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August 12, 2020

VIA eFILING AND ELECTRONIC MAIL

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

Re: Petition of PECO Energy Company for Approval of Its Default Service Program for the Period from June 1, 2021 through May 31, 2025
Docket No. P-2020-3019290

Dear Secretary Chiavetta:

In accordance with 52 Pa. Code § 5.412a, please accept the following **Testimony and Exhibits**, for filing on behalf of **PECO Energy Company**, which were duly admitted into the record at the hearing held on July 30, 2020 before Administrative Law Judge Eranda Vero, in the above-referenced matter.

1. **Amended PECO Hearing Exhibit No. 1** (which references all documents)
2. **PECO Statement No. 1 Direct Testimony of John J. McCawley**
3. **PECO Exhibit No. JJM-1: Listing of Prior Case Testimony**
4. **PECO Exhibit No. JJM-2: Index of PECO's Response to the Topics Set Forth in the Secretarial Letter Issued January 23, 2020 at Docket No. M-2019-3007101**
5. **PECO Exhibit No. JJM-3: Procurement Schedule**
6. **PECO Exhibit No. JJM-4: PECO Pennsylvania Default Service Supplier Master Agreement**

7. **PECO Exhibit No. JJM-5: PECO Pennsylvania Default Service Supplier Master Agreement (Redline)**

8. **PECO Exhibit No. JJM-6: PECO Energy Company Default Service Program Request for Proposals**

9. **PECO Exhibit No. JJM-7: Request for Proposals Protocol**

10. **PECO Exhibit No. JJM-8: PECO Energy Company Default Service Program Request for Proposals (Redline)**

11. **PECO Exhibit No. JJM-9: Request for Proposals Protocol (Redline)**

12. **PECO Exhibit No. JJM-10: PECO Request for Proposals to Supply Solar Alternative Energy Credits in Compliance with Pennsylvania's Alternative Energy Portfolio Standards Act**

13. **HIGHLY CONFIDENTIAL PECO Exhibit No. JJM-11: HIGHLY CONFIDENTIAL Response of the Electric Supplier Coalition to PECO-ESC-2**

14. **HIGHLY CONFIDENTIAL PECO Exhibit No. JJM-12: HIGHLY CONFIDENTIAL RESPONSE of the Electric Supplier Coalition to PECO ESC-I-4**

15. **PECO Exhibit No. JJM-13: Response of the Electric Supplier Coalition to PECO-ESC-I-5**

16. **PECO Statement No. 1-R: Rebuttal Testimony of John J. McCawley**

17. **PECO Statement No. 1-SR: Surrebuttal Testimony of John J. McCawley**

18. **PECO Statement No. 2: Direct Testimony of Joseph A. Bisti**

19. **PECO Exhibit No. JAB-1: PECO System Peak Usage Analysis**

20. **PECO Exhibit No. JAB-2: Pricing Analysis and Time-of-Use (TOU) Pricing Multiplier Calculations**

21. **PECO Exhibit No. JAB-3: TOU Period Allocator Calculations**

22. **PECO Exhibit No. JAB-4: Illustrative TOU Rate Calculation for Residential Class**

23. **PECO Exhibit No. JAB-5: Net Metering, TOU Monthly Accounting and Cashout – Illustrative Example**

24. **PECO Exhibit No. JAB-6: PECO DSP V Estimated Filing and Program Costs**

25. **PECO Exhibit No. JAB-7: PECO Electric Service Tariff (Relevant Pages)**

26. **PECO Exhibit No. JAB-8: PECO Electric Service Tariff (Blackline)**

27. **PECO Exhibit No. JAB-9: Response to 52 Pa. Code § 53.52(a)**

28. **PECO Exhibit No. JAB-10: PECO Electric Price-to-Compare History**

29. **PECO Statement No. 2-R: Rebuttal Testimony of Joseph A. Bisti**

30. **PECO Exhibit No. JAB-1R: Response of OCA to PECO-OCA-I-4**

31. **PECO Exhibit No. JAB-2R: Response of CAUSE-PA to PECO-CAUSE-PA-I-4**

32. **PECO Exhibit No. JAB-3R: Response of Environmental Stakeholders to PECO-ES-I-23**

33. **PECO Exhibit No. JAB-4R: Response of Electric Supplier Coalition to PECO-ESC-I-20**

34. **PECO Statement No. 3: Direct Testimony of Carol Reilly**

35. **PECO Exhibit No. CR-1: Notice of Intent to Participate or Discontinue Participation as a Customer Assistance Program Supplier**

36. **PECO Exhibit No. CR-2: PECO Electric Generation Supplier Coordination Tariff (Relevant Pages)**

37. **PECO Exhibit No. CR-3: PECO Electric Generation Supplier Coordination Tariff (Blackline)**

38. **PECO Exhibit No. CR-4: Response to 52 Pa. Code § 53.52(a)**

39. **PECO Statement No. 3-R: Rebuttal Testimony of Carol Reilly**

40. **PECO Statement No. 4: Direct Testimony of Scott G. Fisher**

41. **PECO Exhibit No. SG-1: Response of the Environmental Stakeholders to ES-I-2**

42. **PECO Exhibit No. SG-2: Response of the Environmental Stakeholders to ES-I-4**

43. **PECO Statement No. 4-R: Rebuttal Testimony of Scott G. Fisher**

In accordance with the Pennsylvania Public Utility Commission's ("Commission's") Emergency Order entered March 20, 2020 at Docket No. M-2020-3019262, HIGHLY CONFIDENTIAL PECO Exhibit Nos. JJM-11 and JJM-12 were filed with the Commission by e-mail to Secretary Chiavetta at rchiavetta@pa.gov. As evidenced by the enclosed Certificate of Service, a copy of this letter was served upon Administrative Law Judge Eranda Vero, and all parties of record.

If you have any questions, please contact me directly at 215.963.5384.

Very truly yours,

Kenneth M. Kulak

Kenneth M. Kulak

KMK/tp
Enclosures

c: Per Certificate of Service (w/encl.)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS DEFAULT SERVICE PROGRAM FOR THE PERIOD FROM JUNE 1, 2021 THROUGH MAY 31, 2025	: : : : :	**Docket No. P-2020-3019290**

CERTIFICATE OF SERVICE

I hereby certify and affirm that I have this day served a copy of the **Letter to Secretary Rosemary Chiavetta regarding PECO Energy Company's Compliance Filing, 52 Pa. Code § 5.412a** on the persons below in the matter specified in accordance with the requirements of 52 Pa. Code § 1.54:

VIA ELECTRONIC MAIL

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Dated: August 12, 2020

Counsel for PECO Energy Company

PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-________________

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECTS: DEFAULT SERVICE RATE DESIGN,
TIME-OF-USE RATES, AND
TARIFF CHANGES

DATED: MARCH 13, 2020

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DIRECT TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

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

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

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rates Specialist. In that capacity, I am responsible for tariff administration, financial analysis, project management and regulatory affairs relating to PECO's electric and gas operations, including preparation of written testimony and other filings in proceedings before the Pennsylvania Public Utility Commission ("Commission" or "PUC").

3. Q. Please describe your educational background.

A. I earned a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph's University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned certification as a Project Management Institute Professional in Business Analysis (PMI-PBA).

4. Q. Please describe your work experience with PECO.

A. In February 2019, I was promoted to my current position within PECO's Regulatory Policy and Strategy department. Prior to that promotion, I was a

Senior Rate Administrator for over three years, during which I assumed oversight responsibilities for tariff administration as described above. In that position, my responsibilities also included analyzing and applying PECO's tariffs to retail customers, as well as coordinating and preparing PECO testimony and comments in several Commission proceedings.

For approximately nine years prior to my role as a Senior Rate Administrator, I was a Senior Analyst in PECO's Energy Acquisition department. The Energy Acquisition department is responsible for PECO's interaction with electric generation suppliers ("EGSs") and for fulfilling PECO's obligation as a default service provider to serve electric retail customers who need, or choose to obtain, default service.

5. Q. Have you previously testified before the Commission?

A. Yes. I have testified in the following proceedings before the Commission:

Docket Nos. C-2008-2058320 and C-2009-2089694 – *Rama Construction Inc. T/A Ramada Inn Int'l Airport v. PECO Energy Company*

Docket Nos. M-2018-3005860 et al. – *Office of Consumer Advocate v. PECO Energy Company*

6. Q. What is the purpose of your direct testimony?

A. The primary purpose of my direct testimony is to describe the rate design to take effect with the commencement of PECO's fifth default service program ("DSP V") on June 1, 2021. With one addition, PECO is adopting the same rate design employed in its fourth default service program ("DSP IV"), which the Commission previously approved as consistent with the Public Utility Code

("Code") and the Commission's default service regulations. The only change PECO is proposing in this filing is the introduction of Time-Of-Use ("TOU") default service rate options for eligible customers in PECO's Residential and Small Commercial procurement classes (the "TOU Rates") to comply with PECO's obligation under Act 129 of 2008 ("Act 129") to offer TOU and real-time rates to all default service customers with smart meters.[1]

In addition, I explain PECO's proposed tariff changes to facilitate shopping for electric generation supply by customers who participate in PECO's Customer Assistance Program ("CAP"). I also describe the Company's DSP V cost-recovery proposal for its plans to implement both optional TOU default service rates and its CAP Shopping Plan ("Plan"). Finally, I cover two topics that the Commission asked electric distribution companies ("EDCs") to address in upcoming default service program ("DSP") filings (adjustment of PECO's Price-to-Compare ("PTC") for default service and TOU rate design).[2]

7. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit JAB-1	System Peak Usage Analysis
Exhibit JAB-2	Pricing Analysis and TOU Pricing Multiplier Calculations
Exhibit JAB-3	TOU Period Allocator Calculations
Exhibit JAB-4	TOU Pricing Methodology – Illustrative Example

[1] 66 Pa.C.S. § 2807(f)(5). The hourly-priced default service rate for the Consolidated Large Commercial and Industrial ("C&I") Class already meets Act 129 requirements.

[2] *Investigation into Default Serv. and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-3007101 (Secretarial Letter issued Jan. 23, 2020) ("January 2020 Secretarial Letter").

Exhibit JAB-5	Net Metering, TOU Monthly Accounting and Cashout – Illustrative Example
Exhibit JAB-6	DSP V Estimated Filing and Program Costs
Exhibit JAB-7	Revised Electric Service Tariff (Relevant Pages)
Exhibit JAB-8	Revised Electric Service Tariff (Blackline)
Exhibit JAB-9	Responses to Questions in 52 Pa. Code § 53.52(a)
Exhibit JAB-10	Electric PTC History, GSA 1 (Residential) and GSA 2 (Small C&I – Rate GS General Service), January 2011 – Present

II. DEFAULT SERVICE RATE DESIGN

8. Q. Mr. Bisti, please provide an overview of PECO's current default service rate design and the costs those rates recover.

A. Under DSP IV, PECO conducts competitive procurements of default service supply for three different customer classes ("procurement classes"):

(i) Residential Class or "GSA 1" (Rate Schedules R and RH);

(ii) Small Commercial Class or "GSA 2" with up to and including 100 kW of annual peak demand (Rate Schedules GS, PD, and HT) and lighting customers (Rate Schedules AL, POL, SLE, SLS, SLC, and TLCL); and

(iii) Consolidated Large C&I Class or "GSA 3/4" whose annual peak demand is greater than 100 kW (Rate Schedules GS, PD, HT and EP).

Each default service rate consists of a generation and transmission component. The Generation Supply Adjustment ("GSA") currently recovers generation supply costs, Alternative Energy Portfolio Standards ("AEPS") compliance costs, and ancillary service costs. In addition, the GSA includes an administrative cost factor and a working capital factor. Administrative costs include the costs incurred by PECO to implement its Commission-approved programs designed to enhance the competitive retail market. PECO allocates administrative costs to the procurement classes based on default service supply sales unless a direct assignment is required. The working capital component is a fixed price per kWh that was established at 0.019¢ per kWh in the settlement of PECO's last electric distribution rate case at Docket No. R-2018-3000164.

PECO recovers Network Integration Transmission Service ("NITS") and Non-Firm Point-to-Point Transmission costs imposed by PJM Interconnection, L.L.C. ("PJM"), for transmission service that PECO acquires on behalf of default service customers through the Company's Transmission Service Charge ("TSC").

The Commission's Regulations (52 Pa. Code § 54.187(h)) provide that default service rates may be adjusted no more frequently than quarterly for customers with load requirements up to 25 kW. Those regulations (52 Pa. Code § 54.187(i)) also provide that default service rates shall be adjusted on a quarterly basis, or more frequently, for customers with load requirements between 25 kW and 500 kW. Finally, the Commission's regulations (52 Pa. Code § 54.187(j)) provide that default service rates shall be adjusted on a monthly basis, or more frequently for customers with load requirements equal to or greater than 500 kW.

9. Q. Please describe how the Company's default service rates are structured and adjusted for customers with annual peak demand up to and including 100 kW.

A. Under the current GSA approved by the Commission in DSP IV, PECO projects the cost of generation supply for each customer class with annual peak of up to and including 100 kW (i.e., residential and small commercial customers) on a quarterly basis. Those GSA projection periods are synchronized with PJM's planning year (June 1-May 31), corresponding to the quarters of June-August, September-November, December-February, and March-May. The projected cost of supply is a function of projected default service sales and projected procurement costs under PECO's generation supply contracts. This projection, combined with PECO's TSC, forms the basis of the PTC that customers may use to evaluate competitive generation service offerings by EGSs.

PECO files the GSA for each quarter 45 days before the start of that quarter. In accordance with its tariff, PECO compares its actual default service supply costs to the billed revenue it receives from customers under the GSA for default service. The GSA includes a charge or credit, known as the "E-Factor," for semi-annual reconciliation of any over/undercollection of actual revenues against actual costs for each procurement class. For example, PECO calculates the over/undercollection for the six-month period January 1 through June 30 by July 15 and includes that amount in the E-Factor during the six-month period beginning September 1. Interest on any overcollection and undercollection accrues from the month of such over/undercollection to the midpoint of the refund period in accordance with the Commission's default service regulations at 52 Pa. Code § 54.190.[3]

[3] Those regulations, adopted by the Commission in 2015, establish a symmetrical rate of interest applicable to both overcollections and undercollections resulting from the reconciliation of default service costs. Specifically, the applicable rate of interest for over/undercollections is the prime rate for commercial borrowing, not to exceed the legal rate of interest, in effect on the last day of the month the over/undercollection occurred,

10. Q. Please describe how the Company's default service rates are structured and adjusted for commercial and industrial customers receiving hourly-priced default service.

A. Under DSP IV, commercial and industrial customers with annual peak demand greater than 100 kW are supplied entirely by hourly priced products for generation. These include the day-ahead hourly price of energy as well as a demand charge based upon the reliability pricing model ("RPM") implemented by PJM. The individual customer's RPM charges are based upon the customer's Peak Load Contribution and RPM prices.

Additionally, the costs of acquiring ancillary services from the PJM market, AEPS compliance costs, an allocated portion of PECO's banked AECs, administrative costs and working capital are charged to these customers each month. The Company provides an estimate of these components of hourly priced default service rates, exclusive of energy and capacity costs, known as the "Hourly Pricing Adder," at least 45 days prior to the start of each quarter.

Under the current GSA, PECO reconciles any over/undercollection for customers receiving hourly-priced default service on a semi-annual basis through the E-Factor in the same manner as the Residential and Small Commercial Classes. Likewise, interest on any over/undercollection accrues in the same manner and at the same rate as for the Residential and Small Commercial Classes, as described above.

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as reported in *The Wall Street Journal*. *See generally Automatic Adjustment Clauses Related to Elec. Default Serv.*, Docket No. L-2014-2421001(Final Rulemaking Order entered June 11, 2015).

11. Q. Has PECO implemented any strategy to mitigate fluctuations in the PTC caused by over/under collections?

A. Yes. Over/undercollections are driven by two factors: (1) the difference between actual and projected supply costs and (2) billing cycle lag. Customer billing cycles (mostly non-calendar months) are not perfectly aligned with the actual incurrence of generation supply costs (mostly calendar months). Because customers are billed at different times throughout the month, the revenue from the month reflects sales from the subject month and the prior month that may have experienced higher or lower usage. This billing cycle lag results in a timing difference between revenue and expense that can produce significant fluctuations in the PTC that are not directly related to the underlying cost of default service supply. PECO uses a semi-annual, rather than quarterly, schedule for the reconciliation of over/undercollection amounts for the Residential and Small Commercial Classes to mitigate the potential volatility in default service rates for these customers.

Billing lag is also the primary driver of fluctuations in the Consolidated Large Commercial and Industrial Class PTC. Billing lag can cause a large overcollection for commercial and industrial customers receiving hourly priced default service in one month immediately followed by a large undercollection the next month. Accordingly, PECO currently reconciles the E-Factor of the GSA for those customers on a semi-annual, instead of a monthly, basis in the same manner as over/undercollections are handled for the Residential and Small Commercial Classes.

12. Q. Is PECO proposing to maintain its existing default service rate design in DSP V?

A. Yes, with the addition of the optional TOU Rates for the Residential and Small Commercial Classes. As discussed in detail in Section III below, under the Company's proposed TOU rate options, eligible default service customers will pay a discounted rate for off-peak usage and a higher rate for peak usage relative to PECO's standard non-time varying default service rate.

13. Q. Is PECO seeking a waiver of the Commission's regulations to continue semi-annual reconciliation of the over/undercollection component of the GSA?

A. Yes. As I explained previously, the Commission's Regulations (52 Pa. Code §§ 54.187(h)-(j)) require adjustment of default service rates on a quarterly basis, or more frequently, for customers with load requirements up to 500 kW and on a monthly basis, or more frequently, for customers with load requirements above 500 kW. However, the Commission has recognized that more extended periods for over/undercollection reconciliation may help keep default rates more market-reflective,[4] and the Commission granted PECO a waiver from these regulations in DSP IV to implement a semi-annual E-Factor reconciliation for the Residential, Small Commercial and Consolidated Large Commercial and Industrial Classes.[5] PECO again requests a waiver of these regulations, to the extent necessary, to maintain its current semi-annual reconciliation schedule for the Residential and

[4] *See Investigation of Pennsylvania's Retail Elec. Mkt.: Recommendations Regarding Upcoming Default Serv. Plans*, Docket No. I-2011-2237952, at pp. 54-55 (Order entered Dec. 16, 2011).

[5] *Petition of PECO Energy Co. for Approval of its Default Serv. Program for the Period from June 1, 2017 through May 31, 2021*, Docket No. P-2016-2534980 (Opinion and Order entered Dec. 8, 2016) ("DSP IV Order"), p. 67.

Small Commercial procurement classes throughout DSP V to continue to mitigate potential default service rate volatility that may otherwise result from billing cycle lag.

14. Q. Is PECO seeking any other waiver of the Commission's Regulations to implement the proposed DSP V rate design?

A. Yes. In the DSP IV Order (p. 67), the Commission granted PECO a waiver of its Regulations (52 Pa. Code § 54.187(j)) to implement a quarterly, instead of monthly, filing schedule for Consolidated Large Commercial and Industrial Class default service rates in the same manner and at the same time as the Residential and Small Commercial Class default service rates. To the extent necessary, PECO again requests a waiver to continue to align the filing schedule for Consolidated Large Commercial and Industrial Class default service rates with PECO's other procurement classes and reduce administrative burden on both the Company and Commission Staff.

III. TIME-OF-USE RATE OPTIONS

15. Q. Does PECO currently offer TOU rate options to Residential or Small Commercial default service customers under DSP IV?

A. No. PECO previously offered a TOU generation rate through a PUC-approved, one-year pilot program known as the "PECO Smart Time Pricing Pilot" ("Pilot").[6] The primary objectives of the Pilot were to gauge customer interest in a TOU rate,

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[6] *Petition of PECO Energy Co. for Approval of its Initial Dynamic Pricing and Customer Acceptance Plan*, Docket No. M-2009-2123944 (Order entered Apr. 15, 2011) ("Dynamic Pricing Order").

assess the reasons why customers chose to enroll in or leave the program, and evaluate the impact of TOU rates on electricity consumption patterns.

The Pilot offered eligible customers a two-part TOU generation rate, a bill protection feature based upon PECO's default service rate at the time, and the option to leave the Pilot at any time without incurring cancellation fees or penalties. The two-part Pilot TOU rate structure offered a higher rate during non-holiday weekday afternoons from 2 p.m. to 6 p.m. and a reduced rate for all other hours of the year. The EGS selected through a competitive procurement process served as the TOU commodity supplier and implementation vendor for the pilot.[7]

The Pilot was offered to nearly 121,000 residential customers and over 3,500 small commercial customers from September 1, 2013 through November 1, 2013. In total, 4,779 residential customers and 23 small commercial customers enrolled, representing about 4% of the targeted population.

16. Q. Please summarize the key findings of the PECO Smart Time Pricing Pilot.

A. End-of-pilot survey and focus group results revealed that the main driver of customer interest and satisfaction with the Pilot was the opportunity to save money on their electric bills. Most residential customers who enrolled in the Pilot took action to shift consumption away from peak hours and saved money as a result, with monthly bill savings exceeding $5 for more than 2,350 customers. Only thirteen customers needed bill protection reimbursement from PECO, and

[7] *Petition of PECO Energy Co. for Expedited Approval of its Dynamic Pricing Plan Vendor Selection and Dynamic Pricing Plan Supplement*, Docket No. P-2012-2297304 (Opinion and Order entered Sept. 26, 2012) (approving modifications to the commodity supply, dynamic rate structure, size and term of the pilot approved in the Dynamic Pricing Order to enable an EGS to provide TOU supply in lieu of PECO).

the total amount refunded was very small (just over $100 in the total program, with individual amounts ranging from $1.01 to $19.23).

The Pilot delivered an average load reduction of 6% per customer during peak hours from June 2014 through August 2014, with load reductions in the 3%-4% range during September and spring months (March through May). The greatest load impact results came from customers who shifted large appliance and heating/cooling energy use outside of peak hours.

17. Q. Why is PECO proposing the new TOU Rates?

A. Since the Pilot, the scope of an EDC's obligation to offer TOU rates to default service customers was the subject of litigation before the Commission and Commonwealth Court.[8] Following this litigation, the Commission proposed a new TOU structure for PPL to satisfy Act 129 requirements.[9] The Commission noted that the proposed TOU design for PPL "may provide future guidance to all EDCs" for incorporation into their own TOU proposals in their individual default service proceedings.[10] At the same time, the PUC made clear that EDCs would have "the flexibility to propose other alternatives and/or modifications regarding their TOU operations" for PUC review and approval in future DSP filings.[11]

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[8] *See Petition of PPL Elec. Utils. Corp. for Approval of a New Pilot Time-of-Use Program*, Docket No. P-2013-2389572 (Order entered Sept. 11, 2014) (holding that Act 129 did not require PPL Electric Utilities Corp. ("PPL") to offer TOU rates directly to customer-generators); *Dauphin Cty. Indus. Dev. Auth. v. Pa. P.U.C.*, 123 A.3d 1124, 1136 (Pa. Cmwlth. 2015) ("*DCIDA*") (holding that Act 129 does not authorize default service providers to delegate the obligation to offer TOU rates to customers with smart meters to EGSs).

[9] *Petition of PPL Elec. Utils. Corp. for Approval of a New Pilot Time-of-Use Program*, Docket Nos. P-2013-2389572 and M-2016-2578051 (Secretarial Letter issued Apr. 6, 2017) ("April 2017 Secretarial Letter").

[10] *Id.*, p. 4.

[11] *Id.*

18. Q. What are the objectives underlying PECO's proposed TOU Rates?

A. In addition to the guidance provided in the April 2017 Secretarial Letter, PECO considered the following objectives in designing the Company's proposed TOU Rates to comply with Act 129 requirements and to implement lessons learned from the Pilot:

1. **Simplicity and value proposition for customer enrollment**. TOU rates can help customers reduce electricity bills by incentivizing customers to shift usage to lower-cost, off-peak hours. However, customers are more likely to enroll in and respond effectively to TOU rates if they understand the TOU rate structure and related potential for savings.

2. **Retail-to-wholesale market connection**. On February 26, 2019, the Commission entered an Order at Docket No. M-2019-3007101 to initiate an investigation of potential opportunities to better reflect wholesale cost causation in default service rates and incentivize customer behavior to lower peak demand. To that end, PECO considered cost-causation principles in developing its proposed TOU Rates to connect the product pricing structure to the PJM energy and capacity markets, as well as the generation component of PECO's default service rates, i.e., the GSA.

3. **Incentives for customer electric vehicle ("EV") adoption**. In the past five years, the number of known EV operators in PECO's service territory has grown significantly, with the number of EVs registered through PECO's Smart Driver Rebate program increasing from 3,000 customers to

over 11,000 customers. In the January 2020 Secretarial Letter (p. 6), the PUC observed that EV use will increase across the Commonwealth in the coming decades. Based on this observation, the Commission directed EDCs to explore TOU rates in the context of EV expansion and consider whether "the lack of TOU rate offerings for operators of EVs presents a barrier to EV adoption."[12] In order to address the Commission's guidance, PECO's proposed TOU Rates include a super off-peak pricing period to encourage EV charging during overnight low-priced energy hours and, in turn, lower the overall total cost of EV ownership.

19. Q. What are the key features of PECO's proposed TOU Rates?

A. As shown in the table below, PECO's proposed TOU Rates differentiate prices across three periods (peak, off-peak and super off-peak) that remain constant year-round based on price multipliers designed to motivate shifting of usage from the higher-cost peak period to lower-cost off-peak periods. The TOU pricing periods are identical for the Residential and Small Commercial Classes.

<u>TOU Pricing Period</u>	<u>Year-Round Days/Hours Included</u>
Peak	2 p.m. – 6 p.m. Monday Through Friday, excluding PJM holidays
Super Off-Peak	Midnight (12 a.m.) – 6 a.m. Every day
Off-Peak	All other hours

[12] January 2020 Secretarial Letter, p. 7.

The proposed TOU rate design is structured to establish a rate premium above PECO's standard, fixed-price default service rate for usage during the peak period and rate discounts from this baseline price for usage during two off-peak periods. The baseline price is the customer's applicable GSA rate, prior to application of the TOU price multipliers discussed later in my testimony.

20. Q. What customers are eligible for PECO's TOU Rates?

A. Consistent with the April 2017 Secretarial Letter, PECO's TOU Rate will be available, with limited exceptions, to default service customers with smart meters who are not receiving hourly priced default service (i.e., the Residential and Small Commercial Classes). As a prerequisite for enrollment, PECO must be able to configure the customer's smart meter to measure energy consumption in watt-hours. The customer must have a valid e-mail address to ensure that the Company is able to provide the enrolled TOU customers with timely and meaningful communications regarding their savings performance. Residential customers enrolled in PECO's CAP will not be eligible for the residential TOU Rate at this time.

21. Q. Please explain why CAP customers will not be offered the residential TOU Rate.

A. As explained by Ms. Reilly in PECO Statement No. 3, CAP customers receive a fixed bill credit each year for the utility service they receive based on their ability to pay regardless of the actual amount of their utility bill. The selection of the TOU Rate could adversely impact those benefits because CAP customers may not have the flexibility to shift usage outside of the higher-priced peak period. In addition, a CAP customer's evaluation of whether CAP benefits outweigh the potential bill savings under a TOU rate is dependent on PECO's current CAP design, which may change during the DSP V term.[13] Therefore, PECO is proposing to exclude CAP customers from the TOU Rate at this time to avoid the risk of higher generation charges on those customers' electric bills that could jeopardize affordability and impose an unreasonable cost burden on all residential customers that pay for the CAP.

22. Q. How did PECO determine the number and times of the price-differentiated usage periods?

A. PECO's proposed TOU pricing structure is designed to reasonably encompass the expected system peak usage times while addressing the need for simplicity to encourage customer enrollment. The Company examined PJM's PECO zonal load data and energy prices over a five-year historic period (2014-2018). As shown on Exhibit JAB-1, system peak usage generally occurred during weekdays over five months of the year (May-September). Over the 2014-2018 period, the hours between 2 p.m. and 6 p.m. from May through September tended to have the highest system loads. Similarly, between May and September each year, energy prices in general were higher during these four hours of the day.

Based on this data, PECO defined the peak period as 2 p.m. to 6 p.m. on non-holiday weekdays. PECO selected the same year-round peak period employed in its Pilot, in which, as I previously explained, participating customers successfully

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[13] The Commission's Bureau of Consumer Services and Law Bureau have been directed to prepare a comprehensive universal service rulemaking order no later than the first quarter of 2020. *See Universal Serv. Rulemaking*, Docket No. L-2019-3012600 (Order entered Jan. 2, 2020).

responded to the TOU price signals to shift usage and achieve bill savings. The proposed peak period also allows for material price differentials that will be more likely to motivate customers to shift consumption to lower-priced (off-peak) hours.

Consistent with the January 2020 Secretarial Letter, PECO's proposed TOU Rates include a super off-peak pricing window to provide cost savings opportunities for EV operators. Based on PECO's system load patterns, the super off-peak period is defined as 12 a.m. to 6 a.m. every day to encourage EV charging within times of low energy prices.

23. Q. Why is PECO proposing year-round price-differentiated usage periods even though the April 2017 Secretarial Letter recommends seasonal variation?

A. PECO is proposing to apply the TOU Rates year round based on the results of the Pilot. This design is easier for customers to understand and reduces the number of variables for customers to consider in changing their consumption patterns. It also simplifies the development of TOU price ratios. PECO believes the year-round nature of its proposed TOU Rates strikes a balance reflective of periods that include the system peak while remaining more convenient and actionable for customers.

24. Q. How did PECO develop the price ratios that will used to set TOU rates for the peak, off-peak and super off-peak usage periods?

A. In the April 2017 Secretarial Letter, the Commission recommended that EDCs develop price multipliers to appropriately motivate shifting of consumption from on-peak to off-peak periods. To that end, PECO first examined five years of historical PJM Day-Ahead Spot Market Pricing data (2014-2018) for the PECO Zone to calculate the ratios of (1) the average annual peak price to the average annual super off-peak price, and (2) the average annual off-peak price to the average annual super off-peak price.

In addition to wholesale energy prices, the calculation of TOU rates depends on the cost of capacity, which varies by procurement class. PECO is proposing to allocate the cost of capacity to peak hours and off-peak hours only. This approach will send cost-based price signals and create larger peak/off-peak price differentials that are more likely to motivate customers to adjust the time of day they use electricity. PECO allocated capacity costs to peak hours using the percentage of the average daily PECO zonal capacity obligation under PJM's five coincident peak ("5CP") methodology[14] over the historic five-year period (2014-2018). PECO calculated these percentages (the "Capacity Cost Allocators") based on the average of the highest hourly demand (in MWh) during the proposed TOU peak pricing period (2-6 p.m.) on each of the PJM 5CP days. PECO added the remaining percentage of capacity costs to the respective off-peak pricing multiplier.

Based on the foregoing analyses, PECO is proposing to set the TOU price multipliers for each procurement class shown in the table below. These multipliers will remain constant throughout the DSP V term. The proposed

[14] The 5CPs are the five highest daily PJM peak loads for each summer (June 1 through September 30).

multipliers reflect the ratios calculated from average PJM PECO zone spot market prices as well as the cost of capacity during peak hours. Detailed calculations of the Company's proposed TOU pricing multipliers are provided in Exhibit JAB-2.

TOU Pricing Period	GSA-1 TOU Pricing Multipliers*	GSA-2 TOU Pricing Multipliers*
Peak	6.5	5.1
Super Off-Peak	1	1
Off-Peak	1.5	1.7

*Ratio to super off-peak TOU price

25. Q. Mr. Bisti, how will the TOU Rates be set for each procurement class using the Company's proposed pricing differentials?

A. As explained by Mr. McCawley in PECO Statement No. 1, PECO will source the residential and small commercial customers' standard and TOU default service from the same supply portfolio for each procurement class. PECO will continue to calculate the standard GSA on a quarterly basis based on the results of these procurements and use the standard GSA as the reference price for PECO's TOU rate calculations. The super off-peak price will be calculated to provide a discount from the standard GSA price in a way that offsets the higher peak and off-peak period prices and ensures revenue neutrality. The revenue neutral super off-peak price for each procurement class is derived from the portion of total system kWh usage attributable to each TOU pricing period. PECO determined these percentages (the "TOU Period Allocators") described in Exhibit JAB-3 based on PJM energy market settlements over the most recent historical five-year period (2014-2018).

The peak and off-peak TOU prices are a factor of multiplying the super off-peak price by the multiplier for the applicable procurement class and TOU pricing period. Exhibit JAB-4 provides an illustration of the TOU Rate for residential customers based on the proposed TOU pricing multipliers for DSP V and the GSA rate effective as of March 1, 2020.

26. Q. Please describe how default service rates will be adjusted for customers enrolled in the Company's TOU Rate.

A. The TOU Rates will be calculated on a quarterly basis, synchronized with the GSA adjustment periods for the Residential and Small Commercial class, using the Company's proposed pricing methodology. TOU customer kWh sales and costs will be included in the semi-annual reconciliation of the over/undercollection component of the GSA for the entire procurement class (i.e., Residential or Small Commercial). PECO's proposed reconciliation process using a single E-Factor for each procurement class will help mitigate potential large swings in GSA over/undercollections that could arise if customers switch between PECO's standard default service rate and TOU default service rate. In addition, the Commission has previously authorized other EDCs to recover TOU over/undercollection amounts from all default service customers based on its finding that the TOU rates mandated by Act 129 are a "form of default service."[15]

27. Q. Will customer-generators in the Residential and Small Commercial Classes who employ net metering be eligible for the TOU Rates?

A. Yes. Customer-generators who employ net metering will be eligible for the TOU Rate, consistent with the April 2017 Secretarial Letter. Customer-generators who employ virtual net metering will not be eligible due to the administrative complexity of offering TOU rates to those customers.

28. Q. Please explain the monthly accounting and annual cash out process for net metering TOU customers.

A. In each billing month, PECO will separately track net excess generation created by TOU net-metering customers within the TOU peak, off-peak and super off-peak periods. Any excess generation will be banked for use by the customer in subsequent billing periods. During any month when a TOU net metering customer consumes power in excess of the power generated by its facilities, the excess generation in the applicable TOU rate period will be used to reduce or offset the customer's bill at the full retail rate, including the current TOU prices for generation, in accordance with the Commission's guidance in the April 2017 Secretarial Letter.

At the end of the PJM planning period on May 31 of each year, a TOU net metering customer's accumulated excess generation will be cashed out based on

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15 *See Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2011-2264771 (Opinion and Order entered Aug. 30, 2012), pp. 22-23.

the applicable TOU rate and TSC in effect at the time that the excess electricity was generated. Exhibit JAB-5 provides a detailed example of how PECO will calculate the TOU net metering customer's total end-of-year compensation.

29. Q. How can customers enroll in PECO's TOU rate options?

A. Eligible default service customers may enroll in PECO's TOU Rates online or through the Company's Care Center. Customers will not be charged enrollment fees and may cancel TOU service at any time without a penalty or fee. Participating customers will remain on the TOU Rate until they affirmatively elect to return to PECO's standard default service rate, switch to an EGS, or otherwise become ineligible.

30. Q. Is PECO proposing any restrictions to reduce "free riders" who enroll in a TOU rate only for times of the year when they do not have to shift usage to save money?

A. Yes. TOU customers leaving the TOU Rate for any reason will be precluded from re-enrolling in the TOU Rate for twelve billing months after switching off the TOU Rate.

31. Q. Please describe PECO's communications plan to inform customers about the new TOU Rates and update enrolled TOU customers about the opportunity for bill savings.

A. PECO's communications plan will focus on introducing the educational tools and information to help customers make a rate choice that works best for them. In accordance with the Commission's guidance in the April 2017 Secretarial Letter, PECO will establish a web page dedicated to the Company's TOU Rate that will summarize the new TOU Rates, describe tips and ideas on how to shift electricity use, and provide information about how customers can determine the effect of the TOU Rates on their monthly electricity bills. PECO's communications plan will also include a one-time bill insert and targeted outreach to the customers who have registered EVs with PECO to introduce the new TOU Rates and instruct customers on how to obtain more information.

PECO will distribute progress letters via e-mail to enrolled TOU customers on a monthly basis that will update customers on their current savings on the TOU Rate and remind customers about the mechanics of the TOU Rates. In addition, PECO will provide quarterly updates on TOU generation prices on its website, concurrently with standard, fixed-price GSA updates, and in the Company's quarterly GSA filings with the Commission.

32. Q. Has PECO estimated the cost to implement its proposed TOU rate options?

A. Yes. As shown on Exhibit JAB-6, the Company anticipates that it will incur two categories of costs totaling approximately $3.8 million (based on preliminary costs estimates) to implement the TOU Rates. First, PECO will incur costs related to training and information technology ("IT") changes to the Company's billing and customer information systems to support TOU enrollment, billing, meter data management, customer self-service, Care Center scripting, and net metering excess generation tracking and compensation. The second category of expenditures is for customer communications, including care center scripting.

This cost estimate is based on PECO's proposed TOU rate design and PECO will recover the actual costs from customers through the administrative cost factor of the GSA as described in Section IV of my direct testimony.

33. Q. When will PECO's proposed TOU Rates be available to eligible customers?

A. PECO proposes to implement the TOU Rates at least twelve months following the Commission's final Order in this proceeding. This implementation timeline will allow sufficient time for the Company to develop customer education materials and complete IT programming necessary to implement the final TOU rate design approved by the PUC in this proceeding.

IV. RECOVERY OF DEFAULT SERVICE PROGRAM AND CUSTOMER ASSISTANCE PROGRAM SHOPPING PLAN IMPLEMENTATION COSTS

34. Q. Is PECO entitled to full and current recovery of all costs associated with DSP V?

A. Yes. In accordance with Section 2807(e)(3.9) of the Code, PECO is formally requesting that the Commission expressly affirm PECO's right to full and current recovery of all costs of DSP V.

35. Q. Is the Company seeking to continue to recover the cost of its default service proceedings through the GSA?

A. Yes. Consistent with the Commission's Policy Statement at 69 Pa. Code § 69.1808(a)(4) and the current GSA, the cost of this proceeding, including consultant fees, attorney fees, and costs related to IT changes, will be recovered through the GSA as an expense over the DSP V term. The estimated administrative cost, including the costs to implement the Company's proposed TOU Rates during the DSP V term, is delineated on Exhibit JAB-6.

36. Q. How does PECO propose to recover Standard Offer Program costs during DSP V?

A. Consistent with PECO's existing tariff and the DSP IV Order (p. 67), the Company proposes to continue to recover Standard Offer Program costs through an EGS participant fee not to exceed $30 per referred customer, with any remaining costs recovered in the following manner: (1) fifty percent from EGSs through a Purchase Of Receivables discount; and (2) fifty percent from Residential and Small Commercial default service customers via the GSA.

37. Q. Mr. Bisti, please describe PECO's proposed mechanism to recover the CAP Shopping Plan implementation costs described by Ms. Reilly in PECO Statement No. 3.

A. The Company is proposing to recover the costs associated with the customer-education initiatives included in the CAP Shopping Plan from residential customers in the current Consumer Education Charge approved by the Commission in Docket No. P-2011-2279773. The Company proposes to recover the remaining Plan implementation costs, which consist primarily of IT changes, from residential customers in a subsequent base rate case.

V. OTHER RETAIL TARIFF CHANGES

38. Q. Is PECO proposing any changes to its Electric Service Tariff to implement new TOU rate options for the Residential and Small Commercial Classes?

A. Yes. PECO is proposing the following tariff revisions to implement its TOU proposal:

- **TOU Prices and Terms and Conditions of Service**. The GSA for the Residential and Small Commercial Classes has been expanded to describe the new TOU Rates, including customer eligibility, pricing provisions, and switching rules. The pricing provisions include the current TOU Rates for each price-differentiated period and the formulas showing how PECO calculates the quarterly changes to the TOU Rates. In addition, PECO's CAP Rider has been revised to clarify that the TOU Rates are not available to CAP customers.
- **Reconciliation of TOU Rates**. PECO has revised the reconciliation provisions of the existing GSA to clarify that TOU and standard default service rate over/undercollections will be calculated in total for each procurement class.
- **TOU customer-generators**. The billing provisions for PECO's Rate RS-2 Net Metering have been revised to describe the accounting and cash-out process for TOU customer-generators.

These changes are shown in the clean and blacklined versions of PECO's electric service tariff attached to my testimony as Exhibit JAB-7 and Exhibit JAB-8, respectively.

39. Q. Does PECO's CAP Rider need to be revised to allow CAP customers to receive competitive generation supply?

A. Yes. PECO is proposing to eliminate the current restriction on availability of the CAP Rider to customers who obtain competitive energy supply. *See* Exhibit JAB-8.

40. Q. Has the Company submitted responses to the questions regarding changes to its tariff required by the Commission's Regulations?

A. Yes. Exhibit JAB-9 provides the Company's responses to the questions in 52 Pa. Code § 53.52(a).

VI. JANUARY 2020 SECRETARIAL LETTER TOPICS

41. Q. Did PECO consider the potential benefits of a semi-annual, instead of quarterly, adjustment schedule for default service rates based on the history of the Company's PTC as directed by the January 2020 Secretarial Letter?

A. Yes. PECO examined its electric PTC for the Residential Class and customers on Rate GS in the Small Commercial Class since PECO implemented its first DSP on January 1, 2011. Exhibit JAB-10 presents PECO's PTC history by quarter and procurement class. PECO assessed the benefits presented by both a six-month and three-month default supply price projection period in the context of the Company's PTC history. While a semi-annual schedule may offer several benefits, including less administrative complexity, quarterly changes to the PTC allow for more incremental adjustments consistent with the ratemaking principle of gradualism and to insulate customers from potential larger rate changes. Based on the Company's analysis, PECO is proposing to continue to adjust its default service rates each quarter, with semi-annual reconciliation of the E-Factor at this time. PECO believes its current approach appropriately balances the responsiveness of the PTC to current market conditions and fluctuations caused by billing lag.

42. Q. How is PECO proposing to make TOU rates available to EV operators during DSP V?

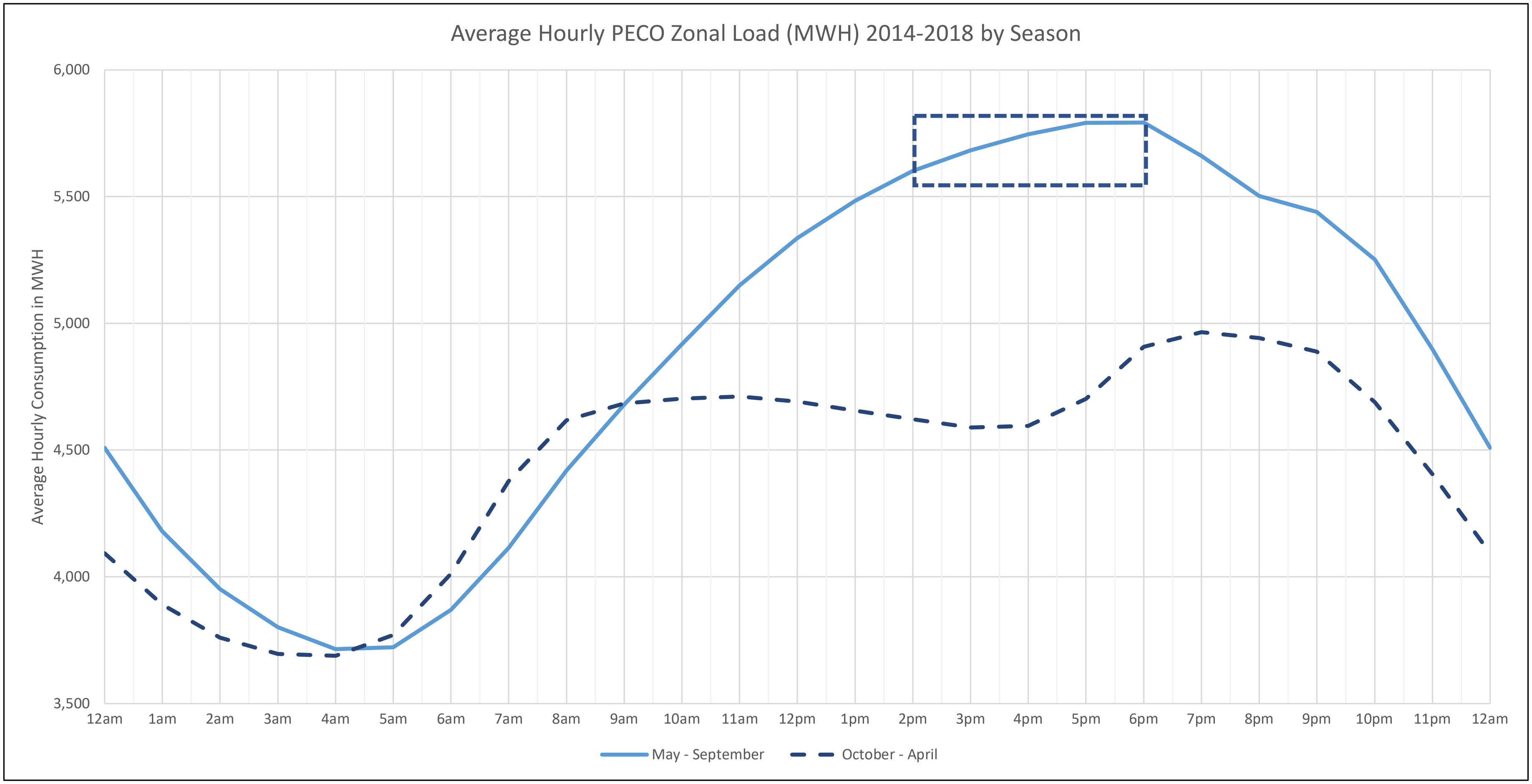
A. As explained in Section III above, PECO's proposed TOU rate design includes a super off-peak pricing time window that features discounted rates that would be attractive for EV charging during the designated hours.

VII. CONCLUSION

43. Q. Does this conclude your direct testimony?

A. Yes.

PECO System Peak Usage Analysis



Pricing Analysis and TOU Pricing Multiplier Calculations

Step 1: PJM PECO Day-Ahead Locational Marginal Pricing (LMP) Analysis

	PJM PECO Day-Ahead (DA) Average LMP Prices				LMP Price Ratios		
Year	**Peak (PP)**	**Off-Peak (OP)**	**Super Off-Peak (SOPP)**	**5-Year Average**	**PP-to-OP**	**PP-to-SOPP**	**OP-to-SOPP**
2014	$64.44	$55.67	$39.31	$52.59	1.16	1.64	1.42
2015	$43.03	$34.87	$24.17	$33.13	1.23	1.78	1.44
2016	$33.42	$25.06	$17.02	$24.01	1.33	1.96	1.47
2017	$34.41	$29.02	$20.95	$27.62	1.19	1.64	1.39
2018	$39.94	$35.38	$26.71	$33.74	1.13	1.49	1.32
5-Year Average	**$43.05**	**$35.99**	**$25.63**	**$34.21**	**1.20**	**1.68**	**1.40**

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 2A: Allocate Capacity Costs to TOU Periods (GSA 1)

Determine highest hourly demand within the TOU Peak Period for each of the 25 PJM RTO CP days from 2014-2018.

PJM RTO 5CP Dates			PECO GSA 1 Demand in Proposed TOU Peak Period (Hour-Ending MWH)				
Year	**Month**	**Day**	**15**	**16**	**17**	**18**	**MAX**
2014	6	17	2,806	3,000	3,253	3,408	3,408
2014	6	18	3,048	3,254	3,494	3,638	3,638
2014	7	1	3,049	3,259	3,462	3,593	3,593
2014	7	22	2,543	2,728	2,923	3,119	3,119
2014	9	5	2,651	2,848	3,097	3,131	3,131
2015	7	20	3,491	3,636	3,795	3,945	3,945
2015	7	28	3,019	3,188	3,380	3,584	3,584
2015	7	29	3,260	3,428	3,625	3,740	3,740
2015	8	17	3,223	3,355	3,476	3,572	3,572
2015	9	3	3,004	3,201	3,390	3,517	3,517
2016	7	25	3,657	3,808	3,777	3,864	3,864
2016	7	27	3,212	3,382	3,583	3,762	3,762
2016	8	10	3,104	3,295	3,514	3,680	3,680
2016	8	11	3,541	3,726	3,875	3,949	3,949
2016	8	12	3,809	3,868	3,871	3,755	3,871
2017	6	12	2,999	3,197	3,427	3,635	3,635
2017	6	13	3,243	3,431	3,648	3,845	3,845
2017	7	19	3,311	3,491	3,682	3,878	3,878
2017	7	20	3,498	3,650	3,826	3,964	3,964
2017	7	21	3,355	3,497	3,674	3,836	3,836
2018	6	18	3,176	3,361	3,549	3,708	3,708
2018	8	27	3,027	3,218	3,433	3,615	3,615
2018	8	28	3,511	3,706	3,909	4,069	4,069
2018	9	4	3,366	3,567	3,774	3,960	3,960
2018	9	5	3,396	3,583	3,785	3,954	3,954
						5-Year Average:	**3,713**
						Total GSA 1 average daily capacity obligation, 2014-2018:	**4,238**

The ratio of these two averages represents the class's historical TOU peak period contribution to the class's overall capacity obligation for its class.

The resulting percentage is proposed as the capacity cost allocator to the TOU Peak Period price.
All remaining capacity costs are allocated to the TOU Off-Peak Period price.
No capacity cost is allocated to the TOU Super Off-Peak Price.

Resulting GSA 1 Capacity Cost Allocators	
Peak	87.6%
Off-Peak	12.4%
Super Off-Peak	0%

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 2B: Allocate Capacity Costs to TOU Periods (GSA 2)

(A) Determine highest hourly demand within the TOU Peak Period for each of the 25 PJM RTO CP days from 2014-2018.

PJM RTO 5CP Dates			PECO GSA 2 Load in Proposed TOU Peak Period (Hour-Ending MWH)				
Year	Month	Day	15	16	17	18	MAX
2014	6	17	979	967	913	865	979
2014	6	18	1,014	999	930	888	1,014
2014	7	1	1,022	1,004	948	900	1,022
2014	7	22	975	958	939	863	975
2014	9	5	916	932	886	817	932
2015	7	20	1,062	1,053	1,003	928	1,062
2015	7	28	1,033	1,022	983	907	1,033
2015	7	29	1,061	1,052	1,011	931	1,061
2015	8	17	1,039	1,020	965	876	1,039
2015	9	3	1,052	1,043	1,001	917	1,052
2016	7	25	1,099	1,087	1,014	922	1,099
2016	7	27	1,060	1,051	1,017	941	1,060
2016	8	10	1,056	1,050	1,017	935	1,056
2016	8	11	1,112	1,105	1,062	969	1,112
2016	8	12	1,111	1,081	1,017	910	1,111
2017	6	12	1,024	1,018	982	908	1,024
2017	6	13	1,075	1,067	1,032	955	1,075
2017	7	19	1,093	1,087	1,049	975	1,093
2017	7	20	1,122	1,109	1,072	992	1,122
2017	7	21	1,072	1,057	1,020	947	1,072
2018	6	18	1,020	1,015	978	900	1,020
2018	8	27	1,013	1,006	972	891	1,013
2018	8	28	1,090	1,081	1,047	969	1,090
2018	9	4	1,082	1,073	1,032	955	1,082
2018	9	5	1,091	1,083	1,047	969	1,091
						5-Year Average:	**1,052**
						Total GSA 1 average daily capacity obligation, 2014-2018:	**1,424**

The ratio of these two averages represents the class's historical TOU peak period contribution to the class's overall capacity obligation for its class.

The resulting percentage is proposed as the capacity cost allocator to the TOU Peak Period price.
All remaining capacity costs are allocated to the TOU Off-Peak Period price.
No capacity cost is allocated to the TOU Super Off-Peak Price.

Resulting GSA 1 Capacity Cost Allocators	
Peak	73.9%
Off-Peak	26.1%
Super Off-Peak	0%

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 3A: Calculate TOU Pricing Multipliers for GSA 1 (labeled below as "Factor vs. Super Off-Peak")

GSA 1 Capacity Cost Allocators	
Peak	87.6%
Off-Peak	12.4%
Super Off-Peak	0%

	Using Loads, Capacity Obligations, and LMPs from 2014			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	132,521,458	621,209,387	136,755,841	890,486,686
Load (MWH)	1,773,991	9,674,397	2,883,751	14,332,140
Energy Cost ($/MWH)	$74.70	$64.21	$47.42	$62.13
Capacity	*Total Capacity Cost:*		*279,090,272*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	244,541,725	34,548,546		279,090,272
Load (MWH)	1,773,991	9,674,397		14,332,140
Capacity Cost ($/MWH)	$137.85	$3.57		$19.47
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$212.55	$67.78	$47.42	$81.61
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.60	0.83	0.58	1.00
Factor vs. Super Off-Peak	4.48	1.43	1.00	1.72

	Using Loads, Capacity Obligations, and LMPs from 2015			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	90,287,906	390,214,046	82,948,840	563,450,792
Load (MWH)	1,839,142	10,055,245	2,946,479	14,840,866
Energy Cost ($/MWH)	$49.09	$38.81	$28.15	$37.97
Capacity	*Total Capacity Cost:*		*229,390,294*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	200,994,101	28,396,193		229,390,294
Load (MWH)	1,839,142	10,055,245		14,840,866
Capacity Cost ($/MWH)	$109.29	$2.82		$15.46
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$158.38	$41.63	$28.15	$53.42
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.96	0.78	0.53	1.00
Factor vs. Super Off-Peak	5.63	1.48	1.00	1.90

	Using Loads, Capacity Obligations, and LMPs from 2016			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	74,089,129	274,635,339	52,570,874	401,295,342
Load (MWH)	1,842,636	10,085,271	2,904,847	14,832,754
Energy Cost ($/MWH)	$40.21	$27.23	$18.10	$27.05
Capacity	*Total Capacity Cost:*		*249,024,823*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	218,198,074	30,826,749		249,024,823
Load (MWH)	1,842,636	10,085,271		14,832,754
Capacity Cost ($/MWH)	$118.42	$3.06		$16.79
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$158.62	$30.29	$18.10	$43.84
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.62	0.69	0.41	1.00
Factor vs. Super Off-Peak	8.76	1.67	1.00	2.42

	Using Loads, Capacity Obligations, and LMPs from 2017			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	66,556,990	296,782,338	62,105,417	425,444,744
Load (MWH)	1,733,073	9,604,639	2,773,505	14,111,217
Energy Cost ($/MWH)	$38.40	$30.90	$22.39	$30.15
Capacity	*Total Capacity Cost:*		*249,287,196*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	218,427,968	30,859,228		249,287,196
Load (MWH)	1,733,073	9,604,639		14,111,217
Capacity Cost ($/MWH)	$126.04	$3.21		$17.67
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$164.44	$34.11	$22.39	$47.82
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.44	0.71	0.47	1.00
Factor vs. Super Off-Peak	7.34	1.52	1.00	2.14

	Using Loads, Capacity Obligations, and LMPs from 2018			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	85,580,496	397,368,498	90,730,272	573,679,267
Load (MWH)	1,893,769	10,188,619	3,010,047	15,092,435
Energy Cost ($/MWH)	$45.19	$39.00	$30.14	$38.01
Capacity	*Total Capacity Cost:*		*313,461,043*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	274,657,744	38,803,299		313,461,043
Load (MWH)	1,893,769	10,188,619		15,092,435
Capacity Cost ($/MWH)	$145.03	$3.81		$20.77
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$190.22	$42.81	$30.14	$58.78
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.24	0.73	0.51	1.00
Factor vs. Super Off-Peak	6.31	1.42	1.00	1.95

	Resulting GSA 1 TOU Pricing Multipliers			
Factor vs. Total	3.17	0.75	0.50	1.00
Factor vs. Super Off-Peak	6.51	1.51	1.00	2.03

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 3A: Calculate TOU Pricing Multipliers for GSA 2 (labeled below as "Factor vs. Super Off-Peak")

GSA 2 Capacity Cost Allocators	
Peak	73.9%
Off-Peak	26.1%
Super Off-Peak	0%

	Using Loads, Capacity Obligations, and LMPs from 2014			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	48,423,918	203,856,030	43,653,244	295,933,193
Load (MWH)	723,624	3,352,212	991,555	5,067,391
Energy Cost ($/MWH)	$66.92	$60.81	$44.03	$58.40
Capacity	*Total Capacity Cost:*		*105,175,582*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	77,683,235	27,492,347		105,175,582
Load (MWH)	723,624	3,352,212		5,067,391
Capacity Cost ($/MWH)	$107.36	$8.20		$20.76
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$174.28	$69.01	$44.03	$79.15
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.20	0.87	0.56	1.00
Factor vs. Super Off-Peak	3.96	1.57	1.00	1.80

	Using Loads, Capacity Obligations, and LMPs from 2015			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	33,721,403	127,277,358	26,927,232	187,925,993
Load (MWH)	742,352	3,372,402	1,017,964	5,132,719
Energy Cost ($/MWH)	$45.43	$37.74	$26.45	$36.61
Capacity	*Total Capacity Cost:*		*88,274,240*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	65,199,816	23,074,425		88,274,240
Load (MWH)	742,352	3,372,402		5,132,719
Capacity Cost ($/MWH)	$87.83	$6.84		$17.20
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$133.26	$44.58	$26.45	$53.81
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.48	0.83	0.49	1.00
Factor vs. Super Off-Peak	5.04	1.69	1.00	2.03

	Using Loads, Capacity Obligations, and LMPs from 2016			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	26,913,424	88,959,821	17,788,655	133,661,900
Load (MWH)	743,331	3,363,136	1,019,546	5,126,013
Energy Cost ($/MWH)	$36.21	$26.45	$17.45	$26.08
Capacity	*Total Capacity Cost:*		*85,722,031*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	63,314,741	22,407,291		85,722,031
Load (MWH)	743,331	3,363,136		5,126,013
Capacity Cost ($/MWH)	$85.18	$6.66		$16.72
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$121.39	$33.11	$17.45	$42.80
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.84	0.77	0.41	1.00
Factor vs. Super Off-Peak	6.96	1.90	1.00	2.45

	Using Loads, Capacity Obligations, and LMPs from 2017			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	26,247,819	100,516,336	21,861,531	148,625,686
Load (MWH)	732,096	3,343,478	1,013,584	5,089,158
Energy Cost ($/MWH)	$35.85	$30.06	$21.57	$29.20
Capacity	*Total Capacity Cost:*		*73,408,862*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	54,220,170	19,188,693		73,408,862
Load (MWH)	732,096	3,343,478		5,089,158
Capacity Cost ($/MWH)	$74.07	$5.74		$14.42
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$109.92	$35.80	$21.57	$43.63
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.52	0.82	0.49	1.00
Factor vs. Super Off-Peak	5.10	1.66	1.00	2.02

	Using Loads, Capacity Obligations, and LMPs from 2018			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	31,074,197	126,583,486	29,535,744	187,193,427
Load (MWH)	744,190	3,395,633	1,036,277	5,176,101
Energy Cost ($/MWH)	$41.76	$37.28	$28.50	$36.16
Capacity	*Total Capacity Cost:*		*91,283,796*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	67,422,689	23,861,107		91,283,796
Load (MWH)	744,190	3,395,633		5,176,101
Capacity Cost ($/MWH)	$90.60	$7.03		$17.64
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$132.36	$44.30	$28.50	$53.80
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.46	0.82	0.53	1.00
Factor vs. Super Off-Peak	4.64	1.55	1.00	1.89

	Resulting GSA 2 TOU Pricing Multipliers			
Factor vs. Total	2.50	0.82	0.50	1.00
Factor vs. Super Off-Peak	5.14	1.67	1.00	2.04

TOU Period Allocator Calculations

		Residential (GSA 1)		Small Commercial (GSA 2)	
TOU Pricing Period	**Year Round Days/Hours Included**	**Total Zonal Load, 2014-2018 (kWh) (GSA 2)**	**TOU Period Allocator* (GSA 1)**	**Total Zonal Load, 2014-2018 (kWh) (GSA 2)**	**TOU Period Allocator* (GSA 2)**
Peak	2 p.m. - 6 p.m. Monday through Friday, excluding PJM Holidays	9,202,230,744	**12%**	3,733,091,154	**14%**
Super Off-Peak	Midnight (12 a.m.) - 6 a.m. Every day	14,698,764,508	**20%**	5,141,477,797	**20%**
Off-Peak	All other hours	50,228,717,200	**68%**	17,034,981,367	**66%**
		74,129,712,452	*100%*	*25,909,550,318*	*100%*

*The TOU Period Allocator represents the ratio of generation (kWh) attributable to each TOU pricing period based on PJM energy market settlements over the most recent historical five-year period (2014-2018).

Illustrative TOU Rate Calculation for Residential Class

The calculations in this exhibit provide an illustration of the Time-Of-Use ("TOU") Rate for residential default service customers based on PECO's proposed TOU pricing multipliers for DSP V (reproduced in Table 1) and the Residential Generation Supply Adjustment ("GSA-1") rate for the Residential Class effective as of March 1, 2020.

Table 1

TOU Pricing Period	Days/Hours Included	TOU Period Allocators PA-GSA(1)	TOU Pricing Multiplier, PM-GSA(1) (Ratio to Super Off-Peak)
Peak ("PP")	2 p.m. – 6 p.m. Monday through Friday, excluding PJM holidays	12%	6.5-to-1
Super Off-Peak ("SOPP")	Midnight(12 a.m.) – 6 a.m. Every day	20%	1-to-1
Off-Peak ("OPP")	All Other Hours	68%	1.5-to-1

There are three steps in developing the TOU Rate for the Residential Class each quarter.

First, PECO will calculate the ratio of the Standard GSA-1 rate to the SOPP price based on the portion of total system kWh usage attributable to each TOU pricing period calculated in PECO Exhibit JAB-3. This factor will remain constant throughout the DSP V term.

Super Off-Peak Price Factor ("SOPP-F")

= [TOU SOPP GSA(1) * 20%] + [TOU OPP GSA(1) * 68%] + [TOU PP GSA(1) * 12%]

= [TOU SOPP GSA(1) * 0.2] + [(1.5 * TOU SOPP GSA(1)) * 0.68] + [(6.5 * TOU SOPP GSA(1)) * 0.12]
= [0.2 * SOPP TOU GSA(1)] + [1.02 * TOU SOPP GSA(1)] + [0.78 * TOU SOPP GSA(1)]
= 2.0 * SOPP TOU GSA(1)

Second, PECO will solve the TOU SOPP price for revenue neutrality. The assumed existing rate used in this illustrative revenue neutrality calculation is the quarterly standard GSA-1 rate effective on March 1, 2020 – $0.05972/kWh. In this example, the revenue neutral TOU SOPP price for the Residential Class effective from March 1, 2020 through May 31, 2020 is as follows:

TOU SOPP GSA(1) = Standard GSA(1-R) *[(1 / SOPP-F GSA(1)]

TOU SOPP GSA(1) = $0.05972 * [1 / 2.0]
= $0.02986

Third, PECO will use this TOU SOPP price and the TOU pricing multipliers to create the peak and off-peak prices of the TOU Rate.

TOU Pricing Period	GSA 1 TOU Price, Rate R (Upcoming 2Q 2020)
Peak	$0.19409/kWh
Super Off-Peak	$0.02986/kWh
Off-Peak	$0.04479/kWh

Net Metering, TOU Monthly Accounting and Cashout – Illustrative Example

Generation and transmission charges used in the calculations below are for explanatory purposes only.

	Jun-Aug	Sep-Nov	Dec-Feb	Mar-May
Residential PTC (GSA 1):	$0.06595	$0.06680	$0.06668	$0.06640
Generation Charge:	$0.05972	$0.06057	$0.06012	$0.05984
Transmission Charge:	$0.00623	$0.00623	$0.00656	$0.00656

Illustrative TOU Prices, GSA 1	Jun-Aug	Sep-Nov	Dec-Feb	Mar-May
Peak ("PP"):	$0.19409	$0.19685	$0.19539	$0.19448
Off-Peak ("OPP"):	$0.04479	$0.04543	$0.04509	$0.04488
Super Off-Peak ("SOPP"):	$0.02986	$0.03029	$0.03006	$0.02992

TOU Pricing Multipliers, GSA 1		
PP-SOPP Ratio:	*(Exhibit JAB-2)*	6.5
OP-SOPP Ratio:	*(Exhibit JAB-2)*	1.5
SOPP Factor:	*(Exhibit JAB-4)*	2

Monthly Metering Data

Month and Year	TOU Period	Consumed kWh ("In")	Exported kWh ("Out")	Monthly Net kWh *(In)* or Out	Monthly Excess kWh for WAPTC$_e$	PTC$_e$ for TOU Period
Jun-20	Peak	300	350	50	50	$0.20032
	Off-Peak	200	100	*(100)*	0	$0.05102
	Super Off-Peak	25	0	*(25)*	0	$0.03609
Jul-20	Peak	400	550	150	150	$0.20032
	Off-Peak	250	300	50	50	$0.05102
	Super Off-Peak	50	0	*(50)*	0	$0.03609
Aug-20	Peak	350	500	150	150	$0.20032
	Off-Peak	125	175	50	50	$0.05102
	Super Off-Peak	75	0	*(75)*	0	$0.03609
Sep-20	Peak	300	150	*(150)*	0	$0.20308
	Off-Peak	100	25	*(75)*	0	$0.05166
	Super Off-Peak	20	0	*(20)*	0	$0.03652
Oct-20	Peak	200	250	50	50	$0.20308
	Off-Peak	75	150	75	75	$0.05166
	Super Off-Peak	25	0	*(25)*	0	$0.03652
Nov-20	Peak	175	200	25	25	$0.20308
	Off-Peak	150	75	*(75)*	0	$0.05166
	Super Off-Peak	10	0	*(10)*	0	$0.03652
Dec-20	Peak	200	150	*(50)*	0	$0.20195
	Off-Peak	150	50	*(100)*	0	$0.05165
	Super Off-Peak	10	0	*(10)*	0	$0.03662
Jan-21	Peak	250	150	*(100)*	0	$0.20195
	Off-Peak	200	50	*(150)*	0	$0.05165
	Super Off-Peak	10	0	*(10)*	0	$0.03662
Feb-21	Peak	200	225	25	25	$0.20195
	Off-Peak	100	25	*(75)*	0	$0.05165
	Super Off-Peak	25	0	*(25)*	0	$0.03662
Mar-21	Peak	300	150	*(150)*	0	$0.20104
	Off-Peak	100	25	*(75)*	0	$0.05144
	Super Off-Peak	20	0	*(20)*	0	$0.03648
Apr-21	Peak	200	250	50	50	$0.20104
	Off-Peak	100	125	25	25	$0.05144
	Super Off-Peak	50	0	*(50)*	0	$0.03648
May-21	Peak	200	400	200	200	$0.20104
	Off-Peak	125	300	175	175	$0.05144
	Super Off-Peak	50	0	*(50)*	0	$0.03648

12-Month Weighted Average TOU Price-To-Compare Equivalent (WAPTC$_e$) and May Annual Cash Out

TOU Period	Month and Year	Consumed kWh ("In")	Exported kWh ("Out")	Monthly Net kWh *(In)* or Out	Monthly Excess kWh for WAPTC$_e$	Net Excess Generation kWh	PTC$_e$ for TOU Period	Monthly Weight	12-month TOU WAPTC$_e$	Cash Out
Peak	Jun-20	300	350	50	50	50	$0.20032	10.02		
	Jul-20	400	550	150	150	200	$0.20032	30.05		
	Aug-20	350	500	150	150	350	$0.20032	30.05		
	Sep-20	300	150	*(150)*	0	200	$0.20308	0.00		
	Oct-20	200	250	50	50	250	$0.20308	10.15		
	Nov-20	175	200	25	25	275	$0.20308	5.08		
	Dec-20	200	150	*(50)*	0	225	$0.20195	0.00		
	Jan-21	250	150	*(100)*	0	125	$0.20195	0.00		
	Feb-21	200	225	25	25	150	$0.20195	5.05		
	Mar-21	300	150	*(150)*	0	0	$0.20104	0.00		
	Apr-21	200	250	50	50	50	$0.20104	10.05		
	May-21	200	400	200	200	250	$0.20104	40.21		
									$0.2009	$50.24
Off-Peak	Jun-20	200	100	*(100)*	0	0	$0.05102	0.00		
	Jul-20	250	300	50	50	50	$0.05102	2.55		
	Aug-20	125	175	50	50	100	$0.05102	2.55		
	Sep-20	100	25	*(75)*	0	25	$0.05166	0.00		
	Oct-20	75	150	75	75	100	$0.05166	3.87		
	Nov-20	150	75	*(75)*	0	25	$0.05166	0.00		
	Dec-20	150	50	*(100)*	0	0	$0.05165	0.00		
	Jan-21	200	50	*(150)*	0	0	$0.05165	0.00		
	Feb-21	100	25	*(75)*	0	0	$0.05165	0.00		
	Mar-21	100	25	*(75)*	0	0	$0.05144	0.00		
	Apr-21	100	125	25	25	25	$0.05144	1.29		
	May-21	125	300	175	175	200	$0.05144	9.00		
									$0.0514	$10.27
Super Off-Peak	Jun-20	25	0	*(25)*	0	0	$0.03609	0.00		
	Jul-20	50	0	*(50)*	0	0	$0.03609	0.00		
	Aug-20	75	0	*(75)*	0	0	$0.03609	0.00		
	Sep-20	20	0	*(20)*	0	0	$0.03652	0.00		
	Oct-20	25	0	*(25)*	0	0	$0.03652	0.00		
	Nov-20	10	0	*(10)*	0	0	$0.03652	0.00		
	Dec-20	10	0	*(10)*	0	0	$0.03662	0.00		
	Jan-21	10	0	*(10)*	0	0	$0.03662	0.00		
	Feb-21	25	0	*(25)*	0	0	$0.03662	0.00		
	Mar-21	20	0	*(20)*	0	0	$0.03648	0.00		
	Apr-21	50	0	*(50)*	0	0	$0.03648	0.00		
	May-21	50	0	*(50)*	0	0	$0.03648	0.00		
									$0.0000	$0.00
									Annual Cashout:	$60.51

PECO DSP V Estimated Filing and Program Costs

Item	Description	Estimated Cost ($Millions)[1]	Recovery Mechanism
1	Cost of DSP V Proceeding (a)	$1.0	GSA
2	Independent Evaluator	$1.2	GSA
3	GSA Forecasting	$0.8	GSA
4	Optional Residential / Small Commercial Time-Of-Use (b)	$3.8	GSA
5	CAP Shopping	$1.2	
	Implementation Costs (c)	$0.7	Base Rates
	Consumer Education	$0.5	Consumer Education Surcharge
6	Customer Referral Program - $30 per customer referred	$1.1	EGS receiving the referral
7	RFP Monitor for Procurement of Solar Alternative Energy Credits	$0.1	GSA

Notes:

1	Estimates subject to change based on final program design and implementation.	
(a)	Consultants	$0.5
	Legal Expense	$0.5
	Total	$1.0
(b)	Expense	$0.9
	Capital	$2.9
	Total	$3.8
(c)	Expense	$0.2
	Capital	$0.5
	Total	$0.7

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 13, 2020 **Effective June 1, 2021**

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

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW – X REVISED PAGE NO. 34, X REVISED PAGE NO. 35, ORIGINAL PAGE NO. 35A,
Updated to reflect effective date of June 1, 2021 (DSP V). Expanded to describe new optional Time-Of-Use (TOU) Pricing Option, including customer eligibility requirements, pricing provisions, and switching rules. Labeled pre-existing non-TOU pricing as "Standard" GSA.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW REVISED PAGE NO. 36 - Updated to reflect effective date of June 1, 2021 (DSP V).

RECONCILIATION - X REVISED PAGE NO. 37 AND X REVISED PAGE NO. 38
Updated to reflect effective date of June 1, 2021 (DSP V). Modified "Applicability" section to clarify that Standard and TOU default service rate over/undercollections will be calculated in total for both Procurement Classes 1 and 2 (each "reconciled in one group"). Removed obsolete language on Procurement Class 3/4 transition.

RATE RS-2 NET METERING - X REVISED PAGE NO. 51, X REVISED PAGE NO. 52, X REVISED PAGE NO. 53
Updated "Metering Provisions" to exclude virtual net metering customers from default service TOU. Supplemented "Billing Provisions" with description of excess generation accounting and cashout processes for customer-generators enrolled in default service TOU. Pages 52 and 53 are repaginated.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER – X REVISED PAGE NO. 77
Eliminated restriction of "Availability" to customers who obtain competitive energy supply. Also added restriction of "Availability" excluding CAP customers from selecting default service TOU.

TABLE OF CONTENTS

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below. **(C)** **(C)**

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula: **(C)** **(C)** **(C)** **(C)** **(C)**

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where; **(C)**

C= The sum of the amounts paid to the full requirements suppliers providing the power for the quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the C component above for the quarterly period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00019/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.XXXXX
RH	GSA (1)	$0.XXXXX
GS	GSA (2)	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

(C)

PD	GSA (2)	$0.XXXXX
HT	GSA (2)	$0.XXXXX
POL*	GSA (2)	$0.XXXXX
SL-S*	GSA (2)	$0.XXXXX
TLCL	GSA (2)	$0.XXXXX
SL-E*	GSA (2)	$0.XXXXX
AL*	GSA (2)	$0.XXXXX
SL-C*, **	GSA (2)	$0.XXXXX

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1, September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1, September 1, December 1 and March 1 commencing XXX and are not prorated. **(C)**

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] as approved in the Company's most recent DSP proceeding at Docket No. XXX are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12%	14%	6.5-to-1	5.1-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1.5-to-1	1.7-to-1

To calculate the quarterly TOU Pricing Option rates, the Company will first calculate the quarterly TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

Current TOU Pricing Option Charges (Year-Round):

TOU Rate	Peak Hours (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak Hours (12-6 AM all days)	Off-Peak Hours (All other times)
R (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
RH (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
GS (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
PD (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
HT (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

TOU Eligibility Requirements and Switching Rules: (C)

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw. **(C)**

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. **(C)** If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

$$\Sigma PJM_{DA} \times \text{usage} / (1\text{-}LL)$$

PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution
RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

$$((PJM_{AS} \times \text{Usage}*1/(1\text{-}LL) + AEPS/S_{AEPS} \times \text{Usage})$$

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0.00019 kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP	
Hourly Pricing Adder* (dollars/kWh)	$0.XXXXX	$0.XXXXX	$0.XXXXX	$0.XXXXX	**(C)**

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

(C) Denotes Change

RECONCILIATION

Applicability: June 1, 2021 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing. **(C)**

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2020 through December 31, 2020 reconciliation **(C)** period. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. Any over/(under) recovery shall be collected after the Occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2021 through August 31, 2021. For purposes of this rider the reconciliation shall be **(C)** calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential Class 2 – Small C&I up to and including 100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard **(C)** Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-GRT})*(1\text{-ALL})/(1\text{-LL})$

Where:

E = Experienced over or under collection plus associated interest
N = Procurement class
M = Migration Rider
O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

(C) Denotes Change

RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment, shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. The GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2021 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. **(C)**
The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

(C) Denotes Change

RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

   3.Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option. **(C)**

(C) Denotes Change

RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP. **(C)**

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   For default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, The Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated. **(C)**

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

5 Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

(C) Denotes Change

RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The installation cannot be directly connected to the Company's distribution system ("stand alone"). Instead, the installation must be connected to a facility (residence or business) that is connected to the Company's distribution system.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R, or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. In addition, these customers are not eligible to select the Time-Of-Use default service pricing option. (C)

Based on the applicable level of income, number of household members, and their historical usage CAP customers will receive a Fixed Credit Option ("FCO") based upon that individual household's need. The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2015-2507139.

DISCOUNT LEVELS: The Company will modify the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred.

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider, and then again every two years, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth.
- Participate in various energy education and conservation programs facilitated by PECO.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE. The minimum charge per month will be the $12 for Residential customers or $30 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP will have their pre-program arrearage ("PPA") forgiven if the Customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. If the customer develops any in-program arrearage while on the CAP Rate-- that is, if the customer does not pay the entire outstanding balance -- then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

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Supplement No. X to
ELECTRIC PA P.U.C NO. 6

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PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 13, 2020 **Effective June 1, 2021**

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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

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW – X REVISED PAGE NO. 34, X REVISED PAGE NO. 35, ORIGINAL PAGE NO. 35A,
Updated to reflect effective date of June 1, 2021 (DSP V) Expanded to describe new optional Time-Of-Use (TOU) Pricing Option, including customer eligibility requirements, pricing provisions and switching rules Labeled pre-existing non-TOU pricing as "Standard" GSA

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW REVISED PAGE NO. 36. Updated to reflect effective date of June 1 2021 (DSP V)

RECONCILIATION - X REVISED PAGE NO. 37 AND X REVISED PAGE NO. 38
Updated to reflect effective date of June 1, 2021 (DSP V) Modified "Applicability" section to clarify that Standard and TOU default service rate over/undercollections will be calculated in total for both Procurement Classes 1 and 2 (each reconciled in one group") Removed obsolete language on Procurement Class 3/4 transition

RATE RS-2 NET METERING - X REVISED PAGE NO. 51, X REVISED PAGE NO. 52, X REVISED PAGE NO. 53
Updated "Metering Provisions" to exclude virtual net metering customers from default service TOU Supplemented "Billing Provisions" with description of excess generation accounting and cashout processes for customer-generators enrolled in default service TOU Pages 52 and 53 are repaginated

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER – X REVISED PAGE NO. 77
Eliminated restriction of "Availability" to customers who obtain competitive energy supply Also added restriction of "Availability" excluding CAP customers from selecting default service TOU

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Provision for the Recovery of Consumer Education Plan Costs – 2nd Revised Page No. 41¶
Reflects annual update to Consumer Education ¶
¶
Rate R Residence Service – 9th Revised Page No. 49¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
¶
Rate R-H Residential Heating Service – 9th Revised Page No. 50¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
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Rate PD Primary Distribution Power – 5th Revised Page No. 56¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
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Rate HT High Tension Power – 5th Revised Page No. 57¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs¶
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Supplement No. to
Tariff Electric Pa. P.U.C. No. 6
Revised Page No. 34
PECO Energy Company Supersedes Revised Page No. 34

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below. (C) (C)

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Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula: (C) (C)

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Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where

C= The sum of the amounts paid to the full requirements suppliers providing the power for the quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the C component above for the quarterly period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

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A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

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S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00019/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors. Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.XXXXX
RH	GSA (1)	$0.XXXXX
GS	GSA (2)	$0.XXXXX

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)

(C)

PD	GSA (2)	$0 XXXXX
HT	GSA (2)	$0 XXXXX
POL*	GSA (2)	$0 XXXXX
SL-S*	GSA (2)	$0 XXXXX
TLCL	GSA (2)	$0 XXXXX
SL-E*	GSA (2)	$0 XXXXX
AL*	GSA (2)	$0 XXXXX
SL-C* **	GSA (2)	$0 XXXXX

* Prices shall exclude capacity from the Procurement Class 2 RFP results
** Rate SL-C was effective July 1 2019 pursuant to the Order at Docket No R-2018 3000164

Procedure For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1 September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods when wholesale electricity demand and prices are high to off-peak periods when demands and prices are lower Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1 September 1 December 1 and March 1 commencing XXX and are not prorated (C)

The year-round TOU Pricing Periods TOU Period Allocators [PA-GSA(n)] and TOU Pricing Multipliers [PM-GSA(n)] as approved in the Company s most recent DSP proceeding at Docket No XXX are as follows

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2 00 – 6 00 p m Monday through Friday excluding PJM holidays	12%	14%	6 5-to-1	5 1-to-1
Super Off-Peak ("SOPP")	Midnight (12 a m) – 6 a m Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1 5-to-1	1 7-to-1

To calculate the quarterly TOU Pricing Option rates the Company will first calculate the quarterly TOU Super Off-Peak Price (SOPP) in accordance with the formula set forth below

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where

Standard GSA(n) = Defined as above for Standard Pricing

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price calculated as follows

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak (PP) and Off-Peak (OPP) prices as follows

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA

Current TOU Pricing Option Charges (Year-Round):

TOU Rate	Peak Hours (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak Hours (12-6 AM all days)	Off-Peak Hours (All other times)
R (GSA 1)	$0 XXXXX	$0 XXXXX	$0 XXXXX
RH (GSA 1)	$0 XXXXX	$0 XXXXX	$0 XXXXX
GS (GSA 2)	$0 XXXXX	$0 XXXXX	$0 XXXXX
PD (GSA 2)	$0 XXXXX	$0 XXXXX	$0 XXXXX
HT (GSA 2)	$0 XXXXX	$0 XXXXX	$0 XXXXX

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)

TOU Eligibility Requirements and Switching Rules: (C)

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company s RS-2 (Net Metering) tariff except for virtual net metered Customers Residential Customers enrolled in the Company s Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO s Standard GSA rate switch to an EGS or otherwise become ineligible

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees However Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4
LOADS GREATER THAN 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw (C)

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Hourly Pricing Service

Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1 September 1 December 1 and March 1 commencing June 1 2021 and are not prorated (C) If the balance of over/(under) recovery gets too large due to billing lag the Company can file a reconciliation that will mitigate the subsequent impact The cost for this hourly service rate shall be as follows

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Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

ΣPJM_{DA} x usage / (1-LL)

PJM_{DA} – PJM on day ahead hourly price
Usage - Electricity used by an end use customer
R = The PJM reliability pricing model (RPM) charge for month for the customer The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution
RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost This includes an allocation of the cost of the Independent Evaluator consultants providing guidance on the development of the procurement strategy legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate

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A / S x Usage
A = Administrative cost
S = Default service sales

AS = The cost on a $/MWH basis of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard multiplied by the customers usage for the month and divided by (1-LL) Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier

$((PJM_{AS}$ x Usage*1/(1-LL) + $AEPS/S_{AEPS}$ x Usage)

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred

If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1 LL)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers the ARR s allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company s Electric Generation Supplier Coordination Tariff Rule 6 6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj) – Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0 00019 kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure The E factor shall be updated semiannually in conjunction with the Reconciliation The applicable above items are converted to the rates listed below

Tariff Rate	GS	PD	HT	EP	
Hourly Pricing Adder* (dollars/kWh)	$0.XXXXX	$0.XXXXX	$0.XXXXX	$0.XXXXX	(C)

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* Includes administrative cost (AC) ancillary service charge (AS) E factor (E) and working capital (WC)

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RECONCILIATION

Applicability: June 1, 2021 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing (C)

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2020 through December 31 2020 reconciliation period The reconciliation shall be separate for each procurement class Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group Any over/(under) recovery shall be collected after the Occurrence of two months from the end of the reconciliation period Recovery shall be over a six month period commencing September 1 and March 1 The initial six month period is March 1, 2021 through August 31 2021. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery The over or under recovery shall be calculated using the formula below The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential Class 2 – Small C&I up to and including 100 kW and Class 3/4 – Large C&I greater than 100 kW For Procurement Classes 1 and 2 Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class (C)

Reconciliation Formula
$E_N = \Sigma O/(U) + I$
Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:
E = Experienced over or under collection plus associated interest
N = Procurement class
M = Migration Rider
O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost AEPS Cost and Administrative Cost

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled the spot market purchases for the period being reconciled plus the cost of any other energy acquired for the period being reconciled Cost shall include energy capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2 Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act (AEPS or the Act) not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits (AEC s) purchased for compliance with the Act the cost of administering and conducting any procurement of Alternative Energy and/or AEC s payments to the AEC program administrator for its costs of administering an alternative energy credits program payments to a third party for its costs in operating an AEC registry any charge levied by PECO s regional transmission operator to ensure that alternative energy sources are reliable a credit for the sale of any AEC s sold during the calculation period and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC s and complying with the AEPS statute

Administrative Cost = This includes the cost of the Independent Evaluator consultants providing guidance on the development of the procurement strategy legal fees incurred gaining approval of the strategy and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No I 2011-2237952 or any other applicable docket that are not recovered from EGS s or through another rate

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed The only cost added by the Company to the full requirements price is for gross receipts tax distribution line losses and administrative cost

Ancillary Services = The following services in the PJM OATT- reactive support frequency control operating reserves supplemental reserves imbalance charges PJM annual charges any PJM assessment associated with non payment by members and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service

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shall be collected after the occurrence of three months and two months, respectively For Procurement Classes 1 2 and 3/4 Hourly ¶
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RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers the ARR s allow a Company to select rights to specific transmission paths in order to avoid congestion charges

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM)

I = interest on the over or under collection at the prime rate of interest for commercial banking not to exceed the legal rate of interest in effect on the last day of the month the over collection or under collection occurs as reported in the Wall Street Journal in accordance with the Order at Docket No L-2014-2421001

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S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled

ALL = The average line losses in a procurement class as a percent of generation

LL = The average line losses for a particular rate (e g HT PD GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6

GRT = The current gross receipts tax rate

Procurement Class - Set of customers for which the company has a common procurement plan

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months The GSA will be effective June 1 September 1 December 1 and March 1 commencing June 1 2021 with over/under collect on recovery occurring over the six month period beginning September 1 and March 1. (C)
The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits

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and for Procurement Class 3/4 Hourly after the two initial transition periods
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lag by three months and two months respectively For Procurement Classes 1 2 and the 3/4 Hourly t
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are June 1 2017 through August 31 2017 and September 1 2017 through February 28 2018
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RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system

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APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers (IEEE) and the Commission.

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Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

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METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

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1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option. (C)

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RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R RH CAP, GS HT PD EP (C)

1 The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year On an annual basis the Company will compensate the customer-generator for kilowatt hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the full retail value for all energy produced consistent with Commission regulations The customer-generator is responsible for the customer charge demand charge and other applicable charges under the applicable Rate Schedule

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For default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise If in a subsequent default service TOU billing period a customer consumes more electricity than produced within a given TOU Pricing Period The Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year On an annual basis the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated (C)

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2 If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company s system during the billing period all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied The customer-generator is responsible for the customer charge demand charge and other applicable charges under the applicable Rate Schedule

3 For customer-generators involved in virtual meter aggregation programs any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system also known as the host account If the host account's usage has been fully offset by this credit and additional excess credit still remains PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name also known as satellite accounts and apply one part to each satellite account in a waterfall -like fashion at each account's designated rate This process continues as PECO bills each subsequent satellite account with any additional excess credits from each divided equally among the remaining satellite accounts Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company s billing process, rather than through physical rewiring of the customer-generator's property for a physical single point of contact The customer-generators are responsible for the customer charge demand charge and other applicable charges under the applicable Rate Schedule

4 Procurement Class 3/4 customer-generators will receive a generation credit at the PJM Day Ahead hourly energy rate for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period

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If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year

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5 Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate

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If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator the variable distribution charges will be reduced by the excess kilowatt hours which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period ending May 31 of each year

Procurement Class 3/4 customer-generators are responsible for the customer charge demand charge and other applicable charges under the applicable Rate Schedule

Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges

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RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS

1 Customer-generators may take net metering services from EGSs that offer such services

2 If a net-metering customer takes service from an EGS the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company s distribution rates Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges The customer-generator is responsible for the customer charge demand charge and other applicable charges under the applicable Rates Schedule

3 If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company s system during the billing period all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered The customer-generator is responsible for the customer charge demand charge and other applicable charges under the applicable Rate Schedule

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4 Pursuant to Commission regulations the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS

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5 If a customer-generator switches electricity suppliers the Company shall treat the end of the service as if it were the end of the PJM planning period

APPLICATION.
Customer-generators seeking to receive service under the provisions of this Rate must submit a written application to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility The installation cannot be directly connected to the Company s distribution system (stand alone) Instead the installation must be connected to a facility (residence or business) that is connected to the Company s distribution system

INTERCONNECTION EXPIRATION.
Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75 A customer-generator (or authorized designee) must submit a completed certificate of completion (COC) for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i e that significant progress in construction of the interconnection has been or will be made) Upon a showing of good cause the application expiration date will be extended The length of the extension may be extended up to but no more than 180 calendar days A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application s original expiration date PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date

MINIMUM CHARGE.
The Minimum Charges under Rate Schedule R RH CAP GS PD, HT and EP apply for installations under this Rate

RIDERS.
Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate

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CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R or RH (excluding mult ple dwel ing unit buildings consisting of two to five dwelling units) Customers must apply for the rates contained in this rider and must demonstrate annua household gross income at or below 150% of the Federal Poverty guidelines In addition these customers are not eligible to select the Time-Of-Use default service pricing option **(C)**

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Based on the applicable level of income number of household members and their historical usage CAP customers will receive a Fixed Credit Option (FCO) based upon that individual household s need The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No M-2015-2507139

DISCOUNT LEVELS: The Company will mod fy the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider and then again every two years customers must verify to PECO s satisfaction that their household income level meets the Availability standards set forth in this Rider Customers being considered for the CAP Rider will be required to

- Provide information sufficient to demonstrate to PECO their household income level
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth
- Participate in various energy education and conservation programs facilitated by PECO

PECO may at its sole discretion supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income el gibility of its customers Such data may come from a customer's participation in or receipt of benefits from the Low Income Home Energy Assistance Program Temporary Assistance for Needy Families Food Stamps Supplemental Security Income and Medicaid Information ava lab e from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process

MINIMUM CHARGE. The minimum charge per month will be the $12 for Residential customers or $30 for Residential Heating customers

ARREARAGE.
Customers who qualify and are enrolled in CAP will have their pre-program arrearage (PPA) forgiven if the Customer pays his / her new discounted CAP bill on time and in full each month With every full and on-time monthly payment one-twelfth of the PPA will be forgiven If the customer develops any in-program arrearage while on the CAP Rate-- that is if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness w ll not resume until the first month in which the fu l outstanding balance is paid

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Responses to Questions in 52 Pa. Code Section 53.52(a)

1. The specific reason for each change.

PECO Energy Company ("PECO" or the "Company") is proposing tariff changes to implement its fifth proposed default service program ("DSP V"), which includes the Company's proposed new time-of-use ("TOU") rate options and PECO's plan ("Plan") to allow customers enrolled in the Company's Customer Assistance Program ("CAP") to purchase competitive generation supply from an electric generation supplier ("EGS"). The Company's DSP V is being filed in compliance with the Commission's regulations at Title 52 Pa. Code Section 54.185.

2. The total number of customers served by the utility.

The total number of electric customers served by PECO was 1,661,605 as of December 31, 2019.

3. A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

Residential and small commercial customers are potentially affected due to proposed tariff changes to introduce TOU rate options under the Generation Supply Adjustment. Other limited changes are explained in PECO Statement No. 2, the direct testimony of Joseph A. Bisti.

4. The effect of the change on the utility's customers.

The primary effect of the proposed changes is to implement new time-of-use rate options for eligible residential and commercial default service customers, which will potentially reduce their electric bill. The tariff changes also will allow CAP customers to purchase competitive generation supply from an EGS. All of the proposed tariff changes and their potential effects are discussed in detail in PECO Statement No. 2.

5. The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The effects of the proposed tariff changes on PECO's revenues and expenses cannot be determined at this time and will depend upon the implementation of PECO's procurement plan that is approved as part of this filing and the market prices in effect when generation supply service is procured. The effects of those tariff changes on PECO's revenues and expenses will also depend on the final Plan design and TOU rate design approved by the Commission.

6. The effect of the change on the service rendered by the utility.

PECO does not expect the proposed tariff changes to affect service.

7. A list of factors considered by the utility.

The changes are being made to comply with the Commission's Default Service Regulations and Policy Statement, the Commission's February 28, 2019 Proposed Policy Statement Order in Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping, the January 23, 2020 Letter of Rosemary A. Chiavetta in Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms, and the April 6, 2017 Letter of Rosemary A. Chiavetta in Docket No. P-2016-2526672 – Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2017 through May 31, 2017. PECO Statement No. 2, the direct testimony of Mr. Bisti, discusses the reasons for all of the proposed tariff changes.

8. Studies undertaken by the utility in order to draft its proposed change.

No specific studies were undertaken.

9. Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

No customer polls were taken.

10. Plans the utility has for introducing or implementing the changes with respect to its customers.

The Company's Petition requesting approval of its DSP V summarizes how the Company proposes to implement the changes and references specific testimony being filed with the Petition that provides further details about DSP V and how it will be implemented.

11. F.C.C., or FERC or Commission Orders or rulings applicable to the filings.

The following orders and PUC guidance are applicable to this filing:

Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping (Proposed Policy Statement Order entered Feb. 28, 2019)

Docket No. P-2016-2534980 - Petition of PECO Energy Company for Approval of Its Default Service Program for the Period June 1, 2017 to May 31, 2021 (Opinion and Order entered Dec. 8, 2016).

Docket No. I-2011-2237952 - Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service (Order entered Feb. 15, 2013).

Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms (Secretarial Letter issued January 23, 2020)

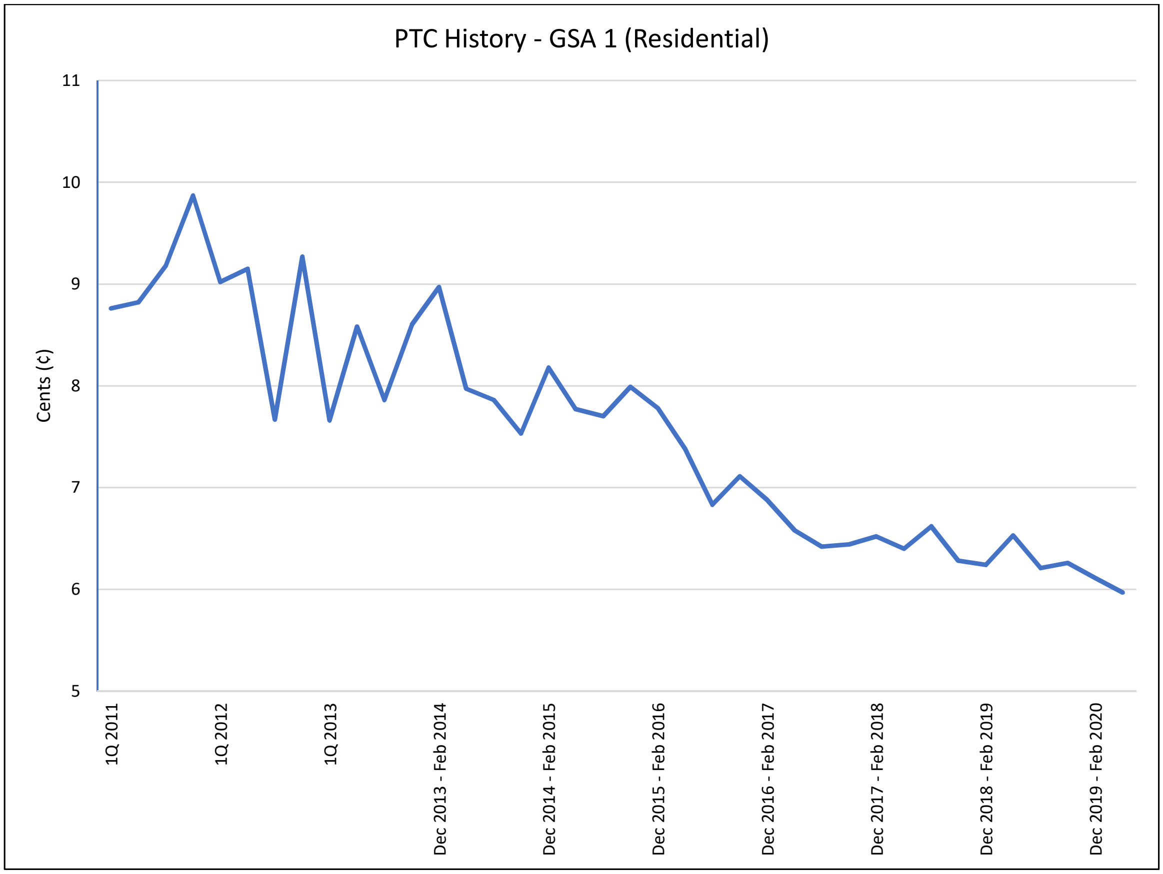
Docket No. P-2016-2526672 – Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2017 through May 31, 2017 (Secretarial Letter issued Apr. 6, 2017)

PECO Electric Price-To-Compare History
"GSA 1" (Residential) and "GSA 2 - Rate GS" (Small C&I General Service)
(January 2011 thru current)

	GSA 1 Residential		
	Price (¢)	Variance	% Change
1Q 2011	8.76		
2Q 2011	8.82	0.06	0.68%
3Q 2011	9.18	0.36	4.08%
4Q 2011	9.87	0.69	7.52%
1Q 2012	9.02	-0.85	-8.61%
2Q 2012	9.15	0.13	1.44%
3Q 2012	7.67	-1.48	-16.17%
4Q 2012	9.27	1.6	20.86%
1Q 2013	7.66	-1.61	-17.37%
Apr-May 2013	8.58	0.92	12.01%
June 2013 - Aug 2013	7.86	-0.72	-8.39%
Sep 2013 - Nov 2013	8.60	0.74	9.41%
Dec 2013 - Feb 2014	8.97	0.37	4.30%
Mar 2014 - May 2014	7.97	-1	-11.15%
June 2014 - Aug 2014	7.86	-0.11	-1.38%
Sep 2014 - Nov 2014	7.53	-0.33	-4.20%
Dec 2014 - Feb 2015	8.18	0.65	8.63%
Mar 2015 - May 2015	7.77	-0.41	-5.01%
June 2015 - Aug 2015	7.70	-0.07	-0.90%
Sep 2015 - Nov 2015	7.99	0.29	3.77%
Dec 2015 - Feb 2016	7.78	-0.21	-2.63%
Mar 2016 - May 2016	7.38	-0.4	-5.14%
June 2016 - Aug 2016	6.83	-0.55	-7.45%
Sep 2016 - Nov 2016	7.11	0.28	4.10%
Dec 2016 - Feb 2017	6.88	-0.23	-3.23%
Mar 2017 - May 2017	6.58	-0.3	-4.36%
June 2017 - Aug 2017	6.42	-0.16	-2.43%
Sep 2017 - Nov 2017	6.44	0.02	0.31%
Dec 2017 - Feb 2018	6.52	0.08	1.24%
Mar 2018 - May 2018	6.40	-0.12	-1.84%
June 2018 - Aug 2018	6.62	0.22	3.44%
Sep 2018 - Nov 2018	6.28	-0.34	-5.14%
Dec 2018 - Feb 2019	6.24	-0.04	-0.64%
Mar 2019 - May 2019	6.53	0.29	4.65%
June 2019 - Aug 2019	6.21	-0.32	-4.90%
Sep 2019 - Nov 2019	6.26	0.05	0.81%
Dec 2019 - Feb 2020	6.11	-0.15	-2.40%
Mar 2020 - May 2020	5.97	-0.14	-2.29%

	GSA 2 Small Commercial - Rate GS		
	Price (¢)	Variance	% Change
1Q 2011	8.73		
2Q 2011	8.69	-0.04	-0.46%
3Q 2011	9.55	0.86	9.90%
4Q 2011	10.1	0.55	5.76%
1Q 2012	8.74	-1.36	-13.47%
2Q 2012	9.13	0.39	4.46%
3Q 2012	7.58	-1.55	-16.98%
4Q 2012	8.47	0.89	11.74%
1Q 2013	7.69	-0.78	-9.21%
Apr-May 2013	9.26	1.57	20.42%
June 2013 - Aug 2013	7.88	-1.38	-14.90%
Sep 2013 - Nov 2013	8.61	0.73	9.26%
Dec 2013 - Feb 2014	9.35	0.74	8.59%
Mar 2014 - May 2014	8.17	-1.18	-12.62%
June 2014 - Aug 2014	7.66	-0.51	-6.24%
Sep 2014 - Nov 2014	8.41	0.75	9.79%
Dec 2014 - Feb 2015	9.06	0.65	7.73%
Mar 2015 - May 2015	7.74	-1.32	-14.57%
June 2015 - Aug 2015	7.94	0.20	2.58%
Sep 2015 - Nov 2015	8.31	0.37	4.66%
Dec 2015 - Feb 2016	8.01	-0.30	-3.61%
Mar 2016 - May 2016	7.87	-0.14	-1.75%
June 2016 - Aug 2016	6.83	-1.04	-13.21%
Sep 2016 - Nov 2016	6.70	-0.13	-1.90%
Dec 2016 - Feb 2017	6.40	-0.30	-4.48%
Mar 2017 - May 2017	5.94	-0.46	-7.19%
June 2017 - Aug 2017	6.22	0.28	4.71%
Sep 2017 - Nov 2017	6.02	-0.20	-3.22%
Dec 2017 - Feb 2018	6.28	0.26	4.32%
Mar 2018 - May 2018	6.01	-0.27	-4.30%
June 2018 - Aug 2018	6.25	0.24	3.99%
Sep 2018 - Nov 2018	6.01	-0.24	-3.84%
Dec 2018 - Feb 2019	6.38	0.37	6.16%
Mar 2019 - May 2019	6.28	-0.10	-1.57%
June 2019 - Aug 2019	6.04	-0.24	-3.82%
Sep 2019 - Nov 2019	5.83	-0.21	-3.48%
Dec 2019 - Feb 2020	5.74	-0.09	-1.54%
Mar 2020 - May 2020	5.87	0.13	2.26%

*PECO modified the three-month periods for the above rates in June of 2013 as part of DSP II.
See Docket No. P-2012-2283641, Order Issued September 27, 2012.


PTC History - GSA 1 (Residential)
Cents (¢)
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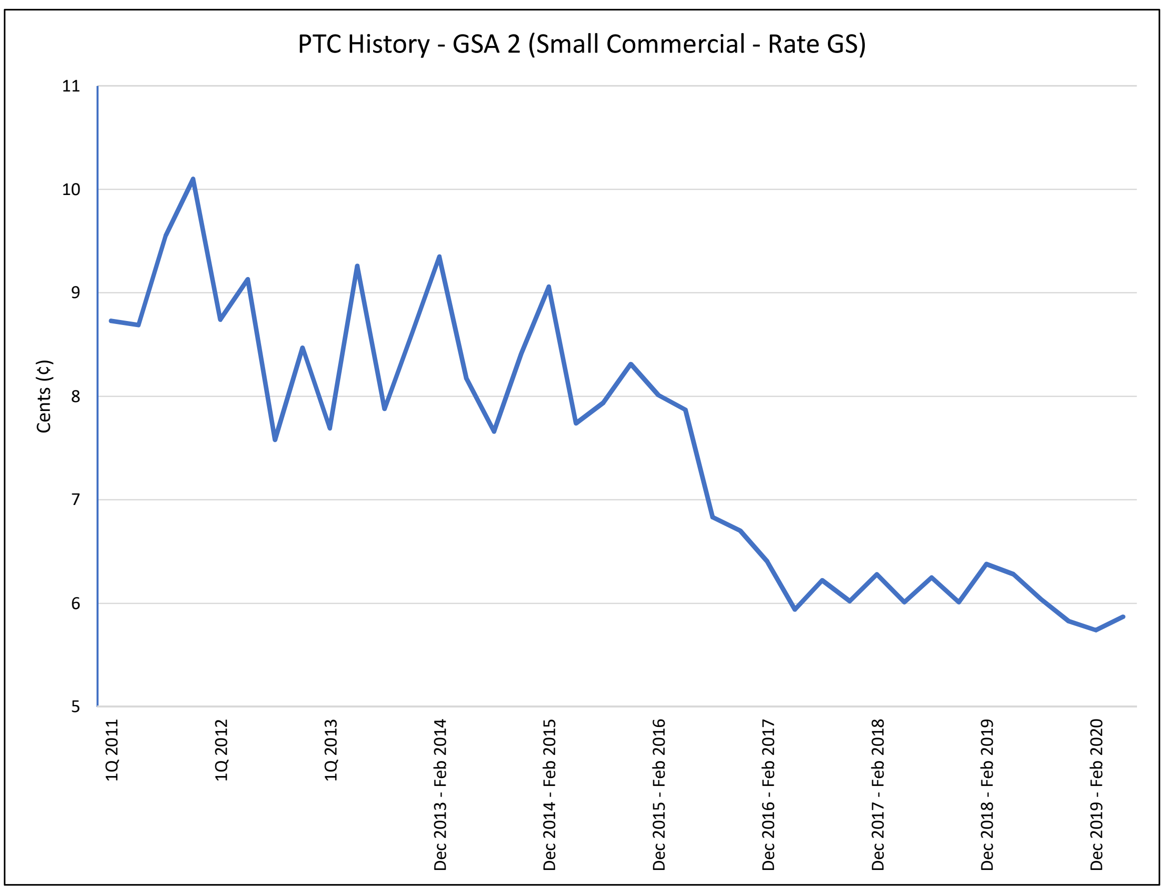
PTC History - GSA 2 (Small Commercial - Rate GS)
Cents (¢)
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Dec 2018 - Feb 2019
Dec 2019 - Feb 2020

PECO ENERGY COMPANY
STATEMENT NO. 2-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-3019290

REBUTTAL TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECTS: COSTS INCLUDED IN DEFAULT SERVICE RATES, RECONCILIATION OF GENERATION SUPPLY OVER/UNDERCOLLECTIONS; TIME-OF-USE RATES, AND RECOVERY OF CUSTOMER ASSISTANCE PROGRAM CUSTOMER SHOPPING PLAN COSTS

DATED: JULY 9, 2020

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OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

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

A. My name is Joseph A. Bisti. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rates Specialist. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony that is marked as PECO Statement No. 2. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to various issues regarding the rate design for PECO's fifth default service program ("DSP V") raised by witnesses for the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), the Electric Supplier Coalition ("ESC"),[1] and the Environmental Stakeholders.[2] My testimony is divided into four parts.

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[1] The Electric Supplier Coalition's members are NRG Energy, Inc. ("NRG"); Direct Energy Services LLC; Interstate Gas Supply Inc., d/b/a IGS Energy; Vistra Energy Corp.; Shipley Choice LLC; ENGIE Resources LLC; and WGL Energy Services, Inc.

[2] The Environmental Stakeholders are Clean Air Council, Sierra Club/PA Chapter and Philadelphia Solar Energy Association.

First, I will respond to the direct testimony of ESC witness Travis Kavulla (ESC St. No. 1), who asserts that PECO's "Price-to-Compare" or "PTC"[3] improperly excludes overhead and other administrative costs that Mr. Kavulla believes the Company incurs to provide default service to its customers who do not select an alternative electric generation supplier ("EGS").

Second, I respond to the proposal of Steven Estomin on behalf of the OCA (OCA St. No. 1) regarding the reconciliation of default service supply costs and revenues for residential customers.

Third, I address the direct testimony of several parties relating to PECO's proposed introduction of time-of-use ("TOU") rate options for eligible default service customers in the Company's Residential and Small Commercial procurement classes (the "TOU Rates"). Specifically, I will address the direct testimony of Harry Geller on behalf of CAUSE-PA, Brian Kalcic on behalf of OSBA (OSBA St. No. 1), Karl R. Rábago on behalf of the Environmental Stakeholders (ES St. No. 1), OCA witness Estomin, and ESC witness Kavulla relating to the following issues:

- Opt-in TOU rate structure (ESC);
- Customer eligibility for the TOU Rates (ESC and CAUSE-PA);
- TOU pricing periods and multipliers (OCA and Environmental Stakeholders);

[3] As explained in my direct testimony, PECO recovers the cost of default service for each procurement class through a class-specific Generation Supply Adjustment ("GSA") charge and a Transmission Service Charge ("TSC"). The price per kilowatt-hour ("kWh") charged under each GSA and the TSC is the PTC for the applicable class and is updated at least quarterly in accordance with the Commission's default service regulations.

- Communications plan and implementation time frame (ESC);
- Reporting requirements (CAUSE-PA); and
- Allocation and recovery of TOU implementation costs (OSBA and ESC).

Finally, I address the recommendations of Barbara R. Alexander on behalf of the OCA (OCA St. No. 2) and CAUSE-PA witness Geller regarding recovery of costs incurred to implement PECO's Customer Assistance Program ("CAP") Shopping Plan ("Plan").

II. COSTS INCLUDED IN PECO'S DEFAULT SERVICE RATES

4. Q. Please summarize ESC witness Kavulla's contentions regarding the costs included in PECO's PTC.

A. Mr. Kavulla contends that PECO's PTC is artificially low because the Company improperly excludes certain administrative and overhead costs from the PTC and instead recovers them through distribution rates. Mr. Kavulla highlights the treatment of particular administrative costs categories, such as information technology ("IT"), billing, collection, education, and regulatory and tariff filings, as well as administrative and general ("A&G") expenses, as examples of the Company's alleged failure to recover all default service costs through the PTC. Mr. Kavulla concludes that the Company's cost allocations are contrary to "industry guidelines" and are harmful to the competitive retail market. He recommends that the Commission require PECO to modify its default service rate design, through a subsequent compliance filing, to recover a "reasonable" portion of its overhead costs through the PTC.

5. Q. Does the Commission identify what types of costs should be included in the PTC?

A. Yes. In a Policy Statement regarding default service and retail electric markets (52 Pa. Code § 69.1808), the Commission identified the types of costs that should be recovered from default service customers. As the Policy Statement explains:

> (a) The PTC should be designed to recover all generation, transmission and other related costs of default service. These cost elements include:
>
> (1) Wholesale energy, capacity, ancillary, applicable RTO or ISO administrative and transmission costs,
>
> (2) Congestion costs will ultimately be recovered from ratepayers. Congestion costs should be reflected in the fixed price bids submitted by wholesale energy suppliers.
>
> (3) Supply management costs, including supply bidding, contracting, hedging, risk management costs, any scheduling and forecasting services provided exclusively for default service by the EDC, and applicable administrative and general expenses related to these activities.
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> (4) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.
>
> (5) Applicable taxes, excluding Sales Tax.
>
> (6) Costs for alternative energy portfolio standard compliance.

6. Q. Has the Commission previously determined that PECO's PTC is consistent with Commission requirements?

A. Yes, on numerous occasions. The Commission has considered PECO's default service rate design (including the costs that would be recovered in the PTC) four separate times in its approvals of PECO's prior default service programs. In addition, the Commission has reviewed PECO's distribution rates three times – in 2010, 2015 and again in 2018 – and determined that those distribution rates were just and reasonable.

In the Company's 2018 electric base rate proceeding, the Commission considered detailed record evidence about the types of costs, including administrative costs, that PECO includes in the PTC. The Commission concluded that the Company's allocations of cost to the PTC were appropriate and rejected the argument of intervenor NRG that additional costs should be removed from distribution base rates and included in the PTC.[4] As the Commission explained:

> A theory that underlies NRG's proposal is that the categories of costs incorporated in alternative energy suppliers' charges to their customers should be the same as the categories of costs incorporated in PECO's PTC. However, rate design is governed by the principle of cost causation. The principle requires that the cost of supplying public utility services is allocated to those who cause the costs to be incurred.[5]

The Commission's Order was affirmed by the Commonwealth Court on June 2, 2020.[6]

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[4] *See Pa. P.U.C. vs. PECO Energy Co.*, Docket No. R-2018-3000164 (Order entered Dec. 20, 2018) (the "*2018 Distribution Rate Order*").

[5] *2018 Distribution Rate Order*, p. 74.

[6] *See NRG Energy, Inc. v. Pa. P.U.C.*, 58 C.D. 2019 (June 2, 2020). A petition for allowance of appeal filed by NRG on July 2, 2020 is pending before the Pennsylvania Supreme Court.

7. **Q.** **Do you believe PECO's proposed allocation of costs to the PTC in this proceeding is consistent with Commission requirements?**

A. Yes, I do. PECO's allocation of costs between default service and distribution in this proceeding is consistent with the allocations approved by the Commission in the *2018 Distribution Rate Order*.

8. **Q.** **Before we turn to the specific cost categories identified by Mr. Kavulla, can you please describe the Company's overall approach to allocating administrative costs between distribution and default service?**

A. Certainly. The Company's allocation of costs between distribution and default service reflects established cost causation principles. Although Mr. Kavulla refers to distribution and default service as "two businesses," PECO's default service obligations are part of its duties as an electric distribution company ("EDC"). Under the Public Utility Code, PECO has an obligation to provide default supply to all distribution customers who do not take generation service from an EGS. PECO customers are not distribution customers **or** default service customers—they are distribution customers who may or may not receive default service. PECO does not consider default service as a separate "business".

If a cost is incurred to support the Company's distribution customers generally (shopping and non-shopping) and is not driven by fulfilling the Company's default service obligations, PECO allocates the cost to distribution. If a cost is incurred as a result of fulfilling the Company's default service obligations, PECO allocates the cost to default service.

9. Q. Let's turn to the cost categories identified by Mr. Kavulla. He contends that PECO should allocate "embedded costs" associated with IT systems to the PTC in addition to including incremental costs associated with default service initiatives. Do you agree?

A. No. The Company's allocation of IT costs is appropriate and consistent with prior allocations that have been approved by the Commission. When IT costs are caused specifically by fulfilling the Company's default service obligations, PECO includes those costs in the PTC. For example, as part of PECO's second default service proceeding, PECO sought – and the Commission approved – recovery of the capital costs for IT upgrades necessary to implement the plan, and those costs were included in the PTC.[7] In this proceeding, the Company is proposing that the cost of IT upgrades needed to implement PECO's TOU Rates for default service customers be included in the PTC. General (or "embedded") IT costs are incurred to serve all distribution customers and are appropriately recovered through distribution rates based on cost causation.

[7] *Petition of PECO Energy Co. for Approval of its Default Service Program II*, Docket No. P-2012-2283641 (Order entered Oct. 12, 2012) ("*DSP II Order*"), pp. 63-64.

10. Q. Mr. Kavulla observes that PECO's current PTC contains no administrative costs for billing, collection, education, regulatory or tariff filings. Please begin by explaining how billing and collection costs are recovered from customers.

A. Consistent with prior Commission approvals, billing and collection costs are recovered through distribution rates. Such recovery is appropriate for billing costs because customers receiving default service are also PECO distribution customers and already receive a PECO bill. Uncollectible accounts expense is included in distribution rates because PECO assumes collection responsibility for both default service and the amounts owed to EGSs who participate in the Company's purchase-of-receivables program.

I note that PECO purchases EGS receivables at full value, with no discount to reflect collection costs. If collections costs were removed from distribution rates and separated into shopping and non-shopping categories, the Company expects that it would recover shopping-related collection costs directly from EGSs.

11. Q. Does the PTC include education, regulatory or tariff filing costs?

A. Yes, such costs are included in the PTC when appropriate, but they can be periodic in nature and therefore are not necessarily reflected in each quarterly PTC.

Education. PECO is proposing to include customer education costs associated with the new TOU Rates in the PTC. In addition, costs associated with educating customers about retail market enhancements not paid for by EGSs may be included in the PTC. The PTC does not include costs associated with educating customers about the benefits of shopping for electricity, which are recovered from all distribution service customers.

Regulatory and Tariff Filings. PECO includes the direct costs incurred for litigation of its default service proceedings in the PTC. Other regulatory and tariff filing costs associated with PECO's default service (e.g., the quarterly filing of PECO's updated PTC) are de minimis and not separately tracked.

12. Q. Mr. Kavulla argues that PECO is improperly omitting certain A&G expenses from its PTC, such as those associated with PECO employees and executives that may spend time on issues related to default service. Do you agree?

A. No. The Company's allocation of A&G expenses is appropriate and consistent with prior allocations that have been approved by the Commission. When A&G expenses are incurred to fulfill the Company's default service obligations, such as costs for the independent evaluator and external consultants, those costs are included in the PTC.

13. Q. Mr. Kavulla contends that PECO's allocation of certain administrative and overhead costs to distribution rates instead of the PTC makes it difficult for EGSs to "compete" with the PTC. Please respond.

A. Default service is not an area in which PECO seeks to "compete" with EGSs or any other entity. The Company is required to be able to provide default service to all of its distribution customers under Pennsylvania law and the Orders of this Commission, regardless of whether the customers shop or do not shop for electricity. PECO makes no profit from providing default service to its distribution customers or standing ready to serve those customers who return to default service after shopping with an EGS. As I have noted previously, the Commission has repeatedly affirmed that PECO's PTC appropriately recovers the costs of default service and that PECO's distribution rates appropriately recover distribution costs.

14. Q. Mr. Kavulla argues that PECO's cost allocations are inconsistent with "industry guidance" and that the improper allocation of costs to distribution is demonstrated by the fact that default service programs like PECO's would be "bankrupt in a matter of days, if not hours, if it was removed from the distribution business." Do you agree?

A. No. PECO's PTC is designed to be consistent with statutory, regulatory and policy requirements specific to default service in Pennsylvania. The quoted NARUC Guidelines cited by Mr. Kavulla simply do not apply to the Company's provision of default service because they address cost allocation in the context *of affiliate transactions*. Despite Mr. Kavulla's hypothetical thought experiment intended to frame default service as a separate business, the reality is that PECO provides default service *as part of* its distribution company obligations. Finally, because PECO is not permitted to make any profit from default service, its provision of default service obviously would not function on a standalone basis. As the Commission noted in the *2018*

Distribution Rate Order (p. 5): "The PTC does not determine the level of costs that would equal an EGS's costs for like services."

15. Q. Mr. Kavulla recommends a multi-step process to modify PECO's rate design and "facilitate the recovery of all costs associated with default service through default service rates, as required by the Commission's regulations." As part of that process, he further recommends that PECO propose new allocators for administrative costs. Please respond.

A. No rate design modifications are necessary. PECO's PTC is already consistent with applicable law and Commission requirements. As I have previously explained, the Company's allocation of costs between default service and distribution service was recently approved by the Commission, and affirmed by the Commonwealth Court,[8] after the presentation of detailed evidence about PECO's cost of service, including administrative costs. The allocations made by the Company in this proceeding to develop the PTC are consistent with the prior Commission-approved allocations. Notably, Mr. Kavulla is unable or unwilling to propose any "reasonable or appropriate allocators" to transfer additional costs to the PTC.

[8] *NRG Energy, Inc. v. Pa. P.U.C.*, 58 C.D. 2019 (June 2, 2020).

III. SEMI-ANNUAL RECONCILIATION OF GENERATION SUPPLY ADJUSTMENT OVER/UNDER COLLECTIONS

16. Q. Mr. Bisti, in your direct testimony, you explained that PECO is proposing to continue to reconcile the over/under collection component of the GSA known as the "E-Factor" for all procurement classes. Have any parties taken issue with that proposal?

A. Yes. OCA witness Estomin supports semi-annual reconciliation of the GSA E-Factor for residential default service customers, but recommends that any over/under collections be based upon a twelve-month reconciliation period instead of the six-month period proposed by PECO. In light of PECO's proposal to introduce TOU default service options, Mr. Estomin argues that a longer reconciliation period will reduce the variability of residential default service rates arising from over/undercollection of those costs.

17. Q. Does PECO agree with Mr. Estomin's recommendation to use a twelve-month reconciliation period?

A. No. In the Company's second default service proceeding, the Commission rejected PECO's proposal to reconcile GSA over/undercollections on an annual basis (with a twelve-month refund/recovery period), citing concerns about the clarity of price signals from the PTC of which the GSA is a component, and underlying wholesale supply costs.[9] The Commission also denied PECO's proposed annual reconciliation as part of the Company's CAP shopping plan proposed in 2013, observing: "[W]e are not inclined to

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9 *See DSP II Order*, p. 56.

exacerbate the effect that the reconciliation of the GSA has on the sensitivity of the PTC by extending the reconciliation period to a full year."[10]

In light of these decisions, the Company proposed a six-month reconciliation period for all default service procurement classes in PECO's last two default service proceedings. In its final Orders issued in those proceedings, the Commission concluded that this semi-annual reconciliation would be beneficial to customers.[11] PECO believes that its proposed six-month reconciliation period continues to benefit customers and appropriately balances the Company's goal of mitigating volatility with the Commission's concern about maintaining the PTC as a price signal for customers and EGSs. In addition, Mr. Estomin has not provided any analysis or other evidence supporting his conclusion that annual reconciliation could provide more stable rates. Mr. Estomin further clarified through discovery that he is not suggesting that an adoption rate of PECO's TOU Rates greater than 1% would necessarily lead to higher over/under collection balances.[12]

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[10] *See Petition of PECO Energy Co. For Approval Of Its Default Serv. Program II,* Docket No. P-2012-2283641 (Order entered Jan. 24, 2014) ("*2014 CAP Shopping Order*"), p. 45.

[11] *See Petition of PECO Energy Co. For Approval Of Its Default Serv. Program For the Period From June 1, 2015 through May 31, 2017,* Docket No. P-2014-2409362 (Opinion and Order entered Dec. 4, 2014), p. 25; *Petition of PECO Energy Co. For Approval Of Its Default Serv. Program For the Period From June 1, 2017 through May 31, 2021*, Docket No. P-2016-2534980 (Opinion and Order entered Dec. 8, 2016), p. 35.

[12] A copy of the OCA's response to Interrogatory PECO (OCA) I-4 is attached to my rebuttal testimony as Exhibit JAB-1R.

IV. TIME-OF-USE RATE OPTIONS

18. Q. ESC witness Kavulla objects to the voluntary, "opt-in" nature of the TOU Rates and contends that the Commission should approve the TOU Rates as the standard default service rate for the Residential and Small Commercial Classes to promote "effective use" of PECO's smart meter investments and market-reflective pricing. Please respond.

A. As the Commission has recognized, Act 129 of 2008 ("Act 129") makes clear that an EDC's TOU program should be optional for default service customers.[13] PECO believes that its proposed voluntary TOU default service rate options and the competitive retail market are the appropriate structures to optimize the Company's smart meter investments required under Act 129 and reasonably balance customer risk mitigation with market-based pricing.

19. Q. Please respond to Mr. Kavulla's contention that PECO has a statutory obligation to offer a real-time price plan, along with the TOU Rates, to residential and small commercial default service customers with smart meters.

A. With the combination of PECO's proposed TOU Rates and the hourly-priced default service rate for the Consolidated Large Commercial and Industrial Class, a TOU or real-time pricing program will be available to all of the Company's default service customers with smart meters. Mr. Kavulla has provided no support for his conclusion that Act 129 requires PECO and other

[13] *See Investigation into Default Serv. and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-3007101 (Secretarial Letter issued Jan. 23, 2020), p. 6. Act 129 provides that "[r]esidential or commercial customers *may* elect to participate in time-of-use rates or real-time pricing." 66 Pa.C.S. § 2807(f)(5) (emphasis added).

default service providers to propose, implement, and offer both TOU rates and real-time pricing for all default service customers simultaneously.

20. Q. Mr. Kavulla also suggests that the Commission should require PECO to implement supplier consolidated billing ("SCB") in conjunction with the TOU Rates. Do you agree?

A. No. Over the past several years, the Commission has considered the legal and public policy issues raised by SCB and declined to proceed with implementation. Most recently, the Commission rejected a petition by NRG to implement its version of SCB for EGSs.[14] In the *NRG SCB Order* (p. 60), the Commission recognized that pivotal questions remained unanswered, including the legality of SCB under Chapters 14 and 29 of the Public Utility Code, the risk of harm to customers and the level of interest in SCB in the EGS community.

After denying the NRG petition for SCB, the Commission convened an en banc hearing in May 2018 to continue its review of SCB issues. Numerous stakeholders filed extensive comments following the en banc hearing that are pending Commission review at Docket No. M-2018-2645254. Mr. Kavulla simply repackages various prior arguments in support of SCB from NRG's 2016 petition and the 2018 en banc hearing that the Commission is already considering in the stand-alone SCB proceedings. As such, the Commission should not address ESC's SCB proposal in this proceeding.

[14] *See Petition of NRG Energy, Inc. for Implementation of Elec. Generation Supplier Consol. Billing*, Docket No. P-2016-2579249 (Order entered Jan. 31, 2018) (the "*NRG SCB Order*").

In addition, Mr. Kavulla has provided no evidence to support his conclusion that implementation of PECO's TOU Rates without SCB will harm the competitive market for time-varying products. Contrary to Mr. Kavulla's assertion that EGSs face challenges in offering TOU rates because they are "without the ability to bill [their] customers directly," EGSs may offer and bill TOU products and services to customers through dual billing.

21. Q. Please describe and respond to the changes to customer eligibility for PECO's TOU Rates proposed by ESC and CAUSE-PA.

A. ESC objects to excluding CAP customers from PECO's TOU Rates. As explained by Ms. Reilly in her rebuttal testimony, PECO recently proposed a change to its current CAP design to provide a percentage of income-based benefit to CAP customers instead of a fixed credit. In light of the impact of PECO's underlying CAP design on the CAP customer's evaluation of the potential value proposition of a TOU rate option, PECO believes it is appropriate to exclude CAP customers from the TOU Rates at this time. Notably, the Commission found that the recent settlement regarding PPL Electric Utilities Corporation's ("PPL's") TOU program implemented pursuant to Act 129 was in the public interest because, among other things, the eligibility exclusion of CAP customers "protects low-income customers" by ensuring that vulnerable customers are not exposed to "potential rate volatility" associated with TOU rates.[15]

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[15] *Proceeding Initiated to Comply with Directives Arising from the Commonwealth Court Order in DCIDA v. PUC, 123 A3d 1124 (Pa. Cmwlth 2015) Reversing and Remanding the Order of the Comm'n Entered Sept.*

In contrast to ESC, CAUSE-PA witness Geller supports the exclusion of CAP customers from PECO's TOU Rates, but proposes additional protections for all low-income customers and customers with known medical usage. Specifically, Mr. Geller proposes that PECO conduct targeted and personalized outreach to vulnerable households seeking to enroll in PECO's TOU Rates about available universal service programs prior to enrollment. As part of such outreach, Mr. Geller recommends that PECO provide a customized bill impact assessment based on the household's actual usage patterns over the prior year to inform the customer's decision to voluntarily enroll in the Company's TOU Rates.

While PECO recognizes CAUSE-PA's concern regarding the potential impact of PECO's TOU Rates on vulnerable customers who may not have the ability to shift their electric usage throughout the day, the additional level of outreach proposed by Mr. Geller would add administrative complexity and cost. Mr. Geller's recommendations would require PECO to screen and verify the household income and medical usage of every customer interested in the optional TOU Rates. Mr. Geller's belief that such information is already contained in PECO's system and therefore does not require "active screening"

22, 2014 at Docket Number P-2013-2389572 in which the Comm'n had Approved PPL's Time of Use Plan, Docket Nos. M-2016-2578051 et al. (Recommended Decision issued Apr. 2, 2018) ("PPL TOU Recommended Decision"), p. 25. The Commission adopted the PPL TOU Recommended Decision without modification by Order entered on May 17, 2018.

is inaccurate.[16] Mr. Geller's proposal will also delay TOU rate enrollments, which could discourage customers from participating.

22. Q. Mr. Bisti, in your direct testimony, you explained that PECO's proposed TOU Rates differentiate prices across three periods that remain constant year-round based on price multipliers designed to motivate shifting of usage from the higher-cost peak period to lower-cost off-peak periods. Do any parties propose changes to PECO's proposed TOU price multipliers?

A. Yes. The OCA recommends that PECO use the proposed TOU pricing multipliers for the first year of the DSP V term, but then apply a recalculated set of multipliers for each successive year using an updated five-year rolling average of PJM Day-Ahead Spot Market data for the PECO Zone to reflect current market conditions.

23. Q. Does PECO believe that Mr. Estomin's proposal to update the TOU price multipliers annually is necessary?

A. No. The TOU price multipliers that PECO proposes for the DSP V term are simple in design and consistent with the Commission's guidance in the April 2017 Secretarial Letter (p. 3) for such multipliers to appropriately motivate shifting of consumption from on-peak to off-peak periods. Mr. Estomin has not provided any empirical evidence that the use of five-year rolling average spot market pricing data will result in significant changes to PECO's proposed

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[16] A copy of CAUSE-PA's response to Interrogatory PECO (CAUSE-PA) I-4 is attached to my rebuttal testimony as Exhibit JAB-2R.

TOU price multipliers. In addition, Mr. Estomin's proposal to update PECO's TOU price multipliers may lead to on-peak/off-peak price differentials that are insufficient to incentivize customers to take action to change their consumption.

24. Q. Do you believe that PECO must perform a cost-benefit analysis in order for the Commission to approve the TOU Rates, as suggested by Mr. Rábago on behalf of the Environmental Stakeholders?

A. No. As explained in my direct testimony, PECO's proposed TOU rate design incorporates the Commission's guidance on EDC TOU rate structures to satisfy Act 129 requirements,[17] implements lessons learned from the PECO Smart Time Pricing Pilot and balances a variety of objectives, including simplicity and the value proposition for enrollment. I note that, in discovery, PECO requested that Mr. Rábago identify electric utilities that have performed cost-effectiveness evaluations before implementing opt-in TOU generation rates. Mr. Rábago did not provide any examples to support his assertion.[18] Indeed, the Commission recently approved PPL's voluntary TOU default service rate options without requiring the pre-implementation benefit-cost analysis Mr. Rábago proposes.[19]

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[17] *Petition of PPL Elec. Utils. Corp. for Approval of a New Pilot Time-of-Use Program*, Docket Nos. P-2013-2389572 and M-2016-2578051 (Secretarial Letter issued Apr. 6, 2017) ("April 2017 Secretarial Letter").

[18] A copy of the Environmental Stakeholder's response to Interrogatory PECO (ES) I-23 is attached to my rebuttal testimony as Exhibit JAB-3R.

[19] *See* PPL TOU Recommendation Decision, pp. 17-18, 21-25.

25. Q. Mr. Rábago also recommends that the Commission require PECO to use a benefit-cost analysis framework to develop proposals for TOU rate pilots directed at building and transportation electrification opportunities. Do you agree?

A. No. With respect to building electrification, Mr. Rábago states that the best examples of opportunities involve distributed generation, dispatchable heat pump water heaters, and behind-the-meter battery storage systems. Each of these technologies is fully programmable and able to use PECO's proposed TOU rate. While Mr. Rábago suggests that PECO should undertake a benefit-cost analysis to develop alternative TOU rates for these technologies, he offers no specific details as how PECO's proposed rates should be modified. Similarly, he does not offer any alternative rate design to support his suggestion that PECO's TOU rates will not be beneficial for increased electrification of larger vehicle fleets.

I note that in the area of transportation electrification, PECO is a supporter of House Bill 1446, which sets a goal of increasing transportation electrification in Pennsylvania 50% by 2030. A version of this legislation was passed by the Pennsylvania Senate at the end of 2019. If enacted, PECO will be working closely with stakeholders outside this proceeding to develop a comprehensive transportation electrification plan for its service territory to support a public access electric vehicle charging network and increased electrification of public transit, school bus, port, freight, rail and airport infrastructure. As part of that process, PECO anticipates investigating a variety of additional rate structures.

26. Q. Mr. Kavulla contends that PECO should develop a more "robust" communications plan and "realistic" implementation timeframe for the TOU Rates. How do you respond?

A. The projected costs and timeline for implementation of PECO's TOU Rates are preliminary estimates based on its proposed TOU rate design and Company experience.[20] While PECO has not yet developed a detailed TOU-related communications and implementation plan, I believe that these estimates are reasonable. Mr. Kavulla has not offered any specific implementation budget and time horizon that he believes is appropriate for PECO's TOU Rates, other than an undefined "adjustment" to Southern California Edison's ("SCE's") efforts to transition its residential electric customers to default TOU rates.[21]

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[20] The $900,000 budget referenced in Mr. Kavulla's direct testimony is not just for PECO's TOU-related communications plan, as Mr. Kavulla suggests. *See* ESC St. No. 1, p. 21, lines 17-19. That budget is PECO's preliminary estimate of total operating and maintenance expenses to implement the TOU rates.

[21] *See* ESC's response to Interrogatory PECO (ESC) I-20, which is attached to my rebuttal testimony as Exhibit JAB-4R. SCE's most recent progress report on the transition to default TOU rates indicates that SCE incurred default TOU-related operating expenses totaling approximately $6.6 million from 2016 through the first quarter of 2020. *See Southern California Edison Company's (U 338-E) Nineteenth Quarterly Report on Progress of Residential Rate Reform*, CPUC Docket No. R.12.06-013 (filed May 1, 2020), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M335/K842/335842358.PDF, p. A-12.

27. Q. Has PECO considered CAUSE-PA's recommendation for PECO to track TOU customers' demographic information and assess the impact of PECO's TOU Rates on low-income and other vulnerable customers?

A. Yes. PECO will agree to evaluate the impacts of the Company's TOU Rates on confirmed low-income customers as part of the annual report required by Act 129. To assist in the preparation of the annual report, PECO will agree to track TOU customers' income and demographic information (e.g., age, race, ethnicity and disability status). However, customers who refuse to disclose this information will not be precluded from enrolling in PECO's TOU Rates.

28. Q. ESC witness Kavulla contends that PECO's TOU-related capital costs recovered under the GSA should include the amortization of such investments over the DSP V term along with a return on the unamortized balance. How do you respond?

A. The Company's proposal to recover TOU-related implementation costs, including capital investments, over the DSP V term as an operating expense for ratemaking purposes is consistent with the Commission's directive regarding recovery of capital costs through the GSA in the DSP II Order (pp. 63-64).

29. Q. Does PECO agree with OSBA witness Kalcic's recommendation that the Company allocate all of its TOU-related implementation costs to the eligible procurement classes based on number of customers instead of on a kWh basis?

A. Yes. PECO agrees with Mr. Kalcic that the costs the Company incurs to implement its TOU Rates are customer-related and will allocate those costs based on the total number of customers in the Residential and Small Commercial Classes, regardless of whether they are taking default service.

V. RECOVERY OF DEFAULT CUSTOMER ASSISTANCE PROGRAM SHOPPING PLAN IMPLEMENTATION COSTS

30. Q. Mr. Bisti, OCA witness Alexander and CAUSE-PA witness Geller argue that CAP Shopping Plan implementation costs should be recovered entirely from EGSs. Do you agree?

A. No. The Company continues to support its original proposal to recover Plan implementation costs (exclusive of customer education costs) from residential customers in a subsequent base rate case, consistent with the Commission's determination in the *2014 CAP Shopping Order* (pp. 40-41).

VI. CONCLUSION

31. Q. Does this conclude your rebuttal testimony?

A. Yes.

PECO Exhibit No. JAB-1R

Response of the Office of Consumer Advocate to the Interrogatories of PECO Energy Company Set I in Docket No. P-2020-3019290

Request: PECO-OCA-I-4.

Reference OCA Statement No. 1, p. 15, lines 1-5.

Please set forth the factual basis, including all studies, workpapers (with formulas intact), analyses, documents and information relied upon, for Mr. Estomin's statement that the impact on the reconciliation adjustment of TOU average rates deviating from the PTC becomes greater than negligible above 1%.

Response:

Assuming that the intended page reference to OCA Statement No. 1 is page 19 rather than page 15, the request appears to be predicated on a misinterpretation of the referenced testimony. The referenced testimony reads:

> If TOU rate participation is low, for example, one percent or less, … the impact on the reconciliation adjustment of TOU average rates deviating from the PTC can be anticipated to be negligible. Higher levels of participation in TOU rates, however, could result in higher reconciliation adjustments.

The testimony, alternatively stated, says that low TOU participation (e.g. less than one percent) would entail a negligible impact on the reconciliation adjustment. With higher levels, a higher reconciliation adjustment could be expected. No "bright line" is drawn in the referenced testimony that suggests any participation above one percent, regardless of how marginal, will necessarily result in reconciliation impacts that are, as is characterized in PECO request PECO-OCA-I-4, "greater than negligible."

Response prepared by: Steven Estomin

PECO Exhibit No. JAB-2R

PECO Default Service Plan Proceeding
Docket P-2020-3019290

Interrogatory Responses of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA) to PECO Energy Company, SET I

PECO-CAUSE-PA-I-4. Reference CAUSE-PA Statement No. 1, p. 25, line 21, through p. 26, line 5.

a. Is it CAUSE-PA's position that customers who refuse to disclose the income and demographic information identified in the referenced statement should be ineligible to participate in the TOU rate options? Please explain your answer.

b. Please explain whether TOU participants will be required to provide updated income and demographic information on a periodic basis to remain on TOU rates.

c. Please explain whether Mr. Geller's proposed data collection requirements apply to all members of the household or solely to the TOU participant.

Response:

(a) No, provided consumers who refuse the information are informed that the reason PECO is requesting the information is to inform the consumer about the availability of affordability programs, to help them understand the projected bill impact of TOU rates, and to study the impact of the new rates.

(b) Mr. Geller is not recommending periodic updates to income or other demographic information, except to the extent needed to perform an analysis of the TOU as recommended in Mr. Geller's testimony

(c) PECO should attempt to collect data on a household level, as it will be of little value to study the impact of TOU on household members without information about household demographics.

Respondent: Harry Geller

Date: June 30, 2020

PECO Exhibit No. JAB-3R

Pennsylvania Public Utility Commission
v.
PECO Energy Company

Petition of PECO Energy Company for Approval of
Default Service Program

Docket No. P-2020-3019290

Response of Environmental Stakeholders
to Interrogatories of PECO Energy Company
PECO-ES Set I.
Response Date: 06/29/2020

PECO-ES-I-23

Reference ES Statement No. 1, p. 32, lines 21-22 and p. 37, lines 7-8. Please identify and provide all ex ante benefit-cost analyses of voluntary, generation-only residential and small commercial TOU rate proposals performed by or on behalf of United States electric utilities of which the Environmental Stakeholders are aware.

RESPONSE

Mr. Rábago has no records in his possession meeting the description of the requested analyses. Mr. Rábago's experience over the past 30 years in the electric utility regulatory field is that utility-proposed rates and rate pilots are typically accompanied by estimates of the costs, savings, and bill impacts that are anticipated to result from the proposed rate or pilot program.

Responsible Witness: Karl Rábago

PECO Exhibit No. JAB-4R

Response of the Electric Supplier Coalition
to the Interrogatories of PECO Energy Company, Set I in
Docket No. P-2020-3019290

Request: PECO-ESC-I-20 Reference ESC Statement No. 1, p. 21, line 21, through p. 22, lines 1-3. Please describe in detail the implementation budget and time horizon that Mr. Kavulla believes is appropriate for PECO's proposed TOU rate options.

Response:

As noted in Mr. Kavulla's testimony, PECO's proposal should be modified in accordance with both Pennsylvania legal requirements and sound public policy. Assuming that those modifications occur, the Southern California Edison program that Barbara Alexander references, on page 22, footnote 52, of Mr. Kavulla's Direct Testimony, provides a guide for a reasonable expenditure, both because SCE has certain of the same 'default provider' features that PECO does. Mr. Kavulla suggests an appropriate adjustment be applied given PECO's smaller customer count.

Response provided by: Travis Kavulla

Date: June 29, 2020

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS DEFAULT SERVICE PROGRAM FOR THE PERIOD FROM JUNE 1, 2021 THROUGH MAY 31, 2025	:	**Docket No. P-2020-3019290**

VERIFICATION

I, Joseph A. Bisti, hereby state that I am a Principal Regulatory and Rates Specialist for PECO Energy Company; that I am authorized to and do make this Verification for it; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 2
- PECO Statement No. 2-R
- PECO Exhibit No. JAB-1
- PECO Exhibit No. JAB-2
- PECO Exhibit No. JAB-3 (corrected)
- PECO Exhibit No. JAB-4
- PECO Exhibit No. JAB-5
- PECO Exhibit No. JAB-6
- PECO Exhibit No. JAB-7
- PECO Exhibit No. JAB-8
- PECO Exhibit No. JAB-9
- PECO Exhibit No. JAB-10
- PECO Exhibit No. JAB-1R
- PECO Exhibit No. JAB-2R
- PECO Exhibit No. JAB-3R
- PECO Exhibit No. JAB-4R

Joseph A Bisti

Dated: July 30, 2020

Joseph A. Bisti

PECO ENERGY COMPANY
STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-________________

DIRECT TESTIMONY

WITNESS: CAROL REILLY

SUBJECTS: CUSTOMER ASSISTANCE PROGRAM
SHOPPING PLAN AND RETAIL MARKET
ENHANCEMENTS

DATED: MARCH 13, 2020

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DIRECT TESTIMONY
OF
CAROL REILLY

I. INTRODUCTION AND PURPOSE

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

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

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Manager of Energy Acquisition Operations. In that capacity, I am responsible for the administration of PECO's retail electric generation supplier ("EGS") and natural gas supplier coordination functions as they relate to electric and natural gas choice. I have been performing these functions since 2007.

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

A. I earned a Bachelor of Science in Electrical Engineering from Widener University in 1992.

I have been employed by PECO and/or Exelon Corporation since 1997. Over that period, I have held engineering, analytical, and management positions in the areas of generation and transmission planning, in addition to my current responsibilities described above.

Prior to joining PECO, I was employed by Delmarva Power & Light Company from 1992 to 1997, where I held positions in the PJM Interconnection and Gas Planning departments.

4. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is twofold. First, I will describe PECO's plan ("Plan") to facilitate shopping for electric generation supply by PECO customers enrolled in the Company's Customer Assistance Program ("CAP"). PECO developed its Plan in compliance with the guidelines set forth in the Policy Statement on Electric Customer Assistance Program Participant Shopping proposed by the Pennsylvania Public Utility Commission ("Commission" or "PUC") on February 28, 2019.[1] Second, I will discuss continuation of PECO's EGS Standard Offer Program ("Standard Offer Program" or "SOP") as a retail market enhancement during PECO's fifth default service program ("DSP V").

5. Q. How is your testimony organized?

A. I will first explain the design of PECO's Plan, including (i) provisions for EGS offers to CAP customers for competitive generation supply; (ii) EGS billing for CAP customers; (iii) the CAP customer enrollment process; and (iv) CAP customer education initiatives. I will also outline proposed revisions to PECO's EGS Coordination Tariff ("Supplier Tariff") necessary to implement the Plan. Finally, I will describe PECO's proposal to continue the SOP, without modification, during the DSP V term.

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[1] *Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping*, Docket No. M-2018-3006578 (Proposed Policy Statement Order entered Feb. 28, 2019) ("Proposed Policy Statement Order").

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

A. Yes. PECO Exhibits CR-1 to CR-4 were prepared at my direction and under my supervision and are described in detail in my testimony.

II. DESIGN OF PECO'S CUSTOMER ASSISTANCE PROGRAM SHOPPING PLAN

7. Q. Ms. Reilly, please describe PECO's current CAP program for electric customers.

A. In accordance with the universal service obligations set forth in the Public Utility Code, PECO's CAP assists low-income customers in PECO's service territory through discounted energy bills. PECO's CAP is a special rate rider for customers with an annual household gross income level at or below 150% of the poverty level as established by federal law. Approximately 111,000 residential customers in PECO's service territory – almost 7% of all PECO residential electric customers – participate in CAP.

In October 2016, PECO transitioned from a tiered rate discount CAP structure to a new Fixed Credit Option ("FCO") design. Under this approach, CAP customers receive a fixed bill credit each year for the utility service they receive based on the income of the customer's household, the number of residents in the household and the utility usage of the household in the prior year. The CAP credit is designed to help ensure that the energy "burden" – the cost of electricity in proportion to household income – is affordable for CAP customers based on poverty level. PECO calculates the CAP credit amount by taking the sum of the CAP customer's actual undiscounted bills over the last twelve months ("Base

Charges") and subtracting the reduced CAP bill amount based on ability to pay ("CAP Payment"). The CAP customer's maximum household payment contribution for total electric home energy is calculated as a percentage of income (ranging from 3% to 17%) and converted to a percentage of the annual bill (the "Allowable Energy Burden"). For each CAP customer, the CAP Payment is determined by multiplying the Base Charges by the Allowable Energy Burden.

A portion of the dollar amount of the aggregate bill credits provided to CAP customers each year is recovered through base rates, and any shortfall is recovered from all residential customers through PECO's Universal Service Fund Charge ("USFC").

8. Q. Are PECO CAP customers now able to shop for electric generation supply?

A. No. However, in accordance with the Commission's direction in its Proposed Policy Statement Order, PECO has developed the Plan to facilitate shopping by CAP customers during DSP V.

9. Q. Please describe the Commission's guidance, which the Company used in designing its Plan to facilitate shopping by PECO CAP customers.

A. In the Proposed Policy Statement Order, the Commission outlined uniform CAP shopping policies and requirements for Pennsylvania electric distribution companies ("EDCs"). The CAP shopping requirements include (1) a CAP shopping product rate at or below the EDC's Price-to-Compare ("PTC") for the duration of the contract; (2) a prohibition in EGS-CAP customer contracts against fees unrelated to the provision of electric generation service, including early termination and cancellation fees; and (3) the following options for CAP customers upon expiration of the current contract period: enter into another contract with their existing EGS with the same CAP protections, switch to another supplier offering a contract with the same CAP protections, or return to default service.[2]

By Secretarial Letter on January 23, 2020, the PUC acknowledged that its proposed CAP shopping policy statement was "unlikely to be final and effective in time for some upcoming DSP proceedings."[3] The Commission therefore directed all EDCs to consider the Commission's prior guidance in the Proposed Policy Statement Order and recent decisions in previous default service proceedings in developing CAP proposals for upcoming DSP filings.[4]

10. Q. Is PECO's Plan consistent with the guidelines provided in the Proposed Policy Statement Order?

A. Yes. Under PECO's Plan, EGSs must charge CAP customers a rate for generation service that is at or below the PECO residential PTC at all times during the contract. Consistent with the Proposed Policy Statement Order, this limitation

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2 Proposed Policy Statement Order, pp. 5, 9-10.

3 *Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-3007101 (Secretarial Letter issued Jan. 23, 2020) ("January 2020 Secretarial Letter").

4 *See Petition of PPL Elec. Utils. Corp. for Approval of a Default Serv. Program for the Period June 1, 2017 through May 31, 2021*, Docket No. P-2016-2526627 (Opinion and Order entered Oct. 27, 2016), *aff'd by*, *Retail Energy Supply Ass'n v. Pa. Pub. Util. Comm'n*, 185 A.2d 1206 (Pa. Cmwlth. Ct. 2018); *Petition of Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania Power Co., West Penn Power Co. for Approval of a Default Serv. Program for the Period Beginning June 1, 2019 through May 31, 2023*, Docket Nos. P-2017-2637855, P-2017-2637857, P-2017-2637858, and P-2017-26378566 (Opinion and Order entered Sept. 4, 2018) ("September 2018 Order"), pp. 58-59. On February 28, 2019, the Commission entered a Final Order ("FirstEnergy DSP V Order") adopting rules and procedures for the CAP shopping program approved in the September 2018 Order and revising the EDCs' standard offer customer referral program scripts.

on rates is intended to promote shopping and access to the competitive market for CAP customers without undermining the affordability of utility service for those customers or increasing the USFC costs paid by PECO residential customers.

Also in accordance with the Proposed Policy Statement Order, EGSs serving CAP customers may not enter into contracts that impose early cancellation and termination fees or other fees unrelated to generation service. This prohibition ensures that the overall rate charged to a CAP customer does not exceed PECO's PTC.

11. Q. Are EGSs in PECO's service territory required to serve CAP customers?

A. No. An EGS serving residential customers in PECO's service territory will have the opportunity, but not the obligation, to provide generation service to CAP customers. An EGS that wishes to serve CAP customers (a "CAP Supplier") must submit a notice of intent to participate as a CAP Supplier (a "CAP Notice"), in the form attached as PECO Exhibit No. CR-1, to the Company's Electric and Gas Choice department. Similarly, a CAP Supplier must submit a CAP Notice of its intention to discontinue offering CAP shopping products. The effective date of the CAP Notice will be the first day of the calendar month at least ten days after submission. EGSs that execute a CAP Notice must agree to comply with all Plan requirements, including pricing limitations for CAP customers.

12. Q. Is PECO proposing any other obligations for EGSs who choose to serve CAP customers?

A. Yes. CAP Suppliers must use PECO's "bill-ready" EDC consolidated billing option for CAP customers, which will ensure that CAP customer benefits are properly applied to their bill. It will also allow PECO to meet its ongoing obligations to the Commission with respect to universal service programs, including reporting on cost effectiveness and affordability. In addition, an EGS offering a current rate to CAP customers must post that rate on the Commission's PAPowerSwitch.com shopping website and also provide it to a customer after a customer request via EGS call centers. Through those mechanisms, CAP customers will be able to shop more effectively for available rates, supported by customer education activities.

13. Q. Please describe the enrollment procedure for CAP customers who accept a CAP Supplier's competitive offering.

A. The customer enrollment process for CAP customers will be the same as for non-CAP customers. An EGS seeking to enroll a CAP customer will submit an enrollment request via the appropriate Electronic Data Interchange ("EDI") transaction for the CAP customer consistent with PECO's current Supplier Tariff and Electric Data Exchange Working Group protocols.

In accordance with the Commission's regulations at 52 Pa. Code § 57.173(2), PECO will send a letter confirming the CAP customer's request to switch to the EGS that submitted the enrollment request. PECO will continue its current practice of designating the effective date for the change in the customer's supplier, the name of the selected EGS and the date PECO may issue the first bill showing the new EGS charges.

As explained earlier in my testimony, CAP Suppliers must agree in advance to comply with the Plan's CAP rate protections by way of a CAP Notice. Therefore, EGSs that submit a CAP enrollment without first submitting a CAP Notice will be rejected.

14. Q. How will EGSs identify CAP customers and tailor products and service options for those customers in accordance with the Plan?

A. PECO's existing EDI 814 protocol includes data elements that identify PECO's CAP customers. Specifically, PECO's information technology system includes two unique rate codes – UD8 (Electric Residential Service CAP) and UB8 (Electric Residential Heating CAP) – that identify CAP customers in EDI transactions. In response to an EGS enrollment request, PECO electronically transmits a file that contains customer account information, including the customer's tariff rate and rate code. PECO will provide notice, via an EDI 814C transaction, when existing EGS customers enroll in or leave CAP ("CAP Change Notice").

Upon implementation of the Plan, CAP customers will also be included on PECO's Eligible Customer List ("ECL") posted on SUCCESS, the Company's supplier coordination website. PECO's ECL is updated monthly in accordance with Commission guidelines, and the UD8 and UB8 rate codes will be included in the CAP customer's rate code field. In addition, timely and accurate information regarding a customer's CAP status is also available through PECO's Advanced Meter Data Portal and to EGSs that submit a historical usage request prior to an enrollment request.

15. Q. Does PECO's current PTC filing schedule support EGS price adaptation to the PTC, which changes each quarter?

A. Yes. PECO files its residential PTC forty-five days before the effective date, which provides ample time for EGSs to develop CAP products, calculate any change to a currently offered CAP rate, and provide notice to existing CAP customers of any rate change. PECO will continue its current communication practices related to quarterly changes to the residential PTC, including publication of quarterly updates to the PTC on the Company's website and notification via a supplier bulletin. In addition, prior to implementation of the Plan, PECO will convene a supplier workshop to notify EGSs of the opportunity to serve CAP customers and will provide information regarding the Company's CAP Shopping Plan rules and procedures through PECO's supplier bulletins and SUCCESS portal.

16. Q. Ms. Reilly, please describe the contract expiration and change notice procedures under the Plan.

A. In accordance with the Proposed Policy Statement Order, a CAP customer will be subject to the following end-of-term options: renew the contract with his or her existing EGS at a new Plan-compliant CAP rate, switch to another supplier offering a Plan-compliant CAP rate or return to default service. If a CAP Supplier seeks to enter into a new agreement with a CAP customer at the end of the term or revise an existing contract consistent with the Plan's pricing restrictions, the CAP Supplier must comply with the Commission's notice regulations at 52 Pa. Code § 54.10. On the other hand, if an EGS elects to return a CAP customer to default service upon contract expiration or cancellation of the CAP customer's contract, the contract cancellation and notice provisions described in the EGS disclosure statement will apply. If the EGS disclosure does not address cancellation and notices, the EGS must provide at least one notice thirty days in advance of discontinuing service to the customer.

17. Q. Will an EGS be permitted to serve current customers who subsequently enroll in or leave CAP under the Plan?

A. Yes. An EGS may continue to serve existing customers who subsequently enroll in PECO's CAP if the EGS complies with the pricing restrictions and other terms set forth in the Supplier Tariff within two billing cycles of receipt of the Company's CAP Change Notice. If the existing EGS is not a CAP Supplier or otherwise elects to discontinue service to the customer in accordance with Section 14 of the Supplier Tariff, the customer will be transferred to default service, effective on the next meter read date after the CAP Change Notice.

If a CAP Supplier has entered into a contract with a CAP customer and subsequently receives a CAP Change Notice that the customer is no longer in the CAP, the EGS has two options. First, the CAP Supplier may elect to maintain the customer on the CAP rate until the end of the contract. Second, the CAP Supplier may discontinue service in accordance with the notice provisions set forth in

Section 14 of PECO's Supplier Tariff and the terms and conditions of the contract, just as with any other residential customer.

18. Q. Will PECO be responsible for monitoring and enforcing the Plan's limitations on EGS contracts under the Plan?

A. No. PECO's bill-ready systems do not provide information on the customer's EGS price necessary to monitor EGS compliance with the Plan pricing requirements. PECO also does not have a mechanism to determine if any of its CAP customers were subjected to early termination/cancellation or other additional fees. In fact, the Commission has previously determined that other EDCs do not have the responsibility to monitor compliance with limitations on EGS contracts with CAP customers because EDCs do not have access to EGS contracts.[5] PECO agrees that the Commission is the appropriate entity to monitor and enforce EGS compliance with the CAP shopping limitations set forth in the Proposed Policy Statement Order and under PECO's Plan.

19. Q. How will PECO calculate the fixed CAP credit amount if a CAP customer shops?

A. After Plan implementation, PECO will continue to calculate the CAP credit amount on a quarterly basis using a twelve-month look-back period for the Base Charges and CAP Payment. As a result, during the initial year that the CAP customer shops, the CAP credit will be calculated using PECO's PTC in effect for the twelve-month period being examined. Thereafter, the fixed bill credit for

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[5] *See* FirstEnergy DSP V Order, 2019 WL 1081029 at **6-7.

shopping CAP customers will be calculated based on EGS charges.[6] To the extent a CAP customer who shops receives a discount off PECO's PTC, the fixed credit amount would also be less than the amount for non-shopping CAP customers with the same Allowable Energy Burden.

20. Q. Please describe the customer education initiatives included in the Plan.

A. Customer education under the Plan will focus on the CAP rate protections that must be included in CAP customer-EGS contracts, as well as the impact of shopping on CAP benefits, and will provide tools to help CAP customers understand and manage their energy bills. First, PECO will modify its CAP care center scripts and training materials to inform CAP customers of their eligibility to shop with EGSs who are approved as CAP Suppliers. Similarly, PECO will modify its practices and procedures for community organizations engaged by PECO to assist in CAP customer enrollments. The Company will publish a list of CAP Suppliers on its website, which will be updated on a monthly basis. Second, PECO will revise its Consumer Education Plan mailings to explain that CAP Suppliers may not charge rates for generation service in excess of PECO's PTC and may not impose early cancellation/termination and other additional fees. In addition, PECO will promote CAP shopping through mailings, postcards, brochures, PECO press releases, PECO Universal Services web pages and existing CAP literature (i.e., CAP enrollment letter, etc.). The CAP customer education campaign will also include customer outreach efforts, web support,

[6] PECO will clarify the calculation of the CAP fixed credit level in a subsequent compliance filing based on the final CAP Shopping Plan design approved by the Commission.

community workshops and advocate-sponsored events for low-income customers. In addition, PECO will promote www.PAPowerSwitch.com as the central independent source of CAP Suppliers.

21. Q. Does PECO propose to extend the SOP to CAP customers?

A. No. The Company's existing SOP is not compatible with the Proposed Policy Statement Order requirement that an EGS always charge a price at or below the PECO PTC. Under the Commission-approved product design for the SOP, EGSs may offer residential customers a twelve-month product with a fixed price that is 7% below the PTC in effect at the time of the standard offer. Under the SOP, this fixed price product could exceed the PTC during the twelve-month term, depending on quarterly PTC fluctuations. As a result, CAP customers would have to be treated differently from other customers participating in the SOP to ensure that the CAP customer's standard offer rate does not exceed the PTC at any time during the twelve-month term of the contract.

22. Q. Has PECO estimated the cost to implement the proposed Plan?

A. Yes. The Company estimates the cost to implement the CAP Shopping Plan will be approximately $1.2 million based on PECO's proposed Plan design. PECO will incur two categories of costs in implementing the Plan. First, PECO will incur costs related to information technology ("IT") changes to its billing system to appropriately calculate CAP customer bill credits and changes and commensurate training for the customer information system to facilitate CAP shopping (approximately $0.7 million). The second category of expenditures is for CAP consumer education (approximately $0.5 million). Cost recovery is discussed by Mr. Joseph A. Bisti in PECO Statement No. 2.

23. Q. When will CAP customers be able to shop for electric generation supply?

A. PECO will require one year to implement the proposed Plan. The implementation period is necessary for the extensive IT system programming, testing and system integration required to implement the Plan.

Considering the projected expense and outreach to CAP customers, PECO proposes to begin the one-year implementation period after approval of the Plan and following receipt of CAP Notices from at least five EGSs. While CAP Notices are not binding, the receipt of at least five CAP Notices will ensure that there is verifiable supplier interest in serving CAP customers in PECO's service territory. PECO believes that demonstrated EGS interest in the form of CAP Notices is appropriate considering the limited number of EGSs willing to serve CAP customers in Pennsylvania.[7]

III. PROPOSED CHANGES TO THE ELECTRIC SUPPLIER TARIFF

24. Q. Ms. Reilly, please describe the Company's Supplier Tariff.

A. The Supplier Tariff sets forth the rights and obligations of PECO and EGSs providing generation service in PECO's service territory. The Supplier Tariff includes detailed provisions relating to billing options, load scheduling and other coordination services, EGS customer arrangements, data exchange, payment

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[7] *See* Comments of PPL Electric Utilities Corp., *Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping*, Docket No. M-2018-3006578 (filed July 30, 2019), pp. 4, 6-7, 11.

obligations, switching requests, discontinuance of service, charges for coordination services provided by PECO (e.g., load data supply), default, limitation of liability, and dispute resolution.

25. Q. Is PECO proposing any changes to the Supplier Tariff to implement CAP customer shopping?

A. Yes. PECO is proposing the following principal revisions to implement the CAP Shopping Plan:

- ***Restrictions on CAP Rates.*** Sections relating to EGS customer arrangements have been revised to provide that EGSs must charge the CAP customers they serve a rate that does not exceed PECO's PTC.

- ***Limitations on EGS-CAP Customer Contracts*****.** Sections relating to EGS customer arrangements have been revised to prohibit early cancellation/termination and other additional fees for CAP customers and to delineate the actions an EGS and CAP customer may take after the expiration of the contract term consistent with the PUC's Proposed Policy Statement Order.

- ***CAP Customer Billing.*** Sections relating to EGS customer arrangements have been revised to provide that EGSs must offer consolidated EDC billing for CAP customers in order to participate as a supplier to CAP customers in PECO's service territory.

These changes are shown in the clean and blacklined versions of PECO's Supplier Tariff attached to my testimony as Exhibits CR-2 and CR-3, respectively.

26. Q. Is PECO proposing any other revisions to its Supplier Tariff that are reflected in Exhibit CR-2?

A. Yes. PECO is proposing minor revisions to remove references to Rates OP and RT consistent with the Commission-approved settlement of PECO's 2010 electric rate case at R-2010-2161575.

27. Q. Has the Company submitted responses to the questions regarding changes to its Supplier Tariff required by the Commission's Regulations?

A. Yes. Exhibit CR-4 provides the Company's responses to the questions in 52 Pa. Code § 53.52(a).

IV. RETAIL MARKET ENHANCEMENTS

28. Q. Will PECO continue the Standard Offer Program that was first implemented as part of PECO's second default service program?

A. Yes. Since June 1, 2017, the Standard Offer Program has resulted in more than 26,000 residential customer and 500 small commercial customer referrals to EGSs that have voluntarily chosen to offer customers a twelve-month contract priced 7% below PECO's default service rate at the time of the offer.

PECO proposes to extend the program for the term of DSP V. An extension of the Standard Offer Program is consistent with the Commission's conclusion in its Final Order approving PECO's current default service program ("DSP IV") that continuation of the SOP was "beneficial" to all customers.[8] In the DSP IV proceeding, the Office of Consumer Advocate ("OCA") generally supported continuation of the SOP, but proposed several conditions regarding the presentation and marketing of the SOP to customers, including modifications to PECO's call handling process and revisions to SOP training materials and scripts. To address the OCA's concerns, PECO revised the scripts and training materials used by PECO and the third-party administrator of the SOP – Kandela[9] – to incorporate the specific disclosures agreed upon in the Commission-approved settlement of the DSP IV proceeding.

29. Q. Is PECO proposing revisions to its call center script initiating a transfer to Kandela?

A. No. The January 2020 Secretarial Letter (p. 10) directed EDCs to review SOP customer scripts in their upcoming DSP filings in light of the PUC's "most recent statement on SOP scripting" in the FirstEnergy DSP V Order (pp. 34-42). To that end, PECO reviewed its current SOP customer scripts produced from the settlement in DSP IV and concluded that the scripts reasonably present the opportunity to enroll in the SOP to customers and incorporate appropriate customer protections.

[8] *Petition of PECO Energy Co. for Approval of its Default Service Program for the Period from June 1, 2017 through May 21, 2021*, Docket No. P-2016-2534980 (Opinion and Order entered Dec. 8, 2016), p. 35.

[9] Allconnect previously served as the third-party administrator of PECO's SOP from the program's inception in 2013 to August 13, 2019.

V. CONCLUSION

30. Q. Does this conclude your direct testimony?

A. Yes.

NOTICE OF INTENT TO PARTICIPATE OR DISCONTINUE PARTICIPATION AS A CUSTOMER ASSISTANCE PROGRAM SUPPLIER

Electric Generation Supplier ("EGS") Name:		DUNS Number (One per EGS):	
Contact Name:		Title:	
E-mail:		Phone:	
Address:	City:	State:	Zip Code:

Please complete the appropriate box below and provide an effective date that is the first day of the calendar month at least ten days after the Notice of Intent to Participate or Discontinue Participation as a Customer Assistance Program Supplier ("CAP Notice") is transmitted to PECO Energy Company ("PECO") by electronic mail at egc@peco-energy.com.

Notice-of-Intent to **ENROLL** Customer Assistance Program ("CAP") customers beginning **MM/01/YEAR**	Notice-of-Intent to **DISCONTINUE** CAP products beginning **MM/01/YEAR**

The submission of this CAP Notice to PECO shall constitute the EGS's acknowledgement and acceptance of all the terms, conditions and requirements of the CAP Shopping Plan approved by the Pennsylvania Public Utility Commission (the "Commission" or "PUC") at Docket No. P-2020-________.

In order to provide generation service to PECO's CAP customers, the EGS agrees to be bound by the following terms:

1. The EGS must charge CAP customers a rate for generation service that is at or below the PECO residential Price-to-Compare at all times during the contract.
2. The EGS may not enter into contracts with CAP customers that impose early cancellation and termination fees or other fees unrelated to generation service.
3. The EGS must comply with all applicable PUC customer notification requirements.
4. The EGS must use PECO's "bill-ready" electric distribution company consolidated billing option for CAP customers.

The undersigned represents and warrants that he or she has the authority to act on behalf of, and to bind the EGS to perform the terms and conditions set forth herein.

Signature of Authorized Representative:	Date:
Name:	Title:

PECO ENERGY COMPANY

ELECTRIC GENERATION SUPPLIER COORDINATION TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

Issued: March 13, 2020 Effective: June 1, 2021

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

Provision for EGS Serving Customers Participating in PECO Energy Company's Customer Assistance Program ("CAP Customers") – x Revised Page No. 23
Reflects provisions regarding EGS arrangements with the Company's Customer Assistance Program customers for compliance with the Order at Docket No. P-2020-________ issued on _____, 2020.

Rule 6.6 Line Losses – X Revised Page No. 29 - Removal of references to retired rates RT and OP consistent with the Commission-approved settlement of PECO's 2010 electric rate case at R-2010-2161575.

Competitive Billing Specifications - Rule 10 - X Revised Page No. 93 - Removal of references to retired rate OP consistent with the Commission-approved settlement of PECO's 2010 electric rate case at R-2010-2161575.

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5.5 Provision for EGSs Serving Customers Participating in PECO Energy Company's Customer Assistance Program ("CAP Customers"). **(C)**
The Tariff provisions in this section apply to EGSs who provide Competitive Energy Supply to low-income customers participating in PECO Energy Company's Customer Assistance Program ("CAP"). The Company will provide notice, via an EDI 814 change transaction, when existing EGS customers enroll in or leave CAP ("CAP Change Notice").

5.5.1 Restrictions on CAP Customer Competitive Energy Supply Pricing. Consistent with the Company's CAP Shopping Plan approved by the Commission at Docket No. P-2020-______ ("Plan"), EGSs who provide Competitive Energy Supply to CAP Customers must charge the CAP Customers they serve a rate that does not exceed PECO's Price-To-Compare at all times during the contract. Additionally, EGSs shall not charge CAP customers any early termination, cancellation or other fees unrelated to Competitive Energy Supply. EGSs shall also comply with all other rules on arrangements with CAP Customers outlined in this Tariff and the Plan.

5.5.2 EGS Notice for Entry and Exit for Serving CAP Customers. EGSs who wish to provide Competitive Energy Supply to CAP customers must first submit a notice of intent to participate as a CAP supplier (a "CAP Notice"), in the form posted on the SUCCESS website, to the Company's Electric and Gas Choice department. The effective date of the CAP Notice will be the first day of the calendar month at least ten days after submission. EGSs that serve CAP Customers and opt to cease serving them must submit a CAP Notice of such intended discontinuance.

5.5.3 Restrictions on CAP Customer Billing Options. EGSs who provide Competitive Energy Supply to CAP Customers must bill using Consolidated EDC Billing with Purchase of Receivables.

5.5.4 Contract Expiration and Change Notice Procedures for CAP Customers. At the end of the CAP supplier contract, CAP suppliers and CAP Customers may take the following actions: renew the contract with their existing EGS at a new Tariff-compliant CAP rate consistent with applicable PaPUC requirements, switch to another supplier offering a Tariff-compliant CAP rate or return to Default PLR Service.

(C) Denotes Change

6.6 Line Losses. For purposes of backcasting, scheduling and reconciliation in Sections 6-8 of this Tariff the following transmission and distribution line loss percentages will be utilized:

For Rates R, RH, GS, SLP, SLS, SLE, SLC, TL, AL, and POL, 10.31%; for Rate PD, 8.41%; and for Rates HT and EP, 3.97%, where wholesale energy requirements = delivered retail energy requirements x [1+ the line loss percentage)]. **(C)**

Alternatively, for the purposes of determining the Generation Supply Adjustment line loss factor, the following transmission and distribution line loss percentages will be utilized:

For Rates R, RH, GS, SLP, SLS, SLE, SLC, TL, AL, and POL, 9.35%; for Rate PD, 7.76%; and for Rates HT and EP, 3.82%, where wholesale energy requirements = delivered retail energy requirements x [1/ (1 – the line loss percentage)]. **(C)**

Wholesale energy obligations for PJM settlement purposes shall be reduced to the extent that PJM and/or the Company separately charge for line losses, such as for a portion or all of transmission line losses under a FERC jurisdictional tariff.

(C) Denotes Change

Subject to the provisions of the partial settlement agreement and the Commission's final Order in Docket No. P-2009-2143607, an amount is deemed disputed if the Customer contacts PECO Energy questioning the charges on the bill and he/she does not agree with PECO's and/or EGS's position regarding the amount due for EGS charges. If the EGS charges are not in dispute, PECO Energy will remit all applicable monies due the EGS, even if the PECO Energy portion is disputed. A Customer's claim of the inability to pay shall not constitute a dispute for purposes of PECO's obligation to pay the EGS its undisputed charges.

10. PECO Energy will pay the EGS in accordance with the following schedule:

a. Residential Rate Classes (Rates R, RH, CAP) - PECO Energy will send the EGS the amount of its undisputed EGS Charges, regardless of whether the Customer has paid PECO, within 25 calendar days from the date of the electronic transmission of the EGS Charges. **(C)**

b. Non Residential Rate Classes. - PECO Energy will send the EGS the amount of its undisputed EGS Charges within 20 calendar days from the date of the electronic transmission of the EGS Charges

c. Payment will not be made to the EGS when EGS Charges are not received by PECO Energy within the specified time period, as explained in paragraph 6 above. Payment for these charges will be made according to the applicable schedule in the following month, if they are received within the appropriate time period along with the current month charges.

d. PECO Energy will make payments of funds payable to the EGS by ACH with remittance advice to a bank designated by the EGS.

e. If the day for payment of EGS charges falls on a weekend, a PECO holiday, or a bank holiday, the EGS payment will occur on the next business day.

11. An EGS offering Consolidated EDC Billing to its Customers acknowledges and agrees that PECO is (a) entitled to receive and retain all payments from the EGS's Customers for purchased receivables, and (b) authorized to conduct collection activities and, if necessary, terminate its delivery service and the EGS's electric generation supply services to Customers whose accounts receivables were purchased and who fail to make payment of amounts due on the Consolidated EDC Bill, including the full amount of the purchased EGS receivables. Any Customer service termination shall be consistent with the provisions of Chapter 14 of the Pennsylvania Public Utility Code and Chapter 56 (or a successor chapter) of the Commission's regulations. Any Customer whose service is terminated for failure to pay Consolidated EDC Billing charges shall be reconnected to POLR service upon payment of the arrears that were subject to the termination (plus any applicable reconnection fees or deposits). The required payment for reconnection may include both distribution and EGS charges.

(C) Denotes Change

9. The EGS will pay PECO Energy in accordance with the following schedule:

   a. Residential Rate Classes (Rates R, RH, CAP) - The EGS will send PECO Energy the amount of the undisputed PECO Charges within 25-calendar days from the date of the electronic transmission of the PECO Charges **(C)**

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10. Budget Billing. The EGS will include on its bill the budget amount for PECO Energy Customers who choose the budget billing option offered by PECO. The following process will apply:

   If the EGS does not offer its own budget bill (and the Commission waives any applicable requirement):

   - PECO Energy will transmit its BUDGET charges (including previous balance and current actual) to the EGS
   - EGS places PECO BUDGET charges on the EGS bill
   - EGS sends bill to Customer
   - EGS pays PECO Energy within 25-calendar days for residential rate classes and 20-calendar days for non-residential rate classes for BUDGET charges
   - Customer pays EGS for PECO BUDGET charges
     Month 12 Process:
   - PECO Energy transmits the previous balance (credit or debit) plus CURRENT charges

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Tariff Electric Pa. P.U.C. No. 1S

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PECO ENERGY COMPANY

ELECTRIC GENERATION SUPPLIER COORDINATION TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

Issued: March 13, 2020 Effective: June 1, 2021

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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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Tariff Electric Pa. P.U.C. No. 1S
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LIST OF CHANGES MADE BY THIS SUPPLEMENT

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Responses to Questions in 52 Pa. Code Section 53.52(a)

1. The specific reason for each change.

PECO Energy Company (PECO or the Company) is proposing supplier tariff changes to implement its plan ("Plan") to allow customers enrolled in the Company's Customer Assistance Program ("CAP") to purchase competitive generation supply from an electric generation supplier ("EGS"). The Company's Plan is being filed in response to the Commission's Proposed Policy Statement Order in Docket No. M-2018-3006578 and the Secretarial Letter in Docket No. M-2019-3007101.

2. The total number of customers served by the utility.

The total number of electric customers served by PECO was 1,661,605 as of December 31, 2019.

3. A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

Residential customers enrolled in CAP are potentially affected due to proposed tariff changes to allow CAP customers to purchase competitive generation supply from an EGS. Other limited changes to remove references to Rates OP and RT are explained in PECO Statement No. 3, the direct testimony of Carol Reilly.

4. The effect of the change on the utility's customers.

The primary effect of the proposed changes is to implement CAP customer shopping in PECO's service territory consistent with the Commission's guidelines set forth in the Proposed Policy Statement Order. All of the proposed tariff changes and their potential effects are discussed in detail in PECO Statement No. 3.

5. The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The effects of the proposed tariff changes on PECO's revenues and expenses cannot be determined at this time and will depend upon the Plan design that is approved as part of this filing and the number of CAP customers who shop.

6. The effect of the change on the service rendered by the utility.

PECO does not expect the proposed tariff changes to affect service.

7. A list of factors considered by the utility.

The changes are being made to address the Commission's February 28, 2019 Proposed Policy Statement Order in Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping and the January 23, 2020 Letter of Rosemary A. Chiavetta in Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms. PECO Statement No. 3, the direct testimony of Ms. Reilly, discusses the reasons for all of the proposed tariff changes.

8. Studies undertaken by the utility in order to draft its proposed change.

No specific studies were undertaken.

9. Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

No customer polls were taken.

10. Plans the utility has for introducing or implementing the changes with respect to its customers.

PECO Statement No. 3, the direct testimony of Ms. Reilly, provides further details about the Plan and how it will be implemented.

11. F.C.C., or FERC or Commission Orders or rulings applicable to the filings.

The following orders and PUC guidance are applicable to this filing:

Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping (Proposed Policy Statement Order entered Feb. 28, 2019)

Docket No. R-2010-2161575 – Pennsylvania Public Utility Commission v. PECO Energy Company (Opinion and Order entered Dec. 21, 2010).

Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms (Secretarial Letter issued January 23, 2020)

PECO ENERGY COMPANY
STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-3019290

REBUTTAL TESTIMONY

WITNESS: CAROL REILLY

SUBJECTS: CUSTOMER ASSISTANCE PROGRAM
SHOPPING PLAN AND STANDARD
OFFER PROGRAM

DATED: JULY 9, 2020

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REBUTTAL TESTIMONY
OF
CAROL REILLY

I. INTRODUCTION AND PURPOSE

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

A. My name is Carol Reilly. I am employed by PECO Energy Company ("PECO" or the "Company") as Manager of Energy Acquisition Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony that is marked as PECO Statement No. 3. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is twofold. First, I will respond to the direct testimony of several parties regarding the design of PECO's proposed plan to allow customers enrolled in PECO's Customer Assistance Program ("CAP") to purchase competitive generation supply ("CAP Shopping Plan" or "Plan"). Specifically, I will address the direct testimony of Harry Geller on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") (CAUSE-PA Statement No. 1), Barbara R. Alexander on behalf of the Office of Consumer Advocate ("OCA") (OCA Statement No. 2), Phillip A. Bertocci on behalf of the Tenant Union Representative Network and Action Alliance of Senior Citizens of Greater Philadelphia ("TURN et al.") (TURN et al.

Statement No. 1) and Travis Kavulla on behalf of the Electric Supplier Coalition ("ESC") (ESC Statement No. 1)[1] relating to the following issues:

- Restrictions on the rates charged by electric generation suppliers ("EGSs") to CAP customers (ESC);
- Obligations of EGSs that offer a CAP rate (ESC);
- Customer protections included in the Plan (CAUSE-PA and TURN et al.);
- Customer education initiatives (CAUSE-PA and OCA); and
- Plan implementation timeline (ESC).

Second, I respond to several issues relating to PECO's proposed continuation of its EGS Standard Offer Program ("Standard Offer Program" or "SOP") presented in the direct testimony of CAUSE-PA witness Geller, OCA witness Alexander, and ESC witness Kavulla.

II. DESIGN OF PECO'S CUSTOMER ASSISTANCE PROGRAM SHOPPING PLAN

4. Q. Ms. Reilly, do any parties propose changes to PECO's CAP Shopping Plan?

A. Yes. ESC witness Kavulla asserts that the limit on EGS prices charged to CAP customers to no more than PECO's applicable residential Price-to-Compare ("PTC") should only apply to the initial offer on the ground that EGSs should be able to adjust CAP rates during the contract term to reflect market conditions. He also expresses concerns with PECO's proposed implementation timeline for the

[1] The Electric Supplier Coalition's members are NRG Energy, Inc.; Direct Energy Services LLC; Interstate Gas Supply Inc., d/b/a IGS Energy; Vistra Energy Corp.; Shipley Choice LLC; ENGIE Resources LLC; and WGL Energy Services, Inc.

Plan and the requirement for EGSs to post their CAP rates on PaPowerSwitch.com.

CAUSE-PA and TURN et al. generally oppose the implementation of a CAP shopping platform in PECO's service territory in light of data showing that PECO's residential customers, including non-CAP confirmed low-income customers, have paid generation service rates greater than PECO's PTC since 2015. CAUSE-PA witness Geller and TURN et al. witness Bertocci recognize that PECO's Plan is consistent with the guidelines set forth in the Policy Statement on Electric Customer Assistance Program Participant Shopping proposed by the Pennsylvania Public Utility Commission (the "Commission") on February 28, 2019.[2] Nonetheless, they contend that PECO's Plan is deficient because, in their view, it does not include adequate monitoring and enforcement mechanisms for EGS compliance with the Plan's pricing restrictions to ensure full universal service protections and affordability of service. If CAP shopping is implemented in PECO's service territory, CAUSE-PA and TURN et al. recommend that the Commission require PECO to actively monitor EGS CAP rates, automatically reject CAP customer enrollment requests for noncompliant

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[2] *Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping*, Docket No. M-2018-3006578 (Proposed Policy Statement Order entered Feb. 28, 2019) ("Proposed Policy Statement Order"). On January 23, 2020, the Commission directed all electric distribution companies ("EDCs") to consider the Commission's prior guidance in the Proposed Policy Statement Order and recent decisions in previous default service proceedings in developing CAP proposals for upcoming default service program filings. *Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-3007101 (Secretarial Letter issued Jan. 23, 2020).

offers and return all CAP customers with noncompliant offers to default service during or at the end of the contract term.

5. Q. Does PECO believe that restrictions on the price for generation for CAP customers should only apply to the initial offer as proposed by ESC?

A. No. First, PECO's proposed restriction on EGS pricing for CAP customers is consistent with the Commission's guidance in the Proposed Policy Statement Order. Moreover, participation in PECO's CAP Shopping Plan is voluntary. PECO also notes that EGSs can offer term lengths and other provisions to CAP customers that the EGS believes are necessary to address its view of price risk. Accordingly, PECO believes that its proposal to require EGSs to offer CAP customers a rate that is below the PTC for the entire contract term strikes a reasonable balance among the Commission's policies of further developing Pennsylvania's competitive retail market, ensuring affordability of service for PECO's low-income customers, and containing costs for all residential customers that pay for CAP.

6. Q. Ms. Reilly, in your direct testimony, you explained that PECO proposes that a minimum of five EGSs submit a form notifying PECO of their intent to participate as a CAP supplier ("CAP Notice") before Plan implementation. Does PECO agree with ESC witness Kavulla that PECO should eliminate this condition?

A. No. PECO believes that the receipt of five ***nonbinding*** CAP Notices from EGSs is a reasonable threshold to ensure verifiable supplier interest in serving CAP customers in PECO's service territory in accordance with Plan requirements before incurring the necessary program and information technology ("IT") expenses. A requirement for five CAP Notices also helps ensure choice for customers, particularly if one or two CAP suppliers subsequently elect not to serve CAP customers after Plan implementation.

7. Q. Does PECO object to the creation of a separate Commission portal on PAPowerSwich.com to publish CAP rates proposed by Mr. Kavulla?

A. No. However, PECO does not agree with Mr. Kavulla's statement that requiring EGSs to post CAP rates on PAPowerSwitch.com would create customer confusion. The PAPowerSwitch website currently has extensive filtering capability to assist customers in assessing EGS offers, including variable or fixed pricing, no cancellation fees, net metering, and renewable energy. PECO believes that utilizing an additional filter for CAP rates would minimize customer confusion and promote transparency.

8. Q. Have you reviewed Mr. Geller's and Mr. Bertocci's position regarding the monitoring and enforcement of EGS compliance with the CAP Shopping Plan?

A. Yes. Both CAUSE-PA and TURN et al. recommend that the Commission require PECO to monitor EGS transactions with its CAP customers and ensure that EGS charges billed to CAP customers do not exceed the PTC. Specifically, they assert that PECO should require EGSs to use "rate-ready" billing to allow for automatic rejection of noncompliant EGS offers to CAP customers.

9. Q. Does PECO agree with this proposal?

A. No. Essentially, CAUSE-PA and TURN et al. are proposing that PECO expand its billing system to obtain and monitor EGS prices. This is a flawed approach for several reasons.

First, there is no need to put PECO into the business of obtaining EGS prices, as accurate EGS pricing information is already available from the EGSs themselves. EGSs are subject to the Commission's jurisdiction and the Commission is fully able to order EGSs to produce detailed, actual pricing information to ensure compliance with CAP requirements. In the event that EGSs may not be compliant with CAP requirements, the Commission has extensive authority over EGSs and a variety of mechanisms to investigate and address any allegations that EGSs are over-charging low-income customers.

Second, under PECO's current "bill-ready" platform, PECO is not able to readily determine customer-specific EGS rates in cents per kWh, as Mr. Geller and Mr. Bertocci suggest. "Bill-ready" billing means that PECO receives calculated results from the EGS for its charges for printing on the customer's consolidated bill instead of the EGS rates used to calculate the dollar amount of its charges. PECO does not receive EGS pricing information (i.e., EGS rate in cents per kWh) that would show whether EGS rates are higher or lower than the PTC. Construction of a "rate-ready" system in which PECO calculates EGS charges based on EGS rates would be a significant undertaking and create substantial additional IT expense for all distribution service customers.

Contrary to Mr. Bertocci's contention, simply dividing a customer's EGS charges printed on the residential bill by kWh usage is not sufficient to monitor EGS pricing and compliance with the Plan's pricing restriction because the monthly EGS charges could include amounts unrelated to the generation service provided in that billing period, such as prior-period billing adjustments. As a result, looking at one month (or even several months) of data will not necessarily provide the actual rate an EGS is charging for generation service.

PECO's current Electronic Data Interchange ("EDI") 810 protocol does include a free text-comment field where EGSs have the option, but not a requirement, to describe generation charges as defined in the Commission's Electronic Data Exchange Working Group ("EDEWG") standards (e.g., in cents per kWh). But even if an EGS completes this field as part of an EDI 810 transaction, there is no functionality to automatically compare any pricing data entered into the text comment field with PECO's PTC. Consequently, even if price data were to be entered into the text comment field, PECO could not provide pricing oversight unless it implemented either a costly manual review of the description provided by the EGS in the text field for each CAP customer enrollment and compare such pricing information to PECO's PTC or a costly IT solution to make such a comparison.

PECO will comply with requests for information from the Commission's Office of Competitive Market Oversight to facilitate Commission monitoring of EGSs that choose to serve CAP customers in PECO's service territory. But PECO should not be required to obtain and monitor EGS pricing and enforce Commission requirements, as CAUSE-PA and TURN et al. propose.

10. Q. Has PECO recently proposed any changes to its CAP program?

A. Yes. On July 8, 2020, PECO filed a proposal to change its CAP design from the existing Fixed Credit Option ("FCO") plan to a Percentage of Income Payment Plan ("PIPP"). PECO proposed this change as an amendment to its 2019-2024 Universal Services and Conservation Plan at Docket No. M-2018-3005795.

11. Q. Does the Commission's guidance set forth in the Proposed Policy Statement Order apply to PIPP?

A. Yes. The Commission's proposed uniform CAP shopping policies and requirements for Pennsylvania EDCs apply to all CAP shopping platforms, regardless of the underlying CAP design. Thus, for example, the Proposed Policy Statement Order requires a CAP shopping product rate at or below the EDC's PTC for the duration of the contract.

If the Commission approves PECO's proposal to adopt a PIPP, the pricing restriction will also apply to the CAP shopping platform under PECO's new PIPP plan. PECO will still not be able to provide oversight of that restriction because PECO, even after the Commission approves a PIPP, will continue to use a "bill-ready" system and thus will still not have line of sight to EGS pricing data that is sufficient for PECO to perform the policing function.

12. Q. Ms. Reilly, do any parties recommend modifications to the customer education initiatives included in the Plan?

A. Yes. The OCA recommends that the Plan's customer education materials include a customer feedback mechanism. The OCA also recommends that PECO develop the means by which the Company will conduct ongoing research about the prices that CAP customers are paying for competitive generation supply with stakeholders prior to Plan implementation.

CAUSE-PA contends that the Company's consumer education efforts alone have proven ineffective to protect low-income and other residential customers from excessive costs associated with shopping. Based on this conclusion, CAUSE-PA requests that PECO redesign the residential customer bill to improve the presentation of shopping information and permit active customer review of the rates they are paying for competitive generation service. To that end, CAUSE-PA proposes various modifications to PECO's residential customer bill, including a stand-alone box on the front of the bill displaying the EGS rate in cents per kWh and the applicable PTC, as well as prominent warnings on CAP customer bills to remind them of the CAP rate protections under the Plan.

13. Q. Does PECO agree with the proposals of the OCA relating to the Plan's customer education initiatives?

A. Not entirely, but PECO will work with interested parties to develop the specific content of messaging to CAP customers and metrics to evaluate the CAP Shopping Plan after PECO receives CAP Notices from at least five EGSs. PECO continues to support its original proposal for an ongoing CAP customer education campaign that will focus on the CAP rate protections that must be included in CAP customer-EGS contracts, the impact of shopping on CAP benefits and the provision of tools to help CAP customers make shopping decisions and manage their energy bills.

14. Q. Does PECO support CAUSE-PA's recommendations regarding revisions to PECO's residential bill format?

A. Yes. However, as previously explained, under its "bill-ready" billing platform, PECO does not receive sufficient information that would allow PECO to automatically print EGS pricing in cents per kWh on the customer's bill. Therefore, PECO proposes to conduct a stakeholder collaborative, within 120 days of a final Order in this proceeding, to explore mechanisms to collect EGS pricing information compatible with PECO's "bill-ready" billing system and to develop bill improvements to ensure that shopping information is clear and transparent to residential customers.

15. Q. Does the Company agree with TURN et al. that PECO should continue to utilize the Company's default service rate to calculate CAP fixed credit amounts for shopping customers?

A. As stated previously, PECO has filed a proposal with the Commission to move to a PIPP CAP program. If and when the Commission approves PECO's PIPP proposal, the details of calculating PECO's current FCO credit for a shopping CAP customer will become moot.

However, if CAP Shopping is implemented while the FCO is still in place, use of EGS pricing in the FCO calculation is necessary to pass on any generation purchase savings to the shopping CAP customer. Conversely, use of the PTC would strip the generation shopping decision out of the FCO calculation and consequently would mean that the shopping CAP customer would not enjoy the savings from the shopping transaction. Because use of the PTC would eliminate a potential source of cost savings to CAP customers, PECO does not support TURN's suggestion.

III. STANDARD OFFER PROGRAM

16. Q. Ms. Reilly, do any of the parties recommend modifications to PECO's Standard Offer Program?

A. Yes. OCA witness Alexander recommends that PECO implement the following changes: (1) modification of PECO's call center scripts to ensure that PECO customer service representatives identify PECO's third-party administrator, Kandela, as the entity that will provide additional information about the SOP after the call transfer; (2) revision of Kandela's scripts and training materials to provide all customer disclosures about the SOP rate before moving to the selection of a supplier; (3) monitoring of Kandela representatives on their presentation of the SOP; (4) discontinuance of the use of PECO's "Smart Energy Choice" brand name for the Standard Offer Program; and (5) new requirements for participating EGSs to provide their SOP customer rates to PECO in cents per kWh. In addition, Ms. Alexander recommends that PECO perform a study of the price that SOP customers pay for competitive generation service after the end of the twelve-month contract to obtain information about the bill impacts and benefits of PECO's Standard Offer Program.

ESC also opposes the use of PECO's "Smart Energy Choice" brand name and proposes other changes to the content of PECO's SOP script that Mr. Kavulla believes would increase the attractiveness of the program. ESC also recommends that PECO implement the following operational and design changes to the SOP: (1) automatic SOP enrollment for all new customers who have not already made an affirmative choice of an EGS; (2) implementation of an online SOP enrollment process through PECO's website; (3) expansion of the scope of customer calls in which the SOP should be presented; and (4) issuance of communications to customers about the SOP on a quarterly basis.

CAUSE-PA, in turn, recommends that PECO amend its SOP to return customers to default service if they do not make an affirmative decision to either stay with their current EGS or select a new EGS at the end of the twelve-month contract. CAUSE-PA also recommends additional outreach to SOP customers about their shopping decisions throughout the duration of the SOP contract to educate them on how to compare offers.

17. Q. Does PECO agree with the specific SOP script and training material changes proposed by OCA witness Alexander and ESC witness Kavulla?

A. No. As I explained in my direct testimony, in accordance with the Commission-approved settlement of PECO's DSP IV proceeding,[3] the Company revised its SOP-related scripts and training materials to incorporate several disclosures requested by the OCA. Those disclosures presented by Kandela customer service representatives include clear and appropriate messaging regarding the operation of the SOP discount rate. Ms. Alexander has not provided any evidence that suggests that Kandela's current SOP scripts cause customer confusion or dissatisfaction.

With respect to ESC's recommended script changes, Mr. Kavulla's proposal to revise the phrase "potential savings opportunity" to eliminate the qualifying term "potential" may lead to customer confusion. This language clearly conveys that the SOP discount at the time of the offer does not guarantee savings over the life of the contract, and such language is necessary to allow customers to make an informed decision regarding enrollment in the program.

18. Q. Are you aware of any customer complaints made to PECO stating that the Kandela Standard Offer Program script causes confusion or dissatisfaction?

A. No. PECO has received no such complaints.

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[3] *Petition of PECO Energy Co. for Approval of its Default Serv. Program for the Period from June 1, 2017 through May 21, 2021,* Docket No. P-2016-2534980 (Opinion and Order entered Dec. 8, 2016), p. 35.

19. Q. Ms. Alexander would also require PECO to print the EGS rate in cents per kWh on SOP customer bills. Does PECO believe this is an appropriate revision?

A. Not at this time. PECO believes that the collaborative process discussed earlier in my rebuttal testimony is the appropriate venue to consider changes to PECO's residential customer bill to improve the ability of SOP customers to compare the EGS rate with the PTC each month.

20. Q. Ms. Alexander has also proposed monitoring and reporting requirements regarding Kandela representatives' presentation of the SOP to customers. Please comment.

A. PECO conducts a monthly evaluation of Kandela's call-handling performance metrics. PECO will incorporate Ms. Alexander's suggested evaluation topics, such as presentation of the customer disclosures consistent with the current SOP-related scripts and training materials, in the Kandela evaluation form.

21. Q. Please respond to Ms. Alexander's recommendation that PECO should perform a study of the rates SOP customers pay for competitive generation service upon contract expiration.

A. PECO does not agree with this recommendation. As with proposals for PECO to monitor EGS pricing, the Commission can obtain accurate pricing information from EGSs who participate in the SOP, and there is no reason for PECO to undertake a study of EGS rates upon expiration of an EGS contract. Any such study would likely require additional IT expenditures, as PECO does not track a customer's status as a SOP customer (other than an initial note that the customer elected to participate in SOP). The collaborative process that PECO has proposed to consider changes to PECO's residential customer bill to improve the ability of customers to compare an EGS rate with the PTC each month may be helpful to SOP and former SOP customers.

22. Q. Does PECO object to discontinuance of its brand name for the Standard Offer Program, "Smart Energy Choice," as Ms. Alexander and Mr. Kavulla recommend?

A. No. PECO will select a new brand name for the SOP based on market research and customer feedback that does not utilize the term "smart" or the PECO corporate name.

23. Q. Do you agree with ESC witness Kavulla that PECO's new/moving customers should be automatically enrolled in the Standard Offer Program?

A. No. The voluntary nature of PECO's Standard Offer Program is consistent with the Commission's guidelines in its Retail Market Investigation and final Order approving PECO's second default service program.[4]

24. Q. Does PECO agree with ESC's proposal to expand the scope of customer calls in which the Standard Offer Program may be presented?

A. No. Mr. Kavulla provides no compelling justification for his proposal. Consistent with the Commission's guidance in the Intermediate Work Plan Order

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[4] *See Investigation of Pennsylvania's Retail Elec. Mkt.: Intermediate Work Plan*, Docket No. I-2011-2237952 (Final Order entered Mar. 2, 2012) ("Intermediate Work Plan Order"), p. 31 ("The Standard Offer Customer Referral Program should be voluntary for customers, i.e., 'opt-in,' as well as for participating EGSs."); *Petition of PECO Energy Co. for Approval of its Default Serv. Program II*, Docket No. P-2012-2283641 (Opinion and Order entered Oct. 12, 2012) ("DSP II Order"), pp. 108-109.

(p. 31) and DSP II Order (pp. 118-119), PECO currently offers the SOP during all calls from new/moving customers, except for calls related to outages, emergencies, terminations and billing disputes in which such a presentation would be inappropriate.

25. Q. Does PECO believe ESC's proposed web enrollment process should be adopted?

A. No. PECO initially allowed customers to enroll in the SOP via telephone or the Company's website beginning in 2013, when participating EGSs were required to serve both residential and small commercial customers. In accordance with the Commission-approved settlement of PECO's DSP III proceeding, on March 2, 2015, the Company implemented system changes to allow SOP suppliers the option to select the rate class of customer accounts they wish to enroll. However, PECO did not enable web-enrollment functionality as part of this system programming to separate SOP enrollments by rate class in light of the associated cost and the relatively low level of SOP enrollment through PECO's website from 2013 through March 2015 (i.e., approximately 3% of total SOP enrollments).

26. Q. Does PECO agree with Mr. Kavulla's proposal for additional periodic communications (e.g., quarterly communications) regarding the SOP to all default service customers?

A. No. In establishing the SOP, the Commission provided specific direction that the SOP was intended to be offered during customer contacts to EDC call centers. The SOP was not intended to expand other promotional communications on behalf of EGSs to default service customers. Accepting ESC's recommendation for quarterly communications promoting the SOP to all PECO default service customers would also increase administrative costs.

27. Q. Does PECO object to Mr. Geller's recommendation that participating customers who do not make an affirmative election at the end of the SOP contract term should revert back to default service?

A. Yes. CAUSE-PA's proposal deviates from the Commission's current guidance about customer options upon expiration of the SOP contract. Consistent with the Intermediate Work Plan Order (p. 21) and DSP II Order (pp. 114-116), PECO's SOP provides the same options at the end of the contract term to SOP customers as other shopping customers.

IV. CONCLUSION

28. Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS DEFAULT SERVICE PROGRAM FOR THE PERIOD FROM JUNE 1, 2021 THROUGH MAY 31, 2025	:	**Docket No. P-2020-3019290**

<u>VERIFICATION</u>

I, Carol Reilly, hereby state that I am Manager of Energy Acquisition Operations for PECO Energy Company; that I am authorized to and do make this Verification for it; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 3
- PECO Statement No. 3-R
- PECO Exhibit No. CR-1
- PECO Exhibit No. CR-2
- PECO Exhibit No. CR-3
- PECO Exhibit No. CR-4

Carol Reilly

Dated: July 30, 2020

Carol Reilly

PECO ENERGY COMPANY
STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-________________

DIRECT TESTIMONY

WITNESS: SCOTT G. FISHER

SUBJECT: DEFAULT SERVICE PROCUREMENT

DATED: MARCH 13, 2020

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DIRECT TESTIMONY
OF
SCOTT G. FISHER

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Scott G. Fisher. My business address is 30 Monument Square, Suite 105, Concord, Massachusetts 01742.

2. Q. What is your current position?

A. I am a Partner with The NorthBridge Group ("NorthBridge"), an economic and strategic consulting firm serving the electric and natural gas industries.

3. Q. On whose behalf are you submitting testimony?

A. I am submitting direct testimony on behalf of PECO Energy Company ("PECO").

4. Q. Please summarize your professional and academic background.

A. Since joining NorthBridge in 1998, I have advised companies in the electric industry on decisions related to risk management, asset valuation and portfolio management, product pricing, contract negotiations, regulatory affairs, supply procurement, rate design, emerging technologies, public policy formulation and negotiations, and overall corporate strategy. I also have served as an expert witness on several of these topics, particularly with respect to default service supply procurement and ratemaking, in state public utility commission proceedings. Before joining NorthBridge, I was a consultant at Strategic Decisions Group, a management consulting firm serving a variety of industries. I received an A.B. from Dartmouth

College and a B.E. from the Thayer School of Engineering at Dartmouth College, with high honors. In addition, I received an M.S. in Engineering-Economic Systems from Stanford University and an M.B.A. from the Tuck School of Business at Dartmouth College, with high honors. I presently serve as a guest lecturer at the Tuck School of Business on energy industry matters.

5. Q. Have you testified previously before this Commission?

A. Yes, I testified in Docket No. P-2008-2062739, Petition of PECO Energy Company for Approval of its Default Service Program and Rate Mitigation Plan ("DSP I"),[1] Docket No. P-2012-2283641, Petition of PECO Energy Company for Approval of its Default Service Program ("DSP II"),[2] Docket No. P-2014-2409362, Petition of PECO Energy Company for Approval of its Default Service Program for the Period from June 1, 2015 through May 31, 2017 ("DSP III"),[3] and Docket No. P-2016-2534980, Petition of PECO Energy Company for Approval of its Default Service Program for the Period from June 1, 2017 through May 31, 2021 ("DSP IV").[4] I also testified in Docket No. P-2012-2301664, Petition of Duquesne Light Company for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2013 through

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1 *See Petition of PECO Energy Company for Approval of Its Default Service Program and Rate Mitigation Plan*, Docket No. P-2008-2062739 (Order entered June 2, 2009) ("DSP I Order").

2 *See Petition of PECO Energy Company for Approval of Its Default Service Program*, Docket No. P-2012-2283641 (Order entered Oct. 12, 2012) ("DSP II Order").

3 *See Petition of PECO Energy Company for Approval of Its Default Serv. Program for the Period from June 1, 2015 through May 31, 2017*, Docket No. P-2014-2409362 (Order entered Dec. 4, 2014) ("DSP III Order").

4 *See Petition of PECO Energy Company for Approval of Its Default Serv. Program for the Period from June 1, 2017 through May 31, 2021*, Docket No. P-2016-2534980 (Order entered Dec. 8, 2016) ("DSP IV Order").

May 31, 2015.[5]

6. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to evaluate PECO's proposed default service plan (the "Default Service Plan" or "Plan" or "DSP V") to procure supply for default service customers for the period beginning June 1, 2021 and ending May 31, 2025. My testimony is divided into two parts. First, I briefly review PECO's first four default service plans, DSP I, DSP II, DSP III, and DSP IV, and identify several lessons learned. This discussion includes an analysis of the "residual compensation" incorporated in the prices of the residential full requirements contracts procured by PECO in accordance with these plans. Second, I evaluate PECO's DSP V with respect to Act 129's (the "Act's") requirement that the plan include a "prudent mix" of contracts designed to ensure the least cost to customers over time.[6]

7. Q. Please summarize your conclusions.

A. First, with regard to the lessons learned from PECO's earlier DSP plans (DSP I, DSP II, DSP III, DSP IV), I conclude the following:

- The participation by multiple suppliers in PECO's open solicitations for fixed-price full requirements ("FPFR") default service supply products, combined with my quantitative analysis of the results of these solicitations, indicate that the resulting contract prices obtained by PECO

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[5] *See Petition of Duquesne Light Co. for Approval of Default Serv. Plan For the Period June 1, 2013 Through May 31, 2015,* Docket No. P-2012-2301664 (Order entered Jan. 25, 2013).

[6] 66 Pa.C.S. § 2807(e)(3.4).

have been reasonable, considering the costs and risks that the suppliers under these contracts assume to the benefit of customers.

- The mix of one-year and two-year FPFR products in PECO's residential default service supply portfolio, and the semi-annual overlapping of their delivery periods, provide price stability benefits for residential customers.

- The basic default service model used by PECO has supported the competitive retail electricity market. In fact, 102 alternative electric generation suppliers ("EGSs" or "competitive retail suppliers") currently serve PECO customers, which is roughly triple the number since the DSP I period began.[7]

Second, with regard to PECO's proposed DSP V, I conclude the following:

- DSP V incorporates a prudent mix of contracts designed to ensure least cost to customers over time, taking into account the benefits of price stability, and includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis, as required by Section 2807(e)(3.4) and Section 2807(e)(3.7) of the Act.[8]

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7 Source: PECO. Data is for the month ending February 25, 2020.

8 In PECO Energy Statement No. 1, PECO witness John J. McCawley provides the details regarding PECO's proposal to solicit long-term contracts for a portion of the solar alternative energy credits ("AECs") required for compliance with Pennsylvania's Alternative Energy Portfolio Standards ("AEPS") Act, and accordingly he addresses how this specific aspect of DSP V is consistent with the Act's requirement that the plan include a

- PECO's Default Service Plan is designed to support the competitive retail electricity market in PECO's service area while providing price stability benefits for small customers.

Each of these findings is discussed further below.

II. REVIEW OF EARLIER DSPS AND THE LESSONS LEARNED

8. Q. Please provide a brief overview of the mix of products procured under DSP I, DSP II, and DSP III.

A. Under PECO's DSP I, a unique and tailored portfolio of supply products was procured for each of four different customer classes at different points in time. The portfolio consisted of a mix of 1-year and 2-year FPFR products and varying levels of spot-priced purchases by customer class.[9] Twenty-five percent of the Residential class portfolio was served through a "block-and-spot" approach in which PECO made forward purchases of energy blocks (of 1-year, 2-year, 5-year, and seasonal delivery periods that were targeted to supply 20% of Residential default service load[10]), and the spot market transactions were made to cover the mismatches between the fixed quantities of block energy supply purchased and the 25% portion of the actual hourly

"prudent mix" of contracts designed to ensure the least cost to customers over time.

9 Some of the initial delivery periods of the full requirements supply products procured in DSP I included an extra five months (from January 1, 2011 to May 31, 2011) to align the delivery periods of subsequent products with the commencement of the annual planning period of PJM Interconnection, L.L.C. ("PJM"), the regional transmission organization in which PECO participates.

10 Unlike full requirements products, deliveries under block products do not scale with changes in default service load, so the percentages of default service load served by the block products often deviated from the targeted percentage.

load requirement.

Under DSP II, PECO began to phase out the block-and-spot aspect of the supply portfolio for the Residential class and replace these products with FPFR products. For smaller customers, DSP II also included more frequent replacements of the supply products, as supply product delivery periods were timed to expire every six months rather than every year. Finally, DSP II involved generally shorter product delivery periods and shorter times between product procurement and the start of delivery.

PECO's DSP III continued the basic procurement strategy that was established in DSP II, with a few changes. For the Medium Commercial class, PECO transitioned the supply portfolio from six-month FPFR products to hourly priced default service. The supply portfolio for the Residential class continued the procurement design established in DSP II consisting of 40% one-year FPFR products and 60% two-year FPFR products, with delivery periods that overlap on a semi-annual basis. During the DSP III period, approximately 96% of the supply portfolio transitioned to this product arrangement. By the end of the DSP III period, the remaining 4% of the overall default service supply portfolio for the Residential class consisted of a mix of 17-month FPFR products (approximately 3% of Residential default service load) and spot purchases (approximately 1% of Residential default service load) directly from the energy markets operated by PJM.

9. Q. Please provide a brief overview of the mix of products procured under DSP IV.

A. PECO's DSP IV, the plan currently in effect, continues the basic procurement strategy that was established in DSP III, which includes procurement of a prudent mix of products from competitive wholesale suppliers and has supported retail market competition.

- PECO consolidated the Medium Commercial class (peak demands 100 kW to 500 kW) and the Large Commercial and Industrial class (peak demands greater than 500 kW) into a Consolidated Large Commercial and Industrial class consisting of customers with peak demands that are equal to or greater than 100 kW. These customers continue to receive default service based on spot market prices. In PECO's service area, the competitive retail market for the Consolidated Large Commercial and Industrial customers is very well developed, as 94% of the load has switched to service from competitive retail suppliers.[11] As such, this customer class does not rely on having price stability in its default service rates, so the continuance of default service based on spot market prices is reasonable for it.

- For the Small Commercial class, PECO has transitioned from the previous supply portfolio composed entirely of one-year FPFR products to a supply portfolio consisting of 50% one-year FPFR products and 50% two-year FPFR products. The inclusion of the two-year products in the supply portfolio was designed to better ensure price stability for those small non-

[11] Source: PECO. Data is for the month ending February 25, 2020. The figure includes customers who will be switched to EGSs within 45 days. Percentage of load is based on kW.

residential customers who do not select service from a competitive retail supplier. PECO continues the practice of overlapping delivery periods on a semi-annual basis, and it also continues the practice of procuring each of the FPFR default service products approximately two months before delivery of the product begins. Specifically, the procurement approach has transitioned from the previous cycle in which 50% of the supply was replaced every six months to a cycle in which 37.5% of the supply is replaced every six months, thereby reducing the likelihood of significant rate changes due to adverse circumstances or market conditions at any given time.

- The supply portfolio for the Residential class continues the basic procurement design established in DSP III, in which 96% of the supply consists of a mix of 40% one-year FPFR products and 60% two-year FPFR products, with delivery periods that overlap on a semi-annual basis. The remaining 4% of the overall default service supply portfolio for the Residential class consists of two tranches (each supplying 1.6% of the Residential class default service load) of two-year FPFR products, and the remaining sliver of the supply need is satisfied through spot purchases.[12] Each of the FPFR default service supply products for the Residential class

[12] Including these two tranches of two-year FPFR products, the total default service supply portfolio for the Residential class consists of 38 tranches of two-year FPFR products (supplying approximately 61% of the load), 24 tranches of one-year FPFR products (supplying approximately 38% of the load), and a small portion of spot purchases.

is procured approximately two months before delivery of the product begins.

The following chart provides a summary of the DSP IV portfolio for each customer class:

DSP IV

Residential	Small Commercial	Consolidated Large Commercial and Industrial
• 96% of the load is supplied by a mix of products in the following proportions: o 40% 1-year FPFR products with delivery periods that overlap on a semi-annual basis o 60% 2-year FPFR products with delivery periods that overlap on a semi-annual basis • The other 4% of the load is supplied by two-year FPFR products (approximately 3% of the supply) and spot purchases (approximately 1% of the supply) • All products are procured approximately two months before delivery of the product begins	Transitioned to: o 50% 1-year FPFR products o 50% 2-year FPFR products • Delivery periods overlap on a semi-annual basis • All products are procured approximately two months before delivery of the product begins	• 100% spot-priced full requirements products with 1-year delivery periods • All products are procured approximately two months before delivery of the product begins

10. Q. Mr. Fisher, you have testified that the majority of default service supply for the Residential, Small Commercial, and Medium Commercial classes was procured in the form of FPFR products in DSP I, DSP II, DSP III, and DSP IV. Please describe the characteristics of an FPFR product.

A. An FPFR default service supply product obligates the seller of the product to satisfy a specified percentage of all of the default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. The seller is paid a predetermined price per megawatt-hour for this service. The full requirements products that PECO has procured under DSP I, DSP II, DSP III, and DSP IV include the generation components required to supply PECO's default service customers, including energy, capacity, and ancillary services, as well as AECs required for AEPS compliance. In PECO's solicitations for FPFR products, qualified bidders compete with one another by submitting the prices at which they are willing to provide the full requirements default service supply, and the suppliers with the lowest prices are selected upon approval of the procurement by the Pennsylvania Public Utility Commission (the "Commission").

11. Q. Have PECO's solicitations for FPFR supply products attracted many qualified suppliers?

A. Yes. Between 9 and 13 suppliers participated in each of the FPFR product solicitations in DSP I, DSP II, DSP III, and DSP IV.[13] Furthermore, the Commission has approved the bid results for approximately 99% of the FPFR default service supply product tranches that have been solicited to date.[14] These facts indicate that

[13] Source: PECO Energy Statement No. 1 (Direct Testimony of John J. McCawley). Participation in this context involves at least completing the steps required to be qualified to submit bids.

[14] Source: http://www.pecoprocurement.com/index.cfm?s=background&p=previousResults. To date, 737 FPFR default service supply product tranches have been solicited by PECO. (The number increases to 757 if the 12-month 2011 "opt-in" fixed-price products for the Large Commercial and Industrial class are included.) The Commission has approved the bid results for all but seven of these tranches. On a related note, insufficient

many suppliers understand the products being solicited and are willing to compete to provide those products. This is beneficial for customers and helps to ensure that the winning prices are the lowest possible for the products being solicited. When bidders are faced with a high likelihood that other bidders are also competing on the basis of price for the same product, they have the incentive to submit their lowest possible price in order to avoid being underpriced by another bidder.

12. Q. Do the bidders in FPFR product solicitations require compensation in the prices that they offer to help them cover the associated costs and risks of their obligation, to the benefit of customers?

A. Yes. As in any market, participants require compensation for the costs and risks that they bear by providing a product.

13. Q. Have you performed a quantitative analysis of the results of PECO's DSP I, DSP II, DSP III, and DSP IV solicitations for FPFR default service supply products, in order to better understand the compensation that is required by suppliers?

A. Yes. I have performed an analysis of the residential supply product pricing.

14. Q. What was the basic approach that you adopted in your analysis?

A. For each of the FPFR product solicitations that PECO completed, I calculated the values of the individual cost components that can be quantified in a fairly simple way,

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bids were received for some of the spot-priced full requirements products solicited in 2010 for the Large Commercial and Industrial class. (*See* Fall 2010 Solicitation Approval Secretarial Letter (9/22/2010)). Spot-priced full requirements products are quite different from FPFR products, as spot-priced full requirements products do not offer the opportunity to potential suppliers to manage all of the costs and risks of full requirements supply at a fixed price on behalf of customers.

I and deducted them from the winning bid prices. Then, by examining whether the difference (i.e., the "residual compensation" required by suppliers to cover the other costs and risks that I did not individually quantify) represents a relatively small or large portion of the winning bid prices, I determine whether this "residual compensation" is reasonable, considering the costs and risks assumed by FPFR product suppliers to the benefit of customers.

15. Q. Please identify the cost components of full requirements service that you individually quantified.

A. For each solicitation, I used market price information and load data available at the time of the solicitation to quantify cost components related to energy (including the effect of load shape), capacity, ancillary services, and various credits.[15]

16. Q. How did you quantify each of these cost components?

A. For energy, I relied on forward block energy prices as reported by the New York Mercantile Exchange ("NYMEX").[16] I then added a load shaping adjustment to account for the fact that market prices are generally higher during hours in which

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[15] For all solicitations except the March 2015 solicitation, I only used market price information and load data available at the time of the solicitation to quantify costs. At the time of the March 2015 solicitation, PJM had filed its Capacity Performance Proposal with the Federal Energy Regulatory Commission, and it was widely recognized that approval of this proposal would increase the costs of capacity for June 2016 and beyond. As such, for the March 2015 solicitation, the price used for capacity for deliveries starting in June 2016 and the corresponding Zonal UCAP Obligation are based on the actual results of the Capacity Performance Transition Incremental Auction, which incorporate the Capacity Performance Resources in PJM's Capacity Performance Proposal.

[16] For any solicitation in which sufficient PECO Zone forward prices were not available, NYMEX forward block energy prices for PJM Western Hub were used and a basis adjustment was applied. The basis adjustment was calculated based on historical market price data available as of the time of the respective solicitation. NYMEX prices were provided by ABB Velocity Suite.

customer loads are higher.[17] The load shaping was performed using actual PECO hourly loads and prices.

For capacity, I applied PJM-published capacity prices to megawatt quantities of required capacity, and I divided the products by the commensurate megawatt-hour loads in order to express capacity costs in terms of dollars per megawatt-hour. The capacity quantities were calculated based on the reported peak load contribution values for the appropriate classes of customers, and the corresponding megawatt-hour load values were calculated from publicly available load values as of the times of the solicitations.

The other cost components that I individually quantified include ancillary services costs,[18] AECs,[19] Auction Revenue Rights ("ARR") credits,[20] and marginal loss credits.[21] These values tend to be much smaller than the cost of energy and capacity and, therefore, they have a much smaller effect on the results of my analysis.[22]

For each solicitation, I quantified these cost components and then deducted the

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17 The calculation of this load shaping adjustment involved applying actual historical percentage differences between load-weighted hourly energy prices and straight-average hourly energy prices.

18 The ancillary services costs that I used were based on PECO's historical ancillary services costs.

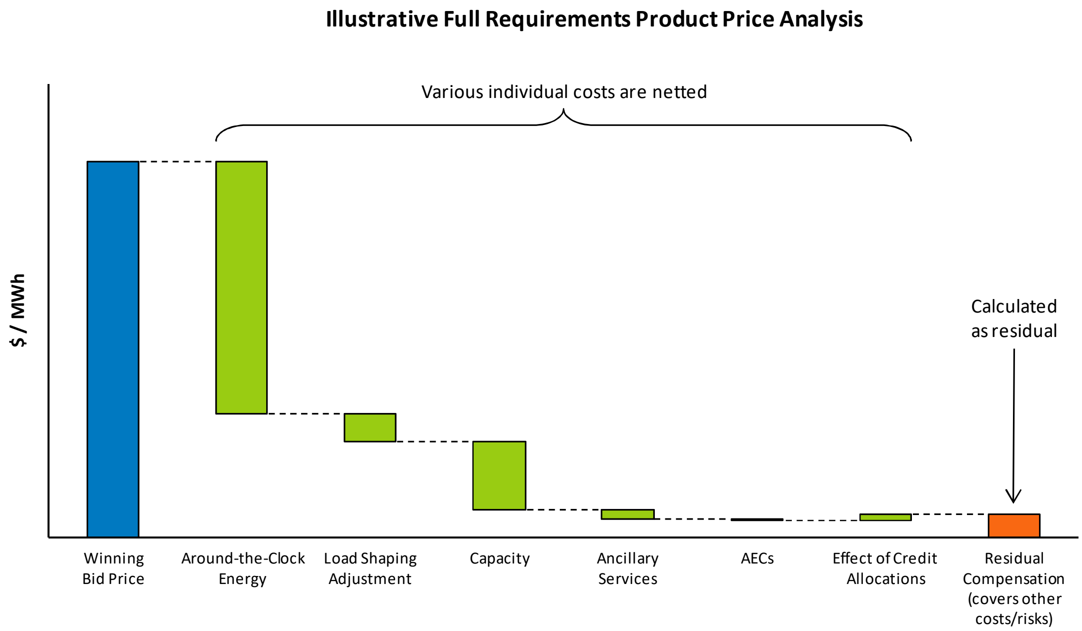
19 The costs of AECs were calculated using AEC prices as of the time of the solicitation and the volume requirements of the winning suppliers.

20 ARR credits were calculated by dividing zonal ARR credit allocations published by PJM by zonal loads calculated from PJM zonal load forecasts.

21 Marginal loss credits were calculated using actual credit data provided by PJM.

22 The values of both the ARR credits and the marginal loss credits were netted from the values of the other cost components that I calculated (i.e., these credit values effectively act as cost components with negative values), because a positive value for these credits equates to a positive dollar value allocated to the winning bidders in the solicitations.

resulting values from the winning bid price to determine how much was left over – the "residual compensation" for all other cost and risk items that were not individually quantified. The following illustrative chart graphically portrays this approach:



17. Q. Do the residual compensation values that you calculated represent the expected "profit margins" or "premiums" for the winning bidders?

A. No, these residual compensation values do not represent the expected profit margins for winning bidders. While it is reasonable for winning bidders to expect some level of profit in order to assume the full requirements obligations, there clearly are costs and risks that were not quantified and deducted from the winning bid prices; suppliers require the residual compensation to cover these costs and risks. Therefore, the residual compensation that I calculated simply represents what is left over after deducting the values of cost components that I individually quantified. It does not represent the expected supplier profit or premium.

18. Q. What are some of the other costs and risks that this "residual compensation" is intended to cover?

A. The residual compensation must cover a wide range of other costs and risks, including:

- <u>Customer migration</u> – the financial costs and risks associated with the uncertainty regarding customer switching and its effect on the default service volumes to be supplied.
- <u>Usage and price uncertainty</u> – various costs and risks due to unexpected events that affect usage and price levels.[23]
- <u>Unexpected congestion</u> – various costs and risks associated with the possibility that differences in prices between a given trading hub and the delivery location will be higher than expected values.
- <u>Adverse selection</u> – the costs and risks associated with the likelihood that high cost-to-serve customers (e.g., with less attractive load shapes) will disproportionately remain on default service due to competitive retail suppliers' lack of interest in marketing to such customers.

[23] These include extreme weather patterns, changes in customer usage patterns, plant outages or transmission line outages (which also affect congestion costs), fuel price shocks, and unexpected economic growth levels. Furthermore, the general positive correlation between loads and prices (e.g., a heat wave drives up both prices and loads) compounds the potential costs associated with this uncertainty.

- Adverse developments in energy markets during the time a bid is held open – even for a few days, while the bids are evaluated and considered for approval by the applicable regulatory body.

- Potential changes in laws and regulations – such changes could impact supplier costs during the contract period.

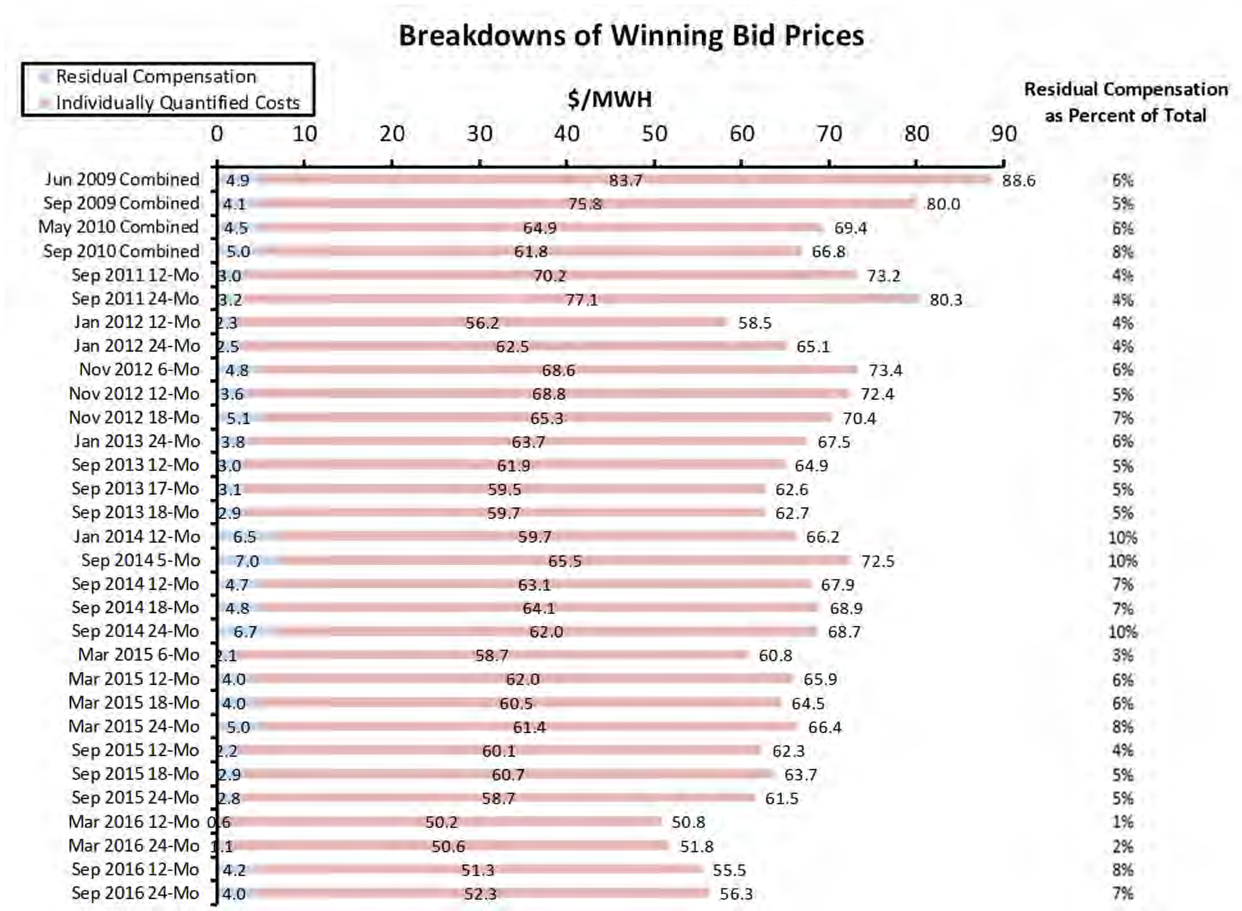
- Administrative and legal costs

- Credit-related costs (e.g., costs associated with posting collateral).

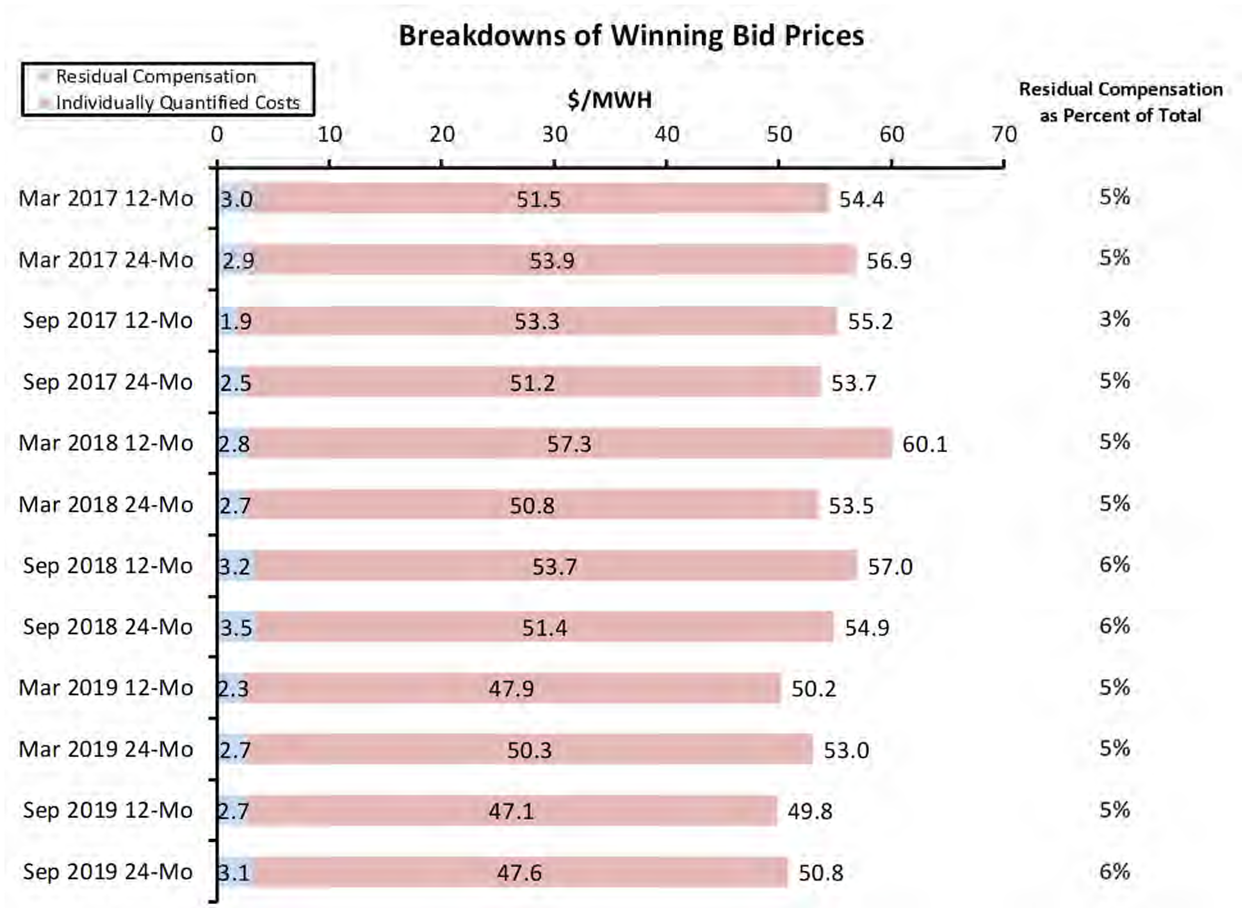
Again, my analysis does not include a quantification and deduction of these costs and risks from the winning bid prices. Therefore, winning bidders in the FPFR solicitations would need to cover these costs and risks in the residual compensation values that I calculated.

19. Q. What residual compensation values did you calculate when you deducted the values of the individually quantified cost components from the winning bid prices?

A. As the following exhibit shows, the residual compensation values for solicitations during DSP I, DSP II, and DSP III generally range between about $2 per megawatt-hour and about $5 per megawatt-hour (about 4% to 8% of the winning supply bid price).



Furthermore, as the following exhibit shows, the residual compensation values in PECO's DSP IV solicitations have been between about $2.50 per megawatt-hour and about $3.50 per megawatt-hour (about 5% to 6% of the winning supply bid price).



20. Q. Do you believe that the residual compensation values that you calculated are reasonable, considering the costs and risks assumed by the winning bidders in these solicitations to the benefit of customers?

A. Yes. As I explained earlier, the participation by multiple suppliers in these open solicitations helped to ensure that the winning prices were the lowest possible for the products being solicited. Furthermore, these residual compensation values represent only a small portion of the winning bid prices, especially considering the other costs and risks that I described above, which FPFR suppliers intend to cover through the residual compensation to the benefit of customers.

21. Q. Do the mix of one-year and two-year FPFR products in PECO's residential default service supply portfolio, and the semi-annual overlapping of their delivery periods, provide price stability benefits for residential customers?

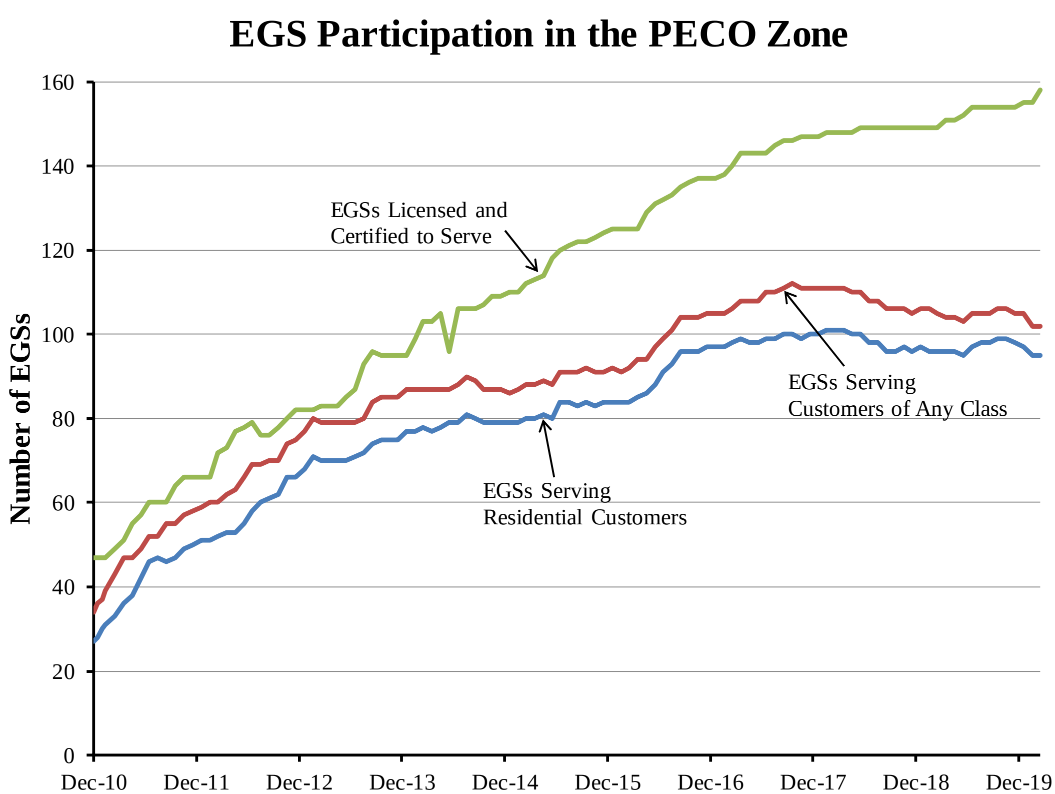
A. Yes, having a majority of two-year FPFR products supplemented almost entirely by one-year FPFR products, all with semiannually overlapping delivery periods, provides price stability benefits for residential customers. PECO's portfolio of overlapping one-year and two-year products limits the percentage of supply that must be solicited or replaced at any given time or in any given short period, thereby reducing the likelihood of significant rate changes due to adverse circumstances or market conditions at any given time. For example, the January 2014 solicitation was held at a time in which unprecedented short-term factors caused potential default service bidders to divert their attention and resources to urgent matters other than PECO's solicitation.[24] This resulted in higher residual compensation values and some unsubscribed tranches. However, PECO's residential product mix and overlapping

[24] During the weeks leading up to PECO's January 2014 solicitation, the regional energy market was in the throes of a prolonged, record-breaking, cold spell. All conventional forms of generation were challenged. As a result, hourly wholesale energy market prices were very volatile during January 2014. It is likely that potential default service bidders needed to divert resources to urgent portfolio management issues precipitated by the extreme market conditions at the time of PECO's January 2014 default service supply solicitation, resulting in low bidder participation. In addition, in light of the urgencies caused by the weather-related turbulence in the markets, both PJM and the neighboring New York Independent System Operator, Inc. ("NYISO"), submitted filings shortly before bids in PECO's default service supply solicitation were due, intervenors were required to file their comments on these filings within one week after the filings were made, and numerous parties dedicated resources to developing and submitting comments in these proceedings in the short periods allotted. Furthermore, bids were due in multiple other default service supply solicitations on the same day or within one day of PECO's January 2014 solicitation's bid due date. Given the issues related to the market-related events that I have described, potential bidders may have had abnormally limited resources available to fully compete in multiple default service supply solicitations at that time, and some may have chosen to focus on solicitations other than PECO's. (PECO Energy Statement No. 3 (Direct Testimony of Scott G. Fisher) in Docket No. P-2014-2409362. *Petition of PECO Energy Co. for Approval of Its Default Serv. Program for the Period from June 1, 2015 through May 31, 2017*, pp. 18-21.)

delivery periods restricted the amount of supply that needed to be solicited in that solicitation to only 27.2% of the overall residential default service supply requirement, thereby limiting the effect on customer rates of the adverse conditions.

22. Q. Has the basic default service model used by PECO supported the competitive retail electricity market?

A. Yes. In fact, since the DSP I period began, competitive retail market activity in PECO's service area has grown considerably. As the following chart shows, there has been substantial growth in the number of EGSs competing in PECO's service area since the DSP I period began:[25]



[25] Data provided by PECO.

The number of EGSs licensed and certified to serve customers in PECO's service area has increased substantially since the start of DSP I, with 158 EGSs currently licensed and certified to serve customers.[26] Similarly, the number of EGSs serving PECO customers has roughly tripled since the DSP I period began, as has the number of EGSs serving PECO residential customers. Currently, 102 EGSs serve PECO customers, and 95 of these EGSs currently serve PECO residential customers.[27] Furthermore, 60% of PECO's total customer load is currently being served by an EGS, with switching percentages equal to 30% for the Residential class, 56% for the Small Commercial class, and 94% for the Consolidated Large Commercial and Industrial class.[28] In contrast, as of October 1, 2010, only a few months before supply deliveries under DSP I began, only 1.7% of PECO's total customer load was being served by an EGS.[29]

Clearly, PECO's transition from long-term, capped default service rates to default service rates based on competitive market pricing for PECO's prudent mix of default service supply products has supported a competitive retail market in PECO's service area.[30]

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[26] Source: PECO. Data is for the month ending February 25, 2020.

[27] Source: PECO. Data is for the month ending February 25, 2020.

[28] Source: PECO. Data is for the month ending February 25, 2020. The figure includes customers who will be switched to EGSs within 45 days. Percentages of load are based on kW.

[29] Figure is "Percentage of Customers Load (MW) Served By An Alternative Supplier As Of 10/1/2010" as found in "Pennsylvania Electric Shopping Statistics – October 1, 2010" published by the PA Office of Consumer Advocate.

[30] The successful phase-out of the block-and-spot aspect of the supply portfolio and the greater reliance on FPFR products also has supported retail market development. Specifically, this has decreased the likelihood of material reconciliations between supply costs and retail revenues that can distort default service rates and

III. EVALUATION OF PECO'S PROPOSED DSP V

23. Q. Please summarize PECO's proposed plan for DSP V.

A. PECO's proposed DSP V will continue the basic procurement strategy that was established in DSP IV, which includes procurement of a prudent mix of products from competitive wholesale suppliers and has supported retail market competition. The following chart provides a summary of the DSP V portfolio for each customer class:

DSP V

Residential	Small Commercial	Consolidated Large Commercial and Industrial
• 96% of the load is supplied by a mix of products in the following proportions: o 40% 1-year FPFR products with delivery periods that overlap on a semi-annual basis o 60% 2-year FPFR products with delivery periods that overlap on a semi-annual basis • The other 4% of the load is supplied by two tranches of 2-year FPFR products (approximately 3% of the supply) and spot purchases (approximately 1% of the supply) • All products are procured approximately two months before delivery of the product begins	Supplied by a mix of: o 50% 1-year FPFR products o 50% 2-year FPFR products • Delivery periods overlap on a semi-annual basis • All products are procured approximately two months before delivery of the product begins	• 100% spot-priced FR products with 1-year delivery periods • All products are procured approximately two months before delivery of the product begins

reduce the transparency of future default service rates, which is important for customers to make informed supply decisions.

24. Q. Mr. Fisher, the Act requires a default service plan to produce a prudent mix of contracts, and include prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.[31] What guidance has the Commission provided in interpreting that standard?

A. On October 4, 2011, the Commission entered its Second Default Service Rulemaking Order, in which it provided guidance regarding interpretation of the terms "least cost" and "prudent mix" as follows:

> [T]he ["least cost"] standard must give the DSP sufficient latitude to select contracts that constitute a "prudent mix" which includes a sufficient variety of products that adequately take into consideration price volatility, changes in generation supply, customer usage characteristics and the need to assure safe and reliable service.[32]
>
> In implementing default service standards, the Commission must be concerned about rate stability as well as other considerations such as ensuring a "prudent mix" of supply and ensuring safe and reliable service. In our view, a default service plan that meets the "least cost over time" standard should not have, as its singular focus, the achievement of the absolute lowest cost over the default service plan time frame but rather a cost for power that is both relatively stable and also economical relative to other options.[33]
>
> Price stability benefits are very important to some customer groups, so an interpretation of "least cost" that mandates subjecting all default service customers to significant price volatility through general reliance on short term pricing is inconsistent with Act 129's objectives.[34]
>
> We agree with the majority of parties that the "prudent mix" of contracts be interpreted in a flexible fashion which allows the DSPs to design their

[31] 66 Pa.C.S. § 2807(e)(3.4), and 66 Pa.C.S. § 2807(e)(3.7).

[32] *Default Serv. and Retail Elec. Mkts.*, Docket No. L-2009-2095604 (Order entered Oct. 4, 2011) ("*Second Default Service Rulemaking Order*"), p. 38.

[33] *Id.*, p. 40.

[34] *Id.*, p. 41.

> own combination of products that meets the various obligations to achieve "least cost to customers over time," ensure price stability, and maintain adequate and reliable service.[35]

> We do reject the positions of those parties that "prudent mix" be defined to always require a specific mix or percentage of types of contract components in each default service plan or a minimum of two types of products.[36]

25. Q. Do you believe that PECO's proposed DSP V incorporates a prudent mix of contracts, and includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis, as required by Section 2807(e)(3.4) and Section 2807(e)(3.7) of the Act?

A. Yes, I do. There are several reasons for this conclusion:

1. The procurement process is designed to ensure the least cost to customers by requiring qualified bidders in the supply product solicitations to compete and be selected based on the lowest price. Furthermore, when FPFR products are solicited, default service customers are provided the benefits of competition on all aspects of the full requirements supply obligation, including the portfolio management function.[37] It is reasonable to assume that bidders in the FPFR product solicitations will consider the costs and risks associated with all forms of supply available to them to satisfy their fixed-price full

[35] *Id.*, p. 60.

[36] *Id.*

[37] FPFR product suppliers have the responsibility for continuously satisfying the uncertain and constantly changing supply requirements at the agreed-upon price, and therefore must manage the associated costs and risks through their supply portfolio decisions.

requirements obligation, and will reflect in their bid prices the benefits of any opportunity that they believe is the least cost supply opportunity.

2. PECO's Plan predominantly relies on FPFR default service supply products, which are well-tested in the marketplace. These products have been successfully procured by PECO in DSP I, DSP II, DSP III, and DSP IV, and are frequently procured by utilities in Pennsylvania and in other jurisdictions.[38]

3. The types of products relied upon under the Plan have been shown to be reasonably priced. Specifically, the participation in the open solicitations for FPFR products, combined with my quantitative analysis of the prices from PECO's FPFR residential default service supply solicitations under DSP I, DSP II, DSP III, and DSP IV, indicate that the prices of such products are reasonable, considering the costs and risks assumed by the winning bidders in these solicitations to the benefit of customers.

4. The Commission has recognized the benefits of reliance on full requirements products in a default service portfolio, as it stated in its Second Default Service Rulemaking Order:

> The [full requirements] process insulates default supply customers from the volatility associated with wholesale market conditions

[38] Examples of specific jurisdictions in which full requirements supply products are procured include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Ohio, Pennsylvania, and Washington D.C.

> with the supplier bearing the risks of factors such as customer migration, weather, load variation and economic activity.[39]

> We do express a preference for continued reliance by DSPs on the [full requirements] approach to the extent this method best suits the DSP's particular procurement needs.[40]

The seller of an FPFR product is responsible for assuming, managing, and covering the financial costs and risks associated with electricity supply, while customers are protected against adverse market and/or generation cost outcomes. Sellers of FPFR products must satisfy their obligation, regardless of how much market prices or generation costs may increase during the delivery period and regardless of the default service load level. Yet if market prices decrease after these types of supply contracts are signed, customers may elect service from a lower cost competitive retail supplier.

5. PECO's Plan continues the use of a standard supply contract, which lets bidders know the terms and requirements of the default service supply obligation well in advance of the bid due date, and therefore allows qualified bidders to submit firm bid prices knowing that these contract terms and conditions will not change. The use of a standard contract also assures qualified bidders that the selection of the winning bidders will be an objective process. Consequently, the use of a standard contract encourages participation in the solicitations from a large number of potential suppliers.

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[39] *Second Default Service Rulemaking Order*, p. 54.

[40] *Id.*, p. 56.

6. PECO's Plan is also prudent because it includes tailored supply portfolios for different customer classes that take into account the benefits of price stability, the different shopping propensity of each customer class, and the desire to support the competitive retail market in PECO's service area.

26. Q. Has the Commission supported the use of a tailored supply portfolio for each customer class?

A. Yes. Specifically, in its Second Default Service Rulemaking Order, in its discussion of the "prudent mix" requirement under Act 129, the Commission stated:

> The Commission notes there was substantial unanimity on this point and agrees with the parties that the "prudent mix" standard should be interpreted to allow for a class-specific product mix that best matches the needs of each DSP customer class.[41]

27. Q. Does PECO's proposed DSP V include a reasonable degree of flexibility to accommodate the possibility of future changes in the default service supply approach?

A. Yes. PECO's proposed DSP V incorporates this flexibility in several ways. First, the default service supply product portfolio for the Consolidated Large Commercial and Industrial class does not include any supply products with delivery periods that extend beyond May 31, 2025, the end of the DSP V period. As a result, the Commission can easily adopt a similar plan or a very different plan for the period starting June 1, 2025, without the need to face situations involving pre-existing

[41] *Second Default Service Rulemaking Order*, p. 69.

default service supply products for this customer class with deliveries that extend beyond the DSP V period.

Second, the first solicitation for Residential and Small Commercial supply products with delivery periods that extend beyond May 31, 2025 (the end of the DSP V period) does not occur until September 2023. As a result, there is a significant amount of time before commitments to new supply products extending beyond the DSP V period are made, should changes need to be made due to legislative or regulatory mandates. In the meantime, these solicitations remain scheduled because they allow for the option for a fairly seamless continuation of the laddered procurement cycle as PECO transitions from DSP V to DSP VI,[42] and they avoid subjecting Residential and Small Commercial customers to a "hard stop" with regard to their supply products at the end of the DSP V period. This is consistent with the approach approved by the Commission in DSP II, DSP III and DSP IV, and it helps to avoid the need to replace a large portion of default service supply in a short period at the end of the DSP V period. Customers could be exposed to magnified risks and rate instability if a default service plan were to require that a large portion of the customers' default service supply must be procured in a short period.

Finally, PECO's proposed DSP V provides flexibility because it relies on full requirements supply products. Full requirements products provide just enough supply

[42] In its Second Default Service Rulemaking Order, the Commission recognized the importance of "laddering" contracts in procuring default service supply. Specifically, the Commission stated, "We agree with those parties that utilizing such practices as laddering contracts, with varying procurement periods and contract durations over multiple procurements provide definite benefits in terms of minimizing the impacts of market volatility and decreasing customer risk." (*Second Default Service Rulemaking Order*, pp. 62-63.)

to satisfy the actual load obligations, thereby mitigating the risk of being saddled with commitments to purchase supply that is not needed. This is especially valuable given ongoing uncertainty about future customer migration.

28. Q. Is PECO's Plan designed to support the competitive retail electricity market?

A. Yes. As in previous PECO default service plans, EGSs will compete against market-based default service rates, as the default service rates will be based on the prices for supply products obtained through competitive solicitations in which multiple bidders compete to sell the products solely on the basis of price. In addition, the use of FPFR supply products for the Residential and Small Commercial classes will allow those classes' default service rates to closely match the market-based supply costs, reducing the likelihood of significant over- and under-collections from retail customers and enhancing rate transparency for retail supply decisions.[43] Furthermore, the FPFR supply products and their procurement timing under PECO's proposed DSP V will result in a relatively stable and transparent residential price-to-compare benchmark against which residential customers can compare competing retail offers. Finally, as discussed by PECO witnesses John J. McCawley (PECO Energy Statement No. 1)

[43] Over- and under-collections are related to the degree to which actual costs during a given period may vary from the retail rates that were set for that period. If there is significant uncertainty about the all-in dollar-per-megawatt-hour default service supply cost for an upcoming rate period when the default service retail supply rate for that period is set, then the likelihood of significant over- and under-collections is increased. This is the case when a block-and-spot supply component is included in the portfolio, because under the block-and-spot approach the electric distribution company must forecast future default service loads and spot prices, and actual outcomes may deviate significantly from the forecasted values. In contrast, FPFR products generally entail very little uncertainty about the default service supply costs on a dollars-per-megawatt-hour basis for any given upcoming rate period at the time that the default service retail rate for that period is set, effectively reducing the potential for significant over- or under-collections. It should be noted that over- and under-collections also can occur due to billing cycle lag.

and Carol Reilly (PECO Energy Statement No. 3), PECO will continue its existing Standard Offer Program through May 31, 2025.

29. Q. Do you believe that FPFR suppliers' bid prices will be noticeably higher due to PECO's proposal to include the supply for PECO's Time-of-Use ("TOU") default service customers in the FPFR products?[44]

A. No. Both the standard default service and the TOU default service will be supplied via the same FPFR products, so customer switching between standard default service and TOU default service will not cause load uncertainty issues that the suppliers otherwise may be expected to price into their bids.[45] Furthermore, since suppliers will be paid the same price for a megawatt-hour of supply whether that supply is for a standard default service customer or a TOU default service customer, suppliers will not bear any revenue risk associated with whether a given megawatt-hour of supply is needed by a standard default service customer or a TOU default service customer. In addition, to the extent that customers elect TOU default service and shift their usage to lower-priced periods or reduce their usage during higher-priced periods, the underlying market-based cost to supply the customers could be reduced, resulting in lower FPFR supplier bid prices over time. Finally, experience with opt-in time-of-use programs indicates that the number of customers who elect PECO's TOU default

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44 In PECO Energy Statement No. 2, PECO witness Joseph A. Bisti describes PECO's TOU default service proposal in detail.

45 In contrast, if the supply for the TOU default service customers were solicited separately, the suppliers of the standard default service FPFR supply products would bear additional risks related to customer switching to and from the TOU default service option. PECO's proposal eliminates these risks and is relatively easy to administer.

service is likely to be relatively small relative to the overall default service customer base. If TOU default service is expected to represent a small percentage of a given FPFR product's supply, then any effects of the TOU default service offering on the FPFR product supplier's bid price should be small.

IV. CONCLUSION

30. Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY	:	
COMPANY FOR APPROVAL OF ITS	:	**Docket No. P-2020-3019290**
DEFAULT SERVICE PROGRAM FOR	:	
THE PERIOD FROM JUNE 1, 2021	:	
THROUGH MAY 31, 2025	:	

PECO Exhibit No. SG-1
(Response of the Environmental Stakeholders to PECO Interrogatory (ES) I-2)

Pennsylvania Public Utility Commission
v.
PECO Energy Company

Petition of PECO Energy Company for Approval of
Default Service Program

Docket No. P-2020-3019290

Response of Environmental Stakeholders
to Interrogatories of PECO Energy Company
PECO-ES Set I.
Response Date: 06/29/2020

PECO-ES-I-2

Reference ES Statement No. 1, p. 3, line 8, through p. 4, line 7, where Mr. Rábago makes eight recommendations to develop and implement a planning process:

a. Does Mr. Rábago have an estimate of the time required to develop this planning process? If so, how long would the planning process take to develop?

b. Please describe the various steps involved in developing a planning process. Who would be involved in developing the process?

c. Does Mr. Rábago have an estimate of the time required to implement the recommended planning process? If so, how long would the planning process take to implement?

d. Does Mr. Rábago have an estimate of the cost required to develop and implement the recommended planning process? If so, provide any cost estimates and any support for those cost estimates.

e. Under Mr. Rábago's recommendation, who would pay for the costs of developing and implementing this planning process? How would the recovery of such costs be allocated?

RESPONSE

a. The time required to develop the recommended planning process depends primarily on the planning capabilities of PECO Energy Company ("the Company"). Developing the planning process should take relatively little time compared to developing the plan and executing the resulting competitive processes. Mr. Rábago recommends benchmarking the process against other planning processes, such as development of an integrated resource plan ("IRP").
b. The steps and participants for the planning process are a direct function of the identification of planning goals. As with any good planning process, the steps should include goal identification, resource and capabilities inventory, decisional protocols, budget and participant task identification, timeline development, stakeholder engagement, Pennsylvania Public Utility Commission ("Commission") and Staff review, and plan execution.

c. Mr. Rábago does not have a specific time estimate for the process. A number of other decisions associated with structure of the adopted process will influence the time required to implement the recommended planning process. The time required should be a key issue considered by the Company when it develops the planning and implementation processes. The time required to implement the planning process should be benchmarked against current planning processes, with appropriate adjustments based on market factors and the Company's ability to execute.
d. Mr. Rábago has not developed a cost estimate.
e. Mr. Rábago did not address cost recovery in his testimony. He presumes that cost recovery for an improved planning process that better aligns with the requirements of law and regulation will be recovered in the same manner as costs associated with the current approach used by the Company.

Responsible Witness: Karl Rábago

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY	:	
COMPANY FOR APPROVAL OF ITS	:	**Docket No. P-2020-3019290**
DEFAULT SERVICE PROGRAM FOR	:	
THE PERIOD FROM JUNE 1, 2021	:	
THROUGH MAY 31, 2025	:	

PECO Exhibit No. SG-2
(Response of the Environmental Stakeholders to PECO Interrogatory (ES) I-4)

Pennsylvania Public Utility Commission
v.
PECO Energy Company

Petition of PECO Energy Company for Approval of
Default Service Program

Docket No. P-2020-3019290

Response of Environmental Stakeholders
to Interrogatories of PECO Energy Company
PECO-ES Set I.
Response Date: 06/29/2020

PECO-ES-I-4

Reference ES Statement No. 1, p. 3, lines 17-18, where Mr. Rábago recommends that PECO be directed to develop and implement a planning process "that transparently evaluates the full range of cost and benefits associated with supply options over time."

a. List and describe the full range of costs associated with supply options over time to which Mr. Rábago is referring.

b. For each item listed, provide how Mr. Rábago proposes to quantify each cost item in terms of dollars per MWH or some other unit of measure over time.

c. Explain how Mr. Rábago would transparently evaluate the full range of costs associated with supply over time across different supply options.

d. List and describe the full range of benefits associated with supply options over time to which Mr. Rábago is referring.

e. For each item listed, provide how Mr. Rábago proposes to quantify each benefit item in terms of dollars per MWH or some other unit of measure over time.

f. Explain how Mr. Rábago would transparently evaluate the full range of benefits associated with supply over time across different supply options.

g. Explain how the full range of costs and benefits associated with the supply options will be evaluated transparently. Will there be an objective, predetermined evaluation process that would allow multiple evaluators, acting independently, to reach the same conclusion about the appropriate default service supply portfolio? Explain your answer.

RESPONSE

a. Mr. Rábago recommended an approach similar to the evaluation processes used in developing an IRP. While Mr. Rábago did not develop or offer a specific list of costs and benefits to be evaluated to ensure a supply portfolio that ensured least cost over time, reference to IRP processes would be a reasonable starting position.
b. See above response to ES-I-4.a.

c. See above response to ES-I-4.a.
d. See above response to ES-I-4.a.
e. See above response to ES-I-4.a.
f. See above response to ES-I-4.a.
g. See above response to ES-I-4.a.

Responsible Witness: Karl Rábago

PECO ENERGY COMPANY
STATEMENT NO. 4-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-3019290

REBUTTAL TESTIMONY

WITNESS: SCOTT G. FISHER

SUBJECT: DEFAULT SERVICE PROCUREMENT

DATED: JULY 9, 2020

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REBUTTAL TESTIMONY
OF
SCOTT G. FISHER

I. INTRODUCTION AND PURPOSE OF REBUTTAL TESTIMONY

1. Q. Please state your full name, professional position, and business address.

A. My name is Scott G. Fisher. I am a Partner at The NorthBridge Group, which is an economic and strategic consulting firm serving the electric and natural gas industries. My business address is 30 Monument Square, Suite 105, Concord, Massachusetts, 01742.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted direct testimony that is marked as PECO Statement No. 4. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The main purpose of my testimony is to respond to arguments and recommendations offered by Environmental Stakeholders[1] witness Karl R. Rábago and Electric Supplier Coalition ("ESC")[2] witness Travis Kavulla regarding the default service supply product mix and procurement approach. My rebuttal testimony is divided into two parts. First, after providing a brief contextual overview of various intervenor testimony relating to PECO's proposed default service plan (the "Default Service

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[1] The Environmental Stakeholders are Clean Air Council, Sierra Club/PA Chapter, and Philadelphia Solar Energy Association.

[2] The Electric Supplier Coalition's members are NRG Energy, Inc.; Direct Energy Services LLC; Interstate Gas Supply Inc., d/b/a IGS Energy; Vistra Energy Corp.; Shipley Choice LLC; ENGIE Resources LLC; and WGL Energy Services, Inc.

Plan" or "Plan" or "DSP V") for the period beginning June 1, 2021 and ending May 31, 2025, I respond to specific arguments offered by Mr. Rábago regarding the default service supply product mix. Second, I respond to Mr. Kavulla's recommendation that the Pennsylvania Public Utility Commission (the "Commission") transition PECO out of the default service provider role.

4. Q. Please summarize your major conclusions.

A. My main conclusion is that neither Mr. Rábago nor Mr. Kavulla provides any arguments that invalidate the fact that PECO's proposed Default Service Plan complies with the requirement of Pennsylvania's Act 129 of 2008 (the "Act" or "Act 129") that the plan include a "prudent mix" of contracts designed to ensure the least cost to customers over time.[3] In particular:

1. The arguments offered by the Environmental Stakeholders regarding the default service supply product mix should be rejected. Specifically:
    a. PECO considered several factors other than "least price" when assessing whether its plan satisfies the "least cost" standard of Act 129, and its plan incorporates Pennsylvania's existing environmental policies that promote clean energy generation as well as flexibility for changes in these policies that result from their continued development.
    b. Mr. Rábago's recommendation to increase the share of long-

[3] 66 Pa.C.S. § 2807(e)(3.4).

term contracts in PECO's Plan would impose unnecessary risks on default service customers and provide less flexibility to adapt to changes in market and regulatory conditions.

2. ESC's recommendation that the Commission transition PECO out of the default service provider role raises legitimate public policy concerns with the potential for significant customer harm.

Each of these findings is discussed further below.

5. Q. Mr. Fisher, before addressing specific arguments, please provide a contextual overview of various intervenor testimony. Which intervenors have voiced general concerns about PECO's proposed default service supply product mix or procurement approach?

A. Environmental Stakeholders witness Rábago claims that PECO "has failed to show that its proposed DSP V will meet Act 129's required standard of producing a supply mix that reflects a prudent mix of contracts designed to ensure adequate and reliable supply, least cost over time, and reliance on contracting methods that can meet prudent mix requirements."[4] In addition, ESC witness Kavulla claims that PECO's DSP V will not realize "the intended benefits" of the Electricity Generation Customer Choice and Competition Act.[5]

[4] Environmental Stakeholders Statement No. 1, p. 28.

[5] ESC Statement No. 1, pp. 10-14.

6. Q. How do the positions of these two parties relate to each other with respect to the default service supply product mix and procurement approach in PECO's proposed DSP V?

A. These two parties offer very different perspectives, and their recommendations represent opposite ends of the spectrum with respect to the default service supply product mix and procurement approach. On the one hand, Mr. Rábago recommends that PECO actively manage a portfolio of supply products and procurements, taking on "the full job of managing a supply portfolio with diverse supply resources," as Mr. Rábago's opinion is that Pennsylvania law and the Commission's regulations require this of PECO.[6] According to Mr. Rábago, PECO should develop and implement a process that actively engages a wide range of stakeholders in the processes, decisions, and assumptions regarding the default service supply products to be procured.[7] In stark contrast, Mr. Kavulla recommends that the Commission "lay the groundwork" to transition PECO out of the default service role entirely, and rely on EGSs to offer default service supply on behalf of customers who do not affirmatively choose to be served by a specific EGS or whose EGS defaults on its commitment to supply the customer.[8] According to Mr. Kavulla, this will better support the competitive retail market for electricity in PECO's service area.[9] Moreover, while Mr. Rábago recommends that PECO incorporate a larger share of long-term contracts in its default

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6 Environmental Stakeholders Statement No. 1, p. 20.

7 *Id.*, pp. 3-4.

8 ESC Statement No. 1, p. 11.

9 *Id.*, p. 12.

service supply mix,[10] Mr. Kavulla recommends that PECO incorporate no long-term contracts in its default service supply mix.[11]

7. Q. Do any other parties in this proceeding oppose PECO's proposed default service supply product mix or procurement approach?

A. No other intervenor has expressed any opposition to PECO's proposed default service supply product mix or procurement approach, with the exception of a concern voiced by the Office of Consumer Advocate ("OCA") about a 1% "spot energy" portion of the residential supply portfolio,[12] which PECO witness John J. McCawley addresses in PECO Statement No 1-R. In putting his concern into context, OCA witness Stephen L. Estomin states, "In general, I view the composition of the proposed residential Default Service supply portfolio favorably."[13] Furthermore, Dr. Estomin notes, "The mix of 12- and 24-month [FPFR supply products] represent a reasonable balance between rate stability, which is extremely important to residential customers, and the charges reflecting competitive market conditions."[14]

[10] Environmental Stakeholders Statement No. 1, pp. 20-21, 23.

[11] ESC Statement No. 1, p. 27.

[12] OCA Statement No. 1, p. 11.

[13] *Id.*

[14] *Id.*

8. Q. To support his position that PECO should "rebuild its default service program from the ground up,"[15] Mr. Rábago states, "[T]he supply procured by the Company is unrelated to customer preferences and therefore is less likely to support the development of competitive markets."[16] How do you respond?

A. Mr. Rábago is incorrect. The statutory parties and other intervenors have either voiced their support for PECO's proposed default service supply product mix and procurement approach, or have not voiced any opposition.[17]

9. Q. At a high level, what do these facts indicate about PECO's proposed default service supply mix and procurement approach?

A. I will address in detail the specific positions of the intervenors later in my testimony. But at a high level, the fact that no intervenor has voiced any major concerns with regard to the default service supply product mix and procurement approach, except two intervenors that have diametrically opposed positions, indicates that PECO's DSP V strikes a reasonable balance of competing perspectives. PECO's carefully designed approach incorporates stakeholder input through evidentiary proceedings as well as past Commission approvals of both PECO's tailored supply portfolios for different customer classes[18] and the results of default service supply solicitations. It

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[15] Environmental Stakeholders Statement No. 1, p. 28.

[16] *Id.*, p. 26.

[17] See direct testimony on behalf of the OCA, OSBA, CAUSE-PA, and TURN. As noted previously, the OCA voiced a concern about a 1% portion of the residential supply portfolio, but it otherwise supported PECO's approach to supply default service for residential customers.

[18] PECO Energy Company Statement No. 4, p. 27.

provides the benefits of competition on all aspects of the full requirements supply obligation (including the portfolio management function) through the procurement of fixed-price full requirements ("FPFR") products,[19] and it incorporates design components to support the competitive retail electricity market.[20]

II. THE ARGUMENTS OFFERED BY THE ENVIRONMENTAL STAKEHOLDERS REGARDING THE DEFAULT SERVICE SUPPLY PRODUCT MIX SHOULD BE REJECTED

10. Q. Environmental Stakeholders witness Rábago claims that PECO "has failed to show that its proposed DSP V will meet Act 129's required standard of producing a supply mix that reflects a prudent mix of contracts designed to ensure adequate and reliable supply, least cost over time, and reliance on contracting methods that can meet prudent mix requirements."[21] Do you agree?

A. No. I provided extensive findings in my direct testimony that support the fact that PECO's proposed DSP V incorporates a prudent mix of contracts designed to ensure least cost to customers over time, taking into account the benefits of price stability, and includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis, as required by Section 2807(e)(3.4) and Section 2807(e)(3.7) of the Act.[22]

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19 *Id.*, p. 24.

20 *Id.*, pp. 29-30.

21 Environmental Stakeholders Statement No. 1, p. 28.

22 PECO Energy Company Statement No. 4, pp. 23-27.

11. Q. Has the Commission previously concluded that the type of default service supply product mix and procurement approach which PECO is proposing for DSP V satisfies the requirements of Act 129?

A. Yes. PECO's proposed DSP V will continue the basic procurement strategy that was established in DSP IV and approved by the Commission.[23]

12. Q. What arguments and associated recommendations does Mr. Rábago offer to support his claim that PECO has failed to show that its DSP V meets the standards of Act 129?

A. Mr. Rábago presents the following arguments and recommendations:

- PECO reads and applies the term "least cost" as "least price" and does not account for all the cost factors associated with supply over time.[24]
- PECO's approach essentially reads the words "over time" out of the law, regulation, and policy,[25] and PECO should increase the reliance on long-term contracts, especially for renewable energy supply contracts that include solar and wind energy, in the default service supply mix.[26]

I address these arguments and recommendations in the subsections that follow.[27]

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[23] PECO Energy Company Statement No. 4, pp. 9 and 22, referencing *Petition of PECO Energy Co. for Approval of Its Default Serv. Program for the Period from June 1, 2017 through May 31, 2021*, Docket No. P-2016-2534980 (Order entered Dec. 8, 2016).

[24] Environmental Stakeholders Statement No. 1, p. 22.

[25] *Id*.

[26] *Id.*, p. 18, 23.

[27] Mr. Rábago also claims that PECO should "rebuild its default service program from the ground up," actively

A. PECO Considered Several Factors Other Than "Least Price" When Assessing Whether Its Plan Satisfies the "Least Cost" Standard Of Act 129, and Its Plan Incorporates Pennsylvania's Existing Environmental Policies That Promote Clean Energy Generation as Well as Flexibility for Changes in These Policies that Result from Their Continued Development

13. Q. What claims does Mr. Rábago make about the breadth of PECO's interpretation of the "least cost" standard under Act 129?

A. Mr. Rábago argues that PECO has not interpreted the "least cost" standard broadly enough, as he claims that PECO reads and applies the term "least cost" as "least price."[28] Accordingly, Mr. Rábago concludes that PECO's Plan "does not account for all the cost factors associated with supply over time"[29] and "predetermines the range of successful bidders," thereby limiting the bidders that can respond to the default service supply solicitations.[30]

14. Q. Is Mr. Rábago accurate in claiming that PECO "applies the term 'least cost' as 'least price' and does not account for all the cost factors associated with supply over time?"

A. No. PECO considered several factors other than "least price" when determining whether its DSP V Plan satisfies the requirements of Act 129. I evaluated PECO's

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managing a portfolio of supply products and procurements and taking on "the full job of managing a supply portfolio with diverse supply resources," as Mr. Rábago's opinion is that the law and regulations require this of PECO. (Environmental Stakeholders Statement No. 1, pp. 20, 28.) In addition, he claims that PECO has not explained how its proposed DSP V is designed to ensure adequate and reliable service to customers. (Environmental Stakeholders Statement No. 1, p. 23.) PECO witness McCawley addresses these contentions, as well as specific claims made by Mr. Rábago that are exclusive to distributed generation, in PECO Statement No. 1-R.

[28] Environmental Stakeholders Statement No. 1, p. 22.

[29] *Id.*

[30] *Id.*, p. 20.

DSP V with respect to certain requirements of Act 129, specifically that the plan include a prudent mix of contracts designed to ensure the least cost to customers over time, taking into account the benefits of price stability, and includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis, as required by Section 2807(e)(3.4) and Section 2807(e)(3.7) of the Act. The mix of products selected for the proposed portfolio for each customer class is designed to satisfy the requirements of Act 129, considering price and other factors.

15. Q. In PECO's DSP V, how does lowest price relate to other factors that were considered to ensure the satisfaction of the "least cost" standard of Act 129?

A. Act 129 requires that a default service plan include a "prudent mix" of contracts designed to ensure the least cost to customers over time.[31] Several factors contribute to defining the specific prudent mix of products to be procured to ensure least cost.[32] After the Commission approves the program to procure standardized products that comprise the prudent mix, winning bidders will be selected in the solicitations based on the lowest price offers.

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[31] 66 Pa.C.S. § 2807(e)(3.4).

[32] These factors include tailoring the overall price stability levels to the needs of the various customer classes (even in the face of changing loads and customer migration), the extent to which the design of the products covers all supply needs and harnesses competitive market forces in doing so, the likelihood that the competitive procurement processes for the products will encourage bidder participation in the product solicitations, whether the mix includes a reasonable degree of flexibility to accommodate the possibility of future changes in the default service supply approach, whether the mix is designed to support the competitive retail electricity market, and whether successful solicitations for the products are likely to result in reasonable prices. In my direct testimony, I explain how PECO's proposed Plan addresses each of these factors. (PECO Energy Company Statement No. 4, pp. 24-29.)

16. Q. How do you respond to Mr. Rábago's claim that PECO's choice of generally shorter-term full requirements supply products "predetermines the range of successful bidders," thereby limiting the bidders that can respond to the default service supply solicitations and "discriminating against renewable energy?"[33]

A. As I explained in my direct testimony, PECO's solicitations for full requirements supply products have attracted many qualified suppliers.[34] The participation by multiple suppliers in PECO's open solicitations, combined with the quantitative analysis of the results of these solicitations presented in my direct testimony,[35] indicate that the resulting contract prices obtained by PECO have been reasonable, considering the costs and risks that the suppliers under these contracts assume to the benefit of customers.

Furthermore, PECO's reliance on full requirements supply products is especially conducive to innovation and competition with respect to all aspects of the electricity supply obligation, encouraging a wide range of supply options to be considered by the winning bidders to satisfy their full requirements obligation, as opposed to limiting the supply options by restricting the supply procured by PECO to certain types. Through the procurement of full requirements supply products, PECO's Plan is designed to ensure the least cost to customers because bidders compete on the basis of the lowest price to satisfy <u>all</u> aspects of the default service customers' load

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33 Environmental Stakeholders Statement No. 1, pp. 20, 36.

34 PECO Energy Company Statement No. 4, p. 10.

35 *Id.*, pp. 11-18.

requirements, including the portfolio management function.[36] Suppliers of the full requirements products that PECO has proposed to solicit are free to procure the products and follow the procurement strategies that they believe will result in the least-cost full requirements supply, and they have the economic incentives to consider any supply opportunity that would allow them to offer a lower-priced bid and to satisfy their default service supply obligation at the lowest cost. This includes utilizing increased amounts of renewable generation if the renewable generation cost reductions that Mr. Rábago references in his testimony[37] make increasing renewable generation utilization the lowest cost option for default service suppliers. Consequently, PECO's Plan does not "discriminate against renewable energy," as Mr. Rábago claims.[38]

17. Q. How do you respond to Mr. Rábago's claim, "The Company recognizes that the DSP procurement practice of only sourcing FPFR supply contracts drives the competitive market to compete on the same terms, which would likely weaken competition and product innovation in the choice market,"[39] citing PECO's response to an interrogatory served upon PECO by the Environmental Stakeholders?

A. Mr. Rábago's argument is flawed, and it is not supported by PECO's response to the

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[36] This includes responsibility for continuously satisfying the uncertain and constantly changing supply requirements at the agreed-upon price, and therefore involves management of the associated costs and risks.

[37] Environmental Stakeholders Statement No. 1, pp. 10-11.

[38] *Id.*, p. 36.

[39] *Id.*, p. 19.

interrogatory to which Mr. Rábago refers and which he attached to his direct testimony.[40] PECO's response identifies multiple ways that competitive markets are promoted by adopting PECO's proposed prudent mix of full requirements products. Mr. Rábago provides no explanation as to how PECO's response supports his position. However, specific text from PECO's response, to which Mr. Rábago refers, explains that PECO's proposed fixed-price full requirements product approach will produce a relatively stable and transparent residential price-to-compare benchmark against which residential customers can compare competing retail offers.[41]

I can only speculate that Mr. Rábago is contending that this implies that the fixed-price full requirements product approach constrains EGS offers to the same terms and conditions as the default service offering, with EGS offers only differentiating themselves on the basis of price. In fact, this is not the case. To the extent that customers demand service offerings that differ along dimensions such as delivery period, pricing structure, and generating source, EGSs can make offers that meet those customer demands. In fact, contrary to Mr. Rábago's contention that PECO's approach "drives the competitive market to compete on the same terms,"[42] in the competitive market EGSs have the incentive to offer terms of service that are demanded by customers who prefer different terms than those provided by default service. At the same time, the relatively stable and transparent residential price-to-

[40] *Id.*, Ex. KRR-3, p. 43.

[41] *Id.*, p. 19, footnote 45.

[42] *Id.*, p. 19.

compare benchmark provides transparent market information for customers to make educated service choices, especially to the extent that a customer does prefer to be served under terms similar to those associated with default service (but at a lower price).

18. Q. Please respond to Mr. Rábago claims that PECO's Plan does not take advantage of lower emissions from renewable energy generation,[43] and that it should include due consideration of reduced environmental compliance risk.[44]

A. PECO's Plan incorporates Pennsylvania's existing environmental policies that promote clean energy generation, and it has the flexibility to incorporate changes in these policies that result from the continued development of these policies. For example, PECO's default service obligation under Act 129 incorporates the requirements of the Alternative Energy Portfolio Standards Act ("AEPS Act"), which establishes the alternative energy portfolio standard for Pennsylvania.[45] As explained by PECO witness McCawley, PECO's DSP V ensures compliance with Alternative Energy Portfolio Standard ("AEPS") requirements for renewable generation through multiple means and contingency plans.[46] Furthermore, PECO's Plan accommodates any future legislation that modifies the Alternative Energy Portfolio Standard quantity requirements pertaining to renewable generation, by requiring the default service

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43 *Id.*, p. 25.

44 *Id.*, p. 3.

45 66 Pa.C.S. § 2807(e)(3.5).

46 PECO Energy Company Statement No. 1, pp. 14, 26-27, 27-35.

suppliers to provide the resultant modified percentages of Alternative Energy Credits.

In addition, PECO's Plan is designed to incorporate the developing Pennsylvania policies pertaining to greenhouse gas emissions, which most recently stem from "Executive Order 2019-07: Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions," as amended and issued by Governor Wolf on June 22, 2020. As part of his direction in this Executive Order, Governor Wolf has required that the Department of Environmental Protection, by no later than September 15, 2020, develop and present to the Pennsylvania Environmental Quality Board a proposed rulemaking package to abate, control, or limit carbon dioxide emissions from fossil-fuel-fired electric power generators.[47] This proposed rulemaking shall establish a carbon dioxide budget consistent in stringency to that established in the Regional Greenhouse Gas Initiative ("RGGI") participating states and provide for the annual or more frequent auction of carbon dioxide emissions allowances through a market-based mechanism.[48] PECO's Plan is designed to incorporate the facets of this policy as it further develops, specifically with respect to the cost associated with carbon dioxide emissions that this policy will require electric generation resources that emit carbon dioxide in Pennsylvania to internalize, to the benefit of clean energy generation resources.

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47 Executive Order 2019-07: Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, June 22, 2020.

48 *Id.*

19. Q. How do you respond to Mr. Rábago's position that PECO's Plan should incorporate more renewable energy resources?[49]

A. Mr. Rábago does not present a specific plan as to how this would be done or how much more renewable energy should be procured, but presumably he is referring to making dedicated procurements for renewable energy supply above the percentages required by the AEPS Act.[50] Before I address this concept, it is important to note that PECO's Plan does not limit the amount of renewable energy that is procured. Instead, as I have explained previously, PECO's Plan leverages competition to encourage innovation and determine the least cost options to procure default service supply. If increased renewable generation utilization is the lowest cost option for default service suppliers, then the suppliers have the economic incentive to take advantage of this option when formulating the lowest price bids possible in PECO's default service supply solicitations and when satisfying their default service supply obligations.[51] This approach is aligned with the Commission's guidance regarding the Act 129's "least cost" standard, as the Commission has explained that this standard "requires the DSP to develop a procurement plan that will capture the benefits of the

49 Environmental Stakeholders Statement No. 1, pp. 3, 30.

50 On page 18 of Environmental Stakeholders Statement No. 1, Mr. Rábago alludes to greater reliance on long-term contracts for renewable generation. I discuss the use of long-term contracts later in my testimony.

51 This point also dispels Mr. Rábago's assertion, on page 27 of Environmental Stakeholders Statement No. 1, that PECO's Plan does not create an opportunity for default service customers to contribute to incremental reductions in greenhouse gases beyond the minimums required by law. In addition, under PECO's Plan, default service customers may elect service from an EGS that includes a relatively high portion of supply from clean energy generation, if they wish.

competitive wholesale market and reflect the lowest rates to customers over the term of the plan and beyond."[52]

Attempting to use a utility's default service proceeding to place restrictions on the types of generation that should be included in the supply portfolio for the utility's default service offering, beyond the restrictions established in Pennsylvania law, could cause serious issues detrimental to overall policy goals. Specifically, dedicated default service supply procurements for renewable energy above the percentages required by the AEPS Act could result in higher customer rates and significant fairness issues, thereby jeopardizing the "least cost" benefits intended by Act 129.

20. Q. How could dedicated default service supply procurements for renewable energy above the percentages required by the AEPS Act raise customer rates and cause significant fairness issues, thereby jeopardizing the "least cost" benefits intended by Act 129?

A. By placing restrictions (beyond those imposed by the AEPS Act) on the types of generation that can supply all or part of the default service obligation, lower priced types of generation could be restricted from competing to provide their supply, which would result in higher prices for default service supply and therefore higher default service rates for customers. As noted in the Pennsylvania Department of Environmental Protection's "Pennsylvania's Solar Future Plan," which Mr. Rábago has attached to his direct testimony as Exhibit KKR-9, "Programs such as renewable

[52] Second Default Service Rulemaking Order, p. 39.

portfolio standards better isolate specific desired outcomes (i.e. more solar) but they do not necessarily achieve the underlying policy goal (emissions reduction) at the lowest possible cost because they are not driving economy-wide efficiencies."[53]

In addition, placing limits (beyond those imposed by the AEPS Act) on the types of generation that can supply all or part of the default service obligation could raise fairness issues along multiple dimensions. First, only the default service supply portfolio would be subject to the restrictions regarding the types of generation. This could result in two potential outcomes. Either the resultant higher price-to-compare benchmark would reduce the incentive for EGS offers to be as low as possible, resulting in higher priced EGS offers to customers, or the higher default service rates would create an incentive for more default service customers to switch to EGS service, leaving the costs of the renewable energy supply to be incurred by a smaller default service customer base, thereby further driving up the default service rates.

Another fairness issue relates to customers in PECO's service area versus those in other Pennsylvania utility service areas. Specifically, given that clean energy provides climate benefits that are not restricted to local areas, fairness issues could arise if some Pennsylvania citizens are forced to bear costs associated with safeguarding our climate while other Pennsylvania citizens are not required to bear these costs.

Fairness issues also could arise between generation resources, and these issues could jeopardize the ability of the approach to achieve the emission reductions for which it

[53] Environmental Stakeholders Statement No. 1, Exhibit KKR-9, p. 97.

is intended. Specifically, in a competitive market where prices are set by supply and demand dynamics, increasing the supply in the market from one type of clean generation technology (e.g., wind and solar, as suggested by Mr. Rábago)[54] through dedicated procurements for supply that are restricted to that type of generation technology will tend to have wholesale market price effects that lessen the incentives for other clean generation resources (e.g., nuclear and hydroelectric) or carbon mitigating resources to enter or remain in the market. While the full spectrum of clean generation resources provides clean energy, some would be favored while others would be penalized, and achievement of the intended emissions reductions would be jeopardized by the possibility that the policy that mandates one type of clean energy generation contributes to the closure or deferred entry of another clean energy generation resource. In addition, the costs to customers would be magnified to the extent that the cost of the clean energy resource that closed or deferred entry was less than the cost of the type of clean energy resource that was mandated by the restrictions in the dedicated procurements for supply.

21. Q. Do you have evidence that indicates that supply from renewable generation may require a higher price than supply from other types of generation in Pennsylvania?

A. Yes. Market data and recent PJM filings suggest that new Pennsylvania solar and wind generation require a higher price than some other types of generation in Pennsylvania. Pennsylvania's Solar Alternative Energy Credit ("SAEC") compliance

[54] *Id.*, p. 20.

price averaged about $32 per SAEC in 2019, and the Tier I Alternative Energy Credit ("Tier I AEC") compliance price averaged about $6 per Tier I AEC in 2019.[55] Furthermore, recent market prices for SAECs and Tier I AECs have been similar, at about $24 per SAEC and $9 per Tier I AEC.[56] Alternative Energy Credit ("AEC") prices reflect the difference between the cost of building generation resources that qualify for the AECs and the revenue that is available to those generation resources from sources other than the sale of AECs. Economic theory dictates that AEC prices should approach zero when and if the cost to build the associated type of generation is similar to the market price for generation (absent the AEC revenue).

Second, PJM recently filed its compliance filing at FERC concerning the expanded Minimum Offer Price Rule.[57] In that filing, PJM evaluated the cost of new entry for various types of generation in each zone in PJM, including the PECO Zone. For the PECO Zone, PJM determined that tracking and fixed-tilt solar generation would require capacity prices of $207 per MW-day and $395 per MW-day, respectively, to cover their net cost of new entry, and onshore wind generation would require a capacity price of $1,091 per MW-day.[58] Future capacity prices are uncertain, but the most recent Base Residual Auction capacity price for the PECO Zone, specifically for

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55 https://www.pennaeps.com/reports/. Tier I AECs are provided to wind generation.

56 Megawatt Daily, July 6, 2020, p. 7.

57 Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request For An Extended Comment Period of at Least 35 Days ("PJM MOPR Compliance Filing"), Federal Energy Regulatory Commission Docket Nos. ER18-1314 & EL18-178 (consolidated). (https://www.pjm.com/directory/etariff/FercDockets/4443/20200318-er18-1314-003.pdf)

58 *PJM MOPR Compliance Filing*, Appendix A to Keech Affidavit. (https://www.pjm.com/directory/etariff/FercDockets/4443/20200318-er18-1314-003.pdf)

the 2021/22 delivery year, was $165.73 per MW-day,[59] well below PJM's estimates of the costs of new entry of the types of generation identified above. This data indicates that, by limiting the types of generation that can supply all or part of the default service obligation to these resources, lower priced types of generation could be restricted from competing to provide their supply, which would result in higher default service rates for customers.

B. Mr. Rábago's Recommendation to Increase the Share of Long-Term Contracts in PECO's Plan Would Impose Unnecessary Risks on Default Service Customers and Provide Less Flexibility to Adapt to Changes in Market and Regulatory Conditions

22. Q. Does PECO include any long-term contracts in its Plan?

A. Yes. As explained by John J. McCawley in PECO Statement No. 1, PECO is proposing to replace its existing ten-year Solar AEC contracts with new ten-year Solar Alternative Energy Credit ("SAEC") contracts.[60]

23. Q. How does the proposed annual quantity of SAECs to be procured by PECO under long-term contracts compare to the quantity procured in its previous Commission-approved default service plans?

A. PECO is proposing to double the total annual SAECs to be procured in the form of long-term contracts, from 8,000 SAECs to 16,000 SAECs.[61]

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59 https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

60 PECO Energy Company Statement No. 1, p. 20.

61 *Id.*, p. 29.

24. Q. Which customer classes would be served by the long-term contracts in DSP V?

A. Similar to the approach in DSP IV, PECO will allocate separately procured SAECs across all of its customer classes.[62]

25. Q. What is Mr. Rábago's position regarding the extent to which PECO proposes to satisfy its default service obligations through long-term contracts?

A. Mr. Rábago supports larger increases in the share of long-term contracts than those proposed by PECO.[63]

26. Q. Does Mr. Rábago provide a specific proposal with regard to how much supply should be procured in the form of long-term contracts, or how those contracts should be structured?

A. No. Mr. Rábago does not offer a specific proposal with regard to contract quantity or structure, except to especially encourage long-term renewable energy supply contracts, such as contracts for wind or solar generation.[64]

27. Q. Does Mr. Rábago base his recommendation to increase the share of long-term contracts on any arguments that rely on his interpretation of Act 129?

A. Yes. Mr. Rábago refers to Act 129's requirement that "the prudent mix of contracts…shall be designed to ensure…the least cost to customers over time."[65]

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[62] *Id.*, pp. 20-21, 34.

[63] Environmental Stakeholders Statement No. 1, pp. 16-17.

[64] *Id.*, pp. 18, 19-20.

[65] 66 Pa.C.S. § 2807(e)(3.4).

According to Mr. Rábago, PECO's proposal "[r]elies upon an unreasonably short period of time for ensuring that it will be least cost over time"[66] because "due to its contracting approach, the Company actually limits the definition of least cost over time to a maximum of two years—the term of the longest contracts it secures."[67]

28. Q. Is Mr. Rábago correct in asserting that PECO's proposed product mix and procurement approach rely upon an unreasonably short period of time for ensuring least cost over time as required by Act 129?

A. No. Mr. Rábago appears to equate the period over which a given procurement plan is designed to ensure the least cost to customers over time with the longest single contract's delivery period (while ignoring PECO's proposed long-term contracts for SAECs). This interpretation of the least cost standard not only ignores the long-term contracts that PECO has proposed, but it entirely overlooks how individual supply products are related to each other to ensure aspects of least cost for customers such as the benefits of price stability. I explain this in detail in my direct testimony.[68] In addition, by not including extensive commitments for long-term supply at this time, PECO's DSP V promotes least cost for customers by maintaining the flexibility to develop default service proposals for future time periods that can be most effectively tailored to future market changes or regulatory requirements. Specifically, having the Commission approve DSP plans for four-year periods without extensive long-term

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66 Environmental Stakeholders Statement No. 1, p. 37.

67 *Id.*, pp. 22-23.

68 PECO Energy Company Statement No. 4, pp. 19-20.

contracts allows for the design of a plan that provides clarity during the near-to-medium term (i.e., the term of the default service plan), while allowing for greater flexibility to make modifications in the longer term, through the next DSP proceeding for the subsequent DSP period, after observing how the plan has performed and how external conditions have changed over time. Furthermore, PECO's Plan includes some contracts with deliveries that extend beyond the DSP V period because they allow for the option for a fairly seamless continuation of the laddered procurement cycle as PECO transitions from DSP V to DSP VI, and they avoid subjecting Residential and Small Commercial customers to a "hard stop" with regard to their supply products at the end of the DSP V period, which could otherwise expose customers to magnified risks and rate instability.[69]

The flexibility created by these aspects of PECO's DSP V design contributes to ensuring least cost over time for a period that spans the period of the default service plan and beyond. In its Second Default Service Rulemaking Order, the Commission highlighted the importance of flexibility with respect to the satisfaction of the "least cost over time" standard of Act 129:

> [W]e find no compelling reason to prescribe specific time periods for purposes of evaluating whether an EDC plan meets the standard of producing the "least cost to customers over time"…We do not discern a need to establish precise time constraints that would unduly constrain the flexibility of DSPs to design a procurement plan that best fits the character of the customer base and the service territory.[70]

[69] *Id.*, p. 28.

[70] Second Default Service Rulemaking Order, p. 44.

29. Q. Does Mr. Rábago make any other claims regarding the alignment of PECO's long-term contract proposal and applicable Pennsylvania law?

A. Yes. Mr. Rábago claims, "The Company is proposing ten-year procurements of SAECs in partial satisfaction of its AEPS Act obligations. This is more in keeping with the least cost over time obligation, but it is not enough to establish that the Company is complying with the law."[71]

30. Q. To what law is Mr. Rábago referring?

A. That is unclear, especially as he states that this is "more in keeping with the least cost over time obligation,"[72] which appears to me to indicate an acknowledgement that the inclusion of PECO's proposed long-term contracts contributes to satisfaction of Act 129's requirement that the plan include a "prudent mix" of contracts designed to ensure the least cost to customers over time.[73]

31. Q. To the extent to which Mr. Rábago's intent in stating that PECO's proposed long-term contracts are "not enough to establish that the Company is complying with the law"[74] may refer to any purported requirement of a minimum quantity of long-term contracts in a default service plan, how do you respond?

A. In its Second Default Service Rulemaking Order, the Commission provided guidance

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[71] Environmental Stakeholders Statement No. 1, p. 21.

[72] *Id.*

[73] 66 Pa.C.S. § 2807(e)(3.4).

[74] Environmental Stakeholders Statement No. 1, p. 21.

regarding interpretation of the terms “least cost” and “prudent mix.” The Commission’s guidance included the following:

> We agree with the majority of parties that the “prudent mix” of contracts be interpreted in a flexible fashion which allows the DSPs to design their own combination of products that meets the various obligations to achieve “least cost to customers over time,” ensure price stability, and maintain adequate and reliable service.[75]
>
> We do reject the positions of those parties that “prudent mix” be defined to always require a specific mix or percentage of types of contract components in each default service plan or a minimum of two types of products.[76]

In other words, the Commission’s guidance is that flexibility is a valuable aspect in satisfying the requirements of Act 129, and no minimum quantity of long-term contracts is stipulated.

32. Q. Is there merit to Mr. Rábago’s claim that PECO’s proposal to procure SAECs, but not other components of customers’ default service requirements, through long-term contracts “is exactly the approach to contracting that the Commission rejected as ‘too restrictive’ when it adopted its Final Policy Statement in 2011?”[77]

A. No. Mr. Rábago has confused the Commission’s position that default service plans <u>may</u> include long-term contracts for supply components other than SAECs with his understanding that default service plans <u>must</u> include long-term contracts for supply components other than SAECs. Specifically, the Commission’s Final Policy Statement states:

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[75] Second Default Service Rulemaking Order, p. 60.

[76] *Id.*

[77] Environmental Stakeholders Statement No. 1, p. 16.

> The Commission continues to maintain the position that EDCs should have maximum flexibility to design their supply portfolios…[A]s long as a DSP's procurement portfolio includes a "prudent mix" of contracts, the DSP <u>should be permitted</u> to use long-term contracts to procure all products in the procurement plan.[78] (emphasis added)

This is further emphasized in the Commission's Second Default Service Rulemaking Order:

> We do not agree with this interpretation, which would effectively limit the use of long-term contracts to procurement of renewable requirements. As we have stated throughout this Order, we are adopting a position that maximizes a DSP's flexibility to meet its default supply requirement, the "prudent mix" obligation and the "least cost to customers over time" mandate by not limiting the degree to which the DSP utilizes whatever component it chooses to achieve the "prudent mix" standard.[79]

In other words, the Commission determined that it would be "too restrictive" to disallow from default service plans long-term contracts for supply components other than SAECs, but it did not require such long-term contracts to be included in a given default service plan as Mr. Rábago claims. Once again, the Commission is providing flexibility in developing default service plans through its position, and not limiting it as Mr. Rábago's interpretation would do.

33. Q. In any of its Orders, has the Commission provided any additional guidance regarding the proportion of long-term contracts in default service plans?

A. Yes. In a December 16, 2011 Commission Order in the Retail Markets Investigation, the Commission recommended that the use of long-term contracts be limited in future

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78 *Default Serv. and Retail Elec. Mkts.*, Docket No. M-2009-2140580 (Order entered Sept. 23, 2011) ("Final Policy Statement"), pp. 10-11.

79 Second Default Service Rulemaking Order, p. 78.

default service plans:

> [T]he Commission continues to recommend the following:...that EDCs limit the proportion of long-term contracts that make up their default service plan energy portfolios, and consider using already existing long-term contracts from previous or presently effective default service plans.[80]

34. Q. Mr. Fisher, as a general matter, do you oppose the use of long-term contracts?

A. No, I support the use of long-term contracts in certain circumstances, but the use of long-term contracts for default service supply can result in risks for customers, especially given the uncertainty about default service load levels over longer periods of time.

35. Q. Please elaborate on the risks to which customers may be exposed by the use of long-term contracts for default service supply.

A. One important risk pertaining to customer rates relates to the uncertainty about the amount of load that PECO will supply in the future as the default service provider. The longer the term of a fixed-price, non-load-following supply product such as those suggested by Mr. Rábago, the more likely it is that loads will deviate substantially from expectations at the time that the product was procured, resulting in costly scenarios for customers, such as those in which excess supply must be sold at a loss, or those in which the product price is ultimately above market levels and the product constitutes an unexpectedly high portion of the default service supply portfolio.

80 *Investigation of Pennsylvania's Retail Elec. Mkt.: Recommendations Regarding Upcoming Default Serv. Plans*, Docket No. I-2011-2237952 (Order entered Dec. 16, 2011), p. 19.

At the same time, these long-term contracts for default service supply can significantly increase customers' financial risks associated with customer migration. For example, suppose PECO were to procure long-term contracts for fixed quantities of supply, or for quantities of supply that are based on the output of a given power generation resource, at fixed prices. If market prices then decline and customers exercise their option to switch to EGS service, PECO could be left with excess supply that it would be forced to sell at a loss, and/or customers would find that an unexpectedly high portion of their default service supply portfolio is composed of above-market contracts, and these customers would need to pay for the above-market costs through higher default service rates. This would further encourage customers to switch to EGS service, leaving the above-market costs of the long-term contracts to be incurred by a smaller default service customer base, thereby further driving up the default service rates. In this perverse situation, default service rates would tend to increase as market prices decline.

This type of risk is further compounded to the extent that the long-term contracts are tied to the output of a specific generating facility, such as the long-term renewable contracts that Mr. Rábago suggests,[81] and the cost of renewable generation continues to decrease as Mr. Rábago expects.[82] In this case, locking into a long-term contract with a specific renewable generating facility in the near-term would forgo the benefits to customers of future cost decreases in renewable generation. The resultant higher

81 Environmental Stakeholders Statement No. 1, pp. 18, 20.

82 *Id.*, pp. 11, 18-19.

default service supply rates would create an incentive for more default service customers to switch to EGS service, leaving the long-term contract supply costs that are reflective of the outdated technology to be incurred by a smaller default service customer base, thereby further driving up the default service rates.

36. Q. What other issues do long-term contracts for default service supply entail?

A. Long-term contracts reduce the flexibility to make future changes to the default service supply portfolio if they are warranted. Ironically, even Mr. Rábago requests that the Commission take advantage of this flexibility, which is provided by PECO's approach of not relying heavily on long-term supply contracts. Specifically, when discussing the ability to implement his recommended supply portfolio changes, Mr. Rábago states, "The good news is that the Company's short-term contracting approach means that new supply procurements can be phased in as soon as they are developed and well-before the end of the term of the current DSP V proposal."[83] While I disagree that Mr. Rábago's recommended supply portfolio changes should be adopted, this illustrates that PECO's proposal to continue its basic supply approach, which does not include a heavy reliance on long-term contracts, provides long-term value by more easily allowing for future changes to the supply portfolio if they are warranted. This flexibility would not be provided if PECO were to engage in larger quantities of long-term default service supply contracts, as Mr. Rábago recommends.

[83] *Id.*, p. 28.

Long-term contracts for default service supply also can pose issues associated with potential future changes in laws, regulations, and Commission directives. For example, if PECO were to engage in larger quantities of long-term default service supply contracts that span the time periods of future default service plans, and in the future it is determined that customers would be better served if the default service provider responsibility for PECO's service area were granted to a third party, the existence of those long-term contracts could cause issues associated with the transfer of the default service provider responsibility. This point is recognized by ESC witness Kavulla in ESC Statement No. 1.[84]

37. Q. Given all of these considerations, what do you conclude regarding Mr. Rábago's recommendation to increase the share of long-term contracts in DSP V beyond the increases already proposed by PECO?

A. Mr. Rábago's recommendation to increase the share of long-term contracts in PECO's Plan would impose unnecessary risks on default service customers and provide less flexibility to adapt to changes in market and regulatory conditions.

[84] ESC Statement No. 1, p. 27.

III. ESC'S RECOMMENDATION THAT THE COMMISSION TRANSITION PECO OUT OF THE DEFAULT SERVICE PROVIDER ROLE RAISES LEGITIMATE PUBLIC POLICY CONCERNS WITH THE POTENTIAL FOR SIGNIFICANT CUSTOMER HARM

38. Q. Please summarize the argument that ESC witness Kavulla offers to support his recommendation that the Commission transition PECO out of the default service provider role.

A. According to Mr. Kavulla, competition in Pennsylvania's electric market is stagnating.[85] To support his claim, Mr. Kavulla cites a decrease in the number of active and pending EGS customers in PECO's service area from 507,005 in March 2017 to 425,215 in February 2020.[86] According to Mr. Kavulla, the causes of the alleged stagnation in the competitive market are structural flaws in the design of the retail market, including the presence of PECO as a domineering default service provider.[87] Mr. Kavulla claims that the very presence of a default service provider that is also the local transmission-and-distribution monopoly results in what he characterizes as "a provider-of-first resort arrangement."[88] He also suggests that mass market customers, including residential and small commercial customers, often will not make affirmative choices for their supplier unless they are "required" or forced to

[85] *Id.*, p. 6.

[86] *Id.*

[87] *Id.*, pp. 7-8.

[88] Mr. Kavulla makes claims about other structural market design issues to explain why more customers have not switched: the inability of EGSs to have a direct relationship with their customers through monthly consolidated bills and an unlevel playing field due to alleged cross-subsidization that causes distribution customers, including those who have switched to an EGS, to pay for costs related to PECO's default service. (ESC Statement No. 1, p. 8.) These issues are addressed more directly by PECO witness Bisti in PECO Statement No. 2-R.

make such a choice.[89] This ultimately leads to his recommended solution, which is that the Commission should transition PECO out of the default service provider role and make default service a "true backstop" provided by EGSs.[90] Mr. Kavulla does not describe what this "true backstop" service would be, and instead he just states that it would be "provided by EGSs."[91]

39. Q. Does PECO's Plan support the competitive retail electricity market?

A. Yes. In my direct testimony, I explain in detail the ways in which PECO's plan is designed to support the competitive retail electricity market.[92] Under PECO's Plan, to the extent that EGSs are able to develop new value-added or tailored services (such as a service offering that is supplied entirely by clean power) to meet the needs of individual customers, or to the extent that they can assemble a low-cost supply portfolio and offer customers an attractive price, these EGSs may attract customers, and customers will receive benefits associated with retail competition. Furthermore, the price-to-compare benchmark will reflect the lowest prices offered in competitive supply solicitations, thereby encouraging the development of the most competitively priced offers from EGSs. At the same time, PECO's plan is designed to provide stable prices based on competitive supply solicitations for mass market default service customers who do not have the time, energy, sophistication, or resources to seek out

89 ESC Statement No. 1, p. 12.

90 *Id.*, p. 3.

91 *Id*.

92 PECO Energy Company Statement No. 4, pp. 29-30.

and confidently choose an offering from an EGS that provides the type of product or the level of price stability that the customer needs or desires.[93] This approach is well aligned with the Commission's established policy objective of ensuring a cost for power that is both relatively stable and economical for customers.[94]

40. Q. Do other intervenors in this proceeding support the default service model that PECO proposes?

A. Yes. The statutory parties and other intervenors have either voiced their support for the default service model that PECO proposes, which includes the assignment of PECO as the default service provider, and the choice of supply product mix and procurement approach, or have not voiced any opposition.[95]

41. Q. Do Mr. Kavulla's statistics regarding the numbers of customers being served by an EGS indicate that a fundamental change in the default service model is needed so that all customers are served by EGSs?

A. No. Mr. Kavulla's suggestions, that the Commission should treat the number of customers who have chosen to be served by an EGS as the measuring stick to determine the extent to which customers are receiving the benefits of competition, and that fundamental changes in the established Pennsylvania default service model should be made on that basis, are misguided. If the primary policy goal were to

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93 *Id.*, pp. 19-20, 29.

94 Second Default Service Rulemaking Order, p. 40.

95 See direct testimony on behalf of the OCA, OSBA, CAUSE-PA, and TURN. As noted previously, the OCA voiced a concern about a 1% portion of the residential supply portfolio, but it otherwise supported PECO's approach to supply default service for residential customers.

maximize the number of customers who are being served by an EGS, as Mr. Kavulla indicates,[96] then policymakers in Pennsylvania could have achieved the policy goal long ago by establishing very high or very volatile default service rates that likely would be unattractive to mass market customers, or by simply assigning all customers to EGSs without their permission. This, however, would not be good public policy, nor would it be consistent with the requirements of Act 129.

42. Q. Do Mr. Kavulla's quoted numbers of residential default service customers in PECO's service area, or his characterization of these numbers as a "dominant market share"[97] held by PECO, in any way indicate that default service customers in PECO's service area are not receiving benefits from competitive markets?

A. No. Under the existing default service model, regardless of how many customers are being served through default service, they are all being provided benefits from competitive markets because the model requires qualified bidders in the default service supply product solicitations to compete and be selected based on the lowest price. PECO simply passes through the resultant supply costs to customers. Any insinuation that a greater number of default service customers equates to a less competitive default service offering or a financial benefit to PECO is invalid. Furthermore, as I noted in my direct testimony, 102 EGSs currently serve PECO customers, 95 of these EGSs currently serve PECO residential customers, and 60% of

[96] ESC Statement No. 1, p. 6.

[97] *Id.*, p. 7.

PECO's total customer load is currently being served by an EGS.[98] Clearly, there are many options available to default service customers to take advantage of the benefits of the competitive retail market, if they choose to do so.

43. Q. Are there valid reasons why the numbers of customers being served by an EGS have decreased somewhat?

A. Yes. Decreases in Pennsylvania indicate that customers who had previously made a choice to be served by an EGS either subsequently decided instead to receive default service, or their EGS chose to no longer serve them.

44. Q. Why may some customers have made reasonable decisions not to be served by an EGS, thereby contributing to a decrease in customers being served by an EGS?

A. In recent years, numerous studies have been issued that cite instances in several states in which competitive retail suppliers have been charging significantly more than default service rates and/or engaging in misleading marketing practices. CAUSE-PA witness Harry Geller discusses several of these reports in his direct testimony.[99] Mr. Geller also presents his own study, which indicates that EGSs in PECO's service area have on average consistently charged residential customers amounts in excess of default service rates over the past five years, and that the amount that residential EGS customers pay on average in excess of the default service rate has increased each year

[98] PECO Energy Statement No. 4, p. 21. As noted, data is for the month ending February 25, 2020. The 60% value includes customers who will be switched to EGSs within 45 days, and is based on kW.

[99] CAUSE-PA, Statement No. 1, pp. 17-20.

for the last five years.[100] It is reasonable to conclude that the published reports and associated public press, as well as first-hand customer experiences, relating to various EGSs' excessive customer charges and/or misleading marketing practices, have had a detrimental effect on the willingness of customers to elect service from an EGS, contributing to a lower number of customers being served by an EGS.

Furthermore, for some residential and small commercial customers who have not switched from default service to an EGS, the expected gains from learning more about retail market choices may be too small to make the learning worthwhile. The potential cost savings may be insufficient to divert customers' time from their other affairs to further educate themselves about the retail electricity market and compare and analyze EGS offers.

45. Q. Do either of these reasons justify adopting Mr. Kavulla's recommendation to transition PECO out of the default service provider role and force these customers, and all other customers, to be served by an EGS?

A. No. Customers who elect to terminate service from an EGS based on their experiences, as well as those who elect not to be served by an EGS based on information that they receive or due to their other daily demands, should not be forced to be served by an EGS, as Mr. Kavulla recommends.

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100 *Id.*, pp. 10-13.

46. Q. Have some EGSs exited the market, thereby contributing to the decrease in customers being served by an EGS?

A. Yes. Some EGSs exited the market in the aftermath of the wholesale market price spikes experienced in January 2014, often referred to as the Winter 2014 Polar Vortex.[101] For example, in August 2014, FirstEnergy Solutions ("FES"), a major competitive retail supplier that served 2.7 million customers, announced that it was withdrawing from the competitive residential and small commercial electric markets in six states.[102] In September 2015, it was reported that FES had aggressively expanded its business in Pennsylvania's competitive electricity market three years prior, but "recently mailed a wave of letters to PECO Energy Co. customers who signed up with FirstEnergy to supply their power, declining to renew their contracts."[103] According to FES, the non-renewals of contracts would continue to 2019.[104] Around the same time, other competitive suppliers went out of business due to unexpected wholesale market conditions, and their customers were switched back to default service supply.[105]

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101 Extreme cold weather, unplanned generator shutdowns, natural gas curtailments, and fuel-oil delivery problems contributed to record electricity prices in January 2014 in Pennsylvania.

102 FirstEnergy Backs Out of Residential Markets, Megawatt Daily, August 11, 2014, p. 12.

103 FirstEnergy Solutions Dropping PECO Customers, Philadelphia Inquirer, September 30, 2015. Similarly, it was reported that FES had "allowed a large tranche of Duquesne Light customers in Pittsburgh to lapse. The total number of Duquesne Light customers supplied by competitive power-generators dropped by 36,000, or 15 percent, in a few months."

104 FirstEnergy Solutions Dropping PECO Customers, Philadelphia Inquirer, September 30, 2015.

105 2013-2014 Winter Polar Vortex, ConEdison Solutions, July 2014, p. 4.

47. Q. Does the exit of an EGS such as FES in an2y way support Mr. Kavulla's recommendation that the Commission transition PECO out of the default service provider role and force customers to be served by an EGS?

A. No. FES cited volatility in the underlying wholesale market as the primary reason why it was exiting the residential and small commercial retail electric markets. "Essentially what we're doing is derisking our business…What we've seen, especially coming out of the polar vortex…is that volatility of the electric market is reducing our ability to offer long-term stable pricing to customers…And it's also increasing our risk of serving retail load," explained Diane Francis, an FES spokeswoman.[106] In other words, the reason that FES cited for its exit from the market was not related to any structural flaws in the design of the retail market that Mr. Kavulla alleges to support his recommendation.

48. Q. Why does Mr. Kavulla's recommendation, that the Commission transition PECO out of the default service provider role, raise legitimate public policy concerns with the potential for significant customer harm?

A. Under the existing, established default service model, mass market customers who choose not to shop, or who do not have the time, energy, sophistication, or resources to make an informed service decision, are charged default service rates that reflect the cost of supply from competitive wholesale solicitations, in which many parties compete to provide the supply on the basis of lowest price. The selection of winning bidders is subject to Commission approval, and the timing and definitions of the

[106] FirstEnergy Backs Out of Residential Markets, Megawatt Daily, August 11, 2014, pp. 12-13.

supply products that are procured are established through a Commission proceeding in which the benefits of price stability are considered. Consequently, these customers are provided stable rates established through the competitive market with active Commission oversight.

In contrast, under Mr. Kavulla's proposal, these customers would be involuntarily assigned to an EGS, and the same assurances cannot be made that the rates that the EGS charges would be as stable, subject to competitive market forces, and subject to the same level of Commission oversight on an ongoing basis. Under Mr. Kavulla's proposal, whenever EGSs are allowed to charge rates to their assigned customers at their discretion without Commission approval of the rates, whether that be after just one initial fixed-price period or after several fixed-price periods in the future, the assigned customers will be exposed to the potential loss of the stable, competitively-priced rate upon which they rely. Therefore, under the undefined "true backstop" service provided by EGSs that Mr. Kavulla recommends, customers are at risk of not receiving service at least cost over time as required by Act 129.[107]

The OCA elaborated on this contrast from the perspective of a consumer advocate in its 2011 comments to the Commission:

> In the OCA's view, the means to address customer reluctance to actively engage in the retail market is not to eliminate the default service model or force the removal of the EDC from the default service role. It is the EDC that has the obligation to connect every single household, business and industry in Pennsylvania to the electric grid, and it is the EDC that is ultimately responsible for the provision or safe, adequate. and reliable electric service. <u>With these ultimate responsibilities, it is difficult to</u>

[107] 66 Pa.C.S. § 2807(e)(3.4).

> envision any generic cost benefit from replacing the EDC as default service provider with another entity, and in particular, with an entity that must seek to earn a profit from the default service role. Default service customers are currently able to receive fairly stable, reasonably priced generation service from their EDC. At the same time, customers who choose to shop for an alternative generation supplier may be able to find an offer that is more suitable for them. Default service customers continue to receive the benefit of wholesale generation markets through the competitive least cost procurement process of Act 129, even if they do not choose to shop with an alternative retail supplier. But shopping customers also receive the benefit of knowing that there is a Commission-approved default service provider that must provide them with service at a Commission-approved price if their competitive supplier fails or decides to leave the Pennsylvania market. In the OCA's view, this "security" feature of default service enhances the competitive market in Pennsylvania because it permits customers to participate in the market without fear of jeopardizing their service.[108] (emphasis added)

The protections described above, which are ensured in the existing default service model but which are jeopardized under Mr. Kavulla's recommendation, are especially important because the default service customers at risk include low-income customers, many of whom rely on receiving affordable and stable electricity prices from their default service.

49. Q. Are there factors that magnify this potential for significant customer harm under Mr. Kavulla's proposal?

A. Yes, there are several. First, the numerous studies cited by CAUSE-PA witness Geller,[109] which identify instances in several states in which competitive retail suppliers have been charging significantly more than default service rates and/or

[108] Comments of the OCA, *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952, June 3, 2011, pp. 19-20.

[109] CAUSE-PA, Statement No. 1, pp. 17-20.

engaging in misleading marketing practices, cast doubt on the ability to rely upon EGSs to charge rates reflective of "least cost" to customers that they obtain through involuntary assignment.

Second, Mr. Kavulla's recommendation to transition the default service role to EGSs lacks actionable detail, and the limited detail that he does provide in a similar proposal that he recently presented in New Jersey is particularly troubling with respect to its lack of customer protections on an ongoing basis. In New Jersey, Mr. Kavulla has recommended that qualified EGSs compete in some form of competitive solicitation to provide a fixed-price, term-limited (e.g., 12 or 24-month) default service product for an initial period of the transition.[110] After the initial period, the market would transition to be "fully competitive, with no regulatory obligation on any [EGS] to serve customers."[111] This lack of EGS responsibility, after the short initial period, to provide stable and competitively priced service to the customers to which they would be assigned, is particularly troubling for the reasons that I have described above. Furthermore, Mr. Kavulla's recommendation would abandon the underlying prudent mix of default service supply products that has been established and tested over multiple default service plans to provide price stability and other benefits for mass market customers.

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110 Comments and Responses by Mr. Kavulla on Behalf of NRG Energy, Inc., *New Jersey Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities Docket No. EO20030203 (May 20, 2020), p. 13.

111 *Id.*, p. 14.

Third, if Mr. Kavulla's claim is true that customers tend not to proactively make a decision regarding their service if they are defaulted to a service, then the risk to customers of being significantly harmed is even further magnified. Specifically, instead of tending to remain on a stable default service rate established through competitive solicitations with significant Commission oversight, under Mr. Kavulla's proposal, the customer would tend to remain on a rate charged by an EGS without the same assurances regarding competitive pricing, rate stability, and Commission oversight over time.

Finally, Mr. Kavulla's recommendation represents a radical departure from the default service model that the Commission has adopted for major Pennsylvania utilities and that has been established in almost every state with a restructured electricity market.

50. Q. Are there other risks of significant customer harm under Mr. Kavulla's proposal?

A. Yes. Actual experience casts doubt on the ability of EGSs to perform under an obligation to stand ready at all times to provide competitively priced and stable rates to any and all mass market default service customers in PECO's service area on an ongoing basis.

Unlike the many wholesale default service supply solicitations that have been successfully conducted throughout PJM under the existing model in which the utility serves as the default service provider, experience with the assignment to an EGS of customers who take no affirmative action, as Mr. Kavulla proposes, has been problematic for customers. In October 2000, NewPower Holdings, Inc.

("NewPower") reached an agreement with PECO in which NewPower would be assigned up to 20 percent of PECO's residential customers who had not selected an EGS.[112] As of March 31, 2002, NewPower was serving approximately 185,500 customers in PECO's service area under this agreement.[113] However, on February 22, 2002, NewPower provided notice to PECO of its intent to terminate the agreement.[114] Its assigned customers were returned to PECO in May 2002.[115]

Also, as I explained previously, EGSs such as FES and others have exited the business of making direct sales to mass market customers due to issues associated with managing wholesale market volatility.[116] Yet, effectively managing wholesale market volatility is critical to provide stable default service rates to any and all mass market customers on an ongoing basis.

While EGSs may be able to provide attractive service offerings on the EGS's own terms regarding the choice of customers to which it extends offers, the specific products it offers, the pricing that it offers for those products, and when it makes these offers, taking on the default service provider's responsibility to reliably stand ready at all times to serve any and all mass market customers at stable and reasonable rates involves very different demands. All of the experience that I have cited above indicates that the existing, proven default service model should be preserved to best

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[112] Form 10-Q NewPower Holdings Inc., May 15, 2002.

[113] *Id.*

[114] *Id.*

[115] Office of Consumer Advocate Annual Report for Fiscal Year 2001-2002, p. 6.

[116] FirstEnergy Backs Out of Residential Markets, Megawatt Daily, August 11, 2014.

assure that competitive and stable pricing is provided to mass market default service customers who need it, and that competition in the retail market is supported.

51. Q. Do you have any comments regarding Mr. Kavulla's claim that the default service provider role should be transitioned to EGSs because, according to Mr. Kavulla, EGSs currently face an "unlevel playing field" because PECO's default service rate is allegedly artificially low due to a misallocation of overhead costs?[117]

A. PECO witness Joseph A. Bisti addresses Mr. Kavulla's claims about cost allocation in PECO Energy Statement No. 2-R. However, in his attempt to make a conceptual apples-to-apples comparison of the levels of EGS rates and default service rates, Mr. Kavulla has neglected a separate but relevant factor. Specifically, Mr. Kavulla has ignored the fact that, unlike EGSs, suppliers of the FPFR products that comprise PECO's default service supply must stand ready to serve their percentage of the default service load at a predetermined fixed price, regardless of how frequently customers switch to or from default service in response to market conditions or for any other reason. Customers have an incentive to elect service from an EGS when the default service rate is higher than the prices that EGSs offer, and they have an incentive to elect default service when the rate is lower than those prices. This customer switching option (to guarantee a predetermined fixed price to which customers may return and from which they may leave) can be very valuable for customers, but can be costly to the seller of the FPFR default service supply product given the need to provide additional supply when market prices are high and/or

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[117] ESC Statement No. 1, pp. 8, 47-48.

manage excess supply when market prices are low. Logically, it can be expected that FPFR bidders will include some compensation in their bid prices to cover the costs and risks associated with providing this option. Consequently, any arguments that the default service rate may be artificially low must also recognize that there are also costs and risks included in the default service rate due to this special option that FPFR default service suppliers provide to customers at their expense, which EGSs are not required to provide. Mr. Kavulla does not recognize this factor when arguing that the default service rate provides an artificially low benchmark against which EGSs cannot reasonably compete.

52. Q. What do you conclude regarding ESC's recommendation that the Commission transition PECO out of the default service provider role?

A. ESC's recommendation raises legitimate public policy concerns with the potential for significant customer harm. Instead of catering to ESC's desire to involuntarily assign customers to EGSs, the Commission should continue to balance the interests of customers, EGSs, default service suppliers, and the default service provider when considering a default service plan.

IV. CONCLUSION

53. Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS DEFAULT SERVICE PROGRAM FOR THE PERIOD FROM JUNE 1, 2021 THROUGH MAY 31, 2025	:	**Docket No. P-2020-3019290**

AMENDED VERIFICATION

I, Scott G. Fisher, hereby state that I am a Partner with The Northbridge Group; that I am authorized to and do make this Verification for PECO Energy Company; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 4
- PECO Statement No. 4-R
- PECO Exhibit No. SGF-1
- PECO Exhibit No. SGF-2

Scott G. Fisher

Dated: August 4, 2020

Scott G. Fisher