancing services to address these differences in daily deliveries and usage. *Id.* PECO provides both High Volume Transportation (HVT) and Low Volume Transportation (LVT) service. *Id.* The balancing requirements imposed on HVT and LVT customers differ, and different balancing charges are assessed for HVT and LVT customers. *Id.*

As Mr. Mierzwa explained, in PECO's 2024 Section 1307(f) PGC proceeding, PECO's HVT balancing charge excluded certain costs associated with the interstate pipeline transportation

arrangements that deliver gas to and from storage. *Id.* at 3-5 citing *Pa. PUC v. PECO Energy Co.*, Docket No. R-2024-3048767, R.D. at 18-19 (*PECO 2024 Section 1307(f) R.D.*). PECO utilizes its interstate pipeline storage arrangements to provide balancing service and under several of those arrangements, separate interstate pipeline firm transportation arrangements are required to deliver gas to and from storage. OCA St. 1 at 3. Thus, OCA argued in PECO’s 2024 Section 1307(f) PGC case that costs associated with these firm transportation arrangements should be included in the calculation of the HVT balancing charge. *Id.*

In PECO’s 2024 Section 1307(f) PGC proceeding, OCA Witness Mierzwa recommended that the Company’s HVT balancing charge calculation be revised to include: “(1) the fuel retention charges assessed to PECO under the interstate pipeline transportation arrangements utilized to deliver gas to and from storage; and (2) the fuel retention charges assessed on the gas PECO injects into and withdraws from storage under its interstate pipeline storage service arrangements.” OCA St. 1 at 3.

PECO agreed to investigate and prepare a study of the feasibility of including interstate pipeline transportation and storage fuel retention charges in the HVT balancing charge calculation in the last purchased gas case. OCA St. 1 at 3-4, citing *Pa. PUC v. PECO Energy Co.*, Docket No. R-2024-3048767, Joint Petition for Settlement at ¶18 (*PECO 2024 Section 1307(f) Settlement*). Under the HVT balancing charge study required by the former settlement, PECO was required to provide a copy of its HVT balancing charge study and report the results of its investigation in this instant proceeding. *Id.* at 4, *See also PECO 2024 Section 1307(f) R.D.* at 18-19.

By and through its filings and testimony in this instant case, PECO proposed two HVT balancing charge options for consideration in this instant proceeding, following the study it

conducted in accordance with the settlement in PECO's 2024 Section 1307(f) PGC proceeding. OCA St. 1 at 4. PECO's first option, and preferred method, utilized the same balancing charge mechanism as it proposed in the PECO 1307f 2024 proceeding. *Id.*

Under the first presented option, the HVT balancing charge would be calculated as it was calculated in the 2024 proceeding, and in previous years, exclusive of interstate pipeline transportation and storage fuel retention charges. *Id.* The HVT balancing charge calculated under the first option was \$0.0203 per Mcf. *Id.*, *See also* PECO Exhibit BGT-1.

Under PECO's proposed second option, PECO included interstate pipeline transportation and storage fuel retention charges, which Mr. Mierzwa had recommended as best practice in the PECO 2024 Section 1307(f) proceeding. OCA St. 1 at 4. The HVT balancing charge under the second option, in this instant case, was \$0.0229 per Mcf and presented in Exhibit BGT-3. *Id.* Mr. Mierzwa recommended that the HVT balancing charge presented in Exhibit BGT-3 be adopted and approved in this proceeding. *Id.*

Upon review of both options, Mr. Mierzwa recommended that the Commission select and order the second HVT option that PECO presented, whereby PECO has included interstate pipeline transportation and storage fuel retention charges, and so the HVT balancing charge under the second option is \$0.0229 per Mcf and is presented in Exhibit BGT-3. *Id.* The OCA recommended the same because the balancing charge under the second option reflects the true delivered costs, ensures fair comparison, and promotes the least cost procurement model that reinforces prudent, customer-focused planning.

The Settlement provides:

19. Balancing Charge (BC) Rate

- A. Under the terms of the 2008 Gas Base Rate Case Settlement, PECO is required to update the BC as part of its annual Section 1307(f) filing. As set forth on Page 3 of PECO Statement No. 3, the Direct Testimony of Blerina Gaba-Teme in the PGC 42 Filing (and also included in Appendix A), PECO proposed two BC options: the first option was \$0.0203 per MCF. The second option was \$0.0229 per Mcf. Both options had a proposed effective date of December 1, 2025. The second option was included as part of PECO's commitment to investigate the feasibility of including applicable fixed storage costs in the calculation of the High Volume Transportation ("HVT") BC. (PECO St. No. 3, p. 3).
- B. The Settling Parties have agreed to adopt the second of PECO's as-filed BC options. Accordingly, the BC, effective December 1, 2025, will be \$0.0229 per Mcf. The associated tariff pages are included in Appendix A.

Settlement ¶ 19.

Achieving a settlement that reflected the OCA's recommended balancing charge rate was an integral part of achieving an overall resolution of this case. The balancing charge rate was the only issue that OCA identified and sought relief for. The OCA, as explained above and in testimony, recommended the second balancing charge rate to more accurately capture actually incurred costs. As such, the OCA submits that the Settlement is in the public interest and should be adopted.

The OCA acknowledges, by and through this instant Settlement, that the natural gas costs incurred by the Companies during the historic period were otherwise done so under adherence to a least cost fuel procurement policy. A least cost fuel procurement policy protects ratepayers from unnecessary and imprudent gas costs. Thus, the OCA believes and therefore avers that this settlement is in the public interest and protects consumers.

IV. CONCLUSION

The Office of Consumer Advocate submits that the terms of the Settlement are in the public interest and in the interest of PECO's ratepayers. Based on the above reasons, the Office of Consumer Advocate submits that the proposed Settlement should be approved.

Respectfully Submitted,

/s/ Katie Kennedy

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