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May 31, 2022

Via E-Filing

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

SUBJECT: PECO Purchased Gas Cost No. 39 Effective December 1, 2022
Docket No. R-2022-3032250, Supplement No. 11 to Gas Tariff No. 4

Dear Secretary Chiavetta:

This letter transmits for filing with the Pennsylvania Public Utility Commission (the "Commission") the Purchased Gas Cost ("PGC") No. 39 filing of PECO, consisting of the following:

1. Statement No. 1 – Direct Testimony of Scott J. Hughes (including exhibits)
2. Statement No. 2 – Direct Testimony of Anthony P. DiFelice (including exhibits)

As required by Commission Order entered December 6, 1985 at Docket No. P-850081, the Company has begun the advance public notice of the proposed gas rate changes contained in the PGC No. 39 filing through bill inserts and newspaper advertisements.

Due to the continuing COVID-19 pandemic, PECO's employees are working in the office on a part-time basis. Accordingly, PECO employees will have limited access to photocopying and U.S. mail, among other services. PECO requests that all communications with PECO employees continue to be transmitted by email. Additionally, this package is being served only via email to those on the Certificate of Service, per their requests for electronic service only.

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

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Sincerely,

Richard G. Webster, Jr
Vice President
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Enclosures

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

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2022-3032250**
v.	:	
	:	
PECO ENERGY COMPANY	:	

CERTIFICATE OF SERVICE

I, Brandon J. Pierce, Esquire, hereby certify that I am on this day serving copies of PECO's Statement No. 1 – Direct Testimony of Scott J. Hughes (including Exhibits) and Statement No. 2 – Direct Testimony of Anthony P. DiFelice (including Exhibits) upon the participants listed below in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant):

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By:_______________________________

Dated: May 31, 2022

Brandon J. Pierce, Esquire
PA Attorney No.:307665

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY

Docket No. R-2022-3032250

DIRECT TESTIMONY
OF
SCOTT J. HUGHES

PECO STATEMENT NO. 1

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DIRECT TESTIMONY OF SCOTT J. HUGHES

I. INTRODUCTION

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

A. My name is Scott J. Hughes. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

2. Q. What is your educational background?

A. I received a Bachelor of Arts degree from Eastern University in 1994. I received a Master of Science degree from the University of Pennsylvania in 1997.

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

A. Yes. I submitted testimony on behalf of PECO Energy Company ("PECO" or the "Company") in the following Purchased Gas Cost ("PGC") proceedings:

PGC 21	Docket No. R-0049423
PGC 37	Docket No. R-2020-3019661
PGC 38	Docket No. R-2021-3025629

4. Q. Please describe your work experience relevant to your Direct Testimony.

A. I have been employed by PECO since 1986. I started as a Credit Analyst and I have also spent time doing analytical work in both Revenue Protection and Customer Service. In 1995, I joined the Regulatory Performance and Planning Group as a Regulatory Assessor and in 1998, I joined the Large Account Services Group as an Account Manager for Commercial Developers. I joined the Gas Supply Group in 1999 as a Senior Operations Area Analyst, then from 2001 to 2007, I worked as a Senior Natural Gas

Analyst, before transitioning to the position of Principal Acquisition Analyst, which I held until May 2019. Over that time, my responsibilities included tracking departmental Key Performance Indicators, supply planning, storage asset management, asset optimization, daily, monthly, seasonal and long-term natural gas purchasing, analyzing and authorizing capacity releases and scheduling natural gas flow on interstate pipelines.

5. Q. Please identify your current job responsibilities.

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

II. <u>PURPOSE OF TESTIMONY</u>

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

A. The purpose of my Direct Testimony is to present the information required in Section 1317(a) of the Pennsylvania Public Utility Code (the "Code") (*See* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility Commission (the "Commission") may make the findings required by Section 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that PECO's PGC rates and charges for the historic period (April 1, 2021 through March 31, 2022), the estimated period (April 1, 2022 through November 30, 2022) and the PGC application period (December 1, 2022 through November 30, 2023) are just and reasonable. To that end, I am sponsoring the information previously filed by the Company on April 29, 2022 in support of PGC 39 (the "Advance Information"). Additionally, I will describe the Company's natural gas purchase policies and practices, including PECO's use of natural gas pipeline transportation and storage contracts, and set forth its plans for evaluating and continuing to incorporate Marcellus Shale production into its supply portfolio.

I will also describe the Company's current hedging program and present the Company's proposal to research possible changes to its hedging program to continue to ensure future price stability for its customers. I will then describe the Company's natural gas purchase policies and practices, including PECO's use of natural gas pipeline transportation and storage contracts and explain its High Volume Transportation ("HVT") Gas Choice program. Additionally, I will discuss PECO's off-system sales sharing mechanism. Finally, I will furnish certain information that PECO committed to provide under the terms of the Joint Petition for Complete Settlement in the 2021 PGC proceeding at Docket No. R-2021-3025629 ("2021 Joint Petition").

7. Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibits SJH-1 through SJH-4 which are discussed later in my Direct Testimony. Additionally, as previously mentioned, I am sponsoring the Advance Information, which has been separated into Sections 1 through 22, and which correspond, generally, to the PGC filing requirements set forth in 66 Pa. C.S.A § 1317.

8. Please provide a general description of PECO's natural gas system.

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

9. Q. Please identify PECO's interstate transmission suppliers.

A. Texas Eastern Transmission, LP ("Texas Eastern"), Transcontinental Gas Pipeline Corporation ("Transco") and Eastern Shore Natural Gas Company ("Eastern Shore") and Adelphia Gateway[1] are the four interstate natural gas pipelines that deliver natural gas directly to PECO's city gates. In addition, Eastern Gas Transmission and Storage, Inc. ("EGTS"), Texas Eastern and Transco also provide natural gas storage services, which PECO uses to meet winter daily and peaking requirements. In the case of EGTS storage service, intermediate transportation service from Texas Eastern is required to deliver the natural gas to PECO's city gate.

[1] The Adelphia Gateway project was first discussed in the Direct Testimony of Carlos P. Thillet (PECO Stmt. No. 1), Docket No. R-2018-3001568, pages 34 and 35. The project came into service in April 2022.

III. HISTORIC AND PROJECTED NATURAL GAS PURCHASES

10. Q. Please describe the information provided in Section 1 of the Advance Information.

A. The information provided in Section 1 of the Advance Information accounts for all of the Company's purchased natural gas costs during the period from January 1, 2021 through March 31, 2022 and includes the source of the natural gas, the price and the associated volumes. This information also includes applicable rates, demand components and incremental purchased natural gas costs associated with contracted interstate pipeline transportation and storage services. All costs detailed in Section 1 result from applying the Company's policy to purchase natural gas on a basis that ensures system reliability at the least-cost.

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

A. Yes. In October of 2021, PECO provided incorrect meter usage information for a HVT customer being supplied by Constellation Energy Group, who was at that time also a subsidiary of Exelon Corporation, PECO's parent corporation, and an affiliate of PECO. This error overstated customer usage by 1,812 MCF for the month of October 2021. That erroneous data was posted on the Company's Electronic Bulletin Board ("EBB")[2]. Per the Balancing Provision for transportation sales customers as found on page 54 of the Company's Gas Service Tariff, Constellation delivered gas equal to the posted deliveries. If PECO had allocated the excess deliveries to the

[2] PECO utilizes its EBB to Provide HVT Suppliers with daily nomination, confirmation, usage and balancing data for their customers.

customer's account, it would have caused the customer to incur a month end balance exceeding its total contract quantity of 54 Mcf. This large month end imbalance would have caused the customer to be subjected to Month Balancing Service fees as found at page 55 of the gas tariff. At the customer's usage rate of about 20 Mcf per day it would have taken about three months for the customer to pull down its bank to where Monthly Banking Service fees would no longer be applicable. In order to mitigate the over delivery situation without inconveniencing the HVT customer, PECO purchased the 1,812 Mcf from Constellation at the October monthly weighted average cost of gas of 4.068/Mcf for a total of $7,371.65. Additionally, as of February 1, 2022, Constellation is no longer affiliated with PECO or Exelon Corporation.

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

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

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

A. No. When a transportation customer uses PECO's purchased natural gas under Rate IS ("Interruptible Service"), these fuel costs are excluded from costs to be recovered from PECO's PGC customers. In addition, PECO provides Standby Sales Service for firm and interruptible transportation customers whereby those customers may purchase natural gas from the Company at the standard retail rate should a customer's supplier fail to deliver gas. The revenues derived from Standby Sales Service are credited toward recovery of purchased natural gas costs through the Section 1307(f) mechanism. If a firm transportation ("FT") customer fails to elect Standby Sales Service and nevertheless uses PECO's purchased natural gas to make up for deficient supplier deliveries, or if an interruptible customer consumes unauthorized volumes, the customer is charged tariff rates for the natural gas used and assessed a penalty for the delivery deficiency. These penalty revenues are also credited to PECO's PGC customers.

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

A. Sections 6 and 7 of the Advance Information provide the projected cost of purchasing natural gas for the estimated period (April 1, 2022 through November 30, 2022) and the PGC application period (December 1, 2022 through November 30, 2023), respectively. This information includes the expected source of the natural gas, the price, and the associated volumes. The projected purchases reflect the Company's policy to purchase natural gas on a basis that ensures system reliability at the least-cost. Sections 6 and 7 of the Advance Information include all projected interstate pipeline costs, storage demand costs, variable storage and fuel-related costs, and commodity costs for the relevant time periods. As shown in Section 6 of the Advance Information, the total projected cost applicable to the PGC for the estimated period is approximately $193.8 million. As shown in Section 7 of the Advance Information, the total projected cost applicable to the PGC for the application period is approximately $446.2 million.

IV. DESIGN DAY REQUIREMENTS

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

A. Yes. Details of PECO's design day methodology and a description of its 2022-2023 winter design day requirements are included in Section 16 of the Advance Information. As described in Section 16, PECO's supply resources, combined with peaking and delivered supply, will satisfy the Company's design day requirement of 881,719 Mcf for the 2022-2023 winter season.

16. Q. Is PECO proposing a change to its design day as a result of its experience during the 2021-2022 winter season?

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

V. PECO'S NATURAL GAS PURCHASE POLICIES AND PRACTICES

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

A. Yes, it does.

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

A. PECO's natural gas procurement policy is designed to achieve a reasonable balance of long- and short-term natural gas purchases under different pricing approaches, in order to achieve system supply reliability at the least-cost. As previously discussed, the details of PECO's actual natural gas purchases for the fifteen (15) months ending March 31, 2022 and its estimates through November 30, 2023 are presented in the Advance Information (Sections 1, 6 and 7). PECO utilizes its interstate transportation and storage entitlements to obtain and deliver market-priced supplies to the PECO natural gas distribution system.

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

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

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

Additionally, PECO continued and extended its Ratable Hedging Program as authorized by the Joint Petition for Complete Settlement in last year's PGC proceeding at Docket No. R-2021-3025629.

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

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

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

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

PECO also mitigates its exposure to price volatility by using its interstate pipeline storage entitlements. In addition to providing a source of wintertime deliverability, access to pipeline storage allows PECO to purchase natural gas during the summer period. The natural gas procured in the summer period can be redelivered during periods of strong demand, when prices could potentially be higher (typically, the winter period). However, summer prices for natural gas are not always predictably lower than winter prices.

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

A. Yes. As shown in Sections 16 and 22 of the Advance Information, 27.4% of the Company's required design day supply, which equates to 241,659 Mcf, will be received via delivery from contracted underground storage. In addition, LNG, propane and delivered peaking services combined represent about 20.5% of the required design day supply. Accordingly, as shown in Sections 16 and 22 of the Advance Information, 155,940 Mcf are available from LNG, 24,831 Mcf are available from propane, and the deficit of 116,785 Mcf will met by delivered peaking services contracts and available to meet peak day needs.[3] Overall, the use of storage and LNG enables PECO to substantially mitigate its exposure to the price volatility that typically occurs during the winter, while ensuring sufficient deliverability to meet firm demand.

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

23. Q. Are there limitations on PECO's source of supply from its LNG facility, its Propane facility or contracted storage?

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

[3] For the upcoming 2022-2023 winter, PECO entered into two types of winter-delivered supply contracts that reduce the quantity required to be obtained via RFP to meet its peak day of 40,785 Dth/day. First, PECO has under contract a 10-day call option for 40,000 Dth/day of delivered supply priced at summer index prices plus demand charges. Second, PECO, through its approved hedging program, entered into fixed price delivered supply contracts equal to 36,000 Dth/day.

24. Q. Please explain PECO's strategy to ensure system reliability.

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

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

25. Q. What was PECO's experience regarding meeting customer demand this past winter?

A. As illustrated in Table SJH-1 below, PECO experienced a winter that was overall, by degree day, 9.7% warmer than a normal winter. November and January were colder than normal at 4.6% and 5% respectively.[4] Variations from normal weather by season, month, or day present balancing challenges. These challenges can be exacerbated by certain factors. For example, on warmer than normal days, they can be made worse by the increase in firm supply receipts associated with the LVT Gas Choice

[4] PECO defines a normal winter as 3,854 heating degree days ("HDD").

program and the Company's Ratable Hedging Program, and on colder than normal days, by exposure to market area price volatility and limited LNG, propane and underground storage inventory. PECO utilized its balancing assets, such as contracted storage, as well as its daily load balancing processes to minimize costs this past winter.

Table SJH-1

Heating Degree Days (HDD)						
	November 2021	December 2021	January 2022	February 2022	March 2022	Total
HDD Normal	517	802	956	808	654	3,737
HDD Actual	541	605	1004	697	527	3,374
Difference	24	-197	48	-111	-127	-363
HDD vs Normal	4.6%	-24.6%	5.0%	-13.7%	-19.4%	-9.7%

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

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

27. Q. Did PECO enter into any Off-System Sales where the purchase price exceeded the sales price? If so, please explain.

A. Yes. During the three day period of April 10 through April 12, 2021, in order to avoid potential pipeline penalties, PECO sold 15,000 Dth per day at $1.62/Dth against a purchase price of $2.04/Dth for a net loss of $18,900. The reasons for the sale were unseasonably warm weather, the unavailability of WSS injections because of pipeline maintenance, and because S-2 injections per contract are not available until April 16th of each year.

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

A. Yes. The Company had two of its top 20 sendout days this past winter. The coldest day, and the day with the highest system sendout, this past winter was January 29, 2022, with an average daily temperature of 18°F and sendout of 748,912 Mcf (or 775,8735 Dth), which was the 14th highest sendout day of all time. Saturday, January 15, 2022, was the 18th highest sendout day of all time with an average temperature of 19°F and a sendout of 734,810 Mcf (or 674,436 Dth). For perspective, Table SJH-2 below, provides the top 20 highest sendout days in the Company's history.

Table SJH-2

Rank	System Sendout MCF	System Sendout DTH	Date	Airport Temperature	Wind Speed
1	803,438	842,026	Saturday, January 6, 2018	11	13
2	793,273	829,341	Friday, January 5, 2018	12	21
3	777,457	826,437	Sunday, February 15, 2015	10	20
4	767,421	826,143	Thursday, February 19, 2015	11	19
5	779,424	820,160	Sunday, December 31, 2017	12	10
6	779,531	813851	Thursday, January 31, 2019	15	19
7	782,361	813,775	Monday, January 21, 2019	16	16
8	758,591	809,417	Tuesday, January 07, 2014	11	14
9	769,719	801927	Friday, February 1, 2019	15	13
10	765,275	798,674	Wednesday, January 30, 2019	14	16
11	738,003	789,663	Friday, February 20, 2015	14	8
12	748,358	786,130	Monday, January 1, 2018	16	13
13	750,530	783,802	Thursday, January 4, 2018	19	22
14	748,912	775,873	Saturday, January 29, 2022	18	16
15	733,825	773,227	Tuesday, January 2, 2018	20	9
16	723,416	770,513	Wednesday, January 07, 2015	16	18
17	717,189	763,790	Saturday, February 13, 2016	15	17
18	734,810	763,436	Saturday, January 15, 2022	19	10
19	721,526	760,693	Thursday , December 28, 2017	17	9
20	714,223	759,219	Monday, February 16, 2015	15	7

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

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

30. Q. Did PECO's supply contracts perform as required during the winter of 2021-2022?

A. Yes. For the winter of 2021-2022, all natural gas scheduled under PECO's supply contracts was delivered to PECO's city gate.

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

A. Yes, while the Company believes that its current mix of FT, firm storage, propane, LNG, and delivered peaking contracted services provides adequate peaking capacity to ensure the system reliability necessary to meet peak demand in a safe, least-cost manner at present, PECO continues to analyze supply portfolio and on-system LNG solutions to address observations from experiences these past few winters, as well as for peak-day demand projections. Given the Company's projections, the deficit between currently contracted-for pipeline storage and FT deliveries, as well as LNG and propane capacity, and anticipated future peak-day firm-demand will continue to grow unless the Company adds new contractual or on-system supply options. Although this past winter was relatively mild, the Company's projected growth in design day and overall demand supports the Company's continuing review of how to best manage its natural gas supply portfolio. To that end, PECO has continued its examination of potential long- and short-term solutions to assist in meeting customer demand during the heating season, including peak-day demand. The results of this examination are discussed below in response to Questions 32 through 36.

32. Q. Please provide detail on the current and projected deficit between currently contracted-for pipeline storage and FT deliveries, as well as LNG and propane capacity and peak day demand requirements.

A. As provided at page 8 of Section 16 (Section 17, for winter demand, and Section 22, for deficit information, in Dth) of the Advance Information, PECO is projecting a deficit of 112,618 Mcf between the design day firm demand requirements and current resources for the 2022-2023 winter period. The projected 10-year design day requirement increases to 897,782 Mcf (915,737 Dth) for the 2031-2032 winter period, which is 16,063 Mcf (16,384 Dth) higher than the 2022-2023 requirement of 881,719 Mcf

(899,353 Dth). Without expansion of the Company's on-system storage capabilities or the entry into additional FT pipeline or storage contracts increasing firm delivery entitlements to PECO's city gates, the deficit to be met by delivered winter services is expected to increase to 128,681 Mcf (133,442 Dth) for the winter of 2031-2032.

33. Q. Please provide an update on the steps the Company took to ensure availability of supply for the winter of 2021-2022.

A. As described in the Direct Testimony of Carlos P. Thillet in PECO's prior PGC proceedings (PGC 35 through 38), PECO continues to analyze and adopt multiple solutions to procure reliable, least-cost assets for both the short- and long-term peak day supply deficits. To that end, to ensure the availability of winter delivery services for the winter of 2021-2022 (as explained at page 2 of Section 22 of the Advance Information in PGC 38 (Docket No. R-2020-3019661)), PECO took the following steps to acquire the 115,818 Dth needed:

- PECO has under a multi-year contract for a 10-day call option for 40,000 Dth/day of delivered supply at summer index prices, plus demand charges; and
- PECO procured 36,000 Dth/day of delivered supply via the Company's Ratable Hedging program.
- PECO also procured a 10 call option for 39,000 Dth/day via an RFP issued on September 20, 2021.

In addition to the steps discussed above, in order to ensure adequacy of LNG and propane inventory for the winter, on September 20, 2021, PECO issued an RFP to seven potential counterparties for call options for (1) up to 800,000 gallons of trucked LNG and (2) up to 1,124,000 gallons of trucked propane. Through the RFP process PECO was able to enter into a call option for the trucked LNG. Although PECO did not receive any responses to the propane RFP, the Company was able to identify a counter-party not contacted during the original RFP and successfully negotiated a deal with them for a call for trucked propane.

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

Yes. As further explained in my response to Question 36 below, PECO, as part of the Natural Gas Reliability Project, is making significant improvements to its LNG vaporization capability. In November of 2021, PECO Gas Supply personnel were informed by PECO's Gas and Plant Operations department that the project schedule may cause liquefaction to be unavailable for the entirety of the April through November 2022 liquefaction season. Because of that possibility, the likelihood that during the remainder of the 2021-22 winter LNG inventory could be reduced, and the necessity of ensuring adequacy of LNG supply for the winter of 2022-23,[5] PECO utilized its call option and purchased 59 truckloads (51,656 Dth) of LNG. The first delivery was received on January 19, 2022, and continued until March 22, 2022, when PECO was informed that due to long lead time supply chain issues, the work that could have disrupted the season liquefaction had been postponed to the following year. It should be noted

[5] To ensure reliability for PECO's customers, and because of the potential need for LNG vaporization to meet winter high demand days, intra-day swings in demand, pressure support and as a replacement for supply not delivered due to pipeline disruptions, PECO enters every winter season with LNG inventory at close to full levels.

that one of the reasons for the decision to postpone the work was because of the potential that if certain work was started too late, it could jeopardize the ability to vaporize for the winter of 2022-2023.

35. Q. How does the Company plan to ensure availability of supply for the winter of 2022-2023?

A. PECO will utilize both short- and long-term solutions to address its supply needs for the winter of 2022-2023. As to the short-term solutions, similar to previous winters, PECO will depend on delivered supply in order to meet part of its design day requirements.[6] PECO has taken the following steps to ensure the availability of the 116,785 Dth/day of required delivered supply:

- PECO has in place a multi-year contract for a 10-day call option for 40,000 Dth/day of delivered supply at summer index prices, plus demand charges; and
- PECO will procure 36,000 Dth/day of delivered supply via the Company's Ratable Hedging program.

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

- On or before July 1, 2022, PECO will issue a notice of Additional Capacity Constraints, as explained in the Company's DSO program, which is anticipated to produce a similar yield as in prior years.
- PECO will issue an RFP for delivered supply equal to the total winter delivered resources required, less those volumes obtained by the two contracts and DSO program participation listed above; and
- PECO will issue an RFP to help gauge the price and availability of trucked propane and LNG as a potential supplement to its inventory.

[6] PECO's design day requirements can be found at page 2 of Section 22 of the Advance Information.

36. Q. Please describe the actions PECO is pursuing to address the longer term peak day requirements through the winter of 2030-2031.

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

First, PECO has continued its evaluation of participation in pipeline open seasons as a way of securing additional cost-effective FT to PECO's City Gate. As discussed below (*see* Question 47) PECO's continued efforts to evaluate pipeline open seasons and capacity made available via permanent capacity releases to see if any new, cost-effective, firm natural gas transportation source to PECO's city gate became available. Provided in that discussion is a description of the Company's involvement in the Transco Regional Energy Access ("REA") Project. The REA Project is now scheduled to be placed into service in December of 2024 and will provide PECO with 100,000 Dth/day of Firm Capacity from the Leidy Marcellus production area to PECO's City gate.

Second, as discussed in detail in the Direct Testimony of Carlos P. Thillet in the Company's last seven PGC proceedings, PECO continued its LNG investment and continues to take actions that will lead to increasing

LNG Vaporization capability at the Company's West Conshohocken facility from 160,000 Mcf/day to 220,000 Mcf/day, directly reducing reliance on delivered supply. The Natural Gas Reliability Project, of which the increased LNG Vaporization capability is a part, is also discussed in depth in the Direct Testimony of Carlos P. Thillet (PECO Statement No. 2) in Docket No. P-2021-3024328.[7] 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. Due to the delays I discuss in the response to Question 34, the project is now scheduled to come into service for the winter of 2023-2024.

37. 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 SJH-3 provides a comparison of projected design day demand compared to current and planned future assets.

[7] 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.

Table SJH-3

DESIGN DAY DEMAND VS ASSETS (Dth/D)					
WINTER	DESIGN DAY DEMAND	PROJECTED TOTAL ASSETS	GAP	% GAP	Notes
2022-2023	914,343	797,558	116,785	15%	Assets equal current Pipeline FT and Storage deliveries plus PECO LNG and Propane vaporization assets
2023-2024	904,000	857,558	46,442	5%	Reliablity Project increases LNG vaporization by 60,000 Dth/d
2024-2025	918,000	957,558	-39,558	-4%	Tranco REA project planned inservice date increases FT deliveries by 100,000 Dth/d
2025-2026	920,000	957,558	-37,558	-4%	Assets at steady state
2026-2027	926,000	957,558	-31,558	-3%	
2027-2028	927,000	957,558	-30,558	-3%	
2028-2029	928,000	957,558	-29,558	-3%	
2029-2030	929,000	957,558	-28,558	-3%	
2030-2031	930,000	957,558	-27,558	-3%	
2031-2032	931,000	957,558	-26,558	-3%	

The projected total assets for the winter of 2022-2023 include all of PECO's current firm assets, which increase by 60,000 Dth/day beginning in the winter of 2023-2024, and by an additional 100,000 Dth/day beginning in the winter of 2024-2025, resulting in a total additional 160,000 Dth/day.[8]

[8] These increases in firm assets are directly tied to the in-service dates of the Company's Natural Gas Reliability Project and the REA project, respectively.

The acquisition of these firm assets will result in the elimination of the current firm gap between total assets and design day demand of 15.0%. By the winter of 2031-2032, PECO will have supplemental capacity beyond the projected design day of 3%. This supplemental capacity will better enable the Company to serve its customers should future instances occur where any of the interstate pipelines delivering supply to PECO's service area are subjected to equipment failures, integrity concerns, or other obstacles or force majeure events that prevent them from meeting their contracted obligations during periods of high natural gas demand. Supplemental capacity would also provide a degree of flexibility to ensure deliverability and help to lessen exposure to market area price volatility.

VI. REGIONAL AND SUSTAINABLE NATURAL GAS ACQUISITION STRATEGY

38. Q. Has the Company purchased any natural gas produced in Marcellus Shale regions?

A. Yes. PECO has purchased natural gas from Marcellus Shale production areas. Since 2010, PECO has incorporated increasing quantities of locally-produced Marcellus Shale natural gas into its portfolio of supply assets. The only supply PECO purchases that it presumes is not from the Marcellus production regions are those necessary for injections into its WSS storage contract, located upstream on Transco's main line.[9] PECO uses its FT

[9] 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.

contracts to purchase and transport natural gas primarily from both the Southwestern and the Northeastern/Leidy production areas in Pennsylvania.

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

39. Q. Please describe any steps the Company has taken to Acquire Responsibly Sourced Gas (RSG) or Renewable Natural Gas (RNG).

As per the Joint Petition for Complete Settlement in PECO's 2021 PGC proceeding, the Company agreed to provide in this PGC filing a report on progress it has made in its investigation of RNG and RSG. Below I provide that report, which includes information pertaining to (i) any acquisition of RNG and/or RSG for PECO's natural gas supply portfolio made to date; and (ii) what further actions the Company plans to take regarding such products in the future. To that end the Company took the following three steps:

1. On Dec 22, 2021, at Docket R-2021-3030171, PECO filed proposed changes to its Gas Service Tariff and Gas Choice Supplier Coordination Tariff that specifies RNG quality standards for RNG introduced directly into PECO's natural gas system. The tariff language is an important step in PECO's efforts to acquire a source

of RNG in support of PECO's Path to Clean initiative. In determining the proposed tariff language, the Company analyzed its distribution system requirements and considered related filings from other Pennsylvania Local Distribution Companies ("LDC") as well as from PECO's affiliate, Baltimore Gas and Electric. The tariff language was approved by Commission Order dated February 24, 2022.

2. On March 31, 2022 as part of a summer gas supply RFP issued March 11, 2022 (*See*, Exhibit SJH-1) PECO included the following language:

> *PECO will consider purchasing up to 1K dth/day of any of the above packages as baseload (non take-or-release) Certified Responsibly Sourced Gas (RSG) or Renewable Natural Gas (RNG - with or without the associated RINs) at a fixed or index-based price*.

The RFP was sent to 14 different potential suppliers. The request was for supply for April 1 through October 31, 2022. PECO received no responses for RNG and one response for RSG. The RSG price quoted was at an index plus a premium of four cents. Because there was no guarantee of recovery of the premium, PECO did not act on the offer.

3. PECO is currently in discussions with a potential on-system producer of RNG to construct a gas line and interconnection to

allow the producer to deliver RNG onto PECO's natural gas distribution system. PECO is also currently discussing the potential purchase of the RNG production for use in its natural gas supply portfolio used to serve PGC customers. The purchase price being discussed is at natural gas index prices and would comport with least-cost practices. Currently, PECO is not planning to purchase the Renewable Identification Numbers (RINs) and thus will not pay a premium for the supply nor will PECO obtain the environmental attributes associated with the RNG. Instead, PECO considers its possible actions in promoting this project as beneficial to the growth of the RNG production and as a possible, reliable source of supply for the short or long term. The planned in-service date is fourth quarter of 2024.

VII. PECO'S HEDGING POLICY

40. Q. Please describe PECO's hedging policy.

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

41. Q. Please briefly summarize PECO's current Ratable Hedging Program.

A. In the 2016 Joint Petition for Complete Settlement (PGC 33, Docket No. R-2016-2545925), PECO agreed to implement its current "Ratable Hedging Program," which was extended for additional years in the 2017 Joint Petition for Complete Settlement (PGC 34, Docket No. R-2017-2602611), the 2018 Joint Petition for Complete Settlement (PGC 35, Docket No. R-2018-3001568), the 2019 Joint Petition for Complete Settlement (PGC 36, Docket No. R-2019-3009624), the 2020 Joint Petition for Complete Settlement (PGC 37, Docket No. R-2020-3019661) and the 2021 Joint Petition for Complete Settlement (PGC 38, Docket No. R-2021-3025629). Under this program, PECO hedges approximately 12% of its projected purchase volumes. The hedges under the Ratable Hedging Program began in November 2016 and will continue through July 2024. All hedges in this program are made between three (3) and twenty-four (24) months in advance of the delivery date for the purchased natural gas. In addition, as agreed in the 2020 Joint Petition, PECO no longer engages in hedging for summer purchases. For convenience, I have attached the current Ratable Hedging Program execution schedule to my Direct Testimony as Exhibit SJH-2.

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

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

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

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

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

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

A. Yes, during the historic period (April 2021 through March 2022), PECO issued RFPs for six (6) execution periods (these periods are highlighted in yellow in Exhibit SJH-2, with all previous executions appearing in blue). As shown in Table SJH-4 below, for the historic period, PECO has purchased approximately 5.45 MMDTH of hedged natural gas under the program at a weighted average cost of $5.2747 per Dth.

Table SJH-4

Ratable Hedge Program Executed Hedges April 2021 through March 2022			
Execution Month	**DTH**	**$/DTH**	**Total $**
July 2021	1,812,000	$4.4275	$ 8,022,630
November 2021	1,818,000	$5.0185	$ 9,123,720
March 2022	1,818,000	$6.3753	$11,590,380
Total	5,448,000	$5.2747	$28,736,730

43. Q. **Is PECO proposing any changes to the Ratable Hedging Program?**

A. Yes, PECO is proposing that the Ratable Hedging Program be extended for an additional year. Table SJH-5 below provides the proposed hedging schedule for Year 9:

Table SJH-5

Year 9 Winter		Execution Periods					
	Total Daily	Nov '23	Mar '24	Jul '24	Nov '24	Mar '25	Jul '25
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000

44. Q. **Does the Company engage in Financial Hedging as part of its current hedging program?**

A: No. Pursuant to Paragraph 19(d)(4) of the 2016 Joint Petition, PECO has not engaged in any financial hedges. However, in an effort to further mitigate ratepayer exposure to price volatility, the Company plans to research both the possibility of entering into financial hedges and the possibility of making changes to the volumes associated with the Ratable Hedging program in the future, and in its 2023 PGC Filing, the Company will present results of its hedging research and analysis and any related proposals to utilize financial hedges or otherwise change the existing hedging program.

VIII. THE BALANCING CHARGE

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

A. Yes. Under the terms of the Settlement of the Company's 2008 Gas Distribution Base Rate Case at Docket No. R-2008-2028394, the Company is required to update the balancing charge as part of its annual 1307(f) filing.

Pursuant to the terms of the 2020 Joint Petition for Complete Settlement in the PGC 37 proceeding (Docket No. R-2020-3025629), the balancing charge calculation was revised to include: (i) the costs associated with the interstate pipeline transportation arrangements required to deliver natural gas to and from storage; and (ii) aggregate daily HVT imbalances experienced during the summer months, as opposed to only the winter months as was the historical practice. As shown in Exhibit SJH-3 accompanying my Direct Testimony, the Company is proposing a balancing charge of $0.0176 per Mcf to become effective on December 1, 2022, which is $0.0035 less per Mcf than the currently effective balancing charge.

46. Q. Why did the balancing charge decrease by $0.0035 per Mcf?

A. Please refer to Exhibit SJH-4, which provides the calculations used to establish the current balancing charge and the proposed balancing charge, along with a line-by-line comparison showing the changes between the two. The decrease is driven by deviations in a number of different factors, including, decreased storage costs and decreased aggregate imbalances for customers.

47. Q. Has PECO continued its evaluation of participation in pipeline open seasons as a way of securing additional cost-effective Firm Transportation to PECO's City Gate?

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

The Regional Energy Access ("REA") project was referred to as Project X in Company Witness Carlos Thillet's Direct Testimony submitted in support of PECO's prior PGC proceedings – PGC 36, PGC 37, and PGC 38. On February 10, 2020, PECO executed a Precedent Agreement with Transco for 100,000 Dth/day of REA capacity. The firm transportation capacity will enable PECO to move natural gas from receipt points in the Leidy Pennsylvania Marcellus Shale production area to delivery points on PECO's distribution system. The initial term is for 15 years with a projected in-service date of December 2023. The capacity will provide PECO with a least-cost, reliable, source of supply enabling the Company to meet its firm demand by reducing the delivered supply needed to eliminate the peak-day supply gap, while providing deliveries to PECO gate stations and further eliminating exposure to market area price volatility.

Transco filed its 7(c) FERC Application on March 26, 2021. Subsequently, on April 28, 2021, Exelon Corporation filed comments in support of the REA application. The REA Project is now scheduled to be placed into service in December of 2024 and will provide PECO with

100,000 Dth/day of Firm Capacity from the Leidy Marcellus production area to PECO's City gate.

48. Q. Did participation in PECO's LVT Gas Choice program continue to grow for the 12-month period ending March 31, 2021?

A. As indicated in Table SJH-6 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, 2022 participation decreased slightly. In addition, the number of suppliers increased during this period from 60 to 61. PECO expects strong participation in this program to continue.

Table SJH-6

12-Month Period Ending March 31	Customers participating in LVT program	YOY Change	Aggregate Daily Delivery Quantity	Aggregate Daily Contract Quantity
2011	7,915		21,186	12,152
2012	32,062	305.10%	33,201	24,917
2013	52,267	75.50%	44,997	36,444
2014	72,211	28.30%	51,765	37,557
2015	80,410	11.40%	46,887	55,748
2016	81,088	0.80%	46,896	58,573
2017	81,472	5.00%	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	-7.31%	66,013	66,013

IX. FIRM INTERSTATE PIPELINE CONTRACTS

49. Q. Please identify the firm interstate natural gas pipeline service agreements that have been subject to renewal since PECO's last PGC

proceeding (PGC 38) and that remain in effect.

A. Table SJH-7 below lists the storage and transportation service agreements that were subject to renewal/termination notice during the past year and identifies whether PECO opted to renew each agreement. All contracts were renewed.

<u>Table SJH-7</u>

Pipeline Contract	Earliest Termination Date	Notice Period	Renewed (Yes or No)
Texas Eastern			
FTS-7 Transportation	4/15/2025	24 Months	Yes
FTS-8 Transportation	4/15/2025	24 Months	Yes
SS-1 Storage	4/30/2025	24 Months	Yes
Transco			
WSS Storage	3/31/2024	12 Months	Yes
S-2 Storage	4/16/2024	12 Months	Yes
Eastern Gas Transmission & Storage, Inc.			
FT	3/31/2027	24 Months	Yes
GSS Storage	3/31/2028	24 Months	Yes
GSS Storage	3/31/2027	24 Months	Yes
Adelphia			
FT Transportation	04/08/2032	12 Months	Yes

50. Q. Why did PECO choose to allow the contracts identified above to evergreen for an additional term?

A. First, PECO continues to require the above-mentioned services primarily to satisfy the temperature-sensitive demands of both its retail sales customers and its Gas Choice customers for whom PECO is the supplier of last resort ("SOLR"). Second, each of these agreements is designed to provide satisfactory capacity to transport the natural gas supplies needed to serve the demand of PECO's retail sales customers, especially during the winter period. As the SOLR, PECO also needs these contracts to serve Gas Choice customers that may return to PECO for supply during the winter period. PECO has not yet discovered a more economical alternative to continuing these contracts.

Third, consistent with the settlement of PECO's natural gas restructuring proceeding at Docket No. R-00994787, on November 18, 2020 and April 6, 2021, PECO issued RFPs for its firm storage and transportation contracts that were subject to termination and/or renewal. The RFPs were sent to Pennsylvania NGSs, including Gas Choice Suppliers participating in PECO's Gas Choice programs, interstate pipeline companies and others. In response to the RFPs, interested parties were given the opportunity to provide a contract service as a replacement to service provided by the pipeline supplier. None of the responses received provided a more cost-effective alternative to the contracts listed in Table SJH-7 above.

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

A. PECO regularly reviews all pipeline open seasons (*see* Question 47) to assess opportunities for new and replacement services. Additionally, PECO regularly contacted pipeline representatives to discuss its supply portfolio needs and to explore potentially less costly options to existing services. Despite these efforts, PECO could not obtain any comparable replacement services at a lower cost than the existing services. Therefore, it is necessary for PECO to retain these agreements as part of its overall capacity portfolio to satisfy the demand requirements of its retail sales and Gas Choice customers.

52. Q. Please explain how PGC customers benefit from PECO's active participation in the recent FERC rate case proceedings filed by Eastern Gas Transmission and Storage, Inc. ("EGTS") and Texas Eastern.

A. PECO's active participation in the FERC rate case proceedings filed by EGTS and Texas Eastern in 2021, is expected to benefit PECO's PGC customers by achieving litigated or settlement rates in both cases that are less than the increases sought in the as-filed rates, resulting in smaller rate increases for PECO and its PGC customers. I provide a brief explanation of these cases below.

EGTS: On September 30, 2021, EGTS filed revised tariff records consistent with the requirements for a Natural Gas Act ("NGA") Section 4 general rate case at Docket No. RP21-1187. EGTS and the other parties engaged in numerous rounds of settlement discovery and settlement conferences. PECO is actively participating in the negotiations and the settlement conferences. Those negotiations and testimony preparation are ongoing.

Texas Eastern: On July 30, 2021, Texas Eastern filed revised tariff records consistent with the requirements for a NGA Section 4 general rate case at Docket No. RP21-1001. PECO, along with numerous other parties, filed protests to Texas Eastern's filing, due mainly to Texas Eastern's use of a 25% federal corporate income tax rate on the assumption that the tax rate would be increased by the time the proposed rates became effective. FERC subsequently rejected Texas Eastern's filing by order dated August 31, 2021. Texas Eastern then filed a new NGA Section 4 general rate case at Docket No. RP21-1188 on September 30, 2021 with the currently effective federal income tax rate.[10] Texas Eastern and the other parties engaged in numerous rounds of settlement discovery and settlement conferences. PECO is actively participating in the negotiations and the settlement conferences. Those negotiations and testimony preparation are ongoing.

X. HVT GAS CHOICE PROGRAM INFORMATION

53. Q. Please describe the HVT Gas Choice program.

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

54. Q. Did the Advance Information contain any information regarding the HVT Gas Choice program?

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

[10] Thereafter, Texas Eastern filed a request for rehearing, arguing that the July 30, 2021 Section 4 filing should not have been rejected. On January 20, 2022, FERC issued an order addressing the issues on rehearing and setting aside its August 31, 2021 order in part. The Commission left it to the Chief Administrative Law Judge to make a determination regarding consolidating the two Section 4 proceedings.

55. Q. What information is contained in Section 10 of the Advance Information?

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

56. Q. What information is provided in Sections 11 and 12 of the Advance Information?

Section 11 of the Advance Information includes a report reflecting specific contract information for each HVT Gas Choice customer. Specifically, the following information is provided for each customer: the customer's rate, size category (greater than or less than 18,000 Mcf per year), daily transportation contract quantity, firm stand-by sales quantity, if any, and commodity rate. Section 12 of the Advance Information provides the monthly transportation volume for each transportation customer for each month beginning April 1, 2021 and ending March 31, 2022. Specifically, the following information is provided for each customer: the customer's rate; total monthly deliveries in Mcf; and total transportation deliveries. Because this information is voluminous, PECO does not file it with the Advance Information but will provide it upon request.

XI. OFF-SYSTEM SALES SHARING MECHANISM

57. Q. Is PECO proposing to extend the Off-System Sales sharing mechanism?

A. Yes. Pursuant to Paragraph 21 of the 2021 Joint Petition, the Off-System Sales sharing mechanism was extended at the 25% rate through November 30, 2024. In this PGC proceeding, PECO is proposing to further extend this mechanism through November 30, 2025.

58. Q. **How would PECO's natural gas customers benefit from an extension?**

A. An extension will allow the Company to enter into longer term Asset Management Agreements. The Company believes that, under certain conditions, the per-Dth value of transportation and storage capacity released under a longer term arrangement is enhanced and, therefore, can potentially provide a larger reduction in natural gas costs.

XII. SETTLEMENT COMMITMENTS

59. Q. **Did the 2021 Joint Petition require anything of the Company with respect to Lost and Unaccounted For Gas ("LUFG") monitoring and reporting?**

A. The 2021 Joint Petition did not impose any reporting obligations on the Company as it relates to LUFG. However, Paragraph 20 sets forth the three-year weighted average for the periods ending March 31, 2021 and June 30, 2021. Consistent with its reporting in prior PGC proceedings, PECO has voluntarily provided the LUFG percentages for the period ending March 31, 2022 in Table SJH-8 below, consistent with the methodology used for prior reporting. The weighted average LUFG for the 36-month period ending June 30, 2022 will be provided when the requisite data becomes available.

Table SJH-8

	Sendout in Mcf	Billed Sales in Mcf	LUFG
12 Months Ending 3/31/20	84,510,551	84,400,524	0.1%
12 Months Ending 3/31/21	89,347,192	86,980,491	2.6%
12 Months Ending 3/31/22	88,449,680	86,529,132	2.2%
36 Months Ending 3/31/22	262,307,423	257,910,147	1.7%

60. Q. What does the 2021 Joint Petition require with respect to the retainage volume adjustment?

A. In Paragraph 18 of the 2021 Joint Petition the Company agreed to use a retainage volume adjustment rate for transportation service customers of 2.3% for the twelve months beginning December 1, 2021, and ending November 30, 2022, which was calculated in accordance with the requirements of the 2020 Joint Petition. The Company further agreed (as they initially had in the PGC 37 proceeding) that Direct Pipeline customer sendout and volumes delivered would be removed from the retainage rate calculation on a going forward basis. Accordingly, PECO will provide the new retainage rate (and the supporting calculations) for the PGC 39 application period when the data is available, in mid-July 2022. The Company proposes to continue the agreed upon retainage calculation mechanism for the period ending November 30, 2023.

XIII. CONCLUSION

61. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

PECO Energy Company
March 11, 2022

Request for Proposal (RFP)

Take or Release Baseload Supply

PECO Energy Company (PECO) has identified a need for the following baseload supply:

Transco	**Location**	**Term**
Up to 25,000 Dth/Day	ST 85	Apr 1, 2022 – Oct 31, 2022
Up to 30,200 Dth/Day	Leidy Line Rec	Apr 1, 2022 – Oct 31, 2022

Texas Eastern	**Location**	**Term**
Up to 47,000 Dth/Day	M2 Receipts (Pool 79508)	Apr 1, 2022 – Oct 31, 2022
10,686 Dth/Day **(FIRM – not take-or-release)**	Crayne (75009)	Apr 1, 2022 – Oct 31, 2022

Pricing

PECO requests the proposals be priced based on Inside FERC First of Month Index (FOMI).

All supplies must represent firm daily deliveries for the applicable period, except that **PECO shall have "take or release" provisions, with the ability to nominate from 0% to 100% of the MDQ 5 days before the start of each month**.

PECO will accept bids on both full and/or partial volumetric packages.

PECO will consider purchasing up to 1K dth/day of any of the above packages as baseload (non take-or-release) Certified Responsibly Sourced Gas (RSG) or Renewable Natural Gas (RNG - with or without the associated RINs) at a fixed or index-based price.

Contract Obligation

The supply must be delivered to the contracted receipt points on a firm basis.

Responses to the above request are due by 11:00am (EST), Thursday, March 17, 2022 and should be addressed to:

Scott Hughes
Manager, Gas Acquisition
PECO Energy Company
2301 Market Street, S18-1
Philadelphia, PA 19101
shughes@peco-energy.com

Year 1 Summer		Execution Periods		
	Total Daily	Nov '16	Dec '16	Jan '17
Delivery Month	Hedged DTH	5 Months Out	4 Months Out	3 Months Out
Apr '17	16,800	5,600	5,600	5,600
May '17	16,800	5,600	5,600	5,600
Jun '17	16,800	5,600	5,600	5,600
Jul '17	16,800	5,600	5,600	5,600
Aug '17	16,800	5,600	5,600	5,600
Sep '17	16,800	5,600	5,600	5,600
Oct '17	16,800	5,600	5,600	5,600

Year 1 Winter		Execution Periods			
	Total Daily	Nov '16	Feb '17	May '17	Aug '17
Delivery Month	Hedged DTH	12 Months Out	9 Months Out	6 Months Out	3 Months Out
Nov '17	36,000	9,000	9,000	9,000	9,000
Dec '17	36,000	9,000	9,000	9,000	9,000
Jan '18	36,000	9,000	9,000	9,000	9,000
Feb '18	36,000	9,000	9,000	9,000	9,000
Mar '18	36,000	9,000	9,000	9,000	9,000

Year 2 Summer		Execution Periods					
	Total Daily	Nov '16	Feb '17	May '17	Aug '17	Nov '17	Feb '18
Delivery Month	Hedged DTH	18 Months Out	15 Months Out	12 Months Out	9 Months Out	6 Months Out	3 Months Out
Apr '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
May '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jun '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jul '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Aug '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Sep '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Oct '18	16,800	2,800	2,800	2,800	2,800	2,800	2,800

Year 2 Winter		Execution Periods					
	Total Daily	Nov '16	Mar '17	Jul '17	Nov '17	Mar '18	Jul '18
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '18	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '18	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '19	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '19	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '19	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 3 Summer		Execution Periods					
	Total Daily	Apr '17	Aug '17	Dec '17	Apr '18	Aug '18	Dec '18
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Apr '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
May '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jun '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jul '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Aug '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Sep '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Oct '19	16,800	2,800	2,800	2,800	2,800	2,800	2,800

* PECO did not receive the required three bids for the Year 3 Summer Aug '17 package and thus, did not hedge this package.

Year 3 Winter		Execution Periods					
	Total Daily	Nov '17	Mar '18	Jul '18	Nov '18	Mar '19	Jul '19
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '19	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '19	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '20	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '20	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '20	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 4 Summer		Execution Periods					
	Total Daily	Apr '18	Aug '18	Dec '18	Apr '19	Aug '19	Dec '19
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Apr '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
May '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jun '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Jul '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Aug '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Sep '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800
Oct '20	16,800	2,800	2,800	2,800	2,800	2,800	2,800

Year 4 Winter		Execution Periods					
	Total Daily	Nov '18	Mar '19	Jul '19	Nov '19	Mar '20	Jul '20
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '20	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '20	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '21	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '21	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '21	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 5 Summer		Execution Periods					
	Total Daily	Apr '19	Aug '19	Dec '19	Apr '20	Aug '20	Dec '20
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Apr '21	14,000	2,800	2,800	2,800	2,800	2,800	-
May '21	14,000	2,800	2,800	2,800	2,800	2,800	-
Jun '21	14,000	2,800	2,800	2,800	2,800	2,800	-
Jul '21	14,000	2,800	2,800	2,800	2,800	2,800	-
Aug '21	14,000	2,800	2,800	2,800	2,800	2,800	-
Sep '21	14,000	2,800	2,800	2,800	2,800	2,800	-
Oct '21	14,000	2,800	2,800	2,800	2,800	2,800	-

Year 5 Winter		Execution Periods					
	Total Daily	Nov '19	Mar '20	Jul '20	Nov '20	Mar '21	Jul '21
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '21	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '21	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '22	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '22	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '22	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 6 Summer		Execution Periods					
	Total Daily	Apr '20	Aug '20	Dec '20	Apr '21	Aug '21	Dec '21
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Apr '22	5,600	2,800	2,800	-	-	-	-
May '22	5,600	2,800	2,800	-	-	-	-
Jun '22	5,600	2,800	2,800	-	-	-	-
Jul '22	5,600	2,800	2,800	-	-	-	-
Aug '22	5,600	2,800	2,800	-	-	-	-
Sep '22	5,600	2,800	2,800	-	-	-	-
Oct '22	5,600	2,800	2,800	-	-	-	-

* PECO did not receive the required three bids for the Year 6 Summer Apr '20 package and thus, did not hedge this package.

Year 6 Winter		Execution Periods					
	Total Daily	Nov '20	Mar '21	Jul '21	Nov '21	Mar '22	Jul '22
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '22	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '22	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 7 Winter		Execution Periods					
	Total Daily	Nov '21	Mar '22	Jul '22	Nov '22	Mar '23	Jul '23
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 8 Winter		Execution Periods					
	Total Daily	Nov '22	Mar '23	Jul '23	Nov '23	Mar '24	Jul '24
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Exhibit SJH-3

2022 Balancing Charges					
Annual Cost for Storage (PECO PGC 38, Section7 Page 1)				$	23,944,188
Aggregate Imbalances for TS Customers					
	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries			
Dec-20	63,553	55,983			
Jan-21	58,359	94,788			
Feb-21	94,515	35,077			
Mar-21	31,597	66,618			
Apr-21	33,823	52,650			
May-21	58,189	51,122			
Jun-21	25,599	66,232			
Jul-21	64,754	24,898			
Aug-21	30,373	69,710			
Sep-21	20,323	64,723			
Oct-21	29,369	66,363			
Nov-21	83,445	40,069			
Total	593,899	688,233			
Total Aggregate 12 Month Daily TS Imbalance in MCF					1,282,132
Projected Annual PGC Volume in MCF					65,720,240
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					1.95%
Annual Storage Cost Applicable to Transportation Customers					
1.95% of	$ 23,944,188			$	467,126
Revenue From Excess Delivery Penalty Charge for Dec 20 through Nov 21 In mcf		71,391	$ 0.25	$	17,847.75
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers				$	449,278
Divided by TS MCF Actual Dec 20 through Nov 21					25,511,702
Balancing Charge per MCF					$0.0176

2022 Balancing Charges Exhibit SJH-4

Annual Cost for Storage (PECO PGC 38, Section7 Page 1)

Fixed Storage Costs (includes associated transport)	$	23,944,188
Storage Injection Cost	$	-
Storage Withdrawal Cost	$	-
TOTAL	$	23,944,188

Aggregate Imbalances for TS Customers

	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries
Dec-20	63,553	55,983
Jan-21	58,359	94,788
Feb-21	94,515	35,077
Mar-21	31,597	66,618
Apr-21	33,823	52,650
May-21	58,189	51,122
Jun-21	25,599	66,232
Jul-21	64,754	24,898
Aug-21	30,373	69,710
Sep-21	20,323	64,723
Oct-21	29,369	66,363
Nov-21	83,445	40,069
Total	593,899	688,233

Total Aggregate 12 Month Daily TS Imbalance in MCF					1,282,132
Projected Annual PGC Volume in MCF					65,720,240
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					1.95%
Annual Storage Cost Applicable to Transportation Customers					
1.95% of $ 23,944,188				$	467,126
Revenue From Excess Delivery Penalty Charge for Dec 20 through Nov 21 In mcf	71,391	$	0.25	$	17,847.75
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers				$	449,277.90
Divided by TS MCF Actual Dec 19 through Nov 20					25,511,702
Balancing Charge per MCF					$0.0176

2021 Balancing Charges Exhibit SJH-4

Annual Cost for Storage (PECO PGC 37, Section7 Page 1)

Fixed Storage Costs (includes associated transport)	$	24,417,250
Storage Injection Cost	$	-
Storage Withdrawal Cost	$	-
TOTAL	$	24,417,250

Aggregate Imbalances for TS Customers

	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries
Dec-19	80,066	52,939
Jan-20	41,646	103,356
Feb-20	56,352	22,735
Mar-20	60,089	39,372
Apr-20	49,501	89,491
May-20	73,820	50,347
Jun-20	48,384	66,020
Jul-20	58,519	68,357
Aug-20	35,429	41,673
Sep-20	51,482	75,067
Oct-20	41,206	47,260
Nov-20	107,809	66,953
Total	704,303	723,570

Total Aggregate 12 Month Daily TS Imbalance in MCF					1,427,873
Projected Annual PGC Volume in MCF					65,808,028
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					2.17%
Annual Storage Cost Applicable to Transportation Customers					
2.17% of $ 24,417,250				$	529,795
Revenue From Excess Delivery Penalty Charge for Dec 19 through Nov 20 In mcf	69,762	$	0.25	$	17,440.50
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers				$	512,354.01
Divided by TS MCF Actual Dec 19 through Nov 20					24,308,491
Balancing Charge per MCF					$0.0211

PECO STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY

DOCKET NO. R-2022-3032250

DIRECT TESTIMONY
OF
ANTHONY P. DIFELICE

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DIRECT TESTIMONY OF ANTHONY P. DIFELICE

I. INTRODUCTION

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

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

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

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

3. Q. Please describe your educational background.

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

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

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

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

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

a. PGC No. 18 at Docket No. R-00016366;

b. PGC No. 19 at Docket No. R-00027391;

c. PGC No. 20 at Docket No. R-00038409;

d. PGC No. 21 at Docket No. R-00049423;

e. PGC No. 22 at Docket No. R-00050537;

f. PGC No. 23 at Docket No. R-00061501;

g. PGC No. 24 at Docket No. R-00072331;

h. PGC No. 26 at Docket No. R-2009-2108705;

i. PGC No. 27 at Docket No. R-2010-2174034;

j. PGC No. 28 at Docket No. R-2011-2239263;

k. PGC No. 29 at Docket No. R-2012-2302784;

l. PGC No. 30 at Docket No. R-2013-2363227;

m. PGC No. 31 at Docket No. R-2014-2420283;

n. PGC No. 32 at Docket No. R-2015-2480969;

o. PGC No. 33 at Docket No. R-2016-2545925;

p. PGC No. 34 at Docket No. R-2017-2602611;

q. PGC No. 35 at Docket No. R-2018-3001568;

r. PGC No. 36 at Docket No. R-2019-3009624;

s. PGC No. 37 at Docket No. R-2020-3019661 and

t. PGC No. 38 at Docket No. R-2021-3025629.

In addition, I submitted testimony in the Company's proceeding, regarding the determination of the Gas Procurement Charge ("GPC"), at Docket No. P-2012-2328614, in compliance with the Pennsylvania Public Utility Commission's (the "Commission") Order for Promotion of Competitive Retail Markets at Docket No. L-2008-2069114.

II. PURPOSE OF TESTIMONY

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

A. My Direct Testimony will describe and support the development of the PGC rates filed by the Company in this proceeding, PGC No. 39, to become effective December 1, 2022. Pursuant to the Company's Gas Restructuring Settlement, filed and approved at Docket No. R-00994787, the PGC rate is unbundled into the Sales Service Cost ("SSC") and the Balancing Service Cost ("BSC"). The SSC is a charge to those customers purchasing natural gas supply from PECO. The BSC recovers costs associated with the operations of contract storage facilities and PECO's peaking services from all of PECO's low-volume customers, whether they purchase their natural gas supply from PECO or from a competitive natural gas supplier. Low-volume customers are defined as customers taking service under Rate Schedules GR, CAP, GC, OL, L and MV-F.

My Direct Testimony also will provide the monthly demand charge for Rate TS (Transportation Service) standby sales service to become effective December 1, 2022.

III. EXHIBITS SPONSORED

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

A. I am sponsoring the following exhibits:

- Exhibit APD-1 is a table comparing the Company's current PGC No. 38-Q2 rates, effective on June 1, 2022, with the proposed PGC No. 39 rates, effective December 1, 2022.
- Exhibit APD-2 provides the development of the Merchant Function Charge ("MFC") for the applicable rate classes for the proposed December 1, 2022 PGC rates as well as the total PGC rates for the applicable rate classes.
- Exhibit APD-3 summarizes the computation of the PGC No. 39 SSC, exclusive of the MFC.
- Exhibit APD-4 summarizes the computation of the PGC No. 39 BSC.

Also included in my Direct Testimony as Exhibit APD-5 are the following pages, in both regular text and "redlined" versions, of PECO's proposed Supplement No. 11 to Tariff Gas – Pa. P.U.C. No. 4 ("Supplement No. 11"):

- 10th revised Page No. 1 and 10th revised Page No. 2.
- 5th revised Page Nos. 39 and 45, reflecting a $1.3367 per Mcf total decrease in the Section 1307(f) rates for Rates GR and CAP, a $1.3317 per Mcf total decrease for Rate GC and a $1.3309 per Mcf total decrease for Rates OL, L and MV-F.
- 2nd revised Page No. 40, extending the Off-System Sales Sharing Mechanism through November 30, 2025.
- 5th revised Page Nos. 43 and 44, reflecting the MFC and the Price to Compare.
- 2nd revised Page No. 68, reflecting a $0.0035 per Mcf decrease in the Transportation Balancing Charge to a value of $0.0176 per Mcf.

IV. PROPOSED PGC RATES

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

A. The "historic period" (December 1, 2021 through April 30, 2022) and the "estimated period" (May 1, 2022 through November 30, 2022) together comprise the "E" factor period. The "C" factor period, or PGC No. 39 application period, begins December 1, 2022 and ends November 30, 2023.

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

A. Yes. In addition, the natural gas cost information previously filed by the Company on April 29, 2022 in support of PGC 39 (the "Advance Information") is sponsored by Company Witness Scott J. Hughes, who is submitting PECO Statement No. 1. In addition, Company Witness Hughes will sponsor the proposed extension of the Off-System Sales Sharing Mechanism and the determination of the Transportation Balancing Charge.

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

A. As set forth in its tariff, the Company recovers the projected cost of purchased natural gas and natural gas procurement charges through the Commodity Charge ("CC") factor of the SSC and the "C" factor of the BSC. In addition, amounts for prior period over/under collections, refunds, interest and other items are recovered through the GCA of the SSC and the "E" factor of the BSC. In total, under PGC No. 38, which was approved by the Commission at Docket No. R-2021-3025629, the Company began recovering $6.2265 per Mcf for Rates GR and CAP, $6.2078 per Mcf for Rate GC and $6.2050 per Mcf for Rates OL, L and MV-F as the bundled SSC and BSC charges applicable to its retail sales service as of December 1, 2021. That amount was updated by a February 25, 2022 filing for PGC No. 38-Q1 that put into effect, as of March 1, 2022, PGC rates of $5.8156 per Mcf for Rates GR and CAP, $5.7991 per Mcf for Rate GC and $5.7966 per Mcf for Rates OL, L and MV-F. Finally, the May 31, 2022 filing for PGC No. 38-Q2 effective June 1, 2022 has PGC rates of $8.8383 per Mcf for Rates GR and CAP, $8.8116 per Mcf for Rate GC and $8.8076 per Mcf for Rates OL, L and MV-F.

11. Q. Please describe the MFC and its impact on the June 1, 2022 PGC rate.

A. As a result of the Commission's Order at Docket No. P-2012-2328614,[1] an MFC was created separately for Rates GR and CAP and Rate GC. The charge recovers uncollectible charge-offs related to natural gas supply from PGC customers who procure their natural gas supply from PECO. It is based on write-off factors of 0.45% for Rates GR and CAP and 0.11% for Rate GC and 0.06% for Rates OL, L and MV-F. These write-off factors are from the Commission's Final Order in PECO's 2020 Gas Distribution Base Rate Case at Docket No. R-2020-3018929. The write-off factors are applied to the CC, including the GPC portion of the PGC rate, to produce the applicable MFCs. Subsequently, the MFCs are included in the CC portion of the SSC. The MFC charges initially became effective on June 1, 2015.

These MFCs will change with PGC rate changes due to the changing CC including GPC charges, and are not reconcilable. As a result of the different MFCs and the subsequent different CCs, the PGC rates will have different values depending on the applicable rate classes. Specifically, the June 1, 2022 value of the MFC is $0.0354 per Mcf for Rates GR and CAP, $0.0087 per Mcf for Rate GC and $0.0047 per Mcf for

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

Rates OL, L and MV-F. This leads to a June 1, 2022 total CC value of $7.8997 per Mcf for Rates GR and CAP, $7.8730 per Mcf for Rate GC and $7.8690 per Mcf for Rates OL, L and MV-F (*see* Table APD-1, below).

Table APD-1

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC including GPC	$7.8643	$7.8643	$7.8643
MFC	$0.0354	$0.0087	$0.0047
Total CC including GPC and MFC **Effective June 1, 2022**	$7.8997	$7.8730	$7.8690

The June 1, 2022 GCA value of $0.4461 per Mcf is the same for Rates GR, CAP, GC, OL, L and MV-F. The June 1, 2022 BSC of $0.4925 per Mcf is also the same for these rates. The resultant PGC rates are shown below in Table APD-2.

Table APD-2

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC	$7.8997	$7.8730	$7,8690
GCA	$0.4461	$0.4461	$0.4461
BSC	$0.4925	$0.4925	$0.4925
Total PGC Rate **Effective June 1, 2022**	$8.8383	$8.8116	$8.8076

12. Q. How does the MFC impact the December 1, 2022 PGC No. 39 rate?

A. The PGC rates will differ, depending on the applicable tariff rate class. Exhibit APD-2 shows the derivation of the proposed December 1, 2022 PGC rates.

The write-off factors for uncollectible charge-offs are applied to the December 1, 2022 CC, including the GPC, to yield an MFC (effective December 1, 2022) of $0.0287 per Mcf for Rates GR and CAP, $0.0070 per Mcf for Rate GC and $0.0038 per Mcf for Rates OL, L and MV-F. As a result, the total December 1, 2022 CC, including the GPC and MFC, is $6.4145 per Mcf for Rates GR and CAP, $6.3928 per Mcf for Rate GC and $6.3896 per Mcf for Rates OL, L and MV-F as shown below in Table APD-3 and in Exhibit APD-2.

Table APD-3

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC including GPC	$6.3858	$6.3858	$6.3858
MFC	$0.0287	$0.0070	$0.0038
Total CC including GPC and MFC **Effective December 1, 2022**	$6.4145	$6.3928	$6.3896

Note that the GPC and the write-off factors for the MFC calculation will be updated based on the Commission's final determination in PECO's 2022 natural gas distribution base rate case at Docket No. R-2022-3031113 (the "2022 Gas Base Rate Case"). The effective date of rates for the 2022 Gas Base Rate Case is anticipated to be on January 1, 2023.

13. Q. Please describe the rates proposed for PGC No. 39 effective December 1, 2022.

A. Adding the GCA of $0.5530 per Mcf and the BSC of $0.5341 per Mcf to the above total CC values produces PGC rates effective December 1, 2022 of $7.5016 per Mcf for Rates GR and CAP, $7.4799 per Mcf for Rate GC and $7.4767 per Mcf for Rates OL, L and MV-F as shown below in Table APD-4 and in Exhibit APD-2.

Table APD-4

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC	$6.4145	$6.3928	$6.3896
GCA	$0.5530	$0.5530	$0.5530
BSC	$0.5341	$0.5341	$0.5341
Total PGC Rate Effective **December 1, 20221**	$7.5016	$7.4799	$7.4767

14. Q. Please summarize the differences between the PGC No. 39 and the PGC No. 38-Q2 rates.

A. The CC component of the SSC, exclusive of the MFC, is projected to decrease by $1.4785 per Mcf, from $7.8643 per Mcf in PGC No. 38-Q2 to $6.3858 per Mcf in PGC No. 39. The GCA reconciliation component of the SSC will increase from $0.4461 per Mcf in PGC No. 38-Q2 to $0.5530 per Mcf in PGC No. 39. Lastly, the BSC will increase from $0.4925 per Mcf to $0.5341 per Mcf.

15. Q. Please explain what caused the CC component of the SSC, exclusive of the MFC, to decrease from $7.8643 per Mcf in PGC No. 38-Q2 to $6.3858 per Mcf in PGC No. 39.

A. The $6.3858 per Mcf value of the CC, exclusive of the MFC, for PGC No. 39 is comprised of two parts. The first component is the projected recoverable fuel cost of $413.1 million for the period December 1, 2022 through November 30, 2023 divided by twelve-month projected sales of 64,907,702 Mcfs for the same period, which equates to $6.3639 per Mcf. In addition, a GPC of $0.0219 per Mcf is included in the CC component. The calculation of the $7.8643 per Mcf CC rate, exclusive of the MFC, for PGC No. 38-Q2 reflects a value of $7.8424 per Mcf for the combination of actual and projected fuel costs and certain over/under collection data for the period December 1, 2021 through November 30, 2022.[2] The CC rate also includes the same GPC value of $0.0219 per Mcf.

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

16. Q. Please explain what caused the GCA rate to increase from a value of $0.4461 per Mcf in PGC No. 38-Q2 to $0.5530 per Mcf in PGC No. 39.

A. The $0.1069 per Mcf increase in the GCA rate is due to four factors. First, there was a change in the over/under collection component for the commodity cost, from a $23.5 million under-collection balance as of November 30, 2021 reflected in the PGC No. 38-Q2 rate, to a projected $24.3 million under-collection balance as of November 30, 2022, which is to be collected from customers during the PGC No. 39 application period. Second, there was a change in the accompanying interest balance from a $0.3 million under-collection balance at November 30, 2021 reflected in the PGC No. 38-Q2 rate to a projected $1.0 million under-collection balance as of November 30, 2022, which is to be recovered from customers during the PGC No. 39 application period. Third, there was a decrease in the balance for supplier refunds, including interest, from an over-collection balance of $2.8 million as of November 30, 2021 reflected in the PGC 38-Q2 rate to a projected under-collection balance of $0.6 million as of November 30, 2022. Finally, the balance of Rate IS (Interruptible Service) profit has changed from an under-collection balance of $36,577 as of November 30, 2021 to a projected under-collection balance of $3,343 as of November 30, 2022. The changes in the commodity cost under-collection, interest and supplier refund balances act to increase the GCA rate while the change in the Rate IS profit balance acts to decrease the GCA rate.

17. Q. Please explain what caused the BSC rate to increase from $0.4925 per Mcf in PGC No. 38-Q2 to $0.5341 per Mcf for PGC No. 39.

A. The portion of the total BSC rate for PGC No. 39 associated with contract storage and peaking services of $0.5448 per Mcf is based on a projected recoverable cost of $35.4 million for the period December 1, 2022 through November 30, 2023 divided by twelve-month projected sales of 64,907,702 Mcfs for the same period. The associated value of $0.5020 per Mcf for PGC No. 38-Q2 reflects a combination of actual and projected costs and certain over/under-collection data for the period December 1, 2021 through November 30, 2022.[3] This change caused an increase of $0.0428 per Mcf in the BSC rate for PGC No. 39.

The combination of changes for over/under-collection balances for various items of the BSC rate act to decrease the BSC rate by $0.0012 per Mcf. The over/under-collection balance associated with contract storage and peaking services changed from a $58,077 under-collection balance as of November 30, 2021 to a projected under-collection balance of $0.3 million as of November 30, 2022. In addition, the over-collection balance for miscellaneous surcharge monies increased from $0.5 million as of December 1, 2021 to a projected over-collection balance of $0.8 million as of November 30, 2022. Lastly, the net interest balance changed from an over-collection balance of $137,559 as of November 30, 2021 to a projected over-collection balance of $161,265 as of November 30, 2022.

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

V. SALES SERVICE COST COMPONENTS

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

A. Exhibit APD-1 is a single sheet titled "Proposed Changes in PGC Rate Prices Effective December 1, 2022." This sheet consists of three columns, the first of which shows the unbundled rates effective June 1, 2022 from PGC No. 38-Q2. The second column shows the proposed changes to the PGC No. 38-Q2 rates. The third column is the sum of Columns 1 and 2 and shows the PGC No. 39 proposed rates set forth in Supplement No. 11, which are to become effective on December 1, 2022. Exhibit APD-1 shows a total decrease of $1.3367 per Mcf between the proposed PGC No. 39 rates and current PGC No. 38-Q2 rates for Rates GR and CAP, a total decrease of $1.3317 per Mcf for Rate GC and a total decrease of $1.3309 per Mcf for Rates OL, L and MV-F.

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

A. Exhibit APD-2 provides the development of the MFC and its effect on the CC by rate class for the PGC No. 39 rate to be effective December 1, 2022. In addition, the GCA and BSC are included to determine the total PGC No. 39 rates by rate class to be effective December 1, 2022.

20. Q. Please describe the information shown on page 1 of Exhibit APD-3, which develops the SSC, exclusive of the MFC, for PGC No. 39 to be effective December 1, 2022.

A. Exhibit APD-3, page 1, summarizes the projected cost of natural gas, the GPC and details of the experienced net under-collection ("E" factor or GCA). Page 1, line 1, shows the allocated projection of the commodity cost of natural gas of $413,064,034 and the associated rate of $6.3639 per Mcf.

In addition, as a result of the Commission's Order at Docket No. R-2020-3018929, a GPC of $0.0219 per Mcf, to recover procurement-related costs including labor, pensions, benefits, outside legal, information technology and working capital, is shown on page 1, line 1. It is applied to PGC customers who obtain natural gas supply from PECO. This charge is included in the calculation of the CC portion of the SSC for PGC No. 38-Q2 and the proposed PGC No. 39. The charge is not reconcilable and will remain constant until the Commission's final determination in the 2022 Gas Base Rate Case. The updated GPC will be reflected at the time of the effective date of rates from the 2022 Gas Base Rate Case, expected to be January 1, 2023.

Summing the components of the projected cost of natural gas of $6.3639 per Mcf and the GPC of $0.0219 per Mcf, results in a CC, exclusive of the MFC, of $6.3858 per Mcf.

Lines 2.a. - d. summarize the items used to develop the GCA factor. This sheet shows a net amount of approximately $25.8 million in under-collections, Rate IS profits, refunds and interest to be recovered from customers through the GCA factor during the PGC No. 39 application period.

21. Q. Please explain the basis for the approximately $25.8 million net under-collection to be recovered from customers through the GCA factor.

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

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

The recoverable cost of natural gas is subtracted from the CC revenues received, including the adjustment for the prior period reconciliation and excluding GPC and MFC revenues. As of November 30, 2022, the estimated total under-collection balance after reconciliation is expected to be $24,286,034. That figure is brought forward from page 2 to page 1.

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

The difference between revenues received and costs comprises "profit" from Rate IS customers. Seventy-five percent of these profits were returned to PGC customers. As a result of the compliance filing of the 2020 Gas Base Rate Case at Docket No. R-2020-3018929 and later implemented at the effective date of December 1, 2021 for PGC No. 38 at Docket No. R-2021-3025629, the future profits will be incorporated in distribution base rates. The remaining balance of profits through November 30, 2022 of $3,343 will be recovered from customers and is determined by reconciling prior refunds/recoveries of profits through November 30, 2022.

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

The current period over/under-collection for the SSC is determined monthly. The current interest is calculated by applying an annual interest rate to these over/under collections which is then multiplied by a factor based on an equivalent payback to the midpoint of the PGC No. 39 application period.

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

In accordance with Paragraph 22 of the 2021 Joint Petition for Complete Settlement in the PGC No. 38 proceeding, the Company uses the prime rate effective sixty days prior to the date of this filing, which was 3.50%, for the period December

2021 through November 2022. Based on this interest rate, the current interest for the period December 2021 through November 2022 to be recovered from customers for the GCA during the PGC No. 39 application period amounts to $363,821.

Combining the under-collection balance of $348,996 as of November 30, 2021, the current interest to be recovered from customers for the December 2021 through November 2022 period of $858,146 and the estimated recovery from customers of $248,491 from December 1, 2021 through November 30, 2022 (Exhibit APD-3, page 6), the total interest balance at November 30, 2022 for the GCA to be recovered from customers during the PGC No. 39 application period has an estimated value of $958,651.

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

This item is comprised of the actual refunds returned to the Company by suppliers after July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 39 application period less the amount expected to be recovered from customers through November 30, 2022. The net result is an estimated amount of $593,025 to be recovered from customers as of November 30, 2022.

VI. BALANCING SERVICE COST COMPONENTS

22. Q. Please describe the information shown on page 1 of Exhibit APD-4, which develops the BSC for PGC No. 39 to be effective December 1, 2022.

A. Exhibit APD-4, page 1, summarizes the projected cost that PECO will incur under natural gas storage and peaking agreements with various interstate pipeline and natural gas marketing companies and details the experienced net over/under-collection balance. Page 1, line 1, shows the projected costs for contract storage and peaking services. Lines 2 a. - d. summarize the items used to develop the "E" factor. This sheet shows that the projected recoverable cost for contract storage and peaking services is $35.4 million for the period December 1, 2022 through November 30, 2023. There is also a projected over-collection balance of $0.7 million as of November 30, 2022. This amount includes over-collections, refunds, interest, and miscellaneous surcharge monies to be returned to customers during the PGC No. 39 application period. Page 1, line 3 shows the $34.7 million net amount to be recovered from customers.

23. Q. Please explain the basis for the $34.7 million net amount to be recovered from customers.

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

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

The projected recoverable cost for contract storage facilities and peaking services is $35,361,023 as shown on Exhibit APD-4, page 1.

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

The recoverable cost of natural gas is subtracted from the BSC revenues received, including the adjustment for the prior period reconciliation. The resulting balance is an estimated under-collection of $292,354 as of November 30, 2022, which figure is brought forward from page 2 to page 1.

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

Transportation balancing surcharges and penalties applied to transportation and Rate TCS and Rate IS customers are returned to firm service customers through the BSC. After reconciling refunds of prior balances and adding current surcharge monies, a projected balance of $823,296 as of November 30, 2022 is expected to be returned to customers.

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

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

As a result, the current interest for the period December 2021 through November 2022 to be returned to customers for the BSC during the PGC No. 39 application period amounts to $167,448. The current interest is based on the 3.50% interest rate previously described above for the SSC.

Combining the current interest to be returned to customers of $167,448 for the period December 2021 through November 2022 with the over-collected balance of prior period interest of $137,559 as of December 1, 2021 and including the amount returned to customers of $143,742 during the December 1, 2021 through November 30, 2022 period results in an estimated interest balance for the BSC of $161,265 to be returned to customers during the PGC No. 39 application period.

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

This item is comprised of the actual refunds returned to the Company by suppliers on or before July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 39 application period, less the amount expected to be returned to customers through November 30, 2022. The net result is an estimated amount of $2,041, as of November 30, 2022, to be returned to customers.

VII. OTHER RATES

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

Yes. The updated monthly demand charge for Rate TS standby sales service will be $22.77 per Mcf.

VIII. CONCLUSION

25. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit APD-1

Exhibit APD-1

Proposed Changes in PGC Rate Prices Effective December 1, 2022

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

			06/01/22 Unbundled Rates	Change in Rates	12/01/22 Unbundled Rates
Rates GR and CAP		CC	$7.8997	($1.4852)	$6.4145
		GCA	$0.4461	$0.1069	$0.5530
		BSC	$0.4925	$0.0416	$0.5341
		Total	$8.8383	($1.3367)	$7.5016
Rates GC		CC	$7.8730	($1.4802)	$6.3928
		GCA	$0.4461	$0.1069	$0.5530
		BSC	$0.4925	$0.0416	$0.5341
		Total	$8.8116	($1.3317)	$7.4799
Rates OL, L and MV-F		CC	$7.8690	($1.4794)	$6.3896
		GCA	$0.4461	$0.1069	$0.5530
		BSC	$0.4925	$0.0416	$0.5341
		Total	$8.8076	($1.3309)	$7.4767
Rate OL					
	(1.5 MCF)	**CC**	$11.8035	($2.2191)	$9.5844
	(1.7 MCF)		$13.3773	($2.5150)	$10.8623
	(2.1 MCF)		$16.5249	($3.1067)	$13.4182
	(2.4 MCF)		$18.8856	($3.5506)	$15.3350
	(1.5 MCF)	**GCA**	$0.6692	$0.1603	$0.8295
	(1.7 MCF)		$0.7584	$0.1817	$0.9401
	(2.1 MCF)		$0.9368	$0.2245	$1.1613
	(2.4 MCF)		$1.0706	$0.2566	$1.3272
	(1.5 MCF)	**BSC**	$0.7388	$0.0624	$0.8012
	(1.7 MCF)		$0.8373	$0.0707	$0.9080
	(2.1 MCF)		$1.0343	$0.0873	$1.1216
	(2.4 MCF)		$1.1820	$0.0998	$1.2818
Rate L					
First 50% of Usage		**CC**	$7.8690	($1.4794)	$6.3896
Additional Use			$7.8690	($1.4794)	$6.3896
First 50% of Usage		**GCA**	$0.4461	$0.1069	$0.5530
Additional Use			$0.4461	$0.1069	$0.5530
First 50% of Usage		**BSC**	$0.4925	$0.0416	$0.5341
Additional Use			$0.4925	$0.0416	$0.5341
Standby Sales Demand Charge Under Rate TS-F			$22.57	$0.2000	$22.77
Unit Credit for Rate TS-F Standby Sales Purchases			$0.74	$0.0100	$0.75
Balancing Charge-Transportation			$0.0211	($0.0035)	$0.0176

Exhibit APD-2

PGC No. 39 Calculation Including Gas Procurement Charge (GPC) and Merchant Function Charge (MFC)
Application Period : December 1, 2022 through November 30, 2023
Computation Period : December 1, 2022 through November 30, 2023
$/Mcf

		Rates GR and CAP	Rate GC	Rates OL, L and MV-F
CC Including GPC	Exhibit APD-3, Page 1	$6.3858	$6.3858	$6.3858
x				
Write-Off Factor (a)		0.45%	0.11%	0.06%
=				
MFC		$0.0287	$0.0070	$0.0038
CC Including GPC and MFC		$6.4145	$6.3928	$6.3896
GCA	Exhibit APD-3, Page 1	$0.5530	$0.5530	$0.5530
BSC	Exhibit APD-4, Page 1	$0.5341	$0.5341	$0.5341
Total PGC		$7.5016	$7.4799	$7.4767

(a) From Docket No. R-2020-3018929, the 2020 PECO Gas Distribution Base Rate Case.

Exhibit APD-3

Computation of Sales Service Cost Adjustment No. 39
Application and Computation Period : 12 Months
December 1, 2022 Through November 30, 2023

1. Projected Commodity Charge Excluding Gas Procurement Charge (GPC)	$413,064,034	Pg. 2	$6.3639	/Mcf
GPC From Docket No. R-2020-3018929			$0.0219	/Mcf
Total CC = Commodity Charge Including GPC			**$6.3858**	/Mcf
2. E = Experienced and Estimated Net Over/(Under)				
a. Commodity Cost Over / (Under)	($24,286,034)	Pg. 2	($0.5197)	/Mcf
b. Rate IS Profit Monies	($3,343)	Pg. 5	($0.0001)	/Mcf
c. Net Interest on Item a.	($958,651)	Pg. 6	($0.0205)	/Mcf
d. Supplier Refunds (Including Interest)	($593,025)	Pg. 8	($0.0127)	/Mcf
Experienced Net Over/Under Collections - GCA	($25,841,053)		($0.5530)	/Mcf
3. S = Projected Sales for Computation Period CC	64,907,702	mcf		
4. S = Projected Sales for Computation Period GCA	46,724,926	mcf		
GCA Charge / (Credit) to Customers	**$0.5530**	/Mcf		

Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)	CC/GCA Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance - Nov. 30, 2020								($4,911,377)
Dec	$25,538,069	$53,051	$25,485,018	0.99919320	$25,464,457	$21,581,141	($3,883,316)	($8,794,693)
Jan '21	$29,036,888	$51,282	$28,985,606	0.99952239	$28,971,762	$30,961,888	$1,990,126	($6,804,567)
Feb	$35,238,393	$147,173	$35,091,220	0.99944828	$35,071,860	$32,474,858	($2,597,002)	($9,401,569)
March	$18,814,531	$98,075	$18,716,456	0.99962998	$18,709,531	$26,857,645	$8,148,114	($1,253,455)
April	$9,430,756	$19,318	$9,411,438	0.99957358	$9,407,425	$14,375,788	$4,968,363	$3,714,908
May	$6,449,665	$26,040	$6,423,625	0.99970369	$6,421,722	$8,449,909	$2,028,187	$5,743,095
June	$5,505,508	$19,604	$5,485,904	0.99973007	$5,484,423	$5,014,207	($470,216)	$5,272,879
July	$5,093,433	$6,612	$5,086,821	0.99976122	$5,085,606	$3,336,300	($1,749,306)	$3,523,573
Aug	$4,836,185	$6,246	$4,829,939	0.99978012	$4,828,877	$3,063,216	($1,765,661)	$1,757,912
Sept	$5,331,659	$11,038	$5,320,621	0.99990663	$5,320,124	$3,373,619	($1,946,505)	($188,593)
Oct	$7,021,391	$16,975	$7,004,416	0.99938750	$7,000,126	$4,046,628	($2,953,498)	($3,142,091)
Nov	$30,770,193	$22,658	$30,747,535	0.99922758	$30,723,785	$10,042,443	($20,681,342)	($23,823,433)
12 Months	$183,066,671	$478,072	$182,588,599		$182,489,698	$163,577,642	($18,912,056)	
-PAPUC Bureau of Audits Adjustment								$290,170
12 Months -Nov 30, 2022	$328,402,423	$697,838	$327,704,585		$327,561,125		Balance at Nov 30, 2021	($23,533,263)

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Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)	CC/GCA Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance - Nov. 30, 2021								($23,533,263)
Dec	$32,995,433	$78,998	$32,916,435	0.99929715	$32,893,300	$29,106,930	($3,786,370)	($27,319,633)
Jan '22	$56,576,205	$60,828	$56,515,377	0.99926540	$56,473,861	$48,501,514	($7,972,347)	($35,291,980)
Feb	$42,357,447	$95,788	$42,261,659	0.99945544	$42,238,645	$54,491,110	$12,252,465	($23,039,515)
March	$27,984,313	$96,965	$27,887,348	0.99948565	$27,873,004	$34,677,329	$6,804,325	($16,235,190)
April	$19,749,425	$55,667	$19,693,758	0.99951165	$19,684,140	$23,822,252	$4,138,112	($12,097,078)
May (est)	$22,270,800	$86,220	$22,184,580	0.99975975	$22,179,250	$13,663,941	($8,515,309)	($20,612,387)
June (est)	$15,279,800	$39,611	$15,240,189	0.99975361	$15,236,434	$9,502,431	($5,734,003)	($26,346,390)
July (est)	$14,388,800	$31,909	$14,356,891	0.99982455	$14,354,372	$10,206,910	($4,147,462)	($30,493,852)
Aug (est)	$14,434,800	$39,532	$14,395,268	0.99985192	$14,393,136	$10,239,714	($4,153,422)	($34,647,274)
Sept (est)	$15,016,800	$31,064	$14,985,736	0.99994196	$14,984,866	$11,675,609	($3,309,257)	($37,956,531)
Oct (est)	$24,824,800	$46,601	$24,778,199	0.99981160	$24,773,531	$27,006,561	$2,233,030	($35,723,501)
Nov (est)	$42,523,800	$34,655	$42,489,145	0.99970441	$42,476,586	$53,914,053	$11,437,467	($24,286,034)
12 Months	$328,402,423	$697,838	$327,704,585		$327,561,125	$326,808,354	($752,771)	
12 Months -Nov 30, 2023	$414,234,600	$1,014,618	$413,219,982		$413,064,034			

Exclusions and Allocation Factor

Exclusions

Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	$0	$18,357	$0	$34,473	$221	$0	$53,051
Jan '21	$0	$514	$0	$50,768	$0	$0	$51,282
Feb	$0	$76,789	$0	$70,266	$118	$0	$147,173
March	$0	$489	$0	$97,550	$36	$0	$98,075
April	$0	$75	$0	$18,951	$292	$0	$19,318
May	$0	$926	$0	$24,931	$183	$0	$26,040
June	$0	$4,066	$0	$15,290	$248	$0	$19,604
July	$0	$792	$0	$5,817	$3	$0	$6,612
Aug	$0	$2,584	$0	$3,648	$14	$0	$6,246
Sept	$0	$3,129	$0	$7,873	$36	$0	$11,038
Oct	$0	$2,806	$0	$13,880	$289	$0	$16,975
Nov	$0	$602	$0	$21,608	$448	$0	$22,658
12 Months	$0	$111,129	$0	$365,055	$1,888	$0	$478,072
12 Months -Nov 30, 2022	$0	$119,861	$0	$575,303	$2,674	$0	$697,838

Allocation Factor Calculation

Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	4,533	5,613,983	5,618,516	0.99919320	5,613,983
Jan '21	3,961	8,289,440	8,293,401	0.99952239	8,289,440
Feb	4,798	8,691,716	8,696,514	0.99944828	8,691,716
March	2,582	6,975,468	6,978,050	0.99962998	6,975,468
April	1,550	3,633,369	3,634,919	0.99957358	3,633,369
May	633	2,135,649	2,136,282	0.99970369	2,135,649
June	355	1,314,788	1,315,143	0.99973007	1,314,788
July	220	921,121	921,341	0.99976122	921,121
Aug	186	845,725	845,911	0.99978012	845,725
Sept	83	888,847	888,930	0.99990663	888,847
Oct	617	1,006,724	1,007,341	0.99938750	1,006,724
Nov	1,931	2,497,996	2,499,927	0.99922758	2,497,996
12 Months	21,449	42,814,826	42,836,275		42,814,826

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge
(b) TCS Sales Volume x (Commodity Price Excl TOP + TCS Fixed Commodity Cost Component)
(c) Demand portion based on Rate CGS Firm Reservation Supply Charge / 30.41 x NGS Sales Volume,
Commodity portion based on Weighted Average Commodity Cost of Gas x NGS Sales Volume

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Exclusions and Allocation Factor

Exclusions

Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	$0	$34,148	$0	$44,757	$93	$0	$78,998
Jan '22	$0	$7,158	$0	$53,670	$0	$0	$60,828
Feb	$0	$27,002	$0	$68,723	$63	$0	$95,788
March	$0	$14,477	$0	$81,736	$752	$0	$96,965
April	$0	$2,297	$0	$53,020	$350	$0	$55,667
May (est)	$0	$4,789	$0	$81,223	$208	$0	$86,220
June (est)	$0	$4,392	$0	$35,017	$202	$0	$39,611
July (est)	$0	$4,719	$0	$27,004	$186	$0	$31,909
Aug (est)	$0	$5,422	$0	$33,915	$195	$0	$39,532
Sept (est)	$0	$5,336	$0	$25,522	$206	$0	$31,064
Oct (est)	$0	$4,928	$0	$41,479	$194	$0	$46,601
Nov (est)	$0	$5,193	$0	$29,237	$225	$0	$34,655
12 Months	$0	$119,861	$0	$575,303	$2,674	$0	$697,838
12 Months -Nov 30, 2023	$0	$47,539	$0	$965,072	$2,007	$0	$1,014,618

Allocation Factor Calculation

Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	4,246	6,036,849	6,041,095	0.99929715	6,036,849
Jan '22	6,148	8,363,051	8,369,199	0.99926540	8,363,051
Feb	5,121	9,398,746	9,403,867	0.99945544	9,398,746
March	3,196	6,210,457	6,213,653	0.99948565	6,210,457
April	2,154	4,408,589	4,410,743	0.99951165	4,408,589
May (est)	633	2,634,150	2,634,783	0.99975975	1,607,205
June (est)	355	1,440,428	1,440,783	0.99975361	783,136
July (est)	220	1,253,730	1,253,950	0.99982455	754,447
Aug (est)	186	1,255,913	1,256,099	0.99985192	786,035
Sept (est)	83	1,430,061	1,430,144	0.99994196	927,299
Oct (est)	617	3,274,254	3,274,871	0.99981160	2,675,299
Nov (est)	1,931	6,530,755	6,532,686	0.99970441	5,431,460
12 Months	24,890	52,236,983	52,261,873		47,382,573

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge
(b) TCS Sales Volume x (Commodity Price Excl TOP + TCS Fixed Commodity Cost Component)
(c) Demand portion based on Rate CGS Firm Reservation Supply Charge / 30.41 x NGS Sales Volume,
Commodity portion based on Weighted Average Commodity Cost of Gas x NGS Sales Volume

SSC Revenues

	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	2,725,196	$3.2301	$8,802,656	2,725,196	$0.7297	$1,988,576	$10,791,232
Dec aft 12/1	2,888,787	$3.6705	$10,603,293	2,888,787	$0.0646	$186,616	$10,789,909
Jan '21 bef 12/1	-	$3.2301	$0		$0.7297	$0	$0
Jan '21 aft 12/1	8,289,440	$3.6705	$30,426,390	8,289,440	$0.0646	$535,498	$30,961,888
Feb	8,691,716	$3.6714	$31,910,766	8,691,716	$0.0649	$564,092	$32,474,858
March	6,975,468	$3.7602	$26,229,155	6,975,468	$0.0901	$628,490	$26,857,645
April	3,633,369	$3.8430	$13,963,037	3,633,369	$0.1136	$412,751	$14,375,788
May	2,135,649	$3.8430	$8,207,299	2,135,649	$0.1136	$242,610	$8,449,909
June	1,314,788	$3.7030	$4,868,660	1,314,788	$0.1107	$145,547	$5,014,207
July	921,121	$3.5151	$3,237,832	921,121	$0.1069	$98,468	$3,336,300
Aug	845,725	$3.5151	$2,972,808	845,725	$0.1069	$90,408	$3,063,216
Sept	888,847	$3.6903	$3,280,112	888,847	$0.1052	$93,507	$3,373,619
Oct	1,006,724	$3.9165	$3,942,835	1,006,724	$0.1031	$103,793	$4,046,628
Nov	2,497,996	$3.9171	$9,784,900	2,497,996	$0.1031	$257,543	$10,042,443
12 Months	42,814,826		$158,229,743	42,814,826		$5,347,899	$163,577,642

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SSC Revenues

	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	3,318,033	$3.9171	$12,997,067	3,318,033	$0.1031	$342,089	$13,339,156
Dec aft 12/1	2,718,816	$5.4841	$14,910,259	2,718,816	$0.3154	$857,515	$15,767,774
Jan '22 bef 12/1	-	$3.9171	$0		$0.1031	$0	$0
Jan '22 aft 12/1	8,363,051	$5.4841	$45,863,808	8,363,051	$0.3154	$2,637,706	$48,501,514
Feb	9,398,746	$5.4812	$51,516,407	9,398,746	$0.3165	$2,974,703	$54,491,110
March	6,210,457	$5.1377	$31,907,465	6,210,457	$0.4460	$2,769,864	$34,677,329
April	4,408,589	$4.8486	$21,375,485	4,408,589	$0.5550	$2,446,767	$23,822,252
May (est)	2,634,150	$4.8486	$12,771,942	1,607,205	$0.5550	$891,999	$13,663,941
June (est)	1,440,428	$6.3107	$9,090,110	783,136	$0.5265	$412,321	$9,502,431
July (est)	1,253,730	$7.8424	$9,832,252	754,447	$0.4966	$374,658	$10,206,910
Aug (est)	1,255,913	$7.8424	$9,849,369	786,035	$0.4966	$390,345	$10,239,714
Sept (est)	1,430,061	$7.8424	$11,215,112	927,299	$0.4966	$460,497	$11,675,609
Oct (est)	3,274,254	$7.8424	$25,678,008	2,675,299	$0.4966	$1,328,553	$27,006,561
Nov (est)	6,530,755	$7.8424	$51,216,790	5,431,460	$0.4966	$2,697,263	$53,914,053
12 Months	52,236,983		$308,224,074	47,382,573		$18,584,280	$326,808,354

IS Profits

	Gross Reg IS Revenue (1)	IS Gas Penalty Revenue (2)	Unauth. IS Gas Revenue (3)	"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 75%	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, 2020													$46,047
Dec bef 12/1										2,725,196	$0.0010	$2,725	$43,322
Dec aft 12/1	$20,507	$0	$0	$20,507	3,318	$5.5324	$18,357	$2,150	$1,613	2,888,787	$0.0014	$4,044	$40,891
Jan '21 bef 12/1										0	$0.0010	$0	$40,891
Jan '21 aft 12/1	$768	$0	$0	$768	111	$4.6302	$514	$254	$191	8,289,440	$0.0014	$11,605	$29,477
Feb	$20,935	$0	$0	$20,935	3,919	$19.5940	$76,789	($55,854)	($41,891)	8,691,716	$0.0014	$12,168	($24,582)
March	$1,044	$0	$0	$1,044	163	$2.9992	$489	$555	$416	6,975,468	$0.0012	$8,371	($32,537)
April	$285	$0	$0	$285	26	$2.8952	$75	$210	$158	3,633,369	$0.0011	$3,997	($36,376)
May	$2,253	$0	$0	$2,253	359	$2.5796	$926	$1,327	$995	2,135,649	$0.0011	$2,349	($37,730)
June	$7,025	$0	$0	$7,025	1,244	$3.2686	$4,066	$2,959	$2,219	1,314,788	$0.0011	$1,446	($36,957)
July	$2,313	$0	$0	$2,313	296	$2.6758	$792	$1,521	$1,141	921,121	$0.0010	$921	($36,737)
Aug	$6,160	$0	$0	$6,160	931	$2.7759	$2,584	$3,576	$2,682	845,725	$0.0010	$846	($34,901)
Sept	$4,344	$0	$0	$4,344	612	$5.1129	$3,129	$1,215	$911	888,847	$0.0010	$889	($34,879)
Oct	$4,973	$0	$0	$4,973	671	$4.1815	$2,806	$2,167	$1,625	1,006,724	$0.0010	$1,007	($34,261)
Nov	$844	$0	$0	$844	78	$7.7182	$602	$242	$182	2,497,996	$0.0010	$2,498	($36,577)
12 Months	$71,451	$0	$0	$71,451	11,728		$111,129	($39,678)	($29,758)	42,814,826		$52,866	($82,624)
Balance at Nov 30, 2021													($36,577)

IS Profits

	Gross Reg IS Revenue (1)	IS Gas Penalty Revenue (2)	Unauth. IS Gas Revenue (3)	"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, 2021													($36,577)
Dec bef 12/1										3,318,033	$0.0010	$3,318	($39,895)
Dec aft 12/1	$64,844	$0	$0	$64,844	8,062	$4.2357	$34,148	$30,696	$0	2,718,816	($0.0008)	($2,175)	($37,720)
Jan '22 bef 12/1										0	$0.0010	$0	($37,720)
Jan '22 aft 12/1	$3,329	$0	$0	$3,329	468	$15.2958	$7,158	($3,829)	$0	8,363,051	($0.0008)	($6,690)	($31,030)
Feb	$16,543	$0	$0	$16,543	2,554	$10.5724	$27,002	($10,459)	$0	9,398,746	($0.0008)	($7,519)	($23,511)
March	$8,068	$0	$0	$8,068	1,251	$11.5721	$14,477	($6,409)	$0	6,210,457	($0.0009)	($5,589)	($17,922)
April	$2,424	$0	$0	$2,424	289	$7.9488	$2,297	$127	$0	4,408,589	($0.0009)	($3,968)	($13,954)
May (est)	$8,921	$0	$0	$8,921	820	$5.8400	$4,789	$4,132	$0	1,607,205	($0.0009)	($1,446)	($12,508)
June (est)	$8,220	$0	$0	$8,220	760	$5.7800	$4,392	$3,828	$0	783,136	($0.0009)	($705)	($11,803)
July (est)	$8,818	$0	$0	$8,818	814	$5.8000	$4,719	$4,099	$0	754,447	($0.0008)	($604)	($11,199)
Aug (est)	$10,115	$0	$0	$10,115	932	$5.8200	$5,422	$4,693	$0	786,035	($0.0008)	($629)	($10,570)
Sept (est)	$10,189	$0	$0	$10,189	963	$5.5400	$5,336	$4,853	$0	927,299	($0.0008)	($742)	($9,828)
Oct (est)	$9,459	$0	$0	$9,459	899	$5.4800	$4,928	$4,531	$0	2,675,299	($0.0008)	($2,140)	($7,688)
Nov (est)	$9,848	$0	$0	$9,848	924	$5.6200	$5,193	$4,655	$0	5,431,460	($0.0008)	($4,345)	($3,343)
12 Months	$160,779	$0	$0	$160,779	18,736		$119,861	$40,918	$0	47,382,573		($33,234)	$33,234
Balance at Nov 30, 2022													($3,343)

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

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)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Ret. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: GCA Applicable Sales (7)	Interest Refund rate (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance - Nov. 30, 2020										$120,202
Dec bef 12/1							2,725,196	($0.0291)	($79,303)	$199,505
Dec aft 12/1	$19,405,949	$25,464,457	($6,058,508)	3.25%	18/12	($295,352)	2,888,787	$0.0044	$12,711	($108,558)
Jan '21 bef 12/1							-	($0.0291)	$0	($108,558)
Jan '21 aft 12/1	$30,426,390	$28,971,762	$1,454,628	3.25%	17/12	$66,973	8,289,440	$0.0044	$36,474	($78,059)
Feb	$31,910,766	$35,071,860	($3,161,094)	3.25%	16/12	($136,981)	8,691,716	$0.0044	$38,244	($253,284)
March	$26,229,155	$18,709,531	$7,519,624	3.25%	15/12	$305,485	6,975,468	$0.0036	$25,112	$27,089
April	$13,963,037	$9,407,425	$4,555,612	3.25%	14/12	$172,734	3,633,369	$0.0028	$10,173	$189,650
May	$8,207,299	$6,421,722	$1,785,577	3.25%	13/12	$62,867	2,135,649	$0.0028	$5,980	$246,537
June	$4,868,660	$5,484,423	($615,763)	3.25%	12/12	($20,012)	1,314,788	$0.0027	$3,550	$222,975
July	$3,237,832	$5,085,606	($1,847,774)	3.25%	11/12	($55,048)	921,121	$0.0026	$2,395	$165,532
Aug	$2,972,808	$4,828,877	($1,856,069)	3.25%	10/12	($50,269)	845,725	$0.0026	$2,199	$113,064
Sept	$3,280,112	$5,320,124	($2,040,012)	3.25%	9/12	($49,725)	888,847	$0.0026	$2,311	$61,028
Oct	$3,942,835	$7,000,126	($3,057,291)	3.25%	8/12	($66,241)	1,006,724	$0.0025	$2,517	($7,730)
Nov	$9,784,900	$30,723,785	($20,938,885)	3.25%	7/12	($396,966)	2,497,996	$0.0025	$6,245	($410,941)
12 Months	$158,229,743	$182,489,698	($24,259,955)			($462,535)	42,814,826		$68,608	($531,143)
-PAPUC Bureau of Audits Adjustment										$61,945
Balance at Nov 30, 2021										($348,996)

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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)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Ret. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: GCA Applicable Sales (7)	Interest Refund rate (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance - Nov. 30, 2021										($348,996)
Dec bef 12/1							3,318,033	$0.0025	$8,295	($357,291)
Dec aft 12/1	$27,907,326	$32,893,300	($4,985,974)	3.50%	18/12	($261,764)	2,718,816	($0.0041)	($11,147)	($607,908)
Jan '22 bef 12/1							-	$0.0025	$0	($607,908)
Jan '22 aft 12/1	$45,863,808	$56,473,861	($10,610,053)	3.50%	17/12	($526,082)	8,363,051	($0.0041)	($34,289)	($1,099,701)
Feb	$51,516,407	$42,238,645	$9,277,762	3.50%	16/12	$432,962	9,398,746	($0.0041)	($38,535)	($628,204)
March	$31,907,465	$27,873,004	$4,034,461	3.50%	15/12	$176,508	6,210,457	($0.0063)	($39,126)	($412,570)
April	$21,375,485	$19,684,140	$1,691,345	3.50%	14/12	$69,063	4,408,589	($0.0082)	($36,150)	($307,357)
May (est)	$12,771,942	$22,179,250	($9,407,308)	3.50%	13/12	($356,694)	1,607,205	($0.0082)	($13,179)	($650,872)
June (est)	$9,090,110	$15,236,434	($6,146,324)	3.50%	12/12	($215,121)	783,136	($0.0078)	($6,108)	($859,885)
July (est)	$9,832,252	$14,354,372	($4,522,120)	3.50%	11/12	($145,085)	754,447	($0.0074)	($5,583)	($999,387)
Aug (est)	$9,849,369	$14,393,136	($4,543,767)	3.50%	10/12	($132,527)	786,035	($0.0074)	($5,817)	($1,126,097)
Sept (est)	$11,215,112	$14,984,866	($3,769,754)	3.50%	9/12	($98,956)	927,299	($0.0074)	($6,862)	($1,218,191)
Oct (est)	$25,678,008	$24,773,531	$904,477	3.50%	8/12	$21,104	2,675,299	($0.0074)	($19,797)	($1,177,290)
Nov (est)	$51,216,790	$42,476,586	$8,740,204	3.50%	7/12	$178,446	5,431,460	($0.0074)	($40,193)	($958,651)
12 Months	$308,224,074	$327,561,125	($19,337,051)			($858,146)	47,382,573		($248,491)	($609,655)
Balance at Nov 30, 2022										($958,651)

PUC Adjustment plus Interest

Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2020				(\$1,311)
Dec bef 12/1	2,725,196	\$0.0000	\$0	(\$1,311)
Dec aft 12/1	2,888,787	\$0.0000	\$0	(\$1,311)
Jan '21 bef 12/1	-	\$0.0000	\$0	(\$1,311)
Jan '21 aft 12/1	8,289,440	\$0.0000	\$0	(\$1,311)
Feb	8,691,716	\$0.0000	\$0	(\$1,311)
March	6,975,468	\$0.0000	\$0	(\$1,311)
April	3,633,369	\$0.0000	\$0	(\$1,311)
May	2,135,649	\$0.0000	\$0	(\$1,311)
June	1,314,788	\$0.0000	\$0	(\$1,311)
July	921,121	\$0.0000	\$0	(\$1,311)
Aug	845,725	\$0.0000	\$0	(\$1,311)
Sept	888,847	\$0.0000	\$0	(\$1,311)
Oct	1,006,724	\$0.0000	\$0	(\$1,311)
Nov	2,497,996	\$0.0000	\$0	(\$1,311)
12 Months	42,814,826		\$0	
Balance at Nov 30, 2021				(\$1,311)

PUC Adjustment plus Interest

Month	GCA Applicable Sales (1)	PUC Adj. Factor \$/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2021				(\$1,311)
Dec bef 12/1	3,318,033	\$0.0000	\$0	(\$1,311)
Dec aft 12/1	2,718,816	\$0.0000	\$0	(\$1,311)
Jan '22 bef 12/1	-	\$0.0000	\$0	(\$1,311)
Jan '22 aft 12/1	8,363,051	\$0.0000	\$0	(\$1,311)
Feb	9,398,746	\$0.0000	\$0	(\$1,311)
March	6,210,457	\$0.0000	\$0	(\$1,311)
April	4,408,589	\$0.0000	\$0	(\$1,311)
May (est)	1,607,205	\$0.0000	\$0	(\$1,311)
June (est)	783,136	\$0.0000	\$0	(\$1,311)
July (est)	754,447	\$0.0000	\$0	(\$1,311)
Aug (est)	786,035	\$0.0000	\$0	(\$1,311)
Sept (est)	927,299	\$0.0000	\$0	(\$1,311)
Oct (est)	2,675,299	\$0.0000	\$0	(\$1,311)
Nov (est)	5,431,460	\$0.0000	\$0	(\$1,311)
12 Months	47,382,573		\$0	
Balance at Nov 30, 2022				(\$1,311)

Supplier Refunds Including Interest - Summary Sheet

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) =(1) x (2) x (3)	Total (5) = (1) + (4)	GCA Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5) - (8)
Balance - Nov. 30, 2020									$19,366,643
Dec bef 12/1		6.00%			$0	2,725,196	$0.0114	$31,067	$19,335,576
Dec aft 12/1	$0	6.00%	18/12	$0	$0	2,888,787	$0.4264	$1,231,779	$18,103,797
Jan '21 bef 12/1		6.00%			$0	-	$0.0114	$0	$18,103,797
Jan '21 aft 12/1	$453,086	6.00%	17/12	$38,512	$491,598	8,289,440	$0.4264	$3,534,617	$15,060,778
Feb	$760	6.00%	16/12	$61	$821	8,691,716	$0.4265	$3,707,017	$11,354,582
March	$0	6.00%	15/12	$0	$0	6,975,468	$0.4375	$3,051,767	$8,302,815
April	$26,676	6.00%	14/12	$1,867	$28,543	3,633,369	$0.4478	$1,627,023	$6,704,335
May	$29,799	6.00%	13/12	$1,937	$31,736	2,135,649	$0.4478	$956,344	$5,779,727
June	$0	6.00%	12/12	$0	$0	1,314,788	$0.4367	$574,168	$5,205,559
July	$5,621	6.00%	11/12	$309	$5,930	921,121	$0.4217	$388,437	$4,823,052
Aug	$2,288	6.00%	10/12	$114	$2,402	845,725	$0.4217	$356,642	$4,468,812
Sept	$0	6.00%	9/12	$0	$0	888,847	$0.4151	$368,960	$4,099,852
Oct	$15,936	6.00%	8/12	$637	$16,573	1,006,724	$0.4066	$409,334	$3,707,091
Nov	$88,401	6.00%	7/12	$3,094	$91,495	2,497,996	$0.4066	$1,015,685	$2,782,901
12 Months	$622,567			$46,531	$669,098	42,814,826		$17,252,840	($16,583,742)
Balance at Nov 30, 2021									$2,782,901

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Supplier Refunds Including Interest - Summary Sheet

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) =(1) x (2) x (3)	Total (5) = (1) + (4)	GCA Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5) - (8)
Balance - Nov. 30, 2021									$2,782,901
Dec bef 12/1		6.00%			$0	3,318,033	$0.4066	$1,349,112	$1,433,789
Dec aft 12/1	$11,637	6.00%	18/12	$1,047	$12,684	2,718,816	$0.0323	$87,818	$1,358,655
Jan '22 bef 12/1		6.00%			$0	-	$0.4066	$0	$1,358,655
Jan '22 aft 12/1	$1,480	6.00%	17/12	$126	$1,606	8,363,051	$0.0323	$270,127	$1,090,134
Feb	$0	6.00%	16/12	$0	$0	9,398,746	$0.0325	$305,459	$784,675
March	$0	6.00%	15/12	$0	$0	6,210,457	$0.0505	$313,628	$471,047
April	$0	6.00%	14/12	$0	$0	4,408,589	$0.0656	$289,203	$181,844
May (est)	$0	6.00%	13/12	$0	$0	1,607,205	$0.0656	$105,433	$76,411
June (est)	$0	6.00%	12/12	$0	$0	783,136	$0.0622	$48,711	$27,700
July (est)	$0	6.00%	11/12	$0	$0	754,447	$0.0587	$44,286	($16,586)
Aug (est)	$0	6.00%	10/12	$0	$0	786,035	$0.0587	$46,140	($62,726)
Sept (est)	$0	6.00%	9/12	$0	$0	927,299	$0.0587	$54,432	($117,158)
Oct (est)	$0	6.00%	8/12	$0	$0	2,675,299	$0.0587	$157,040	($274,198)
Nov (est)	$0	6.00%	7/12	$0	$0	5,431,460	$0.0587	$318,827	($593,025)
12 Months	$13,117			$1,173	$14,290	47,382,573		$3,390,216	($3,375,926)
Balance at Nov 30, 2022									($593,025)

Month	Gross Cost of Gas Excl. TOP	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, 2022					
Dec (est)	$67,276,050	$150,407	$67,125,643	0.99960195	$67,098,924
Jan '23 (est)	$81,254,050	$193,306	$81,060,744	0.99950992	$81,021,018
Feb (est)	$67,990,800	$180,004	$67,810,796	0.99951464	$67,777,883
March (est)	$52,240,300	$189,544	$52,050,756	0.99962487	$52,031,230
April (est)	$25,197,800	$81,978	$25,115,822	0.99951656	$25,103,680
May (est)	$17,824,800	$61,413	$17,763,387	0.99976478	$17,759,209
June (est)	$13,281,800	$28,367	$13,253,433	0.99975976	$13,250,249
July (est)	$12,788,800	$22,981	$12,765,819	0.99982877	$12,763,633
Aug (est)	$12,612,800	$28,026	$12,584,774	0.99985542	$12,582,955
Sept (est)	$12,537,800	$20,871	$12,516,929	0.99994321	$12,516,218
Oct (est)	$19,068,800	$32,181	$19,036,619	0.99981527	$19,033,102
Nov (est)	$32,160,800	$25,540	$32,135,260	0.99970976	$32,125,933
12 Months	$414,234,600	$1,014,618	$413,219,982		$413,064,034

SSC Revenues

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)
Dec bef 12/1 (est)	5,888,818	$7.8424	$46,182,466
Dec aft 12/1 (est)	4,773,923	$6.3639	$30,380,767
Jan '23 bef 12/1 (est)	-	$7.8424	$0
Jan '23 aft 12/1 (est)	12,538,670	$6.3639	$79,794,839
Feb (est)	10,545,753	$6.3639	$67,112,118
March (est)	8,516,423	$6.3639	$54,197,664
April (est)	4,453,376	$6.3639	$28,340,842
May (est)	2,690,520	$6.3639	$17,122,198
June (est)	1,477,318	$6.3639	$9,401,506
July (est)	1,284,634	$6.3639	$8,175,283
Aug (est)	1,286,306	$6.3639	$8,185,925
Sept (est)	1,461,399	$6.3639	$9,300,200
Oct (est)	3,339,344	$6.3639	$21,251,251
Nov (est)	6,651,217	$6.3639	$42,327,680
12 Months	64,907,702		$421,772,739

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, 2022			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	$76,563,233	$67,098,924	$9,464,309
Jan '23 bef 12/1 (est)			
Jan '23 aft 12/1 (est)	$79,794,839	$81,021,018	($1,226,179)
Feb (est)	$67,112,118	$67,777,883	($665,765)
March (est)	$54,197,664	$52,031,230	$2,166,434
April (est)	$28,340,842	$25,103,680	$3,237,162
May (est)	$17,122,198	$17,759,209	($637,011)
June (est)	$9,401,506	$13,250,249	($3,848,743)
July (est)	$8,175,283	$12,763,633	($4,588,350)
Aug (est)	$8,185,925	$12,582,955	($4,397,030)
Sept (est)	$9,300,200	$12,516,218	($3,216,018)
Oct (est)	$21,251,251	$19,033,102	$2,218,149
Nov (est)	$42,327,680	$32,125,933	$10,201,747
12 Months	$421,772,739	$413,064,034	$8,708,705

Exhibit APD-4

Computation of Balancing Service Cost Adjustment No. 39
Application and Computation Period : 12 Months
December 1, 2022 Through November 30, 2023

1. C = Projected Cost of Gas for Application Period	$35,361,023	Pg. 2	$0.5448	/Mcf
2. E = Experienced and Estimated Net Over/(Under)				
a. Balancing Over / (Under)	($292,354)	Pg. 2	($0.0045)	/Mcf
b. Miscellaneous Surcharge Monies	$823,296	Pg. 5	$0.0127	/Mcf
c. Net Interest on Item a.	$161,265	Pg. 6	$0.0025	/Mcf
d. Supplier Refunds (Including Interest)	$2,041	Pg. 7	$0.0000	/Mcf
Experienced Net Over/(Under) Collections	$694,248		$0.0107	/Mcf
3. C - E	$34,666,775		$0.5341	/Mcf
4. S = Projected Sales for Computation Period	64,907,702	mcf		
Charge / (Credit) to Customers	$0.5341	/Mcf		

Over/(Under) Collections

Exhibit APD-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, 2020								($1,495,765)
Dec		$1,859,941	$26,906	$1,833,035	0.99943321	$1,831,996	$3,089,707	$1,257,711	($238,054)
Jan '21		$1,913,039	$28,568	$1,884,471	0.99966296	$1,883,836	$4,225,897	$2,342,061	$2,104,007
Feb		$1,997,193	$29,296	$1,967,897	0.99960974	$1,967,129	$4,422,962	$2,455,833	$4,559,840
March		$1,875,682	$32,671	$1,843,011	0.99973842	$1,842,529	$3,751,857	$1,909,328	$6,469,168
April		$1,843,080	$24,685	$1,818,395	0.99970667	$1,817,862	$2,107,793	$289,931	$6,759,099
May		$1,780,648	$25,153	$1,755,495	0.99979987	$1,755,144	$1,261,747	($493,397)	$6,265,702
June		$1,817,562	$23,720	$1,793,842	0.99982002	$1,793,519	$799,473	($994,046)	$5,271,656
July		$1,819,377	$22,626	$1,796,751	0.99984514	$1,796,473	$588,189	($1,208,284)	$4,063,372
Aug		$1,853,546	$22,343	$1,831,203	0.99985864	$1,830,944	$544,791	($1,286,153)	$2,777,219
Sept		$1,837,743	$22,584	$1,815,159	0.99994036	$1,815,051	$557,062	($1,257,989)	$1,519,230
Oct		$1,807,153	$23,092	$1,784,061	0.99961589	$1,783,376	$614,009	($1,169,367)	$349,863
Nov		$1,807,810	$23,655	$1,784,155	0.99946336	$1,783,198	$1,375,258	($407,940)	($58,077)
12 Months		$22,212,774	$305,299	$21,907,475		$21,901,057	$23,338,745	$1,437,688	
12 Months -Nov 30, 2022		$29,283,248	$314,777	$28,968,471		$28,960,541			

Over/(Under) Collections

Exhibit APD-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, 2021								($58,077)
Dec		$1,800,432	$30,487	$1,769,945	0.99949307	$1,769,048	$3,335,941	$1,566,893	$1,508,816
Jan '22		$1,855,100	$31,914	$1,823,186	0.99946220	$1,822,205	$4,777,044	$2,954,839	$4,463,655
Feb		$1,961,837	$33,218	$1,928,619	0.99960636	$1,927,860	$5,438,402	$3,510,542	$7,974,197
March		$2,356,328	$32,671	$2,323,657	0.99963131	$2,322,800	$3,707,047	$1,384,247	$9,358,444
April		$2,394,551	$29,438	$2,365,113	0.99965649	$2,364,301	$2,732,405	$368,104	$9,726,548
May (est)		$2,712,000	$23,876	$2,688,124	0.99975975	$2,687,478	$1,148,226	($1,539,252)	$8,187,296
June (est)		$2,689,000	$20,102	$2,668,898	0.99975361	$2,668,240	$674,984	($1,993,256)	$6,194,040
July (est)		$2,712,000	$22,485	$2,689,515	0.99982455	$2,689,043	$630,500	($2,058,543)	$4,135,497
Aug (est)		$2,712,000	$22,754	$2,689,246	0.99985192	$2,688,848	$631,598	($2,057,250)	$2,078,247
Sept (est)		$2,689,000	$20,230	$2,668,770	0.99994196	$2,668,615	$719,178	($1,949,437)	$128,810
Oct (est)		$2,712,000	$23,000	$2,689,000	0.99981160	$2,688,493	$1,646,622	($1,041,871)	($913,061)
Nov (est)		$2,689,000	$24,602	$2,664,398	0.99970441	$2,663,610	$3,284,317	$620,707	($292,354)
12 Months		$29,283,248	$314,777	$28,968,471		$28,960,541	$28,726,264	($234,277)	
12 Months -Nov 30, 2023		$35,723,000	$351,071	$35,371,929		$35,361,023			

Exclusions and Allocation Factor

Exclusions

Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)
Dec	$22,595	$3,546	$765	$26,906
Jan '21	$22,213	$5,256	$1,099	$28,568
Feb	$21,952	$5,923	$1,421	$29,296
March	$22,449	$9,232	$990	$32,671
April	$22,215	$2,071	$399	$24,685
May	$22,209	$2,824	$120	$25,153
June	$22,101	$1,611	$8	$23,720
July	$22,074	$552	$0	$22,626
Aug	$22,006	$337	$0	$22,343
Sept	$21,947	$637	$0	$22,584
Oct	$22,151	$939	$2	$23,092
Nov	$22,005	$1,324	$326	$23,655
12 Months	$265,917	$34,252	$5,130	$305,299
12 Months -Nov 30, 2022	$269,147	$41,134	$4,496	$314,777

Allocation Factor Calculation

	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	4,533	7,993,150	7,997,683	0.99943321
Jan '21	3,961	11,748,394	11,752,355	0.99966296
Feb	4,798	12,289,419	12,294,217	0.99960974
March	2,582	9,868,112	9,870,694	0.99973842
April	1,550	5,282,690	5,284,240	0.99970667
May	633	3,162,273	3,162,906	0.99979987
June	355	1,972,058	1,972,413	0.99982002
July	220	1,420,404	1,420,624	0.99984514
Aug	186	1,315,603	1,315,789	0.99985864
Sept	83	1,391,609	1,391,692	0.99994036
Oct	617	1,605,673	1,606,290	0.99961589
Nov	1,931	3,596,385	3,598,316	0.99946336
12 Months	21,449	61,645,770	61,667,219	

(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

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Exclusions and Allocation Factor

Exclusions

Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)
Dec	$25,836	$3,544	$1,107	$30,487
Jan '22	$25,948	$4,531	$1,435	$31,914
Feb	$26,023	$5,241	$1,954	$33,218
March	$25,921	$6,750	$0	$32,671
April	$25,425	$4,013	$0	$29,438
May (est)	$18,897	$4,979	$0	$23,876
June (est)	$17,937	$2,165	$0	$20,102
July (est)	$20,820	$1,665	$0	$22,485
Aug (est)	$20,669	$2,085	$0	$22,754
Sept (est)	$18,597	$1,633	$0	$20,230
Oct (est)	$20,322	$2,678	$0	$23,000
Nov (est)	$22,752	$1,850	$0	$24,602
12 Months	$269,147	$41,134	$4,496	$314,777
12 Months -Nov 30, 2023	$267,794	$83,277	$0	$351,071

Allocation Factor Calculation

	Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	4,246	8,371,702	8,375,948	0.99949307
Jan '22	6,148	11,425,603	11,431,751	0.99946220
Feb	5,121	13,004,308	13,009,429	0.99960636
March	3,196	8,665,373	8,668,569	0.99963131
April	2,154	6,268,421	6,270,575	0.99965649
May (est)	633	2,634,150	2,634,783	0.99975975
June (est)	355	1,440,428	1,440,783	0.99975361
July (est)	220	1,253,730	1,253,950	0.99982455
Aug (est)	186	1,255,913	1,256,099	0.99985192
Sept (est)	83	1,430,061	1,430,144	0.99994196
Oct (est)	617	3,274,254	3,274,871	0.99981160
Nov (est)	1,931	6,530,755	6,532,686	0.99970441
12 Months	24,890	65,554,698	65,579,588	

(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	3,880,115	$0.3796	$1,472,892	$0.0354	$137,356	$1,610,248
Dec aft 12/1	4,113,035	$0.3535	$1,453,958	$0.0062	$25,501	$1,479,459
Jan '21 bef 12/1	-	$0.3796	$0	$0.0354	$0	$0
Jan '21 aft 12/1	11,748,394	$0.3535	$4,153,057	$0.0062	$72,840	$4,225,897
Feb	12,289,419	$0.3536	$4,345,539	$0.0063	$77,423	$4,422,962
March	9,868,112	$0.3646	$3,597,914	$0.0156	$153,943	$3,751,857
April	5,282,690	$0.3748	$1,979,952	$0.0242	$127,841	$2,107,793
May	3,162,273	$0.3748	$1,185,220	$0.0242	$76,527	$1,261,747
June	1,972,058	$0.3818	$752,932	$0.0236	$46,541	$799,473
July	1,420,404	$0.3912	$555,662	$0.0229	$32,527	$588,189
Aug	1,315,603	$0.3912	$514,664	$0.0229	$30,127	$544,791
Sept	1,391,609	$0.3776	$525,472	$0.0227	$31,590	$557,062
Oct	1,605,673	$0.3600	$578,042	$0.0224	$35,967	$614,009
Nov	3,596,385	$0.3600	$1,294,699	$0.0224	$80,559	$1,375,258
12 Months	61,645,770		$22,410,003		$928,742	$23,338,745

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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	4,601,339	$0.3600	$1,656,482	$0.0224	$103,070	$1,759,552
Dec aft 12/1	3,770,363	$0.4327	$1,631,436	($0.0146)	($55,047)	$1,576,389
Jan '22 bef 12/1	-	$0.3600	$0	$0.0224	$0	$0
Jan '22 aft 12/1	11,425,603	$0.4327	$4,943,858	($0.0146)	($166,814)	$4,777,044
Feb	13,004,308	$0.4327	$5,626,964	($0.0145)	($188,562)	$5,438,402
March	8,665,373	$0.4340	$3,760,772	($0.0062)	($53,725)	$3,707,047
April	6,268,421	$0.4350	$2,726,763	$0.0009	$5,642	$2,732,405
May (est)	2,634,150	$0.4350	$1,145,855	$0.0009	$2,371	$1,148,226
June (est)	1,440,428	$0.4677	$673,688	$0.0009	$1,296	$674,984
July (est)	1,253,730	$0.5020	$629,372	$0.0009	$1,128	$630,500
Aug (est)	1,255,913	$0.5020	$630,468	$0.0009	$1,130	$631,598
Sept (est)	1,430,061	$0.5020	$717,891	$0.0009	$1,287	$719,178
Oct (est)	3,274,254	$0.5020	$1,643,675	$0.0009	$2,947	$1,646,622
Nov (est)	6,530,755	$0.5020	$3,278,439	$0.0009	$5,878	$3,284,317
12 Months	65,554,698		$29,065,663		($339,399)	$28,726,264

Miscellaneous Surcharge Revenues

	Other Monies To Be Refunded				Other Monies Actually Refunded			
	Unauth TCS/TS Penalty Gas (1)	Rate IS Penalty Gas (2)	Transp Bal Penalty + Surcharge (3)	Total (4) = (1) + (2) + (3)	BSC Applicable Sales (5)	Misc. Surcharge (6)	Misc. Surcharge Refund (7) = (5) x (6)	Cumulative Over/(Under) Refund (8) = (4)-(7)
Balance -Nov 30, 2020								$414,210
Dec bef 12/1					3,880,115	$0.0261	$101,271	$312,939
Dec aft 12/1	$5,175	$0	$33,354	$38,529	4,113,035	$0.0052	$21,388	$330,080
Jan '21 bef 12/1					-	$0.0261	$0	$330,080
Jan '21 aft 12/1	$0	$0	$55,315	$55,315	11,748,394	$0.0052	$61,092	$324,303
Feb	$0	$0	$59,162	$59,162	12,289,419	$0.0052	$63,905	$319,560
March	$32,100	$0	$54,034	$86,134	9,868,112	$0.0060	$59,209	$346,485
April	$0	$0	$49,968	$49,968	5,282,690	$0.0067	$35,394	$361,059
May	$0	$0	$42,912	$42,912	3,162,273	$0.0067	$21,187	$382,784
June	$425	$0	$37,483	$37,908	1,972,058	$0.0066	$13,016	$407,676
July	$100	$0	$38,171	$38,271	1,420,404	$0.0064	$9,091	$436,856
Aug	$8,125	$0	$38,255	$46,380	1,315,603	$0.0064	$8,420	$474,816
Sept	$0	$0	$37,484	$37,484	1,391,609	$0.0063	$8,767	$503,533
Oct	$0	$0	$26,634	$26,634	1,605,673	$0.0062	$9,955	$520,212
Nov	$0	$0	$44,921	$44,921	3,596,385	$0.0062	$22,298	$542,835
12 Months	$45,925	$0	$517,693	$563,618	61,645,770		$434,993	$128,625
Balance at Nov 30, 2021								$542,835

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Miscellaneous Surcharge Revenues

	Other Monies To Be Refunded				Other Monies Actually Refunded			
	Unauth TCS/TS Penalty Gas (1)	Rate IS Penalty Gas (2)	Transp Bal Penalty + Surcharge (3)	Total (4) = (1) + (2) + (3)	BSC Applicable Sales (5)	Misc. Surcharge (6)	Misc. Surcharge Refund (7) = (5) x (6)	Cumulative Over/(Under) Refund (8) = (4)-(7)
Balance -Nov 30, 2021								$542,835
Dec bef 12/1					4,601,339	$0.0062	$28,528	$514,307
Dec aft 12/1	$0	$0	$93,596	$93,596	3,770,363	$0.0081	$30,540	$577,363
Jan '22 bef 12/1					-	$0.0062	$0	$577,363
Jan '22 aft 12/1	$0	$0	$55,822	$55,822	11,425,603	$0.0081	$92,547	$540,638
Feb	$129,450	$0	$70,421	$199,871	13,004,308	$0.0081	$105,335	$635,174
March	$81,900	$0	$56,161	$138,061	8,665,373	$0.0085	$73,656	$699,579
April	$0	$0	$50,752	$50,752	6,268,421	$0.0089	$55,789	$694,542
May (est)	$0	$0	$37,615	$37,615	2,634,150	$0.0089	$23,444	$708,713
June (est)	$0	$0	$35,705	$35,705	1,440,428	$0.0086	$12,388	$732,030
July (est)	$0	$0	$41,445	$41,445	1,253,730	$0.0083	$10,406	$763,069
Aug (est)	$0	$0	$41,142	$41,142	1,255,913	$0.0083	$10,424	$793,787
Sept (est)	$0	$0	$37,019	$37,019	1,430,061	$0.0083	$11,870	$818,936
Oct (est)	$0	$0	$40,453	$40,453	3,274,254	$0.0083	$27,176	$832,213
Nov (est)	$0	$0	$45,288	$45,288	6,530,755	$0.0083	$54,205	$823,296
12 Months	$211,350	$0	$605,419	$816,769	65,554,698		$536,308	$280,461
Balance at Nov 30, 2022								$823,296

Interest on Revenues to be Returned to Customers

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Retd. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: BSC Applicable Sales (7)	Interest Refund (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance -Nov 30, 2020										$93,051
Dec bef 12/1							3,880,115	$0.0031	$12,028	$81,023
Dec aft 12/1	$2,926,850	$1,831,996	$1,094,854	3.25%	18/12	$53,374	4,113,035	$0.0016	$6,581	$127,816
Jan '21 bef 12/1							-	$0.0031	$0	$127,816
Jan '21 aft 12/1	$4,153,057	$1,883,836	$2,269,221	3.25%	17/12	$104,479	11,748,394	$0.0016	$18,797	$213,498
Feb	$4,345,539	$1,967,129	$2,378,410	3.25%	16/12	$103,064	12,289,419	$0.0016	$19,663	$296,899
March	$3,597,914	$1,842,529	$1,755,385	3.25%	15/12	$71,313	9,868,112	$0.0015	$14,802	$353,410
April	$1,979,952	$1,817,862	$162,090	3.25%	14/12	$6,146	5,282,690	$0.0015	$7,924	$351,632
May	$1,185,220	$1,755,144	($569,924)	3.25%	13/12	($20,066)	3,162,273	$0.0015	$4,743	$326,823
June	$752,932	$1,793,519	($1,040,587)	3.25%	12/12	($33,819)	1,972,058	$0.0015	$2,958	$290,046
July	$555,662	$1,796,473	($1,240,811)	3.25%	11/12	($36,966)	1,420,404	$0.0014	$1,989	$251,091
Aug	$514,664	$1,830,944	($1,316,280)	3.25%	10/12	($35,649)	1,315,603	$0.0014	$1,842	$213,600
Sept	$525,472	$1,815,051	($1,289,579)	3.25%	9/12	($31,433)	1,391,609	$0.0014	$1,948	$180,219
Oct	$578,042	$1,783,376	($1,205,334)	3.25%	8/12	($26,116)	1,605,673	$0.0014	$2,248	$151,855
Nov	$1,294,699	$1,783,198	($488,499)	3.25%	7/12	($9,261)	3,596,385	$0.0014	$5,035	$137,559
12 Months	$22,410,003	$21,901,057	$508,946			$145,066	61,645,770		$100,558	$44,508
Balance at Nov 30, 2021										$137,559

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Interest on Revenues to be Returned to Customers

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Retd. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: BSC Applicable Sales (7)	Interest Refund (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance -Nov 30, 2021										$137,559
Dec bef 12/1							4,601,339	$0.0014	$6,442	$131,117
Dec aft 12/1	$3,287,918	$1,769,048	$1,518,870	3.50%	18/12	$79,741	3,770,363	$0.0023	$8,672	$202,186
Jan '22 bef 12/1							-	$0.0014	$0	$202,186
Jan '22 aft 12/1	$4,943,858	$1,822,205	$3,121,653	3.50%	17/12	$154,782	11,425,603	$0.0023	$26,279	$330,689
Feb	$5,626,964	$1,927,860	$3,699,104	3.50%	16/12	$172,625	13,004,308	$0.0023	$29,910	$473,404
March	$3,760,772	$2,322,800	$1,437,972	3.50%	15/12	$62,911	8,665,373	$0.0023	$19,930	$516,385
April	$2,726,763	$2,364,301	$362,462	3.50%	14/12	$14,801	6,268,421	$0.0023	$14,417	$516,769
May (est)	$1,145,855	$2,687,478	($1,541,623)	3.50%	13/12	($58,453)	2,634,150	$0.0023	$6,059	$452,257
June (est)	$673,688	$2,668,240	($1,994,552)	3.50%	12/12	($69,809)	1,440,428	$0.0022	$3,169	$379,279
July (est)	$629,372	$2,689,043	($2,059,671)	3.50%	11/12	($66,081)	1,253,730	$0.0021	$2,633	$310,565
Aug (est)	$630,468	$2,688,848	($2,058,380)	3.50%	10/12	($60,036)	1,255,913	$0.0021	$2,637	$247,892
Sept (est)	$717,891	$2,668,615	($1,950,724)	3.50%	9/12	($51,207)	1,430,061	$0.0021	$3,003	$193,682
Oct (est)	$1,643,675	$2,688,493	($1,044,818)	3.50%	8/12	($24,379)	3,274,254	$0.0021	$6,876	$162,427
Nov (est)	$3,278,439	$2,663,610	$614,829	3.50%	7/12	$12,553	6,530,755	$0.0021	$13,715	$161,265
12 Months	$29,065,663	$28,960,541	$105,122			$167,448	65,554,698		$143,742	$23,706
Balance at Nov 30, 2022										$161,265

Supplier Refunds : Including Interest - Summary Sheet

Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	Cumulative Total
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	(9) = (5)-(8)
Balance	-Nov 30, 2020								$2,041
Dec bef 12/1						3,880,115	$0.0000	$0	$2,041
Dec aft 12/1	$0	6.00%	18/12	$0	$0	4,113,035	$0.0000	$0	$2,041
Jan '21 bef 12/1						-	$0.0000	$0	$2,041
Jan '21 aft 12/1	$0	6.00%	17/12	$0	$0	11,748,394	$0.0000	$0	$2,041
Feb	$0	6.00%	16/12	$0	$0	12,289,419	$0.0000	$0	$2,041
March	$0	6.00%	15/12	$0	$0	9,868,112	$0.0000	$0	$2,041
April	$0	6.00%	14/12	$0	$0	5,282,690	$0.0000	$0	$2,041
May	$0	6.00%	13/12	$0	$0	3,162,273	$0.0000	$0	$2,041
June	$0	6.00%	12/12	$0	$0	1,972,058	$0.0000	$0	$2,041
July	$0	6.00%	11/12	$0	$0	1,420,404	$0.0000	$0	$2,041
Aug	$0	6.00%	10/12	$0	$0	1,315,603	$0.0000	$0	$2,041
Sept	$0	6.00%	9/12	$0	$0	1,391,609	$0.0000	$0	$2,041
Oct	$0	6.00%	8/12	$0	$0	1,605,673	$0.0000	$0	$2,041
Nov	$0	6.00%	7/12	$0	$0	3,596,385	$0.0000	$0	$2,041
12 Months	$0			$0	$0	61,645,770		$0	$0
Balance at Nov 30, 2021									$2,041

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Supplier Refunds : Including Interest - Summary Sheet

Month	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	Supplier Refunds	Interest Rate	Time Factor	Interest	Total	BSC Applicable Sales	Supplier Refund Rate	Supplier Refund	Cumulative Total
	(1)	(2)	(3)	(4) = (1) x (2) x (3)	(5) = (1)+(4)	(6)	(7)	(8) = (6) x (7)	(9) = (5)-(8)
Balance	-Nov 30, 2021								$2,041
Dec bef 12/1						4,601,339	$0.0000	$0	$2,041
Dec aft 12/1	$0	6.00%	18/12	$0	$0	3,770,363	$0.0000	$0	$2,041
Jan '22 bef 12/1						-	$0.0000	$0	$2,041
Jan '22 aft 12/1	$0	6.00%	17/12	$0	$0	11,425,603	$0.0000	$0	$2,041
Feb	$0	6.00%	16/12	$0	$0	13,004,308	$0.0000	$0	$2,041
March	$0	6.00%	15/12	$0	$0	8,665,373	$0.0000	$0	$2,041
April	$0	6.00%	14/12	$0	$0	6,268,421	$0.0000	$0	$2,041
May (est)	$0	6.00%	13/12	$0	$0	2,634,150	$0.0000	$0	$2,041
June (est)	$0	6.00%	12/12	$0	$0	1,440,428	$0.0000	$0	$2,041
July (est)	$0	6.00%	11/12	$0	$0	1,253,730	$0.0000	$0	$2,041
Aug (est)	$0	6.00%	10/12	$0	$0	1,255,913	$0.0000	$0	$2,041
Sept (est)	$0	6.00%	9/12	$0	$0	1,430,061	$0.0000	$0	$2,041
Oct (est)	$0	6.00%	8/12	$0	$0	3,274,254	$0.0000	$0	$2,041
Nov (est)	$0	6.00%	7/12	$0	$0	6,530,755	$0.0000	$0	$2,041
12 Months	$0			$0	$0	65,554,698		$0	$0
Balance at Nov 30, 2022									$2,041

<u>Over/(Under) Collections</u>

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, 2022				
Dec (est)	$3,533,000	$37,746	$3,495,254	0.99960195	$3,493,863
Jan '23 (est)	$3,533,000	$42,149	$3,490,851	0.99950992	$3,489,140
Feb (est)	$3,386,000	$38,941	$3,347,059	0.99951464	$3,345,434
March (est)	$3,533,000	$40,890	$3,492,110	0.99962487	$3,490,800
April (est)	$2,689,000	$29,423	$2,659,577	0.99951656	$2,658,291
May (est)	$2,712,000	$25,291	$2,686,709	0.99976478	$2,686,077
June (est)	$2,689,000	$20,713	$2,668,287	0.99975976	$2,667,646
July (est)	$2,712,000	$22,969	$2,689,031	0.99982877	$2,688,571
Aug (est)	$2,712,000	$23,385	$2,688,615	0.99985542	$2,688,226
Sept (est)	$2,689,000	$20,694	$2,668,306	0.99994321	$2,668,154
Oct (est)	$2,712,000	$23,735	$2,688,265	0.99981527	$2,687,768
Nov (est)	$2,823,000	$25,135	$2,797,865	0.99970976	$2,797,053
12 Months	$35,723,000	$351,071	$35,371,929		$35,361,023

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)	5,888,818	$0.5020	$2,956,187
Dec aft 12/1 (est)	4,773,923	$0.5448	$2,600,833
Jan '23 bef 12/1 (est)	-	$0.5020	$0
Jan '23 aft 12/1 (est)	12,538,670	$0.5448	$6,831,067
Feb (est)	10,545,753	$0.5448	$5,745,326
March (est)	8,516,423	$0.5448	$4,639,747
April (est)	4,453,376	$0.5448	$2,426,199
May (est)	2,690,520	$0.5448	$1,465,795
June (est)	1,477,318	$0.5448	$804,843
July (est)	1,284,634	$0.5448	$699,869
Aug (est)	1,286,306	$0.5448	$700,780
Sept (est)	1,461,399	$0.5448	$796,170
Oct (est)	3,339,344	$0.5448	$1,819,275
Nov (est)	6,651,217	$0.5448	$3,623,583
12 Months	64,907,702		$35,109,674

Interest on Revenues to be Returned to Customers

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)
Balance -Nov 30, 2022			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	$5,557,020	$3,493,863	$2,063,157
Jan '23 bef 12/1 (est)			
Jan '23 aft 12/1 (est)	$6,831,067	$3,489,140	$3,341,927
Feb (est)	$5,745,326	$3,345,434	$2,399,892
March (est)	$4,639,747	$3,490,800	$1,148,947
April (est)	$2,426,199	$2,658,291	($232,092)
May (est)	$1,465,795	$2,686,077	($1,220,282)
June (est)	$804,843	$2,667,646	($1,862,803)
July (est)	$699,869	$2,688,571	($1,988,702)
Aug (est)	$700,780	$2,688,226	($1,987,446)
Sept (est)	$796,170	$2,668,154	($1,871,984)
Oct (est)	$1,819,275	$2,687,768	($868,493)
Nov (est)	$3,623,583	$2,797,053	$826,530
12 Months	$35,109,674	$35,361,023	($251,349)

Exhibit APD-5

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 31, 2022 Effective December 1, 2022

.

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

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 5th Revised Page No. 39
The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

SALES SERVICE COSTS (SSC) – 2nd Revised Page No. 40
The Off-System Sales Sharing Mechanism is extended through November 30, 2025.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 5th Revised Page No. 43 and 5th Revised Page No. 44
The Merchant Function Charges are decreased and the Prices to Compare are decreased.

BALANCING SERVICE COSTS (BSC) – 5th Revised Page No, 45
The Balancing Service Cost is increased.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS – 2nd Revised Page No. 68
The Balancing Charge is decreased.

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

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **$6.4145** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$6.3928**, per Mcf for Rate Schedules GC and **$6.3896** **(D)** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge (“GPC”) and uncollectable charge-offs as reflected in the Merchant Function Charge (“MFC”). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **$0.5530** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales **(I)** 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:

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

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.

(D) Denotes Decrease
(I) Denotes Increase

"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, 2025 and thereafter, until **(C)** terminated or otherwise revised by Final Order of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

(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 **$0.0287** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0070** per Mcf for Rate Schedule GC and at **$0.0038** 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-2020-3018929. 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)** **(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:

MFC = Write-Off Factor x CCEMFC x 1 / (1 – T)

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP **(0.45%),** Rate Schedule GC **(0.11%)** and Rate Schedules OL, L and MV-F (**0.06%)** as determined at Docket No R-2020-3018929, the Company's 2020 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	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0287 per Mcf	**(D)**
Price to Compare	$6.9675 per Mcf	**(D)**

COMPONENT	RATES GC	
Commodity Charge excluding GPC and MFC	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0070 per Mcf	**(D)**
Price to Compare	$6.9458 per Mcf	**(D)**

(D) Denotes Decrease

(I) Denotes Increase

COMPONENT	RATES OL, L and MV-F	
Commodity Charge excluding GPC and MFC	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0038 per Mcf	**(D)**
Price to Compare	$6.9426 per Mcf	**(D)**

(D) Denotes Decrease
(I) Denotes Increase

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 **$0.5341** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs. **(I)**

COMPUTATION OF BALANCING SERVICE COSTS PER MCF

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

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

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

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

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 month mcf of gas to be delivered to customers.

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

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

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

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

QUARTERLY UPDATES

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

(I) Denotes Increase

GAS TRANSPORTATION SERVICE GENERAL TERMS AND CONDITIONS - Continued

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

1.6 BUYER GROUP/LEAD CUSTOMER. A Buyer Group generally consists of up to ten individual Customers who voluntarily join together to obtain either firm or interruptible transportation service. The Company, at its discretion, may require all members of the Buyer Group to execute the same Transportation Service Agreement and make the same elections as to Standby Sales Service. One member of the Buyer Group may be designated by the Company as the Lead Customer who shall be responsible for the timely payment of all bills rendered to the Buyer Group, as well as all day to day dispatch scheduling coordination and administrative communication between the Company and all members of the Buyer Group. A member of one Buyer Group may not be a member of another Buyer Group. Eleven or more individual Customers may form a Buyer Group only upon specific agreement by the Company. Unless otherwise described, the term "Customer" as used throughout these general terms and conditions shall refer to an individual Customer or to a Buyer Group. The Company, at its discretion, may set the maximum Commodity Charge for a Buyer Group at the maximum which any member would be individually required to pay.

1.7 MINIMUM SIZE. The minimum total gas consumption capability required to be eligible for transportation service shall be less than or equal to 5,000 Mcf per year. This minimum shall apply to an individual Customer or to a Buyer Group which, in the aggregate, uses less than or equal to 5,000 Mcf of gas annually.

2. BALANCING PROVISIONS

2.1 GENERAL. Transportation balancing is provided to adjust for the unavoidable minor variations between Customer usage and scheduled deliveries, and is not intended to function as a storage service or a standby sales service. Each Customer shall use best efforts to balance deliveries and usage at all times.

2.2 INTERRUPTED RECEIPTS. On days when no transportation gas is received for the Customer's account, all gas used by the Customer shall be billed as a purchase from the Company. For Customers which have elected Standby Sales Service, the usage shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the usage shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Excess deliveries already being held for the Customer at the time of interruption will be tendered for delivery when transportation receipts resume. If the interruption of receipts continues for more than thirty days, the Company will tender excess deliveries as soon as practicable subject to operating and gas procurement considerations.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.3 BALANCING CHARGE. A **$0.0176** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. The Balancing Charge shall be reviewed and adjusted annually, as necessary, effective December 1 subject to approval of the new charge in the Company’s annual purchased gas cost filing under 66 Pa. C.S. § 1307(f) **(D)**

2.4 ALLOWABLE DAILY VARIATION. In order to minimize the effect of transportation imbalances on the operation of the system, the allowable daily variation between delivered quantities and Customer usage is ten percent of the TCQ.

If a Customer exceeds these limits, the Company shall: (a) in the case of excess deliveries, impose a $0.25 per Mcf penalty charge on that portion of daily excess deliveries greater than the allowable daily variation and have the right to limit the receipt of Gas Transportation if a customer has excess deliveries greater than the allowable daily variation (b) in the case of deficient deliveries, have the right to bill such deficiency as a purchase from the Company. For Customers which have elected Standby Sales Service, the deficiency shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the deficiency shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, Non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

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PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 31, 2022 Effective December 1, 2022

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

NOTICE.

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LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 5th Revised Page No. 39
The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

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SALES SERVICE COSTS (SSC) – 2nd Revised Page No. 40
The Off-System Sales Sharing Mechanism is extended through November 30, 2025.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 5th Revised Page No. 43 and 5th Revised Page No. 44
The Merchant Function Charges are decreased and the Prices to Compare are decreased.

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BALANCING SERVICE COSTS (BSC) – 5th Revised Page No. 45
The Balancing Service Cost is increased.

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GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS – 2nd Revised Page No. 68
The Balancing Charge is decreased.

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

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **$6.4145** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$6.3928** per Mcf for Rate Schedules GC and **$6.3896** **(D)** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **$0.5530** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales **(I)** 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:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

QUARTERLY UPDATES

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

OFF-SYSTEM SALES SHARING MECHANISM

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008, PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first $3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over $3.5 million. Subsequently, effective March 31, 2008 through November 30, 2025 and thereafter, until terminated or otherwise revised by Final Order of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings. **(C)**

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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 **$0.0287** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0070** per Mcf for Rate Schedule GC and at **$0.0038** 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-2020-3018929. 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)** **(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:

MFC = Write-Off Factor x CCEMFC x 1 / (1 – T)

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP **(0.45%),** Rate Schedule GC **(0.11%)** and Rate Schedules OL, L and MV-F (**0.06%)** as determined at Docket No R-2020-3018929, the Company's 2020 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	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0287 per Mcf	**(D)**
Price to Compare	$6.9675 per Mcf	**(D)**

COMPONENT	**RATES GC**	
Commodity Charge excluding GPC and MFC	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0070 per Mcf	**(D)**
Price to Compare	$6.9458 per Mcf	**(D)**

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Supplement No. 11 to
Gas-Pa. P.U.C. No. 4
Fifth Revised Page No. 44

PECO Energy Company Supersedes Fourth Revised Page No. 44

COMPONENT	RATES OL, L and MV-F	
Commodity Charge excluding GPC and MFC	$6.3639 per Mcf	**(D)**
Gas Cost Adjustment	$0.5530 per Mcf	**(I)**
Gas Procurement Charge	$0.0219 per Mcf	
Merchant Function Charge	$0.0038 per Mcf	**(D)**
Price to Compare	$6.9426 per Mcf	**(D)**

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Issued May 31, 2022 Effective December 1, 2022

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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 **$0.5341** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs. **(I)**

COMPUTATION OF BALANCING SERVICE COSTS PER MCF

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

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

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

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

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 month 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 **$0.0176** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. The Balancing Charge shall be reviewed and adjusted annually, as necessary, effective December 1 subject to approval of the new charge in the Company's annual purchased gas cost filing under 66 Pa. C.S. § 1307(f) **(D)**

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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.

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