



**peco**<sup>SM</sup>

AN EXELON COMPANY

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May 28, 2026

**Via E-Filing**

Matthew Homsher, Secretary  
Pennsylvania Public Utility Commission  
Commonwealth Keystone Building  
400 North Street  
Harrisburg, Pennsylvania 17120

**SUBJECT:** PECO Purchased Gas Cost No. 43, Effective December 1, 2026  
Docket No. R-2026-3062148, Supplement No. 16 to Gas Service Tariff  
No. 6

Dear Secretary Homsher:

This letter transmits for filing with the Pennsylvania Public Utility Commission (the "Commission") the Purchased Gas Cost ("PGC") No. 43 filing of PECO Energy Company, consisting of the following:

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

As required by Commission Order entered December 6, 1985, at Docket No. P-850081, the Company has begun the advance public notice of the proposed gas rate changes contained in the PGC No. 43 filing through bill inserts and newspaper advertisements.

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

Matthew Homsher, Secretary  
May 28, 2026  
Page 2

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

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Sincerely,

A handwritten signature in black ink, appearing to be "BJT" with a stylized flourish extending to the right.

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

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY  
COMMISSION**

**v.**

**PECO ENERGY COMPANY**

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**Docket No. R-2026-3062148**

**CERTIFICATE OF SERVICE**

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

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Dated: May 28, 2026

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**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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

**Docket No. R-2026-3062148**

**DIRECT TESTIMONY  
OF  
SUZETTE E. ADAMS**

**PECO STATEMENT NO. 1**

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1 worked in Project Management overseeing large scale projects, I managed the Call  
2 Center, and served as the Chief of Staff to the Chief Customer Officer (CCO) in  
3 Customer Operations.

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

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

18 **II. PURPOSE OF TESTIMONY**

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

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

1 March 31, 2026), the estimated period (April 1, 2026 through November 30, 2026)  
2 and the PGC application period (December 1, 2026 through November 30, 2027)  
3 are just and reasonable. To that end, I am sponsoring the information previously  
4 filed by the Company on May 1, 2026 (the “Advance Filing Information”) in  
5 support of this year’s purchased gas cost proceeding (“PGC 43”). Additionally, I  
6 will describe the Company’s natural gas purchase policies and practices, including  
7 PECO’s use of natural gas pipeline transportation and storage contracts, and set  
8 forth its plans for evaluating and continuing to incorporate Marcellus Shale  
9 production into its supply portfolio.

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

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

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

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

1 PECO’s natural gas system, please refer to Section 13 of the Advance Filing  
2 Information.

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

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

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

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

15 A. The information provided in Section 1 of the Advance Filing Information accounts  
16 for all of the Company’s purchased natural gas costs during the period from January  
17 1, 2025 through March 31, 2026, and includes the source of the natural gas, the  
18 price and the associated volumes. This information also includes applicable rates,  
19 demand components, and incremental purchased natural gas costs associated with  
20 contracted interstate pipeline transportation and storage services. All costs detailed  
21 in Section 1 result from applying the Company’s policy to purchase natural gas on  
22 a basis that ensures system reliability at the least-cost.

23 **11. Q. During the past 12 months, did PECO purchase natural gas from any affiliated**

1 interest?

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

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

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

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

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

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

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

7 A. Sections 6 and 7 of the Advance Filing Information<sup>1</sup> provide the projected cost of  
8 purchasing natural gas for the estimated period (April 1, 2026 through November  
9 30, 2027) and the PGC application period (December 1, 2026 through November  
10 30, 2027), respectively. This information includes the expected source of the  
11 natural gas, the price, and the associated volumes. The projected purchases reflect  
12 the Company's policy to purchase natural gas on a basis that ensures system  
13 reliability at the least-cost. Sections 6 and 7 of the Advance Filing Information  
14 include all projected interstate pipeline costs, storage demand costs, variable  
15 storage and fuel-related costs, and commodity costs for the relevant time periods.  
16 As shown in Section 6 of the Advance Filing Information, the total projected cost  
17 applicable to the PGC for the estimated period is approximately \$155,472 million.  
18 As shown in Section 7 of the Advance Filing Information, the total projected cost  
19 applicable to the PGC for the application period is approximately \$382,009 million.

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<sup>1</sup> The Company filed updated Sections 6 and 7 of the Advance Filing Information on May 5, 2026. Any reference to Sections 6 and 7 of the Advance Filing Information herein refers to the updated Sections 6 and 7.

1 **IV. DESIGN DAY REQUIREMENTS**

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

4 A. Yes. Details of PECO's design day methodology and a description of its 2026-2027  
5 winter design day requirements are included in Section 16 of the Advance Filing  
6 Information. As described in Section 16, PECO's supply resources, combined with  
7 peaking and delivered supply, will satisfy the Company's design day requirement  
8 of 926,731 Mcf for the 2026-2027 winter season.

9 **16. Q. Is PECO proposing a change to its design day as a result of its experience**  
10 **during the 2025-2026 winter season?**

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

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

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

15 A. Yes, it does.

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

17 A. PECO's natural gas procurement policy is designed to achieve a reasonable balance  
18 of long- and short-term natural gas purchases under different pricing approaches,  
19 in order to achieve system supply reliability at the least-cost. As previously  
20 discussed, the details of PECO's actual natural gas purchases for the fifteen (15)  
21 months ending March 31, 2026 and its estimated purchases through November 30,  
22 2027, are presented in the Advance Filing Information (Sections 1, 6 and 7). PECO  
23 utilizes its interstate transportation and storage entitlements to obtain and deliver  
24 market-priced supplies to the PECO natural gas distribution system.

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

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

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

21                         Additionally, PECO continued and extended its Ratable Hedging Program  
22                         as authorized by the Joint Petition for Complete Settlement in last year’s PGC  
23                         proceeding at Docket No. R-2025-3054868.

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

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

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

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

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

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

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

4 A. Yes. As shown in Sections 16 and 22 of the Advance Filing Information, 25.63%  
5 of the Company's required design day supply, which equates to 241,729 Mcf, will  
6 be received via delivery from contracted underground storage. In addition, LNG,  
7 propane, and delivered peaking services combine to represent about 29.66% of the  
8 required design day supply. Accordingly, as shown in Sections 16 and 22 of the  
9 Advance Filing Information, 220,000 Mcf are available from LNG, 25,000 Mcf are  
10 available from propane, and 34,726 Mcf are available from delivered hedged  
11 contracts.<sup>2</sup> Overall, the use of storage and LNG enables PECO to substantially  
12 mitigate its exposure to the price volatility that typically occurs during the winter,  
13 while ensuring sufficient deliverability to meet firm demand.

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

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<sup>2</sup> For the upcoming 2026-2027 winter, PECO, through its approved hedging program, will enter into fixed price delivered supply contracts equal to 36,000 Dth/day.

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

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

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

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

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

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

3 A. As illustrated in Table SA-1 below, PECO experienced a winter that was overall,  
 4 by degree day, 4.3% warmer than a normal winter. December through February  
 5 were colder than normal, and November and March were significantly warmer than  
 6 normal which was offset by the colder than normal temperatures in December  
 7 through February.<sup>3</sup> Variations from normal weather by season, month, or day  
 8 present balancing challenges. These challenges can be exacerbated by certain  
 9 factors. For example, on warmer than normal days, the challenges can be made  
 10 worse by the increase in firm supply receipts associated with the LVT Gas Choice  
 11 program and the Company’s Ratable Hedging Program, and on colder than normal  
 12 days, by exposure to market area price volatility and limited LNG, propane and  
 13 underground storage inventory. PECO utilized its balancing assets, such as  
 14 contracted storage, as well as its daily load balancing processes to minimize costs  
 15 this past winter.

16 **Table SA-1**

Heating Degree Days (HDD)						
	November	December	January	February	March	Total
	2025	2025	2026	2026	2026	
HDD Normal	510	794	940	791	628	3,663
HDD Actual	502	921	1032	877	490	3,822
Difference	-8	127	92	86	-138	159
HDD vs Normal	-1.6%	16.0%	9.8%	10.9%	22.0%	4.3%

<sup>3</sup> PECO defines a normal winter as 3,854 heating degree days (“HDD”).

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

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

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

12           A.     No.

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

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

**Table SA-2**

Rank	Date	Temp	Wind	System Sendout (MCF)
1	Saturday, February 7, 2026	11	23	844,926
2	Sunday, February 8, 2026	15	15	806,161
3	Saturday, January 6, 2018	11	15	800,927
4	Tuesday, January 21, 2025	15	8	791,455
5	Friday, January 5, 2018	12	21	790,627
6	Friday, January 30, 2026	16	9	785,555
7	Monday, January 21, 2019	16	13	782,361
8	Thursday, January 31, 2019	15	9	779,550
9	Sunday, February 15, 2015	10	21	778,349
10	Sunday, December 31, 2017	12	10	776,980
11	Wednesday, January 22, 2025	16	3	773,696
12	Friday, February 1, 2019	15	9	770,605
13	Tuesday, January 20, 2026	21	8	768,283
14	Thursday, February 19, 2015	11	18	767,421
15	Wednesday, January 30, 2019	14	11	766,103
16	Saturday, December 24, 2022	18	17	761,932
17	Tuesday, January 7, 2014	11	16	759,549
18	Thursday, January 29, 2026	18	13	756,962
19	Wednesday, January 28, 2026	18	10	752,528
20	Saturday, January 29, 2022	17	14	748,912

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

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

3 **29. Q. Did PECO's supply contracts perform as required during the winter of 2026-**  
4 **2027?**

5 A. Yes. For the winter of 2026-2027, all natural gas scheduled under PECO's supply  
6 contracts was delivered to PECO's city gate.

1 **30. Q. Based on its experience in recent winters, is PECO considering any changes to**  
2 **its natural gas supply portfolio?**

3 A. Yes. While the Company believes that its current mix of FT, firm storage, propane,  
4 LNG, and delivered peaking contracted services provides adequate peaking  
5 capacity to ensure the system reliability necessary to meet peak demand in a safe,  
6 least-cost manner at present, PECO continues to analyze supply portfolio and on-  
7 system LNG solutions to address observations from experiences these past few  
8 winters, as well as for peak-day demand projections. This past winter was relatively  
9 cold, the Company's projected growth in design day and overall demand supports  
10 the Company's continuing review of how to best manage its natural gas supply  
11 portfolio. To that end, PECO has continued its examination of potential long- and  
12 short-term solutions to assist in meeting customer demand during the heating  
13 season, including peak-day demand. The results of this examination are discussed  
14 below in response to Questions 34 through 36.

15 **31. Q. Please provide an update on the steps the Company took to ensure availability**  
16 **of supply for the winter of 2025-2026.**

17 A. As described in the Direct Testimony in PECO's prior PGC proceedings,<sup>4</sup> PECO  
18 continues to analyze and adopt multiple solutions to procure reliable, least-cost  
19 assets for both the short- and long-term peak day supply deficits. To that end, to  
20 ensure the availability of winter delivery services for the winter of 2025-2026 (as  
21 explained at page 2 of Section 22 of the Advance Filing Information in PGC 42

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<sup>4</sup> See Direct Testimony of Carlos P. Thillet (PGC 35 through 38) and Direct Testimony of Scott J. Hughes (PGC 39).

1 (Docket No. R-2025-3054868)), PECO took the following steps to acquire the  
2 42,556 Dth needed:

- 3 • PECO procured 36,000 Dth/day of delivered supply via the Company's  
4 approved Ratable Hedging program, leaving us with a surplus of 6,556 Dth

5 **32. Q. Did PECO purchase any trucked LNG or propane under the aforementioned**  
6 **call options and if so, why?**

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

9 **33. Q. How does the Company plan to ensure availability of supply for the winter of**  
10 **2026-2027?**

11 A. PECO will utilize both short- and long-term solutions to address its supply needs  
12 for the winter of 2026-2027. As to the short-term solutions, similar to previous  
13 winters, PECO will depend on delivered supply in order to meet part of its design  
14 day requirements.<sup>5</sup> PECO has taken the following steps to ensure the availability of  
15 the 16,853 Dth/day of required delivered supply:

- 16 • PECO will procure 36,000 Dth/day of delivered supply via the Company's  
17 Ratable Hedging program. Which will give us aa surplus of 19,147
- 18 • On or before July 1, 2026, PECO will issue a notice of Additional Capacity  
19 Constraints, as explained in the Company's DSO program, which is  
20 anticipated to produce a similar yield as in prior years.
- 21 • PECO will issue an RFP for delivered supply equal to the total winter  
22 delivered resources required, less those volumes obtained by the two  
23 contracts and DSO program participation listed above.

24 **34. Q. Please describe the actions PECO is pursuing to address the longer term peak**

---

<sup>5</sup> PECO's design day requirements can be found at page 2 of Section 22 of the Advance Filing Information.

1           **day requirements through the winter of 2038-2039.**

2           A.    To reduce reliance on delivered supply, the Company continues to investigate  
3 longer term solutions. The objectives of the longer-term solution are to provide  
4 PECO with a least-cost, reliable source of supply enabling the Company to meet its  
5 firm demand, eliminate the peak-day supply gap while providing deliveries to  
6 PECO gate stations, and further eliminating exposure to market area price volatility.  
7 To that end, PECO is currently involved in two projects that will aid it in meeting  
8 its long-term supply objectives.

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

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

Docket No. P-2021-3024328.<sup>6</sup> In that proceeding, PECO explained the need for the Natural Gas Reliability Project from the standpoint of ensuring the reliability of PECO's natural gas supply to meet design day requirements-

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

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

**Table SA-3**

DESIGN DAY DEMAND VS ASSETS (Dth/D)					
WINTER	DESIGN DAY DEMAND	PROJECTED TOTAL ASSETS	GAP	% GAP	Notes
2026-2027	961,020	977,873	16,853	2%	Assets equal current Pipeline FT and Storage deliveries plus PECO LNG and Propane vaporization assets. Includes Hedged Gas for executed contracts of 36,000 Dth/d.
2027-2028	965,662	977,873	12,211	1%	Assets at steady state
2028-2029	970,159	977,873	7,714	1%	
2029-2030	974,367	977,873	3,506	0%	
2030-2031	978,100	977,873	-227	0%	
2031-2032	981,564	977,873	-3,691	0%	
2032-2033	985,143	977,873	-7,270	-1%	
2033-2034	989,082	977,873	-11,209	-1%	
2034-2035	993,522	977,873	-15,649	-2%	
2035-2036	997,661	977,873	-19,788	-2%	

The projected total assets for the winter of 2026-2027 include all of PECO's current firm assets.

The acquisition of these firm assets will result in the elimination of the current firm gap between total assets and design day demand of 2%. By the winter

<sup>6</sup> PECO filed its Petition for a Finding of Necessity on May 14, 2021. A copy of the Direct Testimony in Docket No. P-2021-3024328, which is confidential, will be made available upon request and execution of a confidentiality agreement acceptable to PECO.

1 of 2027-2028, PECO is projecting to have a deficit beyond the projected design day  
2 of 1%. PECO plans to meet this deficit through the hedging program which may  
3 also result in supplemental capacity, which will better enable the Company to serve  
4 its customers should future instances occur where any of the interstate pipelines  
5 delivering supply to PECO's service area are subjected to equipment failures,  
6 integrity concerns, or other obstacles or force majeure events that prevent them  
7 from meeting their contracted obligations during periods of high natural gas  
8 demand. Supplemental capacity would also provide a degree of flexibility to ensure  
9 deliverability and help to lessen exposure to market area price volatility.

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

11 **36. Q. Has the Company purchased any natural gas produced in Marcellus Shale**  
12 **regions?**

13 A. Yes. PECO has purchased natural gas from Marcellus Shale production areas. Since  
14 2010, PECO has incorporated increasing quantities of locally produced Marcellus  
15 Shale natural gas into its portfolio of supply assets. The only supply PECO  
16 purchases that it presumes is not from the Marcellus production regions are those  
17 necessary for injections into its WSS storage contract, located upstream on  
18 Transco's main line.<sup>7</sup> PECO uses its FT contracts to purchase and transport natural  
19 gas primarily from both the Southwestern and the Northeastern/Leidy production  
20 areas in Pennsylvania.

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<sup>7</sup> Due to the location of certain purchase receipt points, the Company reasonably assumes they are supported by Marcellus Shale gas produced in Pennsylvania. However, the Company is not privy to pipeline information regarding physical flows to the well head. Nor does the Company's least-cost obligation to its firm customers require it to request such proof from its counterparties.

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

8 **37. Q. Please describe any steps the Company has taken to Acquire Renewable**  
9 **Natural Gas (RNG).**

10 A. PECO has continued to pursue a strategy to procure and support the growth of RNG  
11 production and secure a reliable source of RNG supply onto PECO's gas system at  
12 market-based gas prices. PECO is actively pursuing a Renewable Natural Gas  
13 (RNG) project and has completed the appropriate feasibility study to assess the  
14 project. PECO is currently working through the necessary technical and contractual  
15 details required to potentially finalize an interconnection agreement. As previously  
16 noted in prior PGC filings, while PECO does not intend to pay a premium for, or  
17 otherwise acquire, the environmental attributes of the RNG, PECO would like  
18 maximum flexibility to pursue sources of RNG production that would be most  
19 advantageous to PECO's PGC customers.

20 Per the PGC 42 Settlement, if PECO were to acquire RNG, it committed to  
21 do so in a manner that is consistent with the Company's least-cost procurement  
22 strategy for natural gas, *e.g.*, it would pursue the least cost RNG, and would

1                    undertake commercially reasonable efforts to minimize the cost impact to PECO'S  
2                    PGC customers from the costs associated with purchasing RNG.

3    **VII. CONCLUSION**


4    **38. Q. Does this conclude your Direct Testimony?**

5                    A. Yes, it does.

## VERIFICATION

I, Suzette E. Adams, Senior Manager of PECO Energy Company's Gas Supply & Transportation Department, hereby state that the facts set forth in my Direct Testimony PECO Statement No. 1 in the matter at PaPUC Docket No. R-2026-3062148 are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 28, 2026



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Suzette E. Adams

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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

**Docket No. R-2026-3062148**

**DIRECT TESTIMONY  
OF  
SCOTT J. HUGHES**

**PECO STATEMENT NO. 2**

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

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

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

16 **II. PURPOSE OF TESTIMONY**

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

18 A. The purpose of my Direct Testimony is to present certain of the information  
19 required in Section 1317(a) of the Pennsylvania Public Utility Code (the  
20 "Code") (*See* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility  
21 Commission (the "Commission") may make the findings required by Section  
22 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that PECO's  
23 PGC rates and charges for the historic period (April 1, 2025 through March  
24 31, 2026), the estimated period (April 1, 2026 through November 30, 2026),

1 and the PGC application period (December 1, 2026 through November 30,  
2 2027) are just and reasonable. To that end, I will describe the Company’s  
3 current hedging program. Additionally, I will discuss PECO’s off-system  
4 sales sharing mechanism. Finally, I will furnish certain information that  
5 PECO committed to provide under the terms of the Joint Petition for  
6 Complete Settlement in the 2025 PGC proceeding at Docket No. 2025-  
7 3054868 (“2025 Joint Petition”).

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

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

11 **III. PECO’S HEDGING POLICY**

12 **8. Q. Please describe PECO’s hedging policy.**

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

20 **9. Q. Please briefly summarize PECO’s current Ratable Hedging Program.**

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

1 Joint Petition for Complete Settlement (PGC 35, Docket No. R-2018-  
2 3001568), the 2019 Joint Petition for Complete Settlement (PGC 36, Docket  
3 No. R-2019-3009624), the 2020 Joint Petition for Complete Settlement  
4 (PGC 37, Docket No. R-2020-3019661), the 2021 Joint Petition for  
5 Complete Settlement (PGC 38, Docket No. R-2021-3025629), the 2022 Joint  
6 Petition for Complete Settlement (PGC 39, Docket No. R-2022-3032250),  
7 the 2023 Joint Petition for Complete Settlement (PGC 40, Docket No. R-  
8 2023-3040285), the 2024 Joint Petition for Complete Settlement (PGC 41,  
9 Docket No. 2024-3048767), and the 2025 Joint Petition for Complete  
10 Settlement (PGC 42, Docket No. 2025-3054868).

11 Under this program, PECO hedges approximately 11% of its  
12 projected winter purchase volumes. The hedges under the Ratable Hedging  
13 Program began in November 2016 and will continue through July 2028. All  
14 hedges in this program are made between three (3) and 24 months in advance  
15 of the delivery date for the purchased natural gas. In addition, as agreed to in  
16 the 2020 Joint Petition for Complete Settlement, PECO no longer engages in  
17 hedging for summer purchases. For convenience, I have attached the current  
18 Ratable Hedging Program execution schedule to my Direct Testimony as  
19 Exhibit SJH-1.

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

- 23 1. PECO will not enter into any individual hedge unless  
24 there are at least three qualified respondents to the

1 RFP;

2 2. Each transaction will be evaluated and compared to  
3 current index market indicators, and if the proposed  
4 transaction is 10% higher than the indicators, PECO  
5 will not conduct the transaction;

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

10 4. PECO will not make any financial hedges, only  
11 hedges of physical gas.

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

14 A. Yes, during the historic period (April 1, 2025 through March 31, 2026),  
15 PECO issued RFPs for six (6) execution periods (these periods are  
16 highlighted in yellow in Exhibit SJH-1, with all previous executions  
17 appearing in blue). As shown in Table SJH-1 below, for the historic period,  
18 PECO has purchased approximately 5.45 MMDTH of hedged natural gas  
19 under the program at a weighted average cost of \$6.0396 per Dth.

<b>Ratable Hedge Program</b>			
<b>Executed Hedges April 2025 through March 2026</b>			
<b>Execution Month</b>	<b>DTH</b>	<b>\$/DTH</b>	<b>Total \$</b>
July 2025	1,812,000	\$ 5.5750	\$10,101,900
November 2025	1,818,000	\$ 6.0002	\$10,908,300
March 2026	1,818,000	\$ 6.5421	\$11,893,530
Total	5,448,000	\$ 6.0396	\$32,903,730

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

21 A. Yes, PECO is proposing that the Ratable Hedging Program be extended for  
22 an additional year. Table SJH-2 below provides the proposed hedging  
23 schedule for Year 13:



V. SETTLEMENT COMMITMENTS

1  
2 **14. Q. Did the 2025 Joint Petition include any settlement commitments for the**  
3 **Ratable Hedging Program?**

4 A. Yes, Paragraph 21 of the 2025 Joint Petition for Complete Settlement  
5 includes certain commitments regarding the Ratable Hedging Program.

6 **15. Q. What does Paragraph 21 of the 2025 Joint Petition provide?**

7 A. Paragraphs 21(a) and 21(b) acknowledged that the Company complied with  
8 the requirements of its Ratable Hedging Program for all hedges made  
9 through April 2025, and further confirmed that PECO would continue to do  
10 so.

11 Paragraphs 21(c) and 21(d) acknowledged the extension of PECO's  
12 Ratable Hedging Program for an additional year beyond that which was  
13 approved in the 2024 Joint Petition for Complete Settlement. In addition,  
14 Paragraph 21(c) confirmed the removal of summer hedges from PECO's  
15 hedging schedule.

16 **16. Q. What did the 2025 Joint Petition require of the Company with respect**  
17 **to Lost and Unaccounted For Gas ("LUFG") monitoring and reporting?**

18 A. Paragraph 23 sets forth the three-year weighted average for the period ending  
19 March 31, 2025, and June 30, 2025. The 2025 Joint Petition for Complete  
20 Settlement, however, does not impose any further reporting obligations on  
21 the Company as it relates to LUFG. Nonetheless, consistent with its reporting  
22 in prior PGC proceedings, PECO has voluntarily provided the LUFG  
23 percentages for the period ending March 31, 2026 in Table SJH-3 below,  
24 consistent with the methodology set



VI. CONCLUSION

1

2

18. Q. Does this conclude your Direct Testimony?

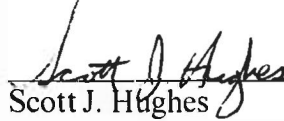
3

A. Yes, it does.

## VERIFICATION

I, Scott J. Hughes, Manager of PECO Energy Company's Gas Acquisition Department, hereby state that the facts set forth in my Direct Testimony PECO Statement No. 2 in the matter at PaPUC Docket No. R-2026-3062148 are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 28, 2026

  
Scott J. Hughes



**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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

**Docket No. R-2026-3062148**

**DIRECT TESTIMONY  
OF  
BLERINA GABA-TEME**

**PECO STATEMENT NO. 3**

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1 Transportation (“HVT”) and Low Volume Transportation (“LVT”) Gas Choice  
2 programs.

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

8 **II. PURPOSE OF TESTIMONY**

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

10 A. The purpose of my Direct Testimony is to present certain of the information  
11 required in Section 1317(a) of the Pennsylvania Public Utility Code (the “Code”)  
12 (*see* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility Commission  
13 (the “Commission”) may make the findings required by Section 1318 of the Code  
14 (*see* 66 Pa. C.S.A. § 1318) for a determination that PECO’s PGC rates and charges  
15 for the historic period (April 1, 2025 through March 31, 2026), the estimated period  
16 (April 1, 2026 through November 30, 2026), and the PGC application period  
17 (December 1, 2026 through November 30, 2027) are just and reasonable. To that  
18 end, I will describe the Company’s natural gas purchase policies and practices,  
19 including PECO’s use of natural gas pipeline transportation and storage contracts,  
20 and explain its HVT Gas Choice program.

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

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

1 **III. THE BALANCING CHARGE**

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

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

12 The Company is calculating a balancing charge as shown in Exhibit BGT-  
13 1, which displays the balancing charge calculation that was adopted in the 2025  
14 Joint Petition. In Exhibit BGT-1, the Company is calculating a balancing charge of  
15 \$0.0231 per Mcf to become effective on December 1, 2026, which is \$0.0002 less  
16 per Mcf than the currently effective balancing charge.

17 **9. Q. Why did the balancing charge decrease by \$0.003 per Mcf?**

18 A. Please refer to Exhibit BGT-2, which provides the calculations of the current  
19 balancing charge and last year's balancing charge, along with a line-by-line  
20 comparison between the two. The increase is driven by deviations in several factors,  
21 including increased fixed storage costs.

22 **10. Q. Please describe the results of the Company's feasibility study concerning**  
23 **including applicable storage related costs in the calculation of the High**

1 **Volume Transportation (“HVT”) balancing charge?**

2 A. As shown in Exhibit BGT-1, the Company is providing all workpapers and  
3 calculations to support including HVT storage related costs. The Company is  
4 including HVT Storage Injection Costs by multiplying each month’s aggregate  
5 daily excess deliveries by a monthly injection weighted average cost of gas  
6 (“WACOG”). The Company is also including the HVT Storage Withdrawal Costs  
7 by multiplying each month’s aggregate daily deficient deliveries by a monthly  
8 withdrawal WACOG. The Storage Injection Costs and the Storage Withdrawal  
9 Cost will be added to the Fixed Storage Costs included in the balancing charge  
10 calculation for a Total Storage Cost.

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

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

15 A. Yes. PECO continues to evaluate pipeline open seasons and capacity made  
16 available via permanent capacity releases to see if any new, cost-effective, firm  
17 natural gas transportation source to PECO’s city gate become available. In general,  
18 each opportunity is analyzed to determine whether PECO’s participation in the  
19 project is needed to meet projections for increased firm demand, or if the project  
20 offers a reliable least-cost alternative to an existing transportation or storage  
21 contract approaching its expiration date. In addition, projects are reviewed to  
22 determine: (1) their ability to deliver firm natural gas from a reliable, liquid market  
23 to PECO; and (2) if they are compatible with PECO’s existing contracts and load  
24 profile.

1           The Regional Energy Access (“REA”) project was referred to as Project X  
2           in Company Witness Carlos Thillet’s Direct Testimony submitted in support of  
3           PECO’s prior PGC proceedings – PGC 36, PGC 37, and PGC 38 – and was also  
4           discussed in Company Witness Scott J. Hughes’ Direct Testimony in support of  
5           PGC 39 and in Julie S. Drezner’s Direct Testimony in support of PGC 40 and PGC  
6           41. On February 10, 2020, PECO executed a Precedent Agreement with Transco  
7           for 100,000 Dth/day of REA capacity. The firm transportation capacity will enable  
8           PECO to move natural gas from receipt points in the Leidy Pennsylvania Marcellus  
9           Shale production area to delivery points on PECO’s distribution system. The initial  
10          term is for 15 years. The capacity will provide PECO with a least-cost, reliable,  
11          source of supply enabling the Company to meet its firm demand by reducing the  
12          delivered supply needed to eliminate the peak-day supply gap, and while providing  
13          deliveries to PECO gate stations and further eliminating exposure to market area  
14          price volatility. Transco filed its 7(c) FERC Application on March 26, 2021.  
15          Subsequently, on April 28, 2021, Exelon Corporation filed comments in support of  
16          the REA application. On February 17, 2023, PECO executed a Service Agreement  
17          with Transco for 100,000 Dth/day of REA capacity. PECO negotiated an early in-  
18          service contract for 32,922 Dth/day of the 100,000 Dth/day REA firm capacity,  
19          effective August 1, 2024 for fifteen years.

20           PECO also submitted one non-binding bid on an open season in 2024. On  
21          May 29, 2024, Adelphia initiated an open season for 22,500 dth/day FT Adelphia  
22          North Zone capacity. PECO participated in the open season and won the non-  
23          binding FT capacity. Ultimately, contract negotiations did not continue due to

several operational concerns identified in the proposed transaction. Also, due to the current Adelphia rate case, PECO and Adelphia are not in negotiations for this incremental project any longer.

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

**12. Q. Did participation in PECO’s LVT Gas Choice program continue to grow for the 12-month period ending March 31, 2026?**

A. As indicated in Table BGT-1 below, PECO’s LVT Gas Choice program continues to be robust. The number of customers in the program has typically increased year-over-year; however, for the 12-month period ending March 31, 2026, participation slightly decreased. In addition, the number of suppliers decreased during this period from 59 to 57. PECO expects strong participation in this program to continue.

**Table BGT-1**

<b>12-Month Period Ending March 31</b>	<b>Customers participating in LVT program</b>	<b>YOY Change</b>	<b>Aggregate Daily Delivery Quantity</b>	<b>Aggregate Daily Contract Quantity</b>
2016	81,088	0.80%	46,896	58,573
2017	81,472	0.50%	46,481	60,324
2018	84,161	3.30%	60,951	60,920
2019	95,293	13.20%	66,786	66,760
2020	105,312	10.50%	74,190	74,166

2021	96,625	-8.20%	70,841	70,841
2022	89,563	-7.30%	66,013	66,013
2023	83,504	-6.80%	64,743	64,743
2024	84,024	0.60%	67,178	67,178
2025	83,668	-0.40%	66,499	66,499
2025	81,152	-3.01%	64,306	64,306

1 **V. FIRM INTERSTATE PIPELINE CONTRACTS**

2 **13. Q. Please identify the firm interstate natural gas pipeline service agreements that**  
3 **have been subject to renewal since PECO’s last PGC proceeding (PGC 42) and**  
4 **that remain in effect.**

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

13 On October 23, 2024, PECO submitted the two-year notice to terminate the  
14 UGI XD contract, effective December 1, 2026. The original purpose of the contract  
15 was to ensure distribution service to North Coventry and Upper Pottsgrove  
16 Townships via interconnection with UGI, which helps serve certain HVT  
17 customers. PECO Gas Engineering has since performed distribution system  
18 upgrades, eliminating the need for the UGI capacity feed and interconnections.  
19 PECO was provided notice on an Eastern Shore Natural Gas Pipeline contract for

8,000 dth/day deliverable to the Jennersville, PA gate station. The contract interconnects with Transco upstream and with the accompanying supply being transported to Eastern Shore from Transco. The contract and Jennersville, PA Gate Station serve a portion of Southwest Chester, Co., in a single source transportation deliverability path. As such, with no reasonable alternatives as determined by no responses to our RFP for this capacity, PECO extended the contract with Eastern Shore for an additional five years ending in 2031.

**Table BGT-2**

Pipeline Contract	Earliest Termination Date	Notice Period	Renewed (Yes or No)
<b>Texas Eastern</b>			
FT-1 Transportation	10/31/2028	24 Months	Yes
CDS Transportation	10/31/2028	24 Months	Yes
FT-1 Phila Lateral	10/31/2031	60 Months	Yes
FT-1 Phila Flex X	10/31/2031]	60 Months	Yes
FT-1 Transportation ELA	10/31/2027	12 Months	Yes
FTS-2 Transportation	3/31/2028	12 Months	Yes
FTS-7 Transportation	4/15/2029	24 Months	Yes
FTS-8 Transportation	4/15/2029	24 Months	Yes
FTS Transportation	3/31/2029	24 Months	Yes
SS-1 Storage	4/30/2029	24 Months	Yes
<b>Transco</b>			
FT Transportation	3/31/2030	36 Months	Yes
FT Transportation	7/31/2029	36 Months	Yes
FT - Leidy	10/31/2028	24 Months	Yes
FT - Trenton Woodbury	10/31/2028	24 Months	Yes
S-2 Storage	3/31/2028	12 Months	Yes
<b>Eastern Gas Transmission &amp; Storage, Inc.</b>			
GSS Storage	3/31/2029	24 Months	Yes
<b>UGI</b>			

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

20 On August 8, 2025, all 90 intervening parties and Transco reached a  
21 settlement in this case. The parties in the rate case agreed to an increase that  
22 ultimately raises PECO's rates by 9.5% or \$6.4 million on the contracts that the  
23 Company has with the pipeline.

1 PECO and the other parties were able to have the pipeline eliminate  
2 Capital Improvements associated with the Modernization Tracker. As a result,  
3 PECO's rates reduced dramatically between the filing on August 30, 2024 and the  
4 final settlement. PECO's rates were to increase close to 40% between the pre-  
5 filing rates and the filed rates.

6 Adelphia filed a Section 4 Rate Case on September 30, 2024 for rate  
7 increases that will go into effect April 1, 2025, subject to refund. PECO  
8 intervened and protested in the filing. At that time, PECO currently only had one  
9 contract with Adelphia for a negotiated rate with the original contract terms  
10 through October 1, 2030, at which time PECO will be subject to cost of service  
11 tariff rates.

12 PECO will continue to actively participate in all relevant FERC  
13 proceedings to achieve the best possible rates and reliability services for PGC  
14 customers.

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

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

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

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

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

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

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

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

8 A. Section 11 of the Advance Filing Information includes a report reflecting specific  
9 contract information for each HVT Gas Choice customer. Specifically, the  
10 following information is provided for each customer: the customer's rate, size  
11 category (greater than or less than 18,000 Mcf per year), daily transportation  
12 contract quantity, firm stand-by sales quantity, if any, and commodity rate. Section  
13 12 of the Advance Filing Information provides the monthly transportation volume  
14 for each transportation customer for each month beginning April 1, 2025 and  
15 ending March 31, 2026. Specifically, the following information is provided for each  
16 customer: the customer's rate; total monthly deliveries in Mcf; and total  
17 transportation deliveries. Because this information is voluminous, PECO does not  
18 file it with the Advance Filing Information but will provide it upon request.

19 **VII. CONCLUSION**

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

21 A. Yes, it does.

2026 Balancing Charges Exhibit BGT-1				
Annual Cost for Storage (PECO PGC 43, Section 7, Page 1)				\$ 28,716,000
Storage Injection Cost				\$ 1,633,229
Storage Withdrawal Cost				\$ 1,724,844
<b>Total</b>				<b>\$ 32,800,073</b>
Aggregate Imbalances for TS Customers				
	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries		
Dec-24	82,053	31,666		
Jan-25	53,818	75,655		
Feb-25	30,929	79,175		
Mar-25	65,138	50,466		
Apr-25	40,858	47,899		
May-25	53,368	27,336		
Jun-25	33,346	89,414		
Jul-25	58,079	81,807		
Aug-25	59,760	36,259		
Sep-25	21,631	58,702		
Oct-25	52,518	46,058		
Nov-25	41,920	55,079		
<b>Total</b>	<b>593,418</b>	<b>679,516</b>		
Total Aggregate 12 Month Daily TS Imbalance in MCF				1,201,047
Projected Annual PGC Volume in MCF				68,800,149
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)				1.75%
Annual Storage Cost Applicable to Transportation Customers 1.75%	of	\$ 32,800,073		\$ 572,592
Revenue From Excess Delivery Penalty Charge for Dec 24 through Nov 25 in mcf		85,495	\$ 0.25	\$ 21,373.75
Calculation of the Proposed Adjusted Balancing Charges				
Storage Cost applicable to Transportation Customers				\$ 551,218
Divided by TS MCF Actual Dec 24 through Nov 25				23,837,010
Balancing Charge per MCF				\$ 0.0231

2026 Balancing Charges Exhibit BGT-2					2025 Balancing Charges Exhibit BGT-2				
<u>Annual Cost for Storage (PECO PGC 42, Section 7, Page 1)</u>					<u>Annual Cost for Storage (PECO PGC 41, Section 7, Page 1)</u>				
Fixed Storage Costs (includes associated transport)					Fixed Storage Costs (includes associated transport)				
\$ 29,442,000					\$ 26,791,000				
Storage Injection Cost					Storage Injection Cost				
\$ 1,633,229					\$ 1,276,387				
Storage Withdrawal Cost					Storage Withdrawal Cost				
\$ 1,724,844					\$ 2,086,070				
Total					Total				
\$ 32,800,073					\$ 30,153,457				
Aggregate Imbalances for TS Customers					Aggregate Imbalances for TS Customers				
	Aggregate Daily	Injection	Aggregate Daily	Withdrawal		Aggregate Daily	Injection	Aggregate Daily	Withdrawal
	Excess Deliveries	Wacog	Deficient Deliveries	Wacog		Excess Deliveries	Wacog	Deficient Deliveries	Wacog
Dec-24	68,067	\$ 3.3973	50,797	\$ 1.9764	Dec-23	82,053	\$ 3.4524	31,666	\$ 2.8073
Jan-25	35,754	\$ 7.3678	79,675	\$ 2.1683	Jan-24	53,818	\$ -	75,655	\$ 2.8967
Feb-25	55,990	\$ -	38,840	\$ 2.1271	Feb-24	30,929	\$ 2.4098	79,175	\$ 2.7444
Mar-25	57,097	\$ 3.7347	43,736	\$ 2.2215	Mar-24	65,138	\$ 3.6186	50,466	\$ 2.9224
Apr-25	36,454	\$ 3.2543	76,966	\$ 2.3364	Apr-24	40,858	\$ 1.4272	47,899	\$ 3.1201
May-25	69,605	\$ 2.5817	52,346	\$ 3.4049	May-24	53,368	\$ 1.4502	27,336	\$ 3.7958
Jun-25	25,165	\$ 2.5061	73,854	\$ 3.3737	Jun-24	33,346	\$ 1.9404	89,414	\$ 3.7783
Jul-25	58,961	\$ 2.5696	54,285	\$ 3.2890	Jul-24	58,079	\$ 2.3110	81,807	\$ 3.5542
Aug-25	28,437	\$ 2.7808	43,996	\$ 3.2488	Aug-24	59,760	\$ 1.4618	36,259	\$ 3.4330
Sep-25	42,491	\$ 2.1868	30,993	\$ 3.2487	Sep-24	21,631	\$ 1.5372	58,702	\$ 3.4286
Oct-25	39,997	\$ 2.1685	52,727	\$ 2.6377	Oct-24	52,518	\$ 1.9010	46,058	\$ 2.1768
Nov-25	41,407	\$ 3.7115	43,407	\$ 2.3832	Nov-24	41,920	\$ 3.0483	55,079	\$ 1.9146
Total	559,425		641,622		Total	593,418		679,516	
Total Aggregate 12 Month Daily TS Imbalance in MCF					Total Aggregate 12 Month Daily TS Imbalance in MCF				
1,201,047					1,272,934				
Projected Annual PGC Volume in MCF					Projected Annual PGC Volume in MCF				
68,800,149					68,895,451				
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)				
1.75%					1.85%				
Annual Storage Cost Applicable to Transportation Customers					Annual Storage Cost Applicable to Transportation Customers				
1.75% of \$ 32,800,073					1.85% of \$ 30,153,457				
\$ 572,592					\$ 557,125				
Revenue From Excess Delivery Penalty Charge for Dec 24 through Nov 25 in mcf					Revenue From Excess Delivery Penalty Charge for Dec 23 through Nov 24 in mcf				
85,495 \$ 0.25 \$ 21,373.75					71,182 \$ 0.25 \$ 17,795.50				
Calculation of the Proposed Adjusted Balancing Charges					Calculation of the Proposed Adjusted Balancing Charges				
Storage Cost applicable to Transportation Customers					Storage Cost applicable to Transportation Customers				
\$ 551,218					\$ 539,329				
Divided by TS MCF Actual Dec 24 through Nov 25					Divided by TS MCF Actual Dec 23 through Nov 24				
23,837,010					23,564,697				
Balancing Charge per MCF					Balancing Charge per MCF				
\$ 0.0231					\$ 0.0229				

## VERIFICATION

I, Blerina Gaba-Teme, Manager of Energy Supplier Services at PECO Energy Company, hereby state that the facts set forth in my Direct Testimony PECO Statement No. 3 in the matter at PaPUC Docket No. R-2026-3062148 are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 28, 2026

  
\_\_\_\_\_  
Blerina Gaba-Teme

**PECO STATEMENT NO. 4**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**V.**

**PECO ENERGY COMPANY**

**DOCKET NO. R-2026-3062148**

**DIRECT TESTIMONY  
OF  
JOSEPH A. BISTI**

**PECO STATEMENT NO. 4**

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**DIRECT TESTIMONY OF JOSEPH A. BISTI**

**I. INTRODUCTION**

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

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

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

A. I am employed by PECO Energy Company (“PECO” or the “Company”) as a Manager of Rate Analysts.

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

A. I received a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph’s University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned a certification as a Project Management Institute Professional in Business Analysis. In September of 2022, I was promoted to my current position.

My professional experience includes various roles involving business analysis, project leadership, and regulatory compliance within PECO’s Retail Rates, Energy Acquisition, and Information Technology departments. I am currently responsible for retail tariff administration, project management and regulatory affairs relating to PECO’s gas and electric operations.

**4. Q. Have you previously submitted testimony in rate proceedings?**

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

1 Docket No. R-2024-3046932 – *Pa. P.U.C v. PECO Energy Company – Gas*  
2 *Division*

3 Docket No. R-2024-3046931 – *Pa. P.U.C v. PECO Energy Company – Electric*  
4 *Division*

5 Docket No. R-2022-3031113 – *Pa. P.U.C v. PECO Energy Company – Gas*  
6 *Division*

7 Docket No. R-2021-3024601 – *Pa. P.U.C v. PECO Energy Company – Electric*  
8 *Division*

9 Docket No. R-2020-3018929 – *Pa. P.U.C v. PECO Energy Company – Gas*  
10 *Division*

11 Docket No. P-2020-3019290 – *Petition of PECO Energy Company for Approval*  
12 *of its Default Service Program For the Period From June 1, 2020 Through May*  
13 *31, 2025*

14 **II. PURPOSE OF TESTIMONY**

15 **5. Q. What is the purpose of your Direct Testimony?**

16 A. My Direct Testimony will describe and support the development of the Purchased Gas  
17 Cost (“PGC”) rates filed by the Company in this proceeding, PGC No. 43, to become  
18 effective December 1, 2026. Pursuant to the Company’s Gas Restructuring Settlement,  
19 filed and approved at Docket No. R-00994787, the PGC rate is unbundled into the Sales  
20 Service Cost (“SSC”) and the Balancing Service Cost (“BSC”). The SSC is a charge to  
21 those customers purchasing natural gas supply from PECO. The BSC recovers costs  
22 associated with the operations of contract storage facilities and PECO’s peaking  
23 services from all of PECO’s low-volume customers, whether they purchase their natural  
24 gas supply from PECO or from a competitive natural gas supplier. Low-volume  
25 customers are defined as customers taking service under Rate Schedules GR, CAP, GC,  
26 OL, L and MV-F.

1 My Direct Testimony also will provide the monthly demand charge for Rate TS  
2 (Transportation Service) standby sales service to become effective December 1, 2026.

3 **III. EXHIBITS SPONSORED**

4 **6. Q. Please identify the exhibits you are sponsoring in this proceeding.**

5 A. I am sponsoring the following exhibits, which were prepared under my supervision:

- 6 • Exhibit JAB-1 is a table outlining the proposed PGC No. 43 rates, effective  
7 December 1, 2026, in comparison to the Company's current PGC No. 42 Q2  
8 rates, effective on June 1, 2026.
- 9 • Exhibit JAB-2 provides the calculation including the Gas Procurement Charge  
10 ("GPC") and the development of the Merchant Function Charge ("MFC") for  
11 the applicable rate classes for the proposed December 1, 2026 PGC rates, as  
12 well as the total PGC rates for the applicable rate classes.
- 13 • Exhibit JAB-3 summarizes the computation of the PGC No. 43 SSC  
14 adjustment, exclusive of the MFC.
- 15 • Exhibit JAB-4 summarizes the computation of the PGC No. 43 BSC  
16 adjustment.

17 Also included with my Direct Testimony as Exhibit JAB-5 are the following  
18 pages, in both regular text and "redlined" versions, of PECO's proposed Supplement  
19 No. 16 to Tariff Gas – Pa. P.U.C. No. 6 ("Supplement No. 16"):

- 20 • Sixteenth revised Page No. 1 and Sixteenth revised Page No. 2.
- 21 • Eighth revised Page Nos. 42 and 48, reflecting a \$0.2940 per Mcf total decrease  
22 in the Section 1307(f) rates for Rates GR and CAP, a \$0.2900 per Mcf total  
23 decrease for Rate GC and a \$0.2882 per Mcf total decrease for Rates OL, L and  
24 MV-F.
- 25 • Third revised Page No. 43, extending the Off-System Sales Sharing Mechanism  
26 through November 30, 2029.
- 27 • Eighth revised Page Nos. 46 and 47, reflecting the Merchant Function Charge  
28 and the Price to Compare.
- 29 • Third revised Page No. 70, reflecting a \$0.0002 per Mcf increase in the  
30 Transportation Balancing Charge to a value of \$0.0231 per Mcf.

1 **IV. PROPOSED PGC RATES**

2 **7. Q. Please identify the specific time periods relevant to this filing.**

3 A. The period December 1, 2025 through April 30, 2026 reflects actual data, and the period  
4 May 1, 2026 through November 30, 2026 reflects projected data. Together, these  
5 comprise the “E” factor period. The “C” factor period, or PGC No. 43 application  
6 period, begins December 1, 2026 and ends November 30, 2027.

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

9 A. As set forth in its tariff, the Company recovers the projected cost of purchased natural  
10 gas and natural gas procurement charges through the Commodity Charge (“CC”) factor  
11 of the SSC and the “C” factor of the BSC. In addition, amounts for prior period  
12 over/under collections, refunds, interest, and other items are recovered through the Gas  
13 Cost Adjustment (“GCA”) of the SSC and the “E” factor of the BSC. In total, under  
14 PGC No. 42, which was approved by the Commission at Docket No. R-2025-3054868,  
15 the Company began recovering \$5.6809 per Mcf for Rates GR and CAP, \$5.6645 per  
16 Mcf for Rate GC and \$5.6566 per Mcf for Rates OL, L and MV-F as the bundled SSC  
17 and BSC charges applicable to its retail sales service as of December 1, 2025. These  
18 amounts were updated by a February 26, 2026 filing for PGC No. 42-Q1 that put into  
19 effect, as of March 1, 2026, PGC rates of \$7.1130 per Mcf for Rates GR and CAP,  
20 \$7.0935 per Mcf for Rate GC and \$7.0840 per Mcf for Rates OL, L and MV-F. These  
21 amounts were then updated further by a May 27, 2026 filing that put into effect, as of  
22 June 1, 2026, PGC rates of \$7.1960 per Mcf for Rates GR and CAP, \$7.1759 per Mcf  
23 for Rate GC, and \$7.1662 per Mcf for Rates OL, L and MV-F.

1 9. Q. Please describe the MFC and its impact on the June 1, 2026 PGC rate.

2 A. The Commission's Order at Docket No. P-2012-2328614<sup>1</sup> created the MFC. This  
3 charge recovers uncollectible charge-offs related to natural gas supply from PGC  
4 customers who procure their natural gas supply from PECO. The MFC rates are  
5 currently based on write-off factors of 0.47% for Rates GR and CAP, 0.16% for Rate  
6 GC, and 0.01% for Rates OL, L and MV-F, in accordance with the Commission's Final  
7 Order in the Company's 2024 Gas Distribution Base Rate Case at Docket No. R-2024-  
8 3046932. These write-off factors are applied to the CC, including the GPC portion of  
9 the PGC rate, to produce the applicable MFCs. Subsequently, the MFCs are included  
10 in the CC portion of the SSC. The MFC charges initially became effective on June 1,  
11 2015.

12 These MFCs change with PGC rate changes due to the changing CC, including  
13 GPC charges, and are not reconcilable. As a result of the different MFCs and the  
14 subsequent different CCs, the PGC rates have different values depending on the  
15 applicable rate classes. Specifically, the June 1, 2026 MFC values are \$0.0304 per Mcf  
16 for Rates GR and CAP, \$0.0103 per Mcf for Rate GC and \$0.0006 per Mcf for Rates  
17 OL, L and MV-F. These lead to June 1, 2026 total CC values of \$6.4955 per Mcf for  
18 Rates GR and CAP, \$6.4754 per Mcf for Rate GC, and \$6.4657 per Mcf for Rates OL,  
19 L and MV-F, as shown in Table JAB-1 below.

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

1

**Table JAB-1**

	<b>Rates GR and CAP (\$/Mcf)</b>	<b>Rate GC (\$/Mcf)</b>	<b>Rates OL, L and MV-F (\$/Mcf)</b>
CC including GPC	\$6.4651	\$6.4651	\$6.4651
MFC	\$0.0304	\$0.0103	\$0.0006
Total CC including GPC and MFC <b>Effective June 1, 2026</b>	\$6.4955	\$6.4754	\$6.4657

2

The June 1, 2026 GCA value of \$0.3659 per Mcf is the same for Rates GR, CAP, GC,  
 3 OL, L and MV-F. The June 1, 2026 BSC of \$0.3346 per Mcf is also the same for these  
 4 rates. The resultant PGC rates are shown below in Table JAB-2.

5

**Table JAB-2**

	<b>Rates GR and CAP (\$/Mcf)</b>	<b>Rate GC (\$/Mcf)</b>	<b>Rates OL, L and MV-F (\$/Mcf)</b>
CC	\$6.4955	\$6.4754	\$6.4657
GCA	\$0.3659	\$0.3659	\$0.3659
BSC	\$0.3346	\$0.3346	\$0.3346
Total PGC Rate <b>Effective June 1, 2026</b>	\$7.1960	\$7.1759	\$7.1662

6 **10. Q. How does the MFC impact the December 1, 2026 PGC No. 43 rate?**

7 A. The PGC rates will differ, depending on the applicable tariff rate class. Exhibit JAB-2  
 8 shows the derivation of the proposed December 1, 2026 PGC rates.

9 The write-off factors for uncollectible charge-offs are applied to the December  
 10 1, 2026 CC, including the GPC, to yield MFCs (effective December 1, 2026) of \$0.0245  
 11 per Mcf for Rates GR and CAP, \$0.0084 per Mcf for Rate GC and \$0.0005 per Mcf for  
 12 Rates OL, L and MV-F. As a result, the total December 1, 2026 CC, including the GPC  
 13 and MFC, is \$5.2456 per Mcf for Rates GR and CAP, \$5.2295 per Mcf for Rate GC,

1 and \$5.2216 per Mcf for Rates OL, L and MV-F, as shown below in Table JAB-3 and  
 2 in Exhibit JAB-2.

3 **Table JAB-3**

	<b>Rates GR and CAP (\$/Mcf)</b>	<b>Rate GC (\$/Mcf)</b>	<b>Rates OL, L and MV-F (\$/Mcf)</b>
CC including GPC	\$5.2211	\$5.2211	\$5.2211
MFC	\$0.0245	\$0.0084	\$0.0005
Total CC including GPC and MFC <b>Effective December 1, 2026</b>	\$5.2456	\$5.2295	\$5.2216

4 **11. Q. Please describe the rates proposed for PGC No. 43 effective December 1, 2026.**

5 Adding the GCA value of \$1.3536 per Mcf and the BSC of \$0.3028 per Mcf to the  
 6 above total CC values produces PGC rates, effective December 1, 2026, of \$6.9020 per  
 7 Mcf for Rates GR and CAP, \$6.8859 per Mcf for Rate GC and \$6.8780 per Mcf for  
 8 Rates OL, L and MV-F as shown below in Table JAB-4 and in Exhibit JAB-2.

9 **Table JAB-4**

	<b>Rates GR and CAP (\$/Mcf)</b>	<b>Rate GC (\$/Mcf)</b>	<b>Rates OL, L and MV-F (\$/Mcf)</b>
CC	\$5.2456	\$5.2295	\$5.2216
GCA	\$1.3536	\$1.3536	\$1.3536
BSC	\$0.3028	\$0.3028	\$0.3028
Total PGC Rate <b>Effective December 1, 2026</b>	\$6.9020	\$6.8859	\$6.8780

10 **12. Q. Please summarize the differences between the PGC No. 43 rates and the PGC No.**  
 11 **42-Q2 rates.**

12 A. The CC component of the SSC, exclusive of the MFC, is projected to decrease from  
 13 \$6.4651 per Mcf in PGC No. 42-Q2 to \$5.2211 per Mcf in PGC No. 43. The GCA  
 14 reconciliation component of the SSC will increase from \$0.3659 per Mcf in PGC No.

1 42-Q2 to a value of \$1.3536 per Mcf in PGC No. 43. Lastly, the BSC will decrease  
2 from \$0.3346 per Mcf to \$0.3028 per Mcf.

3 **13. Q. Please explain what caused the CC component of the SSC, exclusive of the MFC,**  
4 **to decrease from \$6.4651 per Mcf in PGC No. 42-Q2 to \$5.2211 per Mcf in PGC**  
5 **No. 43.**

6 A. The \$5.2211 per Mcf value of the CC, exclusive of the MFC, for PGC No. 43 is  
7 comprised of two parts. The first component is the projected recoverable fuel cost of  
8 \$353.1 million for the period December 1, 2026 through November 30, 2027 divided  
9 by twelve-month projected sales of 68,106,902 Mcf's for the same period, which  
10 equates to \$5.1851 per Mcf. In addition, a GPC of \$0.0360 per Mcf is included in the  
11 CC component. The calculation of the \$6.4651 per Mcf CC rate, exclusive of the MFC,  
12 for PGC No. 42-Q2 reflects a value of \$6.4291 per Mcf for the combination of actual  
13 and projected fuel costs and certain over/under collection data for the period December  
14 1, 2025 through November 30, 2026.<sup>2</sup> The CC rate also includes the same GPC value  
15 of \$0.0360 per Mcf.

16 **14. Q. Please explain what caused the GCA rate to increase from a value of \$0.3659 per**  
17 **Mcf in PGC No. 42-Q2 to a value of \$1.3536 per Mcf in PGC No. 43.**

18 A. The increase in the GCA rate is due to four factors. First, there was a change in the  
19 over/under collection component for the commodity cost, from a \$18.3 million under-  
20 collection balance as of November 30, 2025, reflected in the PGC No. 42-Q2 rate, to a

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

1 projected \$67.6 million under-collection balance as of November 30, 2026, which is to  
2 be collected from customers during the PGC No. 43 application period.

3 Second, there was a change in the accompanying interest balance from a \$1.0  
4 million under-collection balance as of November 30, 2025, reflected in the PGC No.  
5 42-Q2 rate, to a projected \$6.8 million under-collection balance as of November 30,  
6 2026, which is to be recovered from customers during the PGC No. 43 application  
7 period.

8 Third, there was an increase in the balance for supplier refunds, including  
9 interest, from an over-collection balance of \$259,073 as of November 30, 2025,  
10 reflected in the PGC 42-Q2 rate, to a projected over-collection balance of \$9.4 million  
11 as of November 30, 2026.

12 Finally, there was an increase in the balance Miscellaneous Surcharge Monies  
13 from zero balance as of November 30, 2025, reflected in the PGC 42-Q2 rate, to a  
14 projected over-collection balance of \$60,528. The changes in the commodity cost  
15 under-collection and interest under-collection act to increase the GCA rate. The  
16 changes in the over-collection balance of supplier refunds, including interest and  
17 miscellaneous surcharge monies, act to decrease the GCA rate.

18 **15. Q. Please explain what caused the BSC rate to decrease from \$0.3346 per Mcf in PGC**  
19 **No. 42-Q2 to \$0.3028 per Mcf for PGC No. 43.**

20 A. The portion of the total BSC rate for PGC No. 43 associated with contract storage and  
21 peaking services of \$0.4170 per Mcf is based on a projected recoverable cost of \$28.4  
22 million for the period December 1, 2026 through November 30, 2027, divided by  
23 twelve-month projected sales of 68,106,902 Mcf's for the same period. The associated  
24 value of \$0.3795 per Mcf for PGC No. 42-Q2 reflects a combination of actual and

1 projected costs and certain over/under-collection data for the period December 1, 2025  
2 through November 30, 2026.<sup>3</sup> This change caused an increase of \$0.0375 per Mcf in  
3 the BSC rate for PGC No. 43.

4 The combination of changes for over/under-collection balances for various  
5 items of the BSC rate acts to decrease the BSC rate by \$0.0693 per Mcf. The  
6 over/under-collection balance associated with contract storage and peaking services  
7 changed from a \$1.7 million under-collection balance as of November 30, 2025, to a  
8 projected over-collection balance of \$0.3 million as of November 30, 2026. In addition,  
9 the over/under-collection balance for miscellaneous surcharge monies increased from  
10 a \$4.6 million over-collection balance as of December 1, 2025, to a projected over-  
11 collection balance of \$7.1 million as of November 30, 2026. Lastly, the net interest  
12 balance changed from an over-collection balance of \$282,081 as of November 30, 2025,  
13 to a projected over-collection balance of \$348,776 as of November 30, 2026.

#### 14 V. SALES SERVICE COST COMPONENTS

15 **16. Q. Please describe the information shown in Exhibit JAB-1.**

16 A. Exhibit JAB-1 is a single sheet titled “Proposed Changes in PGC Rate Prices Effective  
17 December 1, 2026.” This sheet consists of three columns. The first column shows the  
18 unbundled rates effective June 1, 2026, from PGC No. 42-Q2. The second column  
19 shows the proposed changes to the PGC No. 42-Q2 rates. The third column is the sum  
20 of Columns 1 and 2 and shows the PGC No. 43 proposed rates set forth in Supplement  
21 No. 16, which are to become effective on December 1, 2026. Exhibit JAB-1 shows a

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

1 total decrease of \$0.2940 per Mcf between the proposed PGC No. 43 rates and current  
2 PGC No. 42-Q2 rates for Rates GR and CAP, a total decrease of \$0.2900 per Mcf for  
3 Rate GC, and a total decrease of \$0.2882 per Mcf for Rates OL, L and MV-F.

4 **17. Q. Please describe the information shown in Exhibit JAB-2.**

5 A. Exhibit JAB-2 provides the development of the MFC and its effect on the CC by rate  
6 class for the PGC No. 43 rate to be effective December 1, 2026. In addition, the GCA  
7 and BSC are included to determine the total PGC No. 43 rates by rate class to be  
8 effective December 1, 2026.

9 **18. Q. Please describe the information shown on page 1 of Exhibit JAB-3, which develops  
10 the SSC, exclusive of the MFC, for PGC No. 43 to be effective December 1, 2026.**

11 A. Exhibit JAB-3, page 1, summarizes the projected cost of natural gas, the GPC, and  
12 details of the experienced net under-collection (“E” factor or GCA). Page 1, line 1,  
13 shows the allocated projection of the commodity cost of natural gas of \$353,140,377  
14 and the associated rate of \$5.1851 per Mcf.

15 In addition, in accordance with the Commission’s Final Order in the  
16 Company’s 2024 Gas Distribution Base Rate Case at Docket No. R-2024-3046932, a  
17 GPC of \$0.0360 per Mcf, to recover procurement-related costs including labor,  
18 pensions, benefits, outside legal, information technology and working capital, is shown  
19 on page 1, line 1. The GPC is applied to PGC customers who obtain natural gas supply  
20 from PECO. This charge is included in the calculation of the CC portion of the SSC for  
21 PGC No. 42-Q2 and the proposed PGC No. 43. The charge is not reconcilable and will  
22 remain constant until the next distribution base rate case.

1                   Summing the components of the projected cost of natural gas of \$5.1851 per  
2 Mcf and the GPC of \$0.0360 per Mcf, results in a CC, exclusive of the MFC, of \$5.2211  
3 per Mcf.

4                   Lines 2.a. - e. on Page 1 of Exhibit JAB-3 summarize the items used to develop  
5 the GCA factor. This sheet shows a net amount of approximately \$65.0 million in  
6 under-collections, Rate IS profits, supplier refunds, certain SSC miscellaneous  
7 surcharge costs to be returned to customers, and interest to be recovered from customers  
8 through the GCA factor during the PGC No. 43 application period.

9 **19. Q. Please explain the basis for the approximately \$65.0 million net under-collection**  
10 **to be recovered from customers through the GCA factor.**

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

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

13 The recoverable cost of natural gas is subtracted from the CC revenues received,  
14 including the adjustment for the prior period reconciliation and excluding GPC and  
15 MFC revenues. As of November 30, 2026, the estimated total under-collection balance  
16 after reconciliation is expected to be \$67,648,828. That figure is brought forward from  
17 page 2 to page 1.

18 **Item 2: Rate IS Profit (Exhibit JAB-3, Page 5)**

19 The difference between revenues received and costs comprises “profit” from Rate IS  
20 customers. In accordance with the Company’s compliance filing in its 2020 Gas Base  
21 Rate Case at Docket No. R-2020-3018929 and as later implemented on the effective  
22 date of December 1, 2021 for PGC No. 38 at Docket No. R-2021-3025629, future  
23 profits are incorporated in distribution base rates. The remaining balance of profits

1 through November 30, 2026 of \$1,219 will be returned to customers and is determined  
2 by reconciling prior refunds/recoveries of profits through November 30, 2026.

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

4 The current period over/under-collection for the SSC is determined monthly. The  
5 current interest is calculated by applying an annual interest rate to these over/under  
6 collections which is then multiplied by a factor based on an equivalent payback to the  
7 midpoint of the PGC No. 43 application period.

8 Effective December 1, 2016, as a result of PA Act 47 and as reflected in the  
9 Company's PGC No.33 Compliance Filing at Docket No. R-2016-2545925, the interest  
10 rate used to determine monthly interest for current period under-collections and over-  
11 collections is the prime rate for commercial borrowing in effect sixty (60) days prior to  
12 the tariff filing in accordance with Section 1307(f).

13 In accordance with Paragraph 25 of the 2025 Joint Petition for Complete  
14 Settlement in the Company's PGC No. 42 Proceeding at Docket No. R-2025-3054868,  
15 the Company used the prime rate effective sixty (60) days prior to the date of this filing,  
16 which was 6.75%, for the period December 2025 through November 2026. Based on  
17 this interest rate, the current interest for the period December 2025 through November  
18 2026 to be recovered from customers for the GCA during the PGC No. 43 application  
19 period amounts to \$6,461,557.

20 Combining the under-collection balance of \$970,907 as of November 30, 2025,  
21 the current interest to be recovered from customers for the December 2025 through  
22 November 2026 time period of \$6,461,557 and the estimated recovery from customers  
23 of \$605,909 from December 1, 2025 through November 30, 2026 (Exhibit JAB-3, page  
24 6), the total interest balance at November 30, 2026, for the GCA to be recovered from

1 customers during the PGC No. 43 application period has an estimated value of  
2 \$6,826,555.

3 **Item 4: SSC Miscellaneous Surcharge Revenues-Transportation Balancing**

4 **Monies (Exhibit JAB-3, Page 7)**

5 In accordance with Paragraphs 19a and 19b of the 2025 Joint Petition for Complete  
6 Settlement in the Company's PGC No. 42 Proceeding at Docket No. R-2025-3054868  
7 effective December 1, 2025, certain variable withdrawal and injection costs paid by  
8 Transportation customers as part of their Transportation Balancing charges are being  
9 returned to SSC customers and reconciled through GCA. The amount projected to be  
10 returned to SSC customers as of November 30, 2026 is \$60,528.

11 **Item 5: Supplier Refunds (Including Interest) (Exhibit JAB-3, Page 8)**

12 This item is comprised of the actual refunds returned to the Company by suppliers after  
13 July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 43  
14 application period less the amount expected to be recovered from customers through  
15 November 30, 2026. The net result is an estimated amount of \$9,373,541 to be returned  
16 to the customers as of November 30, 2026.

17 **VI. BALANCING SERVICE COST COMPONENTS**

18 **20. Q. Please describe the information shown on page 1 of Exhibit JAB-4, which develops**  
19 **the BSC for PGC No. 43 to be effective December 1, 2026.**

20 A. Exhibit JAB-4, page 1, summarizes the projected cost that PECO will incur under  
21 natural gas storage and peaking agreements with various interstate pipeline and natural  
22 gas marketing companies and details the experienced net over/under-collection balance.  
23 Page 1, line 1, shows the projected costs for contract storage and peaking services. Lines

1 2 a. - d. on Page 1 of Exhibit JAB-4 summarize the items used to develop the “E” factor.  
2 This sheet shows that the projected recoverable cost for contract storage and peaking  
3 services is \$28.4 million for the period December 1, 2026 through November 30, 2027.  
4 There is also a projected over-collection balance of \$7.8 million as of November 30,  
5 2026. This amount includes over-collections, refunds, interest, and miscellaneous  
6 surcharge monies to be returned to customers during the PGC No. 43 application period.  
7 Page 1, Line 3 shows the \$20.625,005 net amount to be recovered from customers.

8 **21. Q. Please explain the basis for the \$20.6 million net amount to be recovered from**  
9 **customers.**

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

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

12 The projected recoverable cost for contract storage facilities and peaking services is  
13 \$28,402,393 as shown on Exhibit JAB-4, page 1.

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

15 The recoverable cost of natural gas is subtracted from the BSC revenues received,  
16 including the adjustment for the prior period reconciliation. The resulting balance is an  
17 estimated over-collection of \$275,845 as of November 30, 2026, which is brought  
18 forward from page 2 to page 1.

19 **Item 3: Miscellaneous Surcharge Monies (Exhibit JAB-4, Page 5)**

20 Transportation balancing surcharges and penalties applied to Transportation, Rate TCS  
21 and Rate IS customers are returned to firm service customers through the BSC. After  
22 reconciling refunds of prior balances and adding current surcharge monies, a projected  
23 balance of \$7,150,726 as of November 30, 2026, is expected to be returned to  
24 customers.



1 **22. Q. Does the Company propose to update the monthly demand charge for Rate TS**  
2 **standby sales service?**

3 Yes. The updated monthly demand charge for Rate TS standby sales service will be  
4 \$22.41 per Mcf.

5 **VIII. CONCLUSION**

6 **23. Q. Does this conclude your Direct Testimony?**

7 A. Yes, it does.

## VERIFICATION

I, Joseph A. Bisti, Manager of Rate Analysts at PECO Energy Company, hereby state that the facts set forth in my Direct Testimony PECO Statement No. 4 in the matter at PaPUC Docket No. R-2026-3062148 are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 28, 2026

  
\_\_\_\_\_  
Joseph A. Bisti

**Exhibit JAB-1**

## Proposed Changes in PGC Rate Prices Effective December 1, 2026

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

		<u>06/01/26</u> Unbundled Rates	Change in Rates	<u>12/01/26</u> Unbundled Rates	
<b><u>Rates GR and CAP</u></b>					
	CC	\$6.4955	(\$1.2499)	\$5.2456	
	GCA	\$0.3659	\$0.9877	\$1.3536	
	BSC	<u>\$0.3346</u>	<u>(\$0.0318)</u>	<u>\$0.3028</u>	
	Total	\$7.1960	(\$0.2940)	\$6.9020	
<b><u>Rates GC</u></b>					
	CC	\$6.4754	(\$1.2459)	\$5.2295	
	GCA	\$0.3659	\$0.9877	\$1.3536	
	BSC	<u>\$0.3346</u>	<u>(\$0.0318)</u>	<u>\$0.3028</u>	
	Total	\$7.1759	(\$0.2900)	\$6.8859	
<b><u>Rates OL, L and MV-F</u></b>					
	CC	\$6.4657	(\$1.2441)	\$5.2216	
	GCA	\$0.3659	\$0.9877	\$1.3536	
	BSC	<u>\$0.3346</u>	<u>(\$0.0318)</u>	<u>\$0.3028</u>	
	Total	\$7.1662	(\$0.2882)	\$6.8780	
<b>Rate OL</b>					
	(1.5 MCF)	<b>CC</b>	\$9.6986	(\$1.8662)	\$7.8324
	(1.7 MCF)		\$10.9917	(\$2.1150)	\$8.8767
	(2.1 MCF)		\$13.5780	(\$2.6126)	\$10.9654
	(2.4 MCF)		\$15.5177	(\$2.9859)	\$12.5318
	(1.5 MCF)	<b>GCA</b>	\$0.5489	\$1.4815	\$2.0304
	(1.7 MCF)		\$0.6220	\$1.6791	\$2.3011
	(2.1 MCF)		\$0.7684	\$2.0742	\$2.8426
	(2.4 MCF)		\$0.8782	\$2.3704	\$3.2486
	(1.5 MCF)	<b>BSC</b>	\$0.5019	(\$0.0477)	\$0.4542
	(1.7 MCF)		\$0.5688	(\$0.0540)	\$0.5148
	(2.1 MCF)		\$0.7027	(\$0.0668)	\$0.6359
	(2.4 MCF)		\$0.8030	(\$0.0763)	\$0.7267
<b>Rate L</b>					
	First 50% of Usage	<b>CC</b>	\$6.4657	(\$1.2441)	\$5.2216
	Additional Use		\$6.4657	(\$1.2441)	\$5.2216
	First 50% of Usage	<b>GCA</b>	\$0.3659	\$0.9877	\$1.3536
	Additional Use		\$0.3659	\$0.9877	\$1.3536
	First 50% of Usage	<b>BSC</b>	\$0.3346	(\$0.0318)	\$0.3028
	Additional Use		\$0.3346	(\$0.0318)	\$0.3028
<b>Standby Sales Demand Charge Under Rate TS-F</b>			\$23.78	(\$1.3700)	\$22.41
<b>Unit Credit for Rate TS-F Standby Sales Purchases</b>			\$0.78	(\$0.0400)	\$0.74
<b>Balancing Charge-Transportation</b>			\$0.0229	\$0.0002	\$0.0231

**Exhibit JAB-2**

**Exhibit JAB-2**

PGC No. 43 Calculation Including Gas Procurement Charge (GPC) and Merchant Function Charge (MFC)

Application Period : December 1, 2026 through November 30, 2027

Computation Period : December 1, 2026 through November 30, 2027

\$/Mcf

		<u>Rates GR and CAP</u>	<u>Rate GC</u>	<u>Rates OL, L and MV-F</u>
<b>CC Including GPC</b>	Exhibit JAB-3, Page 1	\$5.2211	\$5.2211	\$5.2211
x				
Write-Off Factor (a)		0.47%	0.16%	0.01%
=				
<b>MFC</b>		<u>\$0.0245</u>	<u>\$0.0084</u>	<u>\$0.0005</u>
<b>CC Including GPC and MFC</b>		\$5.2456	\$5.2295	\$5.2216
<b>GCA</b>	Exhibit JAB-3, Page 1	\$1.3536	\$1.3536	\$1.3536
<b>BSC</b>	Exhibit JAB-4, Page 1	<u>\$0.3028</u>	<u>\$0.3028</u>	<u>\$0.3028</u>
<b>Total PGC</b>		\$6.9020	\$6.8859	\$6.8780

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

**Exhibit JAB-3**

**Exhibit JAB-3**

Page 1

Computation of Sales Service Cost Adjustment No. 43  
Application and Computation Period : 12 Months  
December 1, 2026 Through November 30, 2027

1. Projected Commodity Charge Excluding Gas Procurement Charge (GPC)	\$353,140,377	Pg. 2	\$5.1851 /Mcf
GPC From Docket No. R-2024-3046932			<u>\$0.0360</u> /Mcf
<b>Total CC = Commodity Charge Including GPC</b>			<b>\$5.2211</b> /Mcf
2. E = Experienced and Estimated Net Over/(Under)			
a. Commodity Cost Over / (Under)	(\$67,648,828)	Pg. 2	(\$1.4079) /Mcf
b. Rate IS Profit Monies	\$1,219	Pg. 5	\$0.0000 /Mcf
c. Net Interest on Item a.	(\$6,826,555)	Pg. 6	(\$0.1421) /Mcf
d. Miscellaneous Surcharge Monies SSC	\$60,528	Pg. 7	\$0.0013 /Mcf
e. Supplier Refunds (Including Interest)	<u>\$9,373,541</u>	Pg. 8	<u>\$0.1951</u> /Mcf
Experienced Net Over/Under Collections - GCA	(\$65,040,095)		(\$1.3536) /Mcf
3. S = Projected Sales for Computation Period CC	68,106,902	mcf	
4. S = Projected Sales for Computation Period GCA	48,048,073	mcf	
<b>GCA Charge / (Credit) to Customers</b>			<b>\$1.3536</b> /Mcf

Month	Gross Cost of Gas	Total Exclusions	Net Cost of Gas	Allocation Factor	Recoverable Cost of Gas	CC/GCA Revenues In Base	Monthly Over/(Under) Collection	Cumulative Total
	(1)	(2)	(3) = (1) - (2)	(4)	(5) = (3) x (4)	(6)	(7) = (6) - (5)	(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	\$8,871,242	\$14,244	\$8,856,998	0.99760805	\$8,835,812	\$11,988,333	\$3,152,521	(\$9,629,562)
June	\$7,756,081	\$7,482	\$7,748,599	0.99958671	\$7,745,397	\$9,116,755	\$1,371,358	(\$8,258,204)
July	\$6,817,247	\$18,413	\$6,798,834	0.99980231	\$6,797,490	\$5,723,000	(\$1,074,490)	(\$9,332,694)
Aug	\$6,873,459	\$33,188	\$6,840,271	0.99990529	\$6,839,623	\$5,729,009	(\$1,110,614)	(\$10,443,308)
Sept	\$6,849,069	\$149,215	\$6,699,854	0.99988107	\$6,699,057	\$6,820,505	\$121,448	(\$10,321,860)
Oct	\$10,308,253	\$16,302	\$10,291,951	0.99922027	\$10,283,926	\$8,327,044	(\$1,956,882)	(\$12,278,742)
Nov	\$24,867,033	\$12,253	\$24,854,780	0.99997777	\$24,854,228	\$18,850,944	(\$6,003,284)	(\$18,282,026)
12 Months	\$239,485,453	\$252,321	\$239,233,132		\$239,092,081	\$246,903,836	\$7,811,755	
12 Months -Nov 30, 2026	\$391,225,081	\$596,402	\$390,628,679		\$390,433,046			

Month	Gross Cost of Gas	Total Exclusions	Net Cost of Gas	Allocation Factor	Recoverable Cost of Gas	CC/GCA Revenues In Base	Monthly Over/(Under) Collection	Cumulative Total
	(1)	(2)	(3) = (1) - (2)	(4)	(5) = (3) x (4)	(6)	(7) = (6) - (5)	(8)
Balance - Nov. 30, 2025								(\$18,282,026)
Dec	\$50,992,593	\$27,085	\$50,965,508	0.99886662	\$50,907,744	\$41,921,929	(\$8,985,815)	(\$27,267,841)
Jan '26	\$122,276,830	\$162,657	\$122,114,173	0.99938682	\$122,039,295	\$51,610,237	(\$70,429,058)	(\$97,696,899)
Feb	\$68,022,071	\$127,084	\$67,894,987	0.99996326	\$67,892,493	\$56,017,868	(\$11,874,625)	(\$109,571,524)
March	\$22,841,564	\$112,946	\$22,728,618	0.99919219	\$22,710,258	\$41,564,641	\$18,854,383	(\$90,717,141)
April	\$10,512,023	(\$15,774)	\$10,527,797	0.99996712	\$10,527,450	\$25,274,945	\$14,747,495	(\$75,969,646)
May (est)	\$13,734,000	\$32,351	\$13,701,649	0.99798303	\$13,674,013	\$15,590,506	\$1,916,493	(\$74,053,153)
June (est)	\$12,750,000	\$26,995	\$12,723,005	0.99960189	\$12,717,940	\$9,892,288	(\$2,825,652)	(\$76,878,805)
July (est)	\$12,370,000	\$21,126	\$12,348,874	0.99987744	\$12,347,360	\$9,256,658	(\$3,090,702)	(\$79,969,507)
Aug (est)	\$12,732,000	\$19,309	\$12,712,691	0.99994192	\$12,711,953	\$9,396,660	(\$3,315,293)	(\$83,284,800)
Sept (est)	\$12,616,000	\$19,420	\$12,596,580	0.99992129	\$12,595,588	\$10,643,848	(\$1,951,740)	(\$85,236,540)
Oct (est)	\$17,940,000	\$22,050	\$17,917,950	0.99969203	\$17,912,432	\$22,602,772	\$4,690,340	(\$80,546,200)
Nov (est)	\$34,438,000	\$41,153	\$34,396,847	0.99999048	\$34,396,520	\$47,293,892	\$12,897,372	(\$67,648,828)
12 Months	\$391,225,081	\$596,402	\$390,628,679		\$390,433,046	\$341,066,244	(\$49,366,802)	
12 Months -Nov 30, 2027	\$353,846,600	\$564,550	\$353,282,050		\$353,140,377			

Exclusions								Allocation Factor Calculation					
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (2)	Cost of Indtdpt. IS Gas (3)	Cost of TCS Gas (4)	Cost of MV-I Gas (5)	Rate NGS Exclusion (6)	Total Exclusions (7)	Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	\$0	\$0	\$0	\$0	\$220	\$0	\$220	Dec	5,641	6,075,805	6,081,446	0.99907242	6,075,805
Jan '25	\$0	\$0	\$0	\$0	\$304	\$0	\$304	Jan '25	7,232	9,337,992	9,345,224	0.99922613	9,337,992
Feb	\$0	\$0	\$0	\$0	\$265	\$0	\$265	Feb	3,130	8,642,238	8,645,368	0.99963796	8,642,238
March	\$0	\$0	\$0	(\$31,086)	\$259	\$0	(\$30,827)	March	2,088	7,405,461	7,407,549	0.99971813	7,405,461
April	\$0	\$0	\$0	\$31,041	\$221	\$0	\$31,262	April	2,818	4,092,893	4,095,711	0.99931196	4,092,893
May	\$0	\$4,276	\$0	\$9,805	\$163	\$0	\$14,244	May	4,864	2,028,620	2,033,484	0.99760805	2,028,620
June	\$0	\$0	\$0	\$7,416	\$66	\$0	\$7,482	June	603	1,458,424	1,459,027	0.99958671	1,458,424
July	\$0	\$0	\$0	\$18,400	\$13	\$0	\$18,413	July	171	864,802	864,973	0.99980231	864,802
Aug	\$0	\$0	\$0	\$33,173	\$15	\$0	\$33,188	Aug	82	865,710	865,792	0.99990529	865,710
Sept	\$0	\$0	\$0	\$149,194	\$21	\$0	\$149,215	Sept	126	1,059,282	1,059,408	0.99988107	1,059,282
Oct	\$0	\$51	\$0	\$16,183	\$68	\$0	\$16,302	Oct	1,039	1,331,475	1,332,514	0.99922027	1,331,475
Nov	\$0	\$0	\$0	\$12,249	\$4	\$0	\$12,253	Nov	67	3,014,222	3,014,289	0.99997777	3,014,222
12 Months	\$0	\$4,327	\$0	\$246,375	\$1,619	\$0	\$252,321	12 Months	27,861	46,176,924	46,204,785		46,176,924
12 Months -Nov 30, 2026	\$0	\$40,544	\$0	\$554,141	\$1,717	\$0	\$596,402						

(a) Rate CGS was eliminated effective July 1, 2021 as a result of the Company's 2020 Gas Distribution Base Rate Case at Docket No. R-2020-3018929.

Exclusions								Allocation Factor Calculation					
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (2)	Cost of Indtdpt. IS Gas (3)	Cost of TCS Gas (4)	Cost of MV-I Gas (5)	Rate NGS Exclusion (6)	Total Exclusions (7)	Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	\$0	\$4,810	\$0	\$21,989	\$286	\$0	\$27,085	Dec	8,276	7,293,746	7,302,022	0.99886662	7,293,746
Jan '26	\$0	\$951	\$0	\$161,393	\$313	\$0	\$162,657	Jan '26	6,031	9,829,585	9,835,616	0.99938682	9,829,585
Feb	\$0	\$11,159	\$0	\$115,347	\$578	\$0	\$127,084	Feb	392	10,669,054	10,669,446	0.99996326	10,669,054
March	\$0	\$594	\$0	\$112,295	\$57	\$0	\$112,946	March	5,691	7,039,247	7,044,938	0.99919219	7,039,247
April	\$0	\$523	\$0	(\$16,297)	\$0	\$0	(\$15,774)	April	125	3,801,029	3,801,154	0.99996712	3,801,029
May (est)	\$0	\$2,579	\$0	\$29,719	\$53	\$0	\$32,351	May (est)	4,864	2,406,674	2,411,538	0.99798303	1,341,159
June (est)	\$0	\$2,785	\$0	\$24,151	\$59	\$0	\$26,995	June (est)	603	1,514,059	1,514,662	0.99960189	776,755
July (est)	\$0	\$3,217	\$0	\$17,843	\$66	\$0	\$21,126	July (est)	171	1,395,034	1,395,205	0.99987744	817,271
Aug (est)	\$0	\$3,372	\$0	\$15,866	\$71	\$0	\$19,309	Aug (est)	82	1,411,813	1,411,895	0.99994192	908,494
Sept (est)	\$0	\$3,097	\$0	\$16,256	\$67	\$0	\$19,420	Sept (est)	126	1,600,639	1,600,765	0.99992129	1,002,778
Oct (est)	\$0	\$3,156	\$0	\$18,825	\$69	\$0	\$22,050	Oct (est)	1,039	3,372,710	3,373,749	0.99969203	2,610,110
Nov (est)	\$0	\$4,301	\$0	\$36,754	\$98	\$0	\$41,153	Nov (est)	67	7,037,818	7,037,885	0.99999048	5,812,193
12 Months	\$0	\$40,544	\$0	\$554,141	\$1,717	\$0	\$596,402	12 Months	27,467	57,371,409	57,398,876		51,901,422
12 Months -Nov 30, 2027	\$0	\$46,425	\$0	\$517,116	\$1,009	\$0	\$564,550						

(a) Rate CGS was eliminated effective July 1, 2021 as a result of the Company's 2020 Gas Distribution Base Rate Case at Docket No. R-2020-3018929.

SSC Revenues

Exhibit JAB-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	2,028,620	\$5.3602	\$10,873,809	2,028,620	\$0.5494	\$1,114,524	\$11,988,333
June	1,458,424	\$5.7096	\$8,327,018	1,458,424	\$0.5415	\$789,737	\$9,116,755
July	864,802	\$6.0846	\$5,261,974	864,802	\$0.5331	\$461,026	\$5,723,000
Aug	865,710	\$6.0846	\$5,267,499	865,710	\$0.5331	\$461,510	\$5,729,009
Sept	1,059,282	\$5.9137	\$6,264,276	1,059,282	\$0.5251	\$556,229	\$6,820,505
Oct	1,331,475	\$5.7372	\$7,638,938	1,331,475	\$0.5168	\$688,106	\$8,327,044
Nov	3,014,222	\$5.7372	\$17,293,194	3,014,222	\$0.5168	\$1,557,750	\$18,850,944
12 Months	46,176,924		\$231,495,200	46,176,924		\$15,408,636	\$246,903,836

SSC Revenues

Exhibit JAB-3

Page 4

	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	3,613,468	\$5.7372	\$20,731,189	3,613,468	\$0.5168	\$1,867,440	\$22,598,629
Dec aft 12/1	3,680,278	\$5.2325	\$19,257,055	3,680,278	\$0.0180	\$66,245	\$19,323,300
Jan '26 bef 12/1	-	\$5.7372	\$0		\$0.5168	\$0	\$0
Jan '26 aft 12/1	9,829,585	\$5.2325	\$51,433,304	9,829,585	\$0.0180	\$176,933	\$51,610,237
Feb	10,669,054	\$5.2325	\$55,825,825	10,669,054	\$0.0180	\$192,043	\$56,017,868
March	7,039,247	\$5.7140	\$40,222,257	7,039,247	\$0.1907	\$1,342,384	\$41,564,641
April	3,801,029	\$6.2622	\$23,802,806	3,801,029	\$0.3873	\$1,472,139	\$25,274,945
May (est)	2,406,674	\$6.2622	\$15,071,075	1,341,159	\$0.3873	\$519,431	\$15,590,506
June (est)	1,514,059	\$6.3437	\$9,604,733	776,755	\$0.3702	\$287,555	\$9,892,288
July (est)	1,395,034	\$6.4291	\$8,968,815	817,271	\$0.3522	\$287,843	\$9,256,658
Aug (est)	1,411,813	\$6.4291	\$9,076,688	908,494	\$0.3522	\$319,972	\$9,396,660
Sept (est)	1,600,639	\$6.4291	\$10,290,670	1,002,778	\$0.3522	\$353,178	\$10,643,848
Oct (est)	3,372,710	\$6.4291	\$21,683,491	2,610,110	\$0.3522	\$919,281	\$22,602,772
Nov (est)	7,037,818	\$6.4291	\$45,246,838	5,812,193	\$0.3522	\$2,047,054	\$47,293,892
12 Months	57,371,409		\$331,214,746	51,901,422		\$9,851,498	\$341,066,244

IS Profits

	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue (4) = (1)-(2)-(3)	Reg IS Sales Mcf (5)	Commodity Cost/Mcf (6)	Total Reg IS Cost of Gas (7) = (5) x (6)	Increase In Taxable Income (8) = (4) - (7)	Profit to Be Returned To Customers (9) = (8) x 0% (a)	Applicable GCA Sales (10)	IS Profit Return Rate (11)	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
Balance - Nov. 30, 2024													\$1,219
Dec bef 12/1										2,810,485	\$0.0000	\$0	\$1,219
Dec aft 12/1	\$0	\$0	\$0	\$0	0	\$4.1453	\$0	\$0	\$0	3,265,320	\$0.0000	\$0	\$1,219
Jan '25 bef 12/1										0	\$0.0000	\$0	\$1,219
Jan '25 aft 12/1	\$0	\$0	\$0	\$0	0	\$7.7850	\$0	\$0	\$0	9,337,992	\$0.0000	\$0	\$1,219
Feb	\$0	\$0	\$0	\$0	0	\$9.1508	\$0	\$0	\$0	8,642,238	\$0.0000	\$0	\$1,219
March	\$0	\$0	\$0	\$0	0	\$4.1775	\$0	\$0	\$0	7,405,461	\$0.0000	\$0	\$1,219
April	\$0	\$0	\$0	\$0	0	\$3.8775	\$0	\$0	\$0	4,092,893	\$0.0000	\$0	\$1,219
May	\$13,771	\$0	\$0	\$13,771	1,417	\$3.0173	\$4,276	\$9,495	\$0	2,028,620	\$0.0000	\$0	\$1,219
June	\$0	\$0	\$0	\$0	0	\$3.8916	\$0	\$0	\$0	1,458,424	\$0.0000	\$0	\$1,219
July	\$0	\$0	\$0	\$0	0	\$3.1702	\$0	\$0	\$0	864,802	\$0.0000	\$0	\$1,219
Aug	\$0	\$0	\$0	\$0	0	\$2.9084	\$0	\$0	\$0	865,710	\$0.0000	\$0	\$1,219
Sept	\$0	\$0	\$0	\$0	0	\$1.9060	\$0	\$0	\$0	1,059,282	\$0.0000	\$0	\$1,219
Oct	\$432	\$0	\$0	\$432	15	\$3.4155	\$51	\$381	\$0	1,331,475	\$0.0000	\$0	\$1,219
Nov	\$0	\$0	\$0	\$0	0	\$4.0326	\$0	\$0	\$0	3,014,222	\$0.0000	\$0	\$1,219
12 Months	\$14,203	\$0	\$0	\$14,203	1,432		\$4,327	\$9,876	\$0	46,176,924		\$0	\$0

**Balance**

at Nov 30, 2025

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

\$1,219

IS Profits

	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue (4) = (1)-(2)-(3)	Reg IS Sales Mcf (5)	Commodity Cost/Mcf (6)	Total Reg IS Cost of Gas (7) = (5) x (6)	Increase In Taxable Income (8) = (4) - (7)	Profit to Be Returned To Customers (9) = (8) x 0% (a)	Applicable GCA Sales (10)	IS Profit Return Rate (11)	IS Profits Distributed to Custs. (12) = (10) x (11)	Cumulative Over/(Under) Reconciliation (13) = (9) - (12)
Balance - Nov. 30, 2025													\$1,219
Dec bef 12/1										3,613,468	\$0.0000	\$0	\$1,219
Dec aft 12/1	\$5,686	\$0	\$0	\$5,686	756	\$6.3626	\$4,810	\$876	\$0	3,680,278	\$0.0000	\$0	\$1,219
Jan '26 bef 12/1										0	\$0.0000	\$0	\$1,219
Jan '26 aft 12/1	\$796	\$0	\$0	\$796	85	\$11.1890	\$951	(\$155)	\$0	9,829,585	\$0.0000	\$0	\$1,219
Feb	\$3,465	\$0	\$0	\$3,465	386	\$28.9100	\$11,159	(\$7,694)	\$0	10,669,054	\$0.0000	\$0	\$1,219
March	\$1,896	\$0	\$0	\$1,896	187	\$3.1747	\$594	\$1,302	\$0	7,039,247	\$0.0000	\$0	\$1,219
April	\$1,896	\$0	\$0	\$1,896	187	\$2.7972	\$523	\$1,373	\$0	3,801,029	\$0.0000	\$0	\$1,219
May (est)	\$5,920	\$0	\$0	\$5,920	1,194	\$2.1600	\$2,579	\$3,341	\$0	1,341,159	\$0.0000	\$0	\$1,219
June (est)	\$6,046	\$0	\$0	\$6,046	1,165	\$2.3900	\$2,785	\$3,261	\$0	776,755	\$0.0000	\$0	\$1,219
July (est)	\$6,538	\$0	\$0	\$6,538	1,187	\$2.7100	\$3,217	\$3,321	\$0	817,271	\$0.0000	\$0	\$1,219
Aug (est)	\$6,827	\$0	\$0	\$6,827	1,235	\$2.7300	\$3,372	\$3,455	\$0	908,494	\$0.0000	\$0	\$1,219
Sept (est)	\$6,633	\$0	\$0	\$6,633	1,264	\$2.4500	\$3,097	\$3,536	\$0	1,002,778	\$0.0000	\$0	\$1,219
Oct (est)	\$6,835	\$0	\$0	\$6,835	1,315	\$2.4000	\$3,156	\$3,679	\$0	2,610,110	\$0.0000	\$0	\$1,219
Nov (est)	\$8,015	\$0	\$0	\$8,015	1,328	\$3.2400	\$4,301	\$3,714	\$0	5,812,193	\$0.0000	\$0	\$1,219
12 Months	\$60,552	\$0	\$0	\$60,552	10,289		\$40,544	\$20,008	\$0	51,901,422		\$0	\$0

**Balance**

at Nov 30, 2026

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

\$1,219







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	2,028,620	\$0.0000	\$0	(\$1,311)
June	1,458,424	\$0.0000	\$0	(\$1,311)
July	864,802	\$0.0000	\$0	(\$1,311)
Aug	865,710	\$0.0000	\$0	(\$1,311)
Sept	1,059,282	\$0.0000	\$0	(\$1,311)
Oct	1,331,475	\$0.0000	\$0	(\$1,311)
Nov	3,014,222	\$0.0000	\$0	(\$1,311)
12 Months	46,176,924		\$0	
Balance at Nov 30, 2025				(\$1,311)

Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2025				(\$1,311)
Dec bef 12/1	3,613,468	\$0.0000	\$0	(\$1,311)
Dec aft 12/1	3,680,278	\$0.0000	\$0	(\$1,311)
Jan '26 bef 12/1	-	\$0.0000	\$0	(\$1,311)
Jan '26 aft 12/1	9,829,585	\$0.0000	\$0	(\$1,311)
Feb	10,669,054	\$0.0000	\$0	(\$1,311)
March	7,039,247	\$0.0000	\$0	(\$1,311)
April	3,801,029	\$0.0000	\$0	(\$1,311)
May (est)	1,341,159	\$0.0000	\$0	(\$1,311)
June (est)	776,755	\$0.0000	\$0	(\$1,311)
July (est)	817,271	\$0.0000	\$0	(\$1,311)
Aug (est)	908,494	\$0.0000	\$0	(\$1,311)
Sept (est)	1,002,778	\$0.0000	\$0	(\$1,311)
Oct (est)	2,610,110	\$0.0000	\$0	(\$1,311)
Nov (est)	5,812,193	\$0.0000	\$0	(\$1,311)
12 Months	51,901,422		\$0	
Balance at Nov 30, 2026				(\$1,311)

Month	Gross Cost of Gas	Total Exclusions	Net Cost of Gas	Allocation Factor	Recoverable Cost of Gas
	(1)	(2)	(3) = (1) - (2)	(4)	(5) = (3) x (4)
Balance - Nov. 30, 2026					
Dec (est)	\$50,848,550	\$70,142	\$50,778,408	0.99925289	\$50,740,471
Jan '27 (est)	\$65,542,550	\$102,804	\$65,439,746	0.99954848	\$65,410,199
Feb (est)	\$54,386,300	\$90,464	\$54,295,836	0.99996487	\$54,293,929
March (est)	\$40,271,800	\$70,324	\$40,201,476	0.99936732	\$40,176,041
April (est)	\$21,938,300	\$43,176	\$21,895,124	0.99997278	\$21,894,528
May (est)	\$15,512,300	\$33,953	\$15,478,347	0.99795157	\$15,446,641
June (est)	\$13,541,300	\$29,858	\$13,511,442	0.99961932	\$13,506,299
July (est)	\$13,307,300	\$21,244	\$13,286,056	0.99987712	\$13,284,423
Aug (est)	\$13,360,300	\$19,286	\$13,341,014	0.99994245	\$13,340,246
Sept (est)	\$13,273,300	\$19,704	\$13,253,596	0.99992211	\$13,252,564
Oct (est)	\$18,507,300	\$22,814	\$18,484,486	0.99969388	\$18,478,828
Nov (est)	\$33,357,300	\$40,781	\$33,316,519	0.99999065	\$33,316,208
12 Months	\$353,846,600	\$564,550	\$353,282,050		\$353,140,377

SSC Revenues

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)
Dec bef 12/1	5,641,443	\$6.4291	\$36,269,401
Dec aft 12/1	5,427,590	\$5.1851	\$28,142,596
Jan '27 bef 12/1	-	\$6.4291	\$0
Jan '27 aft 12/1	13,351,111	\$5.1851	\$69,226,843
Feb (est)	11,158,391	\$5.1851	\$57,857,375
March (est)	8,989,310	\$5.1851	\$46,610,469
April (est)	4,592,251	\$5.1851	\$23,811,282
May (est)	2,369,640	\$5.1851	\$12,286,822
June (est)	1,583,423	\$5.1851	\$8,210,208
July (est)	1,391,428	\$5.1851	\$7,214,695
Aug (est)	1,424,676	\$5.1851	\$7,387,088
Sept (est)	1,617,487	\$5.1851	\$8,386,832
Oct (est)	3,393,078	\$5.1851	\$17,593,449
Nov (est)	7,167,074	\$5.1851	\$37,161,993
12 Months	68,106,902		\$360,159,053

Interest on Moneys Owed to Customers - Summary

Month	CC Portion of SSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)
Balance			
- Nov. 30, 2026			
Dec bef 12/1			
Dec aft 12/1	\$64,411,997	\$50,740,471	\$13,671,526
Jan '27 bef 12/1			
Jan '27 aft 12/1	\$69,226,843	\$65,410,199	\$3,816,644
Feb (est)	\$57,857,375	\$54,293,929	\$3,563,446
March (est)	\$46,610,469	\$40,176,041	\$6,434,428
April (est)	\$23,811,282	\$21,894,528	\$1,916,754
May (est)	\$12,286,822	\$15,446,641	(\$3,159,819)
June (est)	\$8,210,208	\$13,506,299	(\$5,296,091)
July (est)	\$7,214,695	\$13,284,423	(\$6,069,728)
Aug (est)	\$7,387,088	\$13,340,246	(\$5,953,158)
Sept (est)	\$8,386,832	\$13,252,564	(\$4,865,732)
Oct (est)	\$17,593,449	\$18,478,828	(\$885,379)
Nov (est)	\$37,161,993	\$33,316,208	\$3,845,785
12 Months	\$360,159,053	\$353,140,377	\$7,018,676

**Exhibit JAB-4**

Computation of Balancing Service Cost Adjustment No. 43  
Application and Computation Period : 12 Months  
December 1, 2026 Through November 30, 2027

1. C = Projected Cost of Gas for Application Period	\$28,402,393	Pg. 2	\$0.4170 /Mcf
2. E = Experienced and Estimated Net Over/(Under)			
a. Balancing Over / (Under)	\$275,845	Pg. 2	\$0.0041 /Mcf
b. Miscellaneous Surcharge Monies BSC	\$7,150,726	Pg. 5	\$0.1050 /Mcf
c. Net Interest on Item a.	\$348,776	Pg. 6	\$0.0051 /Mcf
d. Supplier Refunds (Including Interest)	<u>\$2,041</u>	Pg. 7	<u>\$0.0000</u> /Mcf
Experienced Net Over/(Under) Collections	\$7,777,388		\$0.1142 /Mcf
3. C - E	\$20,625,005		\$0.3028 /Mcf
4. S = Projected Sales for Computation Period	68,106,902	mcf	
<b>Charge / (Credit) to Customers</b>			<b>\$0.3028 /Mcf</b>

Over/(Under) Collections

Exhibit JAB-4  
Page 2

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2024							\$401,427
Dec	\$2,216,757	\$24,265	\$2,192,492	0.99932650	\$2,191,015	\$3,132,432	\$941,417	\$1,342,844
Jan '25	\$2,251,466	\$26,692	\$2,224,774	0.99943232	\$2,223,511	\$4,952,906	\$2,729,395	\$4,072,239
Feb	\$2,290,785	\$26,834	\$2,263,951	0.99973298	\$2,263,346	\$4,558,613	\$2,295,267	\$6,367,506
March	\$2,241,138	\$24,383	\$2,216,755	0.99979540	\$2,216,301	\$4,139,334	\$1,923,033	\$8,290,539
April	\$2,322,310	\$29,355	\$2,292,955	0.99951755	\$2,291,849	\$2,469,581	\$177,732	\$8,468,271
May	\$2,404,140	\$27,841	\$2,376,299	0.99843046	\$2,372,569	\$1,308,819	(\$1,063,750)	\$7,404,521
June	\$2,410,647	\$28,125	\$2,382,522	0.99972545	\$2,381,868	\$905,738	(\$1,476,130)	\$5,928,391
July	\$2,403,623	\$29,211	\$2,374,412	0.99988148	\$2,374,131	\$578,902	(\$1,795,229)	\$4,133,162
Aug	\$2,435,354	\$30,131	\$2,405,223	0.99994011	\$2,405,079	\$549,392	(\$1,855,687)	\$2,277,475
Sept	\$2,429,628	\$44,760	\$2,384,868	0.99992397	\$2,384,687	\$661,863	(\$1,722,824)	\$554,651
Oct	\$2,410,950	\$17,287	\$2,393,663	0.99950408	\$2,392,476	\$832,185	(\$1,560,291)	(\$1,005,640)
Nov	\$2,417,314	\$31,176	\$2,386,138	0.99998420	\$2,386,100	\$1,684,915	(\$701,185)	(\$1,706,825)
12 Months	\$28,234,112	\$340,060	\$27,894,052		\$27,882,932	\$25,774,680	(\$2,108,252)	
12 Months -Nov 30, 2026	\$28,988,735	\$272,858	\$28,715,877		\$28,704,197			

Over/(Under) Collections

Exhibit JAB-4  
Page 2

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2025							(\$1,706,825)
Dec	\$2,401,104	\$30,539	\$2,370,565	0.99917813	\$2,368,617	\$4,182,191	\$1,813,574	\$106,749
Jan '26	\$2,504,441	\$3,078	\$2,501,363	0.99954905	\$2,500,235	\$5,796,324	\$3,296,089	\$3,402,838
Feb	\$2,565,089	\$31,763	\$2,533,326	0.99997280	\$2,533,257	\$6,247,766	\$3,714,509	\$7,117,347
March	\$2,507,660	\$36,807	\$2,470,853	0.99941111	\$2,469,398	\$4,293,072	\$1,823,674	\$8,941,021
April	\$2,391,441	\$22,314	\$2,369,127	0.99997660	\$2,369,072	\$2,439,933	\$70,861	\$9,011,882
May (est)	\$2,373,000	\$21,668	\$2,351,332	0.99798303	\$2,346,589	\$1,099,369	(\$1,247,220)	\$7,764,662
June (est)	\$2,348,000	\$20,101	\$2,327,899	0.99960189	\$2,326,972	\$652,105	(\$1,674,867)	\$6,089,795
July (est)	\$2,373,000	\$20,181	\$2,352,819	0.99987744	\$2,352,531	\$562,618	(\$1,789,913)	\$4,299,882
Aug (est)	\$2,373,000	\$19,566	\$2,353,434	0.99994192	\$2,353,297	\$569,384	(\$1,783,913)	\$2,515,969
Sept (est)	\$2,348,000	\$18,632	\$2,329,368	0.99992129	\$2,329,185	\$645,538	(\$1,683,647)	\$832,322
Oct (est)	\$2,373,000	\$21,919	\$2,351,081	0.99969203	\$2,350,357	\$1,360,215	(\$990,142)	(\$157,820)
Nov (est)	\$2,431,000	\$26,290	\$2,404,710	0.99999048	\$2,404,687	\$2,838,352	\$433,665	\$275,845
12 Months	\$28,988,735	\$272,858	\$28,715,877		\$28,704,197	\$30,686,867	\$1,982,670	
12 Months -Nov 30, 2027	\$28,716,000	\$301,973	\$28,414,027		\$28,402,393			

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	\$26,599	\$2,756	\$0	\$29,355
May	\$26,834	\$1,007	\$0	\$27,841
June	\$27,315	\$810	\$0	\$28,125
July	\$27,226	\$1,985	\$0	\$29,211
Aug	\$26,798	\$3,333	\$0	\$30,131
Sept	\$27,178	\$17,582	\$0	\$44,760
Oct	\$15,487	\$1,800	\$0	\$17,287
Nov	\$30,193	\$983	\$0	\$31,176
12 Months	\$312,325	\$27,735	\$0	\$340,060
12 Months -Nov 30, 2026	\$0	\$0	\$0	\$0

Allocation Factor Calculation				
Month	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (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	4,864	3,094,135	3,098,999	0.99843046
June	603	2,195,728	2,196,331	0.99972545
July	171	1,442,565	1,442,736	0.99988148
Aug	82	1,369,029	1,369,111	0.99994011
Sept	126	1,657,143	1,657,269	0.99992397
Oct	1,039	2,094,075	2,095,114	0.99950408
Nov	67	4,239,847	4,239,914	0.99998420
12 Months	27,861	64,954,945	64,982,806	

(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	\$28,827	\$1,712	\$0	\$30,539
Jan '26	(\$3,550)	\$6,628	\$0	\$3,078
Feb	\$24,913	\$6,850	\$0	\$31,763
March	\$26,791	\$10,016	\$0	\$36,807
April	\$24,018	(\$1,704)	\$0	\$22,314
May (est)	\$18,297	\$3,371	\$0	\$21,668
June (est)	\$17,521	\$2,580	\$0	\$20,101
July (est)	\$18,417	\$1,764	\$0	\$20,181
Aug (est)	\$18,005	\$1,561	\$0	\$19,566
Sept (est)	\$16,921	\$1,711	\$0	\$18,632
Oct (est)	\$19,913	\$2,006	\$0	\$21,919
Nov (est)	\$23,056	\$3,234	\$0	\$26,290
12 Months	\$233,129	\$39,729	\$0	\$272,858
12 Months -Nov 30, 2027	\$256,780	\$45,193	\$0	\$301,973

Allocation Factor Calculation				
Month	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	8,276	10,061,426	10,069,702	0.99917813
Jan '26	6,031	13,367,905	13,373,936	0.99954905
Feb	392	14,409,055	14,409,447	0.99997280
March	5,691	9,658,206	9,663,897	0.99941111
April	125	5,341,359	5,341,484	0.99997660
May (est)	4,864	2,406,674	2,411,538	0.99798303
June (est)	603	1,514,059	1,514,662	0.99960189
July (est)	171	1,395,034	1,395,205	0.99987744
Aug (est)	82	1,411,813	1,411,895	0.99994192
Sept (est)	126	1,600,639	1,600,765	0.99992129
Oct (est)	1,039	3,372,710	3,373,749	0.99969203
Nov (est)	67	7,037,818	7,037,885	0.99999048
12 Months	27,467	71,576,699	71,604,166	

(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

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	3,094,135	\$0.4292	\$1,328,003	(\$0.0062)	(\$19,184)	\$1,308,819
June	2,195,728	\$0.4186	\$919,132	(\$0.0061)	(\$13,394)	\$905,738
July	1,442,565	\$0.4073	\$587,557	(\$0.0060)	(\$8,655)	\$578,902
Aug	1,369,029	\$0.4073	\$557,606	(\$0.0060)	(\$8,214)	\$549,392
Sept	1,657,143	\$0.4053	\$671,640	(\$0.0059)	(\$9,777)	\$661,863
Oct	2,094,075	\$0.4032	\$844,331	(\$0.0058)	(\$12,146)	\$832,185
Nov	4,239,847	\$0.4032	\$1,709,506	(\$0.0058)	(\$24,591)	\$1,684,915
12 Months	64,954,945		\$26,852,724		(\$1,078,044)	\$25,774,680

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	4,984,632	\$0.4032	\$2,009,804	(\$0.0058)	(\$28,911)	\$1,980,893
Dec aft 12/1	5,076,794	\$0.4240	\$2,152,561	\$0.0096	\$48,737	\$2,201,298
Jan '26 bef 12/1	-	\$0.4032	\$0	(\$0.0058)	\$0	\$0
Jan '26 aft 12/1	13,367,905	\$0.4240	\$5,667,992	\$0.0096	\$128,332	\$5,796,324
Feb	14,409,055	\$0.4240	\$6,109,439	\$0.0096	\$138,327	\$6,247,766
March	9,658,206	\$0.4274	\$4,127,917	\$0.0171	\$165,155	\$4,293,072
April (est)	5,341,359	\$0.4312	\$2,303,194	\$0.0256	\$136,739	\$2,439,933
May (est)	2,406,674	\$0.4312	\$1,037,758	\$0.0256	\$61,611	\$1,099,369
June (est)	1,514,059	\$0.4060	\$614,708	\$0.0247	\$37,397	\$652,105
July (est)	1,395,034	\$0.3795	\$529,416	\$0.0238	\$33,202	\$562,618
Aug (est)	1,411,813	\$0.3795	\$535,783	\$0.0238	\$33,601	\$569,384
Sept (est)	1,600,639	\$0.3795	\$607,443	\$0.0238	\$38,095	\$645,538
Oct (est)	3,372,710	\$0.3795	\$1,279,944	\$0.0238	\$80,271	\$1,360,215
Nov (est)	7,037,818	\$0.3795	\$2,670,852	\$0.0238	\$167,500	\$2,838,352
12 Months	71,576,699		\$29,646,811		\$1,040,056	\$30,686,867





Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			Cumulative Total (9) = (5)-(8)
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	
Balance	-Nov 30, 2024								\$2,041
Dec bef 12/1						3,871,722	\$0.0000	\$0	\$2,041
Dec aft 12/1	\$0	6.00%	18/12	\$0	\$0	4,498,301	\$0.0000	\$0	\$2,041
Jan '25 bef 12/1						-	\$0.0000	\$0	\$2,041
Jan '25 aft 12/1	\$0	6.00%	17/12	\$0	\$0	12,732,406	\$0.0000	\$0	\$2,041
Feb	\$0	6.00%	16/12	\$0	\$0	11,718,799	\$0.0000	\$0	\$2,041
March	\$0	6.00%	15/12	\$0	\$0	10,202,942	\$0.0000	\$0	\$2,041
April	\$0	6.00%	14/12	\$0	\$0	5,838,253	\$0.0000	\$0	\$2,041
May	\$0	6.00%	13/12	\$0	\$0	3,094,135	\$0.0000	\$0	\$2,041
June	\$0	6.00%	12/12	\$0	\$0	2,195,728	\$0.0000	\$0	\$2,041
July	\$0	6.00%	11/12	\$0	\$0	1,442,565	\$0.0000	\$0	\$2,041
Aug	\$0	6.00%	10/12	\$0	\$0	1,369,029	\$0.0000	\$0	\$2,041
Sept	\$0	6.00%	9/12	\$0	\$0	1,657,143	\$0.0000	\$0	\$2,041
Oct	\$0	6.00%	8/12	\$0	\$0	2,094,075	\$0.0000	\$0	\$2,041
Nov	\$0	6.00%	7/12	\$0	\$0	4,239,847	\$0.0000	\$0	\$2,041
12 Months	\$0			\$0	\$0	64,954,945		\$0	\$0
Balance at Nov 30, 2025									\$2,041

Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			Cumulative Total (9) = (5)-(8)
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	
Balance	-Nov 30, 2025								\$2,041
Dec bef 12/1						4,984,632	\$0.0000	\$0	\$2,041
Dec aft 12/1	\$0	6.00%	18/12	\$0	\$0	5,076,794	\$0.0000	\$0	\$2,041
Jan '26 bef 12/1						-	\$0.0000	\$0	\$2,041
Jan '26 aft 12/1	\$0	6.00%	17/12	\$0	\$0	13,367,905	\$0.0000	\$0	\$2,041
Feb	\$0	6.00%	16/12	\$0	\$0	14,409,055	\$0.0000	\$0	\$2,041
March	\$0	6.00%	15/12	\$0	\$0	9,658,206	\$0.0000	\$0	\$2,041
April (est)	\$0	6.00%	14/12	\$0	\$0	5,341,359	\$0.0000	\$0	\$2,041
May (est)	\$0	6.00%	13/12	\$0	\$0	2,406,674	\$0.0000	\$0	\$2,041
June (est)	\$0	6.00%	12/12	\$0	\$0	1,514,059	\$0.0000	\$0	\$2,041
July (est)	\$0	6.00%	11/12	\$0	\$0	1,395,034	\$0.0000	\$0	\$2,041
Aug (est)	\$0	6.00%	10/12	\$0	\$0	1,411,813	\$0.0000	\$0	\$2,041
Sept (est)	\$0	6.00%	9/12	\$0	\$0	1,600,639	\$0.0000	\$0	\$2,041
Oct (est)	\$0	6.00%	8/12	\$0	\$0	3,372,710	\$0.0000	\$0	\$2,041
Nov (est)	\$0	6.00%	7/12	\$0	\$0	7,037,818	\$0.0000	\$0	\$2,041
12 Months	\$0			\$0	\$0	71,576,699		\$0	\$0
Balance at Nov 30, 2026									\$2,041

Over/(Under) Collections

Exhibit JAB-4

Page 8

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, 2026				
Dec (est)	\$2,456,000	\$32,232	\$2,423,768	0.99925289	\$2,421,957
Jan '27 (est)	\$2,456,000	\$35,485	\$2,420,515	0.99954848	\$2,419,422
Feb (est)	\$2,381,000	\$31,836	\$2,349,164	0.99996487	\$2,349,081
March (est)	\$2,456,000	\$31,253	\$2,424,747	0.99936732	\$2,423,213
April (est)	\$2,348,000	\$24,335	\$2,323,665	0.99997278	\$2,323,602
May (est)	\$2,373,000	\$21,329	\$2,351,671	0.99795157	\$2,346,854
June (est)	\$2,348,000	\$19,817	\$2,328,183	0.99961932	\$2,327,297
July (est)	\$2,373,000	\$20,293	\$2,352,707	0.99987712	\$2,352,418
Oct (est)	\$2,373,000	\$21,629	\$2,351,371	0.99969388	\$2,350,651
Nov (est)	\$2,431,000	\$26,085	\$2,404,915	0.99999065	\$2,404,893
12 Months	\$28,716,000	\$301,973	\$28,414,027		\$28,402,393

BSC Revenues

	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)	5,641,443	\$0.3795	\$2,140,928
Dec aft 12/1 (est)	5,427,590	\$0.4170	\$2,263,305
Jan '27 bef 12/1 (est)	-	\$0.3795	\$0
Jan '27 aft 12/1 (est)	13,351,111	\$0.4170	\$5,567,413
Feb (est)	11,158,391	\$0.4170	\$4,653,049
March (est)	8,989,310	\$0.4170	\$3,748,542
April (est)	4,592,251	\$0.4170	\$1,914,969
May (est)	2,369,640	\$0.4170	\$988,140
June (est)	1,583,423	\$0.4170	\$660,287
July (est)	1,391,428	\$0.4170	\$580,226
Oct (est)	3,393,078	\$0.4170	\$1,414,914
Nov (est)	7,167,074	\$0.4170	\$2,988,670
12 Months	68,106,902		\$28,189,025

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, 2026			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	\$4,404,233	\$2,421,957	\$1,982,276
Jan '27 bef 12/1 (est)			
Jan '27 aft 12/1 (est)	\$5,567,413	\$2,419,422	\$3,147,991
Feb (est)	\$4,653,049	\$2,349,081	\$2,303,968
March (est)	\$3,748,542	\$2,423,213	\$1,325,329
April (est)	\$1,914,969	\$2,323,602	(\$408,633)
May (est)	\$988,140	\$2,346,854	(\$1,358,714)
June (est)	\$660,287	\$2,327,297	(\$1,667,010)
July (est)	\$580,226	\$2,352,418	(\$1,772,192)
Aug (est)	\$594,090	\$2,353,548	(\$1,759,458)
Sept (est)	\$674,492	\$2,329,457	(\$1,654,965)
Oct (est)	\$1,414,914	\$2,350,651	(\$935,737)
Nov (est)	\$2,988,670	\$2,404,893	\$583,777
12 Months	\$28,189,025	\$28,402,393	(\$213,368)

**Exhibit JAB-5**

# PECO ENERGY COMPANY

## GAS SERVICE TARIFF

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COMPANY OFFICE LOCATION

2301 Market Street  
Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 28, 2026

Effective December 1, 2026

**ISSUED BY: Michael A. Innocenzo- President & CEO**  
**PECO Energy Distribution Company**  
**2301 MARKET STREET**  
**PHILADELPHIA, PA. 19103**

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# NOTICE.

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**LIST OF CHANGES MADE BY THIS SUPPLEMENT**

**SALES SERVICE COSTS (SSC) – 8th Revised Page No. 42**

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

**SALES SERVICE COST (SSC) – 3rd Revised Page No. 43**

The Off-System Sales Sharing Mechanism is extended through November 30, 2029.

**MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 8th Revised Page No. 46 and 8th Revised Page No. 47**

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

**BALANCING SERVICE COSTS (BSC) – 8th Revised Page No, 48**

The Balancing Service Cost is decreased.

**GAS TRANSPORTATION SERVICE – GENERAL TERMS AND CONDITIONS – 3rd Revised Page No. 70**

The Balancing Charge is increased.

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SALES SERVICE COSTS (SSC) - Section 1307(f)PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **\$5.2456** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **\$5.2295** per Mcf for Rate Schedules GC and **\$5.2216** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **\$1.3536** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales Service gas shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of gas costs related to Sales Service.

COMPUTATION OF CC AND GCA PER MCF.

The CC and GCA, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formulas set forth below:

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

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

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

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

The CC and GCA so computed, shall be applicable to Customers receiving Sales Service pursuant to the rate schedules identified above. The CC and GCA, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Charges, per Mcf, pursuant to the formulas above, the following definitions shall apply:

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

"C" - Cost in dollars: (a) for all types of purchased gas, project the commodity and all non-storage interstate pipeline costs for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect; plus (b) the cost of gas provided from storage and LNG facilities, less (c) the new monthly cash-out result determined pursuant to Rule 10.11.3, or the successor thereto, of the Gas Choice Supplier Coordination Tariff .

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

"CC1" – defined as the Commodity Charge rate effective December 1 of the current PGC period.

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

GCA - the "E" factor component of the CC, representing the net overcollection or undercollection of Purchased Gas Costs. Applicable to Sales Service and determined to the nearest one-hundredth cent (0.01¢) for service provided under Rate Schedules GR, GC, CAP, OL, L, and MV-F of this Tariff.

"E" - the net (overcollection) or undercollection of Purchased Gas Costs applicable to the CC.

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

Supplier refunds received after July 1, 2001 associated with Commodity Charges will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) beginning with the month such refund is received by the Company.

(I) Denotes Increase

(D) Denotes Decrease

**PECO Energy Company**

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

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

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

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

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

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

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

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

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

**QUARTERLY UPDATES**

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

**OFF-SYSTEM SALES SHARING MECHANISM**

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first \$3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over \$3.5 million. Subsequently, effective March 31, 2008 through November 30, 2029 and thereafter, until terminated or otherwise revised by Final Order (C) of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

(C) Denotes Change

**MERCHANT FUNCTION CHARGE****PROVISIONS FOR RECOVERY OF MERCHANT FUNCTION CHARGES**

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP GC, OL, L and MV-F shall include the Merchant Function Charge ("MFC") at **\$0.0245** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **\$0.0084** per Mcf for Rate Schedule GC and at **\$0.0005** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2024-3046932. The MFC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC") and shall be updated quarterly in conjunction with the calculation of the CC. (D)

**COMPUTATION OF MERCHANT FUNCTION CHARGE**

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

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

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP (**0.47%**), Rate Schedule GC (**0.16%**) and Rate Schedules OL, L and MV-F (**0.01%**) as determined at Docket No R-2024-3046932, the Company's 2024 gas base rate case. The write-off factors shall be updated as part of future base rate cases.

"CCMFC" – the applicable quarterly CC including the GPC and excluding the MFC.

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

The calculation of the MFC shall be updated in conjunction with changes in the CC including the GPC and excluding the MFC and updates in the write-off factors. The MFC shall not be subject to reconciliation for any prior period over or under collections.

**PRICE TO COMPARE**

The Price to Compare ("PTC") is comprised of the Commodity Charge ("CC"), the Gas Cost Adjustment ("GCA"), the Gas Procurement Charge ("GPC") and the Merchant Function Charge ("MFC"). The Commodity Charge includes the Gas Procurement Charge and the Merchant Function Charge. The PTC will change whenever any components of the PTC change. The current PTC's are detailed below:

<b><u>COMPONENT</u></b>	<b><u>RATES GR and CAP</u></b>	
Commodity Charge excluding GPC and MFC	\$5.1851 per Mcf	(D)
Gas Cost Adjustment	\$1.3536 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0245</u> per Mcf	(D)
Price to Compare	\$6.5992 per Mcf	(D)

<b><u>COMPONENT</u></b>	<b><u>RATES GC</u></b>	
Commodity Charge excluding GPC and MFC	\$5.1851 per Mcf	(D)
Gas Cost Adjustment	\$1.3536 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0084</u> per Mcf	(D)
Price to Compare	\$6.5831 per Mcf	(D)

(I) Denotes Increase

(D) Denotes Decrease

**PECO Energy Company**

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<b><u>COMPONENT</u></b>	<b><u>RATES OL, L and MV-F</u></b>	
Commodity Charge excluding GPC and MFC	\$5.1851 per Mcf	(D)
Gas Cost Adjustment	\$1.3536 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	<u>\$0.0005</u> per Mcf	(D)
Price to Compare	\$6.5752 per Mcf	(D)

(I) Denotes Increase  
(D) Denotes Decrease

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

**PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.**

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at **\$0.3028** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs. (D)

**COMPUTATION OF BALANCING SERVICE COSTS PER MCF**

Balancing Service Costs, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formula set forth below:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**QUARTERLY UPDATES**

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

(D) Denotes Decrease

**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 **\$0.0231** 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.

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# PECO ENERGY COMPANY

## GAS SERVICE TARIFF

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COMPANY OFFICE LOCATION

2301 Market Street  
Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 28, 2026

Effective December 1, 2026

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ISSUED BY: Michael A. Innocenzo- President & CEO  
PECO Energy Distribution Company  
2301 MARKET STREET  
PHILADELPHIA, PA. 19103

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# NOTICE.

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PECO Energy Company

Supplement No. 16 to  
Gas-Pa. P.U.C. No. 6

Sixteenth Revised Page No. 1

Supersedes Fifteenth Revised Page No. 1

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**LIST OF CHANGES MADE BY THIS SUPPLEMENT**

**SALES SERVICE COSTS (SSC) – 8th Revised Page No. 42**

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

**SALES SERVICE COST (SSC) – 3rd Revised Page No. 43**

The Off-System Sales Sharing Mechanism is extended through November 30, 2029.

**MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 8th Revised Page No. 46 and 8th Revised Page No. 47**

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

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**BALANCING SERVICE COSTS (BSC) – 8th Revised Page No. 48**

The Balancing Service Cost is decreased.

**GAS TRANSPORTATION SERVICE – GENERAL TERMS AND CONDITIONS – 3rd Revised Page No. 70**

The Balancing Charge is increased.

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Supplement No. ~~16~~ to  
Gas-Pa. P.U.C. No. 6

~~Sixteenth~~ Revised Page No. 2

Supersedes ~~Fifteenth~~ Revised Page No. 2

PECO Energy Company

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PECO Energy Company

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

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at ~~\$5.2456~~ per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, ~~\$5.2295~~ per Mcf for Rate Schedules GC and ~~\$5.2216~~ per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of ~~\$1.3536~~ per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales Service gas shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of gas costs related to Sales Service.

COMPUTATION OF CC AND GCA PER MCF.

The CC and GCA, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formulas set forth below:

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

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

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

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

The CC and GCA so computed, shall be applicable to Customers receiving Sales Service pursuant to the rate schedules identified above. The CC and GCA, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Charges, per Mcf, pursuant to the formulas above, the following definitions shall apply:

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

"C" - Cost in dollars: (a) for all types of purchased gas, project the commodity and all non-storage interstate pipeline costs for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect; plus (b) the cost of gas provided from storage and LNG facilities, less (c) the new monthly cash-out result determined pursuant to Rule 10.11.3, or the successor thereto, of the Gas Choice Supplier Coordination Tariff .

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

"CC1" - defined as the Commodity Charge rate effective December 1 of the current PGC period.

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

GCA - the "E" factor component of the CC, representing the net overcollection or undercollection of Purchased Gas Costs. Applicable to Sales Service and determined to the nearest one-hundredth cent (0.01¢) for service provided under Rate Schedules GR, GC, CAP, OL, L, and MV-F of this Tariff.

"E" - the net (overcollection) or undercollection of Purchased Gas Costs applicable to the CC.

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

Supplier refunds received after July 1, 2001 associated with Commodity Charges will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) beginning with the month such refund is received by the Company.

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

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

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

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

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

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

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

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

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

**QUARTERLY UPDATES**

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

**OFF-SYSTEM SALES SHARING MECHANISM**

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first \$3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over \$3.5 million. Subsequently, effective March 31, 2008 through November 30, 2029 and thereafter, until terminated or otherwise revised by Final Order (C) of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

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**MERCHANT FUNCTION CHARGE**

**PROVISIONS FOR RECOVERY OF MERCHANT FUNCTION CHARGES**

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP GC, OL, L and MV-F shall include the Merchant Function Charge ("MFC") at \$0.0245 per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at \$0.0084 per Mcf for Rate Schedule GC and at \$0.0005 per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2024-3046932. The MFC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC") and shall be updated quarterly in conjunction with the calculation of the CC.

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**COMPUTATION OF MERCHANT FUNCTION CHARGE**

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

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

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP (0.47%), Rate Schedule GC (0.16%) and Rate Schedules OL, L and MV-F (0.01%) as determined at Docket No R-2024-3046932, the Company's 2024 gas base rate case. The write-off factors shall be updated as part of future base rate cases.

"CCEMFC" - the applicable quarterly CC including the GPC and excluding the MFC.

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

The calculation of the MFC shall be updated in conjunction with changes in the CC including the GPC and excluding the MFC and updates in the write-off factors. The MFC shall not be subject to reconciliation for any prior period over or under collections.

**PRICE TO COMPARE**

The Price to Compare ("PTC") is comprised of the Commodity Charge ("CC"), the Gas Cost Adjustment ("GCA"), the Gas Procurement Charge ("GPC") and the Merchant Function Charge ("MFC"). The Commodity Charge includes the Gas Procurement Charge and the Merchant Function Charge. The PTC will change whenever any components of the PTC change. The current PTC's are detailed below:

**COMPONENT**

**RATES GR and CAP**

Commodity Charge excluding GPC and MFC	\$5.1851 per Mcf	(D)
Gas Cost Adjustment	\$1.3536 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	\$0.0245 per Mcf	(D)
Price to Compare	\$6.5992 per Mcf	(D)

**COMPONENT**

**RATES GC**

Commodity Charge excluding GPC and MFC	\$5.1851 per Mcf	(D)
Gas Cost Adjustment	\$1.3536 per Mcf	(I)
Gas Procurement Charge	\$0.0360 per Mcf	
Merchant Function Charge	\$0.0084 per Mcf	(D)
Price to Compare	\$6.5831 per Mcf	(D)

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~~Eighth~~ Revised Page No. 47

Supersedes ~~Seventh~~ Revised Page No. 47

PECO Energy Company

**COMPONENT**

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

**RATES OL, L and MV-F**

\$5.1851 per Mcf (D)  
\$1.3536 per Mcf (I)  
\$0.0360 per Mcf  
\$0.0005 per Mcf (D)  
\$6.5752 per Mcf (D)

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

**PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.**

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at \$0.3028 per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth (D) below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs.

**COMPUTATION OF BALANCING SERVICE COSTS PER MCF**

Balancing Service Costs, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formula set forth below:

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

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

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

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

In computing the Balancing Service Costs, per Mcf, pursuant to the formula above, the following definitions shall apply:  
"BSC" - Balancing Service Costs determined to the nearest one-hundredth cent (0.01¢) to be charged to each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**QUARTERLY UPDATES**

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

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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 \$0.0231 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)

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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.

(I) Denotes Increase

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