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July 16, 2020

VIA eFILING

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

Re: Office of Consumer Advocate v. PECO Energy Company
Docket Nos. M-2018-3005860, C-2018-3006242,
M-2019-3010032 and C-2019-3010737

Dear Secretary Chiavetta:

Enclosed please find Testimony and Exhibits which were filed on behalf of **PECO Energy Company** in the above-referenced matters. Also enclosed is **PECO Hearing Exhibit No. 1** which references all documents.

1. **PECO Statement No. 1 - Direct Testimony of Joseph A. Bisti;**
   Exhibit Nos. JAB-1 to JAB-10

2. **PECO Statement No. 1R - Rebuttal Testimony of Joseph A. Bisti;**
   Exhibit Nos. JAB-1R to JAB 5R

3. **PECO Statement No. 1RJ – Rejoinder Testimony of Joseph A. Bisti;**
   Exhibit Nos. JAB-1RJ to JAB 4RJ

As evidenced by the enclosed Certificate of Service, a copy of this letter was served upon Administrative Law Judge Marta Guhl, and all parties of record.

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

Very truly yours,

Kenneth M. Kulak

KMK/tp
Enclosures

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

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE	:	
	:	
v.	:	**Docket Nos. M-2018-3005860**
	:	**C-2018-3006242**
PECO ENERGY COMPANY	:	
	:	
OFFICE OF CONSUMER ADVOCATE	:	
	:	
v.	:	**Docket Nos. M-2019-3010032**
	:	**C-2019-3010737**
PECO ENERGY COMPANY	:	

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 Testimony and Exhibits** on the following persons in the manner specified in accordance with the requirements of 52 Pa. Code § 1.54:

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Dated: July 16, 2020

Counsel for PECO Energy Company

PECO ENERGY COMPANY
STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE

v.

PECO ENERGY COMPANY

DOCKET NOS. M-2018-3005860
C-2018-3006242

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: CALCULATION OF PECO ENERGY COMPANY'S NON-BYPASSABLE TRANSMISSION CHARGE RATE EFFECTIVE AS OF DECEMBER 1, 2018

DATED: JUNE 5, 2019

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DIRECT TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a 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. My duties include maintenance and oversight of semi-annual adjustments to PECO's two retail transmission rates, the Transmission Service Charge ("TSC") and the Non-Bypassable Transmission Charge ("NBT").

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 professional experience.

A. In February of 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 the TSC and NBT as described above. In that position, my responsibilities also included analyzing and applying PECO's tariffs to retail customers, as well as coordination and preparation of PECO testimony and comments in several proceedings before the Pennsylvania Public Utility Commission ("Commission"). 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") who furnish generation and network transmission service to electric retail customers that choose to shop with alternative suppliers. The Energy Acquisition department is also responsible for fulfilling PECO's obligation as a Default Service Provider ("DSP") to serve electric retail customers who need, or choose to obtain, default service.

5. Q. Please state the purpose of your direct testimony and provide a brief overview of what you will discuss in more detail later in this statement.

A. My testimony responds to averments in the Complaint filed by the Office of Consumer Advocate ("OCA") that PECO's semi-annual adjustment to its Non-Bypassable Transmission Charge ("NBT") set forth in a tariff supplement filed on November 7, 2018 may be unjust, unlawful or unreasonable. PECO's tariff supplement became effective on December 1, 2018, pursuant to the authorization granted by the Commission before the OCA filed its Complaint.

The focus of the OCA's Complaint is a portion of the total of $83 million of net billing adjustments that PJM Interconnection, L.L.C. ("PJM") has made and will continue to make to Regional Transmission Expansion Plan ("RTEP") charges it billed to PECO for transmission enhancements furnished from June 1, 2007 through January 1, 2016. These retrospective billing adjustments implement the terms of a settlement ("Settlement") of a transmission rate proceeding that had been in litigation before the Federal Energy Regulatory Commission ("FERC") for nearly a decade. PJM began issuing the credits to its historical bills covered by the Settlement in July 2018. Consequently, PECO's semi-annual NBT adjustment filed on November 1, 2018 was PECO's first opportunity to include any of the Settlement credits in its NBT rate.

In its November 2018 NBT filing, PECO stated its intent to reflect a credit to customers of approximately $77.5 million, which is all but $5.5 million of the prior-period Settlement credits PECO expects to receive. The remaining $5.5 million is the portion of the total PJM net credit adjustments that relate to RTEP charges PJM billed to PECO prior to January 1, 2011. That date is the effective date on which PECO first implemented, with the Commission's prior approval under Docket R-2010-2161575, its TSC. The TSC is an automatic adjustment clause established under Section 1307(a) of the Public Utility Code to recover PJM transmission charges (including, at that time, RTEP charges) from default service customers outside of distribution base rates on a dollar-for-dollar basis, subject to retrospective reconciliation. Subsequently, under Docket P-2014-2409362, the Commission approved PECO's NBT to become effective June 1, 2015, to recover non-market-based transmission charges (including RTEP) that PECO pays to PJM from all customers (i.e., both those customers who receive generation service from EGSs and those who receive default service from PECO). Like the TSC, the NBT is a fully-reconcilable Section 1307(a) automatic adjustment clause.

As explained in Section III., below, prior to January 1, 2011, PECO did not have in place any mechanism for the full and current recovery from its customers of PJM transmission charges, including RTEP charges, on a reconcilable basis. Moreover, PECO's base rates in effect prior to January 1, 2011 were established before PJM began to impose RTEP charges in 2007 and, therefore, did not reflect any RTEP charges. As a result (and as explained in detail in Section V.), the Company is properly flowing through the NBT all of the retrospective PJM billing adjustments that pertain to periods when PECO recovered PJM transmission charges (including RTEP) from customers (the $77.5 million). PJM RTEP charges imposed prior to January 1, 2011 were not recovered under the TSC or the NBT and were not subject to reconciliation. Therefore, PECO is properly excluding PJM billing adjustments that relate to PJM charges imposed prior to January 1, 2011 (the $5.5 million) from its calculation of NBT charges.

6. Q. Are you sponsoring any exhibits to accompany your direct testimony?

A. Yes. PECO Exhibit Nos. JAB-1 through JAB-10 were prepared by me or under my supervision and are described in detail later in my testimony.

II. PROCEDURAL HISTORY

7. Q. Mr. Bisti, please describe the procedural history of this case leading up to the filing of the OCA's Complaint.

A. On November 7, 2018, PECO filed with the Commission Supplement No. 76 to its Tariff Electric – Pa. P.U.C. No. 5 ("Supplement No. 76") with accompanying supporting schedules. Supplement No. 76 represented PECO's semi-annual adjustment to the Company's NBT for the period of December 1, 2018 through May 31, 2019. PECO's new NBT rates under Supplement No. 76 were calculated to flow through to the Company's distribution customers all of the PJM RTEP billing adjustments that relate to transmission-related services for those customers on and after implementation of a reconcilable adjustment clause for related PJM charges, including RTEP, as of January 1, 2011.

On November 28, 2018, the Commission issued a Secretarial Letter at Docket No. M-2018-3005860 finding that the NBT charges set forth in Supplement No. 76 "are consistent with the tariff and, accordingly, are permitted to become effective as filed" on December 1, 2018. Later in the day on November 28, 2018, after the Commission had issued its Secretarial Letter, the OCA filed its Complaint initiating this proceeding. As discussed in Section V. below, on May 15, 2019, PECO filed its most recent semi-annual adjustment to its

NBT rates for the period June 1, 2019 through November 30, 2019, which continues to reflect all post-2010 PJM billing adjustments made under the Settlement.

8. Q. Please summarize the principal allegations set forth in the OCA's Complaint.

A. The OCA's Complaint relies on two principal facts: (1) PECO will receive PJM bill credits under the Settlement; and (2) the Company is retaining approximately $5.5 million of pre-2011 bill credits in calculating the semi-annual adjustments to its NBT. Based on those facts, the OCA alleges that PECO's NBT may be "unjust, unreasonable, and in violation of the Pennsylvania Public Utility Code, 66 Pa. C.S. Section 1301 *et seq.*"[1]

From the limited facts stated in the Complaint, it appears that the OCA is asserting that the Commission should require PECO to refund to customers all of the prior-period bill adjustment credits (i.e., for periods both before and after January 1, 2011) that PJM is furnishing to PECO pursuant to the Settlement. The OCA's contention is not justified for the reasons discussed in detail in Sections III. and V. below.

III. HISTORY OF PECO'S RATEMAKING TREATMENT OF PJM'S TRANSMISSION-RELATED COSTS

9. Q. Mr. Bisti, please describe RTEP charges that are imposed by PJM.

A. As the FERC-approved Regional Transmission Organization, PJM coordinates the flow of electricity on the transmission system and works cooperatively with

[1] Complaint, ¶ 4.G.

transmission owners within its footprint to ensure safe and reliable transmission service. PJM's RTEP process identifies transmission system upgrades and enhancements necessary to continue providing this level of transmission service across its footprint. PJM RTEP charges, also known as "Transmission Enhancement" charges, compensate the transmission owners responsible for developing these projects. PJM allocates RTEP project costs across transmission owner zones as described later in my testimony. PJM first began to impose RTEP charges on PECO as the default service supplier and on other load serving entities ("LSEs") in the PECO Zone on June 1, 2007.

10. Q. Did PECO reflect RTEP charges in its base rates before January 1, 2011?

A. No. PECO's base rates in effect at the time PJM initiated RTEP charges were established in PECO's 1989 base rate case and were subsequently unbundled effective January 1, 1999, in conjunction with PECO's Commission-approved Restructuring Plan.[2] The 1989 base rates did not provide for the recovery of any RTEP charges because PECO was not yet incurring those charges. PECO therefore absorbed all RTEP charges without recovering those costs from customers while the 1989 base rates were effective.

PECO did not file another distribution rate case until March 2010. In its 2010 case, PECO proposed to recover all PJM-related transmission costs imposed on PECO (including RTEP) through a bypassable, reconcilable TSC established

[2] *Application of PECO Energy Co. for Approval of Its Restructuring Plan Under Section 2806 of the Public Utility Code et al.*, Docket Nos. R-00973953 and P-00971265 (Joint Petition for Settlement filed Apr. 29, 1998) ("Restructuring Plan"), p. 11. The Restructuring Plan was approved by the Commission in its Order and Opinion entered on May 14, 1998.

under Section 1307 of the Public Utility Code. The Commission approved PECO's proposal, and the base rates and TSC approved by the Commission in the 2010 rate case became effective on January 1, 2011.[3]

11. Q. What categories of costs were recovered from default service customers through the TSC approved by the Commission in PECO's 2010 rate case?

A. On January 1, 2011, PECO began to recover from default service customers, through the TSC, all transmission-related charges imposed by PJM on PECO and not paid by default service suppliers under the Supply Master Agreement ("SMA") approved in PECO's first default service proceeding ("DSP I"). Those charges included RTEP costs. *See* PECO Exhibit No. JAB-1. The sample PJM bill appended to PECO's DSP I SMA that identifies PECO's responsibility for RTEP charges is attached hereto as PECO Exhibit No. JAB-2.

12. Q. Did the TSC include any RTEP costs incurred by PECO prior to January 1, 2011?

A. No. The Company's TSC charge included a projection of the transmission-related service costs that PECO would incur on an annual basis from and after January 1, 2011. The TSC also included a factor to reconcile revenues recovered under the TSC with actual costs for reconciliation periods that ended on October 31 each

[3] *Pa. P.U.C. v. PECO Energy Co. – Elec. Division*, Docket No. R-2010-2161575 (Opinion and Order entered Dec. 21, 2010) ("2010 Rate Case Order"), p. 9. On December 21, 2010, PECO filed Supplement No. 8 to PECO Electric Tariff No. 4, bearing an effective date of January 1, 2011, which included the TSC approved by the Commission in the 2010 Rate Case Order ("Compliance Filing"). A copy of the TSC Rider pages of the Compliance Filing are attached hereto as PECO Exhibit No. JAB-1.

year. *See* PECO Exhibit No. JAB-1. However, PECO prorated the first reconciliation period to cover only January 1, 2011 through October 31, 2011.

13. Q. Mr. Bisti, please describe how PECO recovered RTEP costs from customers during PECO's subsequent default service programs.

A. During its second default service program effective June 1, 2013 through May 31, 2015,[4] PECO continued to have the responsibility for paying PJM charges under the SMA, as previously described, and sought recovery of those charges through the bypassable TSC.

On December 4, 2014, the Commission approved PECO's proposed third default service program for the period June 1, 2015 through May 31, 2017 ("DSP III"), as modified by a Joint Petition for Partial Settlement.[5] In the DSP III Order (p. 46), the Commission agreed that PECO, in its capacity as an electric distribution company, should acquire certain non-market based transmission services on behalf of all distribution customers (both shopping and non-shopping) and recover the associated costs on a non-bypassable basis through a new NBT rather than through the existing bypassable TSC. Consistent with the DSP III Order, on June 1, 2015, PECO implemented the non-bypassable NBT to recover: (1) Generation Deactivation/Reliability Must Run charges (PJM bill line 1930)

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[4] *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), pp. 44, 56-60.

[5] *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 (Order entered Dec. 4, 2014) ("DSP III Order").

imposed after December 4, 2014; (2) RTEP charges (PJM bill line 1108); and (3) Expansion Cost Recovery charges (PJM bill line 1730).

14. Q. Did PECO recover RTEP charges through its wholesale transmission rate between June 1, 2007 and December 31, 2010?

A. No. Network Integration Transmission Service ("NITS") is the mechanism by which PECO and other transmission owners recover their annual transmission costs and revenue requirements from PJM network customers.[6]

For the period of January 1, 2007 through December 31, 2010, PECO recovered its cost of providing network service in its transmission zone through a stated rate. PECO's stated FERC transmission rate was fixed at $20,942 per megawatt-year in 1998 based on a black box settlement approved by the FERC at Docket No. ER97-3189-000. PJM RTEP costs did not exist at the time the 1998 settlement was approved.

15. Q. Are the costs of RTEP projects in the PECO zone part of the Company's network service rate?

A. No. Under Schedule 12 of its Open Access Transmission Tariff ("OATT"), RTEP charges are allocated by PJM on behalf of transmission owners to LSEs in the transmission zones that are assigned cost responsibility for the applicable RTEP projects. The network service rate recovers PECO's costs of service

[6] Transmission owners set their rates using either a fixed/stated rate to recover their costs or a forward-looking formula-based rate, which is based on a projection of their transmission revenue requirement for the upcoming operating year.

related to its transmission facilities within its transmission zone. RTEP charges, on the other hand, are imposed on LSEs to recover the costs of transmission facilities owned by other transmission service providers outside the PECO zone. Because RTEP charges to which the Settlement applies were, and still are, assessed on LSEs, not transmission owners, RTEP charges were not, and could not, be a part of PECO's network service rate.

IV. CHANGES TO THE FERC-APPROVED REGIONAL TRANSMISSION EXPANSION PLAN COST ALLOCATION METHODOLOGY UNDER THE SETTLEMENT

16. Q. Mr. Bisti, you have explained that PJM began to bill PECO for RTEP charges in 2007. Please describe the methodology for allocating RTEP costs adopted by the FERC in its Order No. 494 in 2007.

A. Order No. 494[7] directed PJM to continue to allocate RTEP project costs for facilities with capacities of less than 500 kW across the transmission zones within PJM based on a net benefit analysis known as the "DFAX" method.[8] For higher voltage facilities, including Required Transmission Enhancements planned to operate at or above 500 kV, FERC determined that all customers in PJM would pay a "postage stamp" rate. A "postage stamp" rate is a uniform rate per unit of load that all transmission service customers pay based on the aggregated costs of all transmission facilities in the PJM region, irrespective of the "net benefit" any

[7] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,308 (2007) ("FERC Order No. 494"), pp. 45-46.

[8] DFAX represents the percentage of the power flowing from a generator to a load that is carried over a particular transmission facility. The DFAX method models system-wide power flows and determines what facilities an entity's actual power flows will impact.

individual transmission service customer may actually derive from such facilities.[9]

17. Q. Has the RTEP cost allocation methodology approved in FERC Order No. 494 changed?

A. Yes. The entry of FERC Order No. 494 initiated more than a decade of litigation in which certain transmission owners within PJM, including PECO, contested the RTEP cost allocation methodology the FERC had adopted. That litigation was resolved by the Settlement, which the FERC approved on May 31, 2018.[10] The Settlement implements a schedule of adjustments to PJM's prior-period billings for RTEP charges. These retrospective billing adjustments are based on a hybrid method of allocating costs for RTEP transmission enhancements that differs from the method used to calculate the bills PJM originally issued to comply with FERC Order No. 494. The total net bill credits that PECO is now receiving under the Settlement are adjustments to RTEP charges PECO paid between June 1, 2007 and January 1, 2016.

18. Q. What adjustments to PECO's prior PJM bills will be made under the Settlement?

A. Under the Settlement, PJM was charged with tracking and accumulating the aggregate differences, plus interest, between the previous RTEP charges and the revised allocations approved by FERC between January 1, 2016 and June 30,

[9] FERC Order No. 494, pp. 8-9.

[10] *PJM Interconnection, L.L.C.*, Order on Contested Settlement, 163 FERC ¶ 61,168 (2018).

2018, a period referred to as the "transitional period." PJM published a summary of the transitional period billing adjustments in each transmission zone on July 31, 2018.

For the "historical period," from the initiation of RTEP charges in 2007 to January 1, 2016, the total amounts that were reallocated and the corresponding billing adjustments are based on a "black box" settlement. A new Schedule 12-C, Appendix C ("Appendix C"), was added to the OATT to implement the Settlement effective as of January 1, 2016 and continuing through December 31, 2025. Appendix C reflects the parties' agreement to identify the total amounts PJM would collect from, or credit to, LSEs in each responsible transmission zone and does not specify any underlying billing determinants as the basis for the agreed upon total. Appendix C, which is attached to my testimony as PECO Exhibit No. JAB-3, provides that the Company's monthly PJM billing adjustments for this "historical period" are credits of $634,062.44 and $265,733.81 for years 1 through 4 of the Settlement (2016-2019) and years 5 through 10 of the Settlement (2020-2025), respectively.

19. Q. Have you prepared an exhibit showing the Company's calculations of the total amount of PJM bill credits PECO will receive under the Settlement?

A. Yes. PECO Exhibit No. JAB-4 applies the terms of the Settlement to the most recent data available from PJM. PECO will receive approximately $83 million in total net credit adjustments to prior-period bills (i.e., the total bill credits for the "transition period" and the "historical period"). PJM began furnishing those bill credits to PECO in July of 2018, and will continue to provide credits until December 31, 2025. The sum of $83 million is an upward revision of the estimate of $79.5 million set forth in PECO's November 7, 2018 NBT filing.

20. Q. How did PECO determine the portion of the total Settlement amount that relates to the 2007-2010 period?

A. The Company used time-segmented "black box" RTEP reallocation amounts for the PECO Zone provided by PJM during the settlement negotiations at FERC Docket No. EL05-121-009 to determine the portion of RTEP charges paid by PECO during the historical period. Based on the data provided by PJM, PECO calculated that approximately 12.3% of the RTEP charges paid by PECO during the historical period and reallocated under the Settlement relate to the 2007-2010 period. As shown on PECO Exhibit No. JAB-4, PECO's total black box PJM credit amount for the "historical period" is $49,567,831.44. Applying the 12.3% factor along with the Company's default service load percentage for the pre-2011 period calculated in PECO Exhibit No. JAB-5 (91%) to PECO's total black box PJM bill credit for the historical period results in a PJM billing adjustment of $5.5 million for the pre-2011 period.[11] Additional details regarding this calculation are provided in PECO Exhibit No. JAB-6.

[11] Even though PECO's total PJM bill credits under the Settlement increased from approximately $79 million to $83 million, PECO did not increase the $5.5 million portion that related to pre-2011 bill adjustments.

V. THE NON-BYPASSABLE TRANSMISSION CHARGE RATES CALCULATED IN PECO'S TARIFF SUPPLEMENTS REFLECT ALL ADJUSTMENTS TO POST-2010 PJM BILLS AND ARE REASONABLE

21. Q. Please describe how PECO accounted for the PJM billing adjustments in its semi-annual NBT rate calculations.

A. PECO's customers paid reconcilable TSC or NBT charges that included PJM's RTEP charges from and after January 1, 2011. Accordingly, under PECO's approach, all of the PJM RTEP billing adjustments that relate to billing periods from and after January 1, 2011 will flow through to PECO's distribution customers via its NBT rate calculations. The approximately $5.5 million of bill credits that PECO did not include in its NBT calculations relate to transmission service for the 2007-2010 period. During that period, neither the TSC nor NBT were in effect, and PECO's base rates were not subject to any form of retrospective, line-item reconciliation. Indeed, as I previously explained, the revenue requirement for PECO's base rates in effect between June 1, 2007 and December 31, 2010 did not include any RTEP charges. As such, no baseline exists to conduct any such reconciliation, even if one were to be attempted.

22. Q. Did PECO employ its approach of passing through all post-2010 PJM RTEP bill credits to customers in its NBT rates effective December 1, 2018 through May 31, 2019?

A. Yes. In Supplement No. 76, PECO reduced the NBT costs by approximately $49 million that would otherwise be recoverable to begin reflecting the PJM bill credits for the post-2010 period, including credits that PECO began receiving in July of 2018 as well as credits that PECO anticipated receiving by May 31, 2019.

PECO reflected approximately $20.9 million in NBT overcollections from July 2018 through October 2018 resulting from the actual PJM billing adjustments made during that period in the reconciliation factor (the "E-Factor") for the NBT rates effective December 1, 2018. PECO also projected receipt of approximately $28.4 million in additional PJM bill credits through May 31, 2019 and reflected those projected credits as an offset to projected recoverable NBT costs in the "C-Factor."

Table 1 below provides a breakdown of the PJM bill credits passed through to customers by rate class under Supplement No. 76 and the accompanying supporting schedules, which are attached hereto as PECO Exhibit No. JAB-7. The Company's workpapers for the E-Factor calculation under Supplement No. 76 are attached hereto as Exhibit No. JAB-8.

Table 1

Rate Class	**Post-2010 Bill Credit Amount**	**Rate Component**	**PECO Exhibit Cross-Reference**
R, RH	$9,587,409.75	E-Factor	PECO Exhibit No. JAB-8
	$12,994,084.26	C-Factor	PECO Exhibit No. JAB-7, Attachment 2, p. 2.
GS	$4,748,308.94	E-Factor	PECO Exhibit No. JAB-8
	$6,440,295.14	C-Factor	PECO Exhibit No. JAB-7, Attachment 3, p. 2.
HT, PD, EP	$6,568,512.20	E-Factor	PECO Exhibit No. JAB-8
	$8,901,981.16	C-Factor	PECO Exhibit No. JAB-7, Attachment 4, p. 2.

SLE, SLS, POL, AL, TLCL	$14,782.17	E-Factor	PECO Exhibit No. JAB-8
	$20,041.37	C-Factor	PECO Exhibit No. JAB-7, Attachment 5, p. 2.
Total	$49,275,414.99		

Supplement No. 76 excludes approximately $2.75 million in PJM billing adjustments related to transmission service periods prior to January 1, 2011.

23. Q. Did the Company make another semi-annual adjustment to its NBT after the OCA filed its Complaint?

A. Yes. On May 15, 2019, PECO filed its NBT semi-annual adjustment for the period June 1, 2019 through November 30, 2019 in its Supplement No. 13 to its Tariff Electric – Pa. P.U.C. No. 6 ("Supplement No. 13"), which bore an effective date of June 1, 2019 and was docketed at M-2019-3010032. On May 30, 2019, the Commission issued a Secretarial Letter approving PECO's proposed NBT rates under Supplement No. 13 effective June 1, 2019.

As shown in Table 2 below, in Supplement No. 13, PECO reduced the NBT costs by approximately $13.9 million that would otherwise be recoverable to continue reflecting the PJM bill credits for the post-2010 period that PECO anticipated receiving by November 30, 2019. PECO reflected approximately $17,000 in NBT overcollections from November 2018 through April 2019 resulting from the actual PJM billing adjustments made during that period E-

Factor.[12] Details on the Company's E-Factor calculations for Supplement No. 13 are provided in PECO Exhibit No. JAB-10. PECO also offset the projected recoverable NBT costs in the C-Factor by approximately $13.9 million to reflect additional PJM bill credits the Company expects to receive through November 30, 2019.[13]

Table 2

Rate Class	Post-2010 Bill Credit Amount	Rate Component	PECO Exhibit Cross-Reference
R, RH	$7,918.18	E-Factor	PECO Exhibit No. JAB-10
	$6,322,018.97	C-Factor	PECO Exhibit No. JAB-9, Attachment 2, p. 2.
GS	$3,970.70	E-Factor	PECO Exhibit No. JAB-10
	$3,165,767.68	C-Factor	PECO Exhibit No. JAB-9, Attachment 3, p. 2.
HT, PD, EP	$5,520.83	E-Factor	PECO Exhibit No. JAB-10
	$4,399,111.16	C-Factor	PECO Exhibit No. JAB-9, Attachment 4, p. 2.
SLE, SLS, POL, AL, TLCL	$11.56	E-Factor	PECO Exhibit No. JAB-10
	$9,282.02	C-Factor	PECO Exhibit No. JAB-9, Attachment 5, p. 2.
Total	$13,913,601.10		

[12] This amount is substantially lower than the E-Factor amount recovered in Supplement No. 76 because PECO had previously projected receipt of the majority of these adjustments in Supplement No. 76.

[13] This amount is substantially lower than the C-Factor amount recovered in Supplement No. 76 because the adjustments pertaining to the "transitional period" are scheduled to end in June of 2019. Only the black box adjustments pertaining to the "historical period" are scheduled to continue through 2025.

Supplement No. 13 excludes the balance of approximately $2.75 million in PJM billing adjustments related to transmission service periods prior to January 1, 2011.

24. Q. Will the NBT continue to reflect RTEP billing adjustments that PJM will make pursuant to the Settlement through 2025?

A. Yes. All of the remaining PJM bill credits that PECO receives after November 30, 2019 will be passed through to customers as reductions to PECO's NBT-recoverable costs in subsequent semi-annual adjustments to PECO's NBT rate.

25. Q. Would it be either reasonable or equitable to require PECO to include pre-2011 PJM billing adjustments made pursuant to the Settlement in its calculation of NBT charges, as the OCA seems to be suggesting in its Complaint?

A. No. The 2018 Settlement before the FERC that required PJM to make retrospective billing adjustments does not provide any valid basis for a single-issue, line-item adjustment to PECO's pre-2011 base rates. Such an adjustment is particularly inappropriate given that PECO's pre-2011 base rates did not reflect any RTEP charges.

Closer examination of the substantive economic effect of the 2018 FERC Settlement further establishes the lack of reasonable basis for such an adjustment. If PJM had charged PECO correctly from the outset – that is, if PJM's bills from June 2007 to December 31, 2010 had been in the correct amount – PECO would have no cost-based justification to reduce its base rates during that period by $5.5

million. The fact that PJM has retrospectively reduced the RTEP charges that were imposed on and paid by PECO during that pre-2011 period does not provide a reasonable basis for the OCA's position.

Similarly, if PJM had overcharged PECO $5.5 million from June 2007 to December 2010 but discovered its error in December 2010 and issued a $5.5 million bill adjustment in that month, there would not have been a reasonable basis to require PECO to reduce its base rates for that period by $5.5 million. Indeed, counsel advises that, if an attempt had been made at that time to force PECO to reduce its base rates in an amount equal to such billing adjustment, PECO could have, and would have, resisted that demand based on the legal doctrine of Commission-made rates and the associated prohibitions against retroactive and single-issue ratemaking. Again, the fact that the FERC did not approve changes to the RTEP cost allocation methodology until more than a decade after PJM began imposing those charges in the PECO zone does not change this analysis.

VI. CONCLUSION

26. Q. Please summarize your response to the principal allegations set forth in the OCA's Complaint.

A. As discussed above, PJM first began to impose RTEP charges in the PECO Zone on June 1, 2007. PECO's Commission-approved base rates in effect between June 2007 and December 31, 2010 were based on a revenue requirement established pre-RTEP that did not include any of the subsequent RTEP charges paid by PECO. PECO also did not recover RTEP charges through its wholesale stated transmission rate between June 1, 2007 and December 31, 2010. PJM transmission-related costs, including RTEP charges, were recovered from customers on a full, current and reconcilable basis through the TSC or NBT only for periods from and after January 1, 2011. Accordingly, PECO's NBT has been calculated to flow-through to customers all of the Settlement adjustments that relate to RTEP charges PJM billed to PECO from and after January 1, 2011. There is no valid basis to require PECO to refund PJM's adjustments to RTEP charges that PECO paid before those charges became subject to recovery and retrospective reconciliation upon the implementation of the TSC as of January 1, 2011.

27. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

DB1/ 103921723.8

PECO Exhibit No. JAB-1

PECO.

Richard G. Webster, Jr.
Director
Rates and Regulatory Affairs

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Philadelphia, PA 19103

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Philadelphia, PA 19101-8699

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dick.webster@exeloncorp.com

December 21, 2010

BY FED EX
Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Post Office Box 3265
Harrisburg, PA 17105-3265

Re: Supplement No. 8 to Tariff Electric – Pa PUC No. 4
Issued December 21, 2010 - to become effective January 1, 2011
Compliance Filings:
(1) General Base Rate Case for Electric Operations – Docket No. R-2010-2161575
(2) Purchase of Receivables – Docket No. P-2009-2143607
Incorporated by reference are the following:
Docket No. R-009739531/P-000971265, M-2009-2123944, P-2008-2062739, P-00072260 and M-2010-2196682

Dear Secretary Chiavetta:

Pursuant to Commission Opinion and Order at Docket No. R-2010-2161575 entered December 21, 2010, PECO Energy Company ("PECO" or the "Company") is herewith filing eight copies of its Compliance Filing, Supplement No. 8 to Tariff Electric Pa. P.U.C. No. 4, bearing an effective date of January 1, 2011. This filing also is being made in compliance with the Commission Order at Docket No. P-2009-2143607 entered June 18, 2010, with regard to retail tariff changes necessary to implement PECO's Purchase of Receivables Program.

Supplement No. 8 also incorporates the following tariff provisions approved in prior proceedings, as follows:

1. Elimination of Competitive Transition Charges ("CTC") per the Company's Electric Restructuring Order (Docket No.'s R-009739531/P-000971265). A final CTC reconciliation is required on or before March 31, 2011;
2. Incorporation of the Company's Smart Meter tariff provisions contained in Tariff Electric No. 3, Supplement No. 105, approved October 27, 2010, effective January 1, 2011 (Docket No. M-2009-2123944);
3. Incorporation of the Company's Tariff provisions of Generation Supply Adjustment ("GSA") (Docket No. P-2008-2062739) and Alternative Energy Portfolio Standard ("AEPS") (Docket No. P-00072260) contained in Tariff Electric No. 4, Supplement No. 6 to become effective January 1, 2011.

In support of Supplement No. 8 we are also providing the following Exhibits:

Exhibit 1 – Summary of rates by rate schedule;

Exhibit 2 - Detailed proof of revenues associated with the base rate case;

Exhibit 3 - Support for final CAP discount rates and maximum discounts provided under terms of the Settlement at Docket No. R-2010-2161575 (Section D) and related documents;

Exhibit 4 - Support for the Universal Service Fund Charge ("USFC") rate based on the Settlement at Docket No. R-2010-2161575 and the approved USFC annual reconciliation at Docket No. M-2010-2196682.

Please date-stamp the enclosed extra copy of this letter as proof of filing and return it in the envelope provided.

If you have any questions, please do not hesitate to call me.

Sincerely,

cc: Certificate of Service
Commissioner James H. Cawley, Chairman
Commissioner Tyrone J. Christy, Vice Chairman
Commissioner Wayne E. Gardner
Commissioner John F. Coleman, Jr.
Commissioner Robert F. Powelson

**SUPPLEMENT NO. 8 TO
ELECTRIC PA. P.U.C. NO. 4**

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued December 21, 2010 Effective January 1, 2011

**ISSUED BY: D. P. O'Brien – President
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101**

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

[ALL CHANGES ARE PER DOCKET NO. R-2010-2161575 EXCEPT AS NOTED OTHERWISE]

Definition of Terms and Explanation of Abbreviations - 1st Revised Page No. 6, 1st Revised Page No. 8
Revised definition of bad credit to clarify the circumstances under which the Company may require a security deposit. Revised definition of Service to specify rate availability for larger customers.
The Tariff – 1st Revised Page No. 10
Simplified reference to PECO website.
Meter Location – 1st Revised Page No. 11
Revised Rule 3.2- Meter Location to ensure that proper access to the Company's meters and equipment is provided.
Credit -1st Revised Page No. 13
Revised Rule 5.2 Prior Debts, Rule 5.3 Guarantee of Payment and Rule 5.4 Amount of Deposit to clarify the intent and application of the rule.
Return of Deposit – 1st Revised Page No. 14
Revised Rule 5.5 to provide additional details on when a deposit may be required.
Line Extensions for Standard Service – 1st Revised Page No. 15
Revised Rule 7.2 Line Extension definition.
Customers Responsibility – 1st Revised Page No. 18
Revised Rule 10.2 to clarify the customer's responsibility when an unsafe condition exists.
Recovery for Property Damage – 1st Revised Page No. 19
Added new Rule 10.11 Recovery of Property Damage which states the terms for recovery of costs of damaged Company equipment.
Estimated Usage- 1st Revised Page No. 22
Added Rule 14.9 - Approved at Docket M-2009-2123944 from Smart Meter Filing.
Deleted reference to Rate HT, Consolidated Rules 14.6 and 14.8.
Billing and Standard Payment Options – 1st Revised Page No. 24
Approved at Docket No. P-2009-2143607 - Updated Rule 17.4 Payment Processing
Deleted reference to Rate RT.
Billing and Standard Payment Options – 1st Revised Page No. 25
Approved at Docket No. P-2009-2143607. Updated Rule 18.1, Rule 18.2 and Rule 18.7.
Deleted Reference to Rate RT.
Designation of Procurement Class – 1st Revised Page No. 27
Renumbered 22.1 and added effective date for clarity.
State Tax Adjustment Clause – 1st Revised Page No. 30
Reset STAS to zero.
Provisions for Recovery of UNIVERSAL SERVICE FUND CHARGE (USFC) 1st Revised Page No. 38
Approved at Docket No. M-2010-2196682. Revised USFC recovery mechanism.
Provisions for Recovery of SUPPLEMENTAL UNIVERSAL SERVICE FUND COSTS 1st Revised Page No. 39
Deleting Supplement USFC .
Provision for the Recovery of Consumer Education Plan Costs 1st Revised Page No. 40
Deleted Reference to Rate RT.
Transmission Charges – 1st Revised Page 40A
New charging mechanism for Transmission Charges.
Smart Meter Cost Recovery Surcharge – 1st Revised Page 40B
Approved at Docket No. M-2009-2123944 - new recovery mechanism for smart meter costs.
Provisions for the Recovery of Energy Efficiency and Conservation Program Costs (EEPC) 1st Revised Page 40C
Approved at Docket No. M-2009-2093215.
Added details to EEPC charges for lighting rates.
Rate R – Residence Service – 1st Revised Page No. 41
Increased Fixed Distribution Charge and Variable Distribution Charge.
Rate RT- Residence Time of Use Service- 1st Revised Page No. 42
Rate deleted.
Rate RH- Residential Heating Service – 1st Revised Page No. 43
Increased Fixed Distribution Charge and Variable Distribution Charge.
Rate RS-2 Net Metering – 1st Revised Page No. 44 and 1st Revised Page No. 45
Deleted reference to Rate RT.
Corrected maximum capacity limit - Approved at Docket L-00050174.
Rate OP – Off Peak Service – 1st Revised Page No. 46
Fixed Distribution Charge decreased and variable distribution charges increased.
Rate GS- General Service – 1st Revised Page No. 47, 1st Revised Page No. 48, 1st Revised Page No. 49
Increased Fixed Distribution Charges and change in Variable Distribution Charges. Also revised single meter, separate meter provisions and special provisions.
Rate PD- Primary Distribution Power – 1st Revised Page No. 50
Increased Fixed Distribution Charge and Variable Distribution Charge.
Rate HT- High Tension Power – 1st Revised Page No. 51
Increased Fixed Distribution Charge, Variable Distribution Charge and High Voltage Discount.
Rate POL Private Outdoor Lighting – 1st Revised Page No. 52
Distribution Charges increased.
Rate SL-P Street Lighting in City of Philadelphia 1st Revised Page No. 54, 1st Revised Page No. 55 & 1st Revised Page No. 56
Rate deleted.
Rate SL-S 1st Revised Page No. 57
Distribution Charges increased.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Rate SL-E – 1st Revised Page No. 59
Added an additional Service Location Charge and added a Distribution Charge.

Rate TLCL – 1st Revised Page No. 61
Availability of Rate is expanded to include constant load devices.

Rate EP- 1st Revised Page No. 63
Increased Fixed Distribution Charge, Variable Distribution Charge and High Voltage discount.

Rate AL – 1st Revised Page No. 64
Modified availability of rate to eliminate Variable Distribution Charge and replace with a Service Location Charge.

Applicability Index of Riders – 1st Revised Page No. 65
Index Modified to reflect deleted riders.

Auxiliary Service Rider – 1st Revised Page No. 66, 1st Revised Page No. 67 1st Revised Page No. 68
Rate and billing section revised to reflect updated Power Pricing and changes to the variable distribution charge.

Customer Assistance Program (CAP) Rider - 1st Revised Page No. 69
Delete the Rate RT reference, increases the number of tiers, provides for percentage discount rates and provides maximum discount amounts.

Casualty Rider – 1st Revised Page No. 71
Deleted the word "ratchet".

Cooling Thermal Storage HT Rider 1st Revised Page 73
Rider deleted.

Night Service GS Rider – 1st Revised Page 80
Increased billing and metering charge and Off-Peak Charge.

Night Service HT Rider – 1st Revised Page 81
Increased billing and metering charge and Off-Peak Charge.

Night Service PD Rider – 1st Revised Page 82
Increased billing and metering charge and Off-Peak Charge.

Seasonal Capacity Charge Service Rider – 1st Revised Page 84
Rider deleted.

Temporary Service Rider- 1st Revised Page No. 85
Rate impact section revised.

Transformer Rental Rider – 1st Revised Page No. 86
Revised wording to reflect elimination of the rider as of January 1, 2012.

Voluntary Market Price Transition Deferral Rider- 1st Revised Page No. 87
Deleted Rate SL-P reference.

Wind Energy Service Rider – 1st Revised Page No. 88
Deleted Rate RT reference.

Transmission Charges – 1st Revised Page No. 89, 1st Revised Page No. 90 and 1st Revised Page No. 91
Transmission Charges deleted.

TRANSMISSION SERVICE CHARGE

(C)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of all transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's default service load.

Applicability: The surcharge shall be assessed to all default service customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The surcharge shall be calculated on an annual basis using the formula below:

TSC(n) = (C+E+I)/S(n) where;

TSC(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Charges assessed by PJM for network service within the PECO zone. Included in such charges are costs assigned to the load serving entities in the PECO zone under the Regional Transmission Expansion Plan as well as the base network service charge for the zone as well as any load serving entity charges assessed to PECO under the PJM OATT that are listed in PECO's Supply Master Agreement Exhibit D as the responsibility of the Buyer. Included in the cost to be recovered is a working capital (WC) component as defined below.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $356 per mW. WC is a component of the 'C" factor

E – The estimated over or under recovery from the prior year. The reconciliation period shall be the 12 months ended October 31.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 1b = OP,2 = small C&I, 3 = large C&I, 4 = street lighting
Residential – Rates R, RH, OP (reconciled as a group)
Small C&I – Rate GS,
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLS, POL, AL, SLP, TLCL (reconciled as a group)

S – Estimated default service sales for residential class and the street lighting class in the application period. For the commercial and industrial class it shall be the estimated billed demand for the application period. The application period shall be the 12 month period staring the January 1 subsequent to the filing of the updated rate.

Filing Schedule: The estimated surcharge shall be filed December 1 prior to the start of the application period. The rate shall be effective on the first full billing cycle starting after January 1. The filing shall include a reconciliation for the 12 months ended October 31 prior to the filing date. The resultant over or under recovery shall be included in the Transmission service Charge commencing on January 1 following the reconciliation filing.

Current Transmission Service Rate:
Residential
R= $0.0073 per kilowatthour
RH= $0.0039 per kilowatthour
OP= $0.0034 per kilowatthour
Small C&I = $1.82 per billed kW
Large C&I = $2.01 per billed kW
Street Lighting = $0.0000 per kilowatt hour

(C) Indicates Change

PECO Exhibit No. JAB-2

Exhibit C

PECO Energy Company

Default Service Program

Request for Proposals

For Full Requirements Products

________, 2009

NERA

Economic Consulting

EXHIBIT D

SAMPLE PJM INVOICE

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY
FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.:				
Charges:	**Day-ahead**	**Balancing**	**Total**	**Reference**
Spot Market Energy	Seller	Seller	Seller	Schedules 1-3.2.1 & 3.3.1 of PJM Operating Agreement
Transmission Congestion	Seller	Seller	Seller	Schedules 1-3.2.4, 3.4.1 & 5.2 of PJM Operating Agreement
Transmission Losses	Seller	Seller	Seller	Schedules 1-3.2.5 & 3.4.2 of PJM Operating Agreement
Inadvertent Interchange			Seller	Schedules 1-3.7 of PJM Operating Agreement
Regulation			Seller	Schedules 1-3.2.2, 3.2.2A, 3.2.2, & 3.3.2A of PJM Operating Agreement
Synchronized Reserve			Seller	Schedules 1-3.2.3A & 3.3.5 of PJM Operating Agreement
Operating Reserves	Seller	Seller	Seller	Schedules1-3.2.3 & 3.3.3 of PJM Operating Agreement
Synchronous Condensing			Seller	Schedules1-3.2.3 & 3.3.3 of PJM Operating Agreement
Reconciliation for Spot Market			Seller	Schedules 1-3.2.1 & 3.3.1 of PJM Operating Agreement
Reconciliation for Regulation			Seller	Schedules 1-3.2.2, 3.2.2A, 3.2.2, & 3.3.2A of PJM Operating Agreement
Reconciliation for Spinning Reserves			Seller	Schedules 1-3.2.3A & 3.3.5 of PJM Operating Agreement

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY
FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.:				
Charges:	**Day-ahead**	**Balancing**	**Total**	**Reference**
Reconciliation for Transmission Losses			Seller	Schedules 1-3.2.5 & 3.4.2 of PJM Operating Agreement
Reactive Services			Seller	Schedule 3.2.3B of PJM Operating Agreement
Emergency Energy			Seller	Schedule 1-3.2.6, 3.3.4, 3.5.1 & 4.3 of PJM Operating Agreement
FTR Auction			Seller	Schedule 1-7.3.8 of PJM Operating Agreement
Meter Correction			Seller	Schedule 1-3.6 of PJM Operating Agreement
Real-Time Economic Load Response Program			Seller	Sections describing PJM's Economic Load Response Programs in PJM Operating Agreement
Day-Ahead Economic Load Response Program			Seller	Sections describing PJM's Economic Load Response Programs in PJM Operating Agreement
Emergency Load Response Program			Seller	Sections describing PJM's Emergency Load Response Programs in PJM Operating Agreement
Percentage of Default Allocation (See Agreement § 4.11)			Seller	Section 15.2 of PJM Operating Agreement

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.:				
Credits:	**Day-ahead**	**Balancing**	**Total**	**Reference**
Transmission Congestion - Hourly			Seller	Schedules 1-3.2.4, 3.4.1 & 5.2 of PJM Operating Agreement
Transmission Congestion - Annual			Buyer	Schedules 1-3.2.4, 3.4.1 & 5.2 of PJM Operating Agreement
Transmission Losses			Seller	Schedules 1-3.2.5 & 3.4.2 of PJM Operating Agreement
Reconciliation for Transmission Losses			Seller	Schedules 1-3.2.5 & 3.4.2 of PJM Operating Agreement
Regulation			Seller	Schedules 1-3.2.2, 3.2.2A, 3.2.2, & 3.3.2A of PJM Operating Agreement
Synchronized Reserve			Seller	Schedules 1-3.2.3A & 3.3.5 of PJM Operating Agreement
Operating Reserves	Seller	Seller	Seller	Schedules1-3.2.3 & 3.3.3 of PJM Operating Agreement
Synchronous Condensing			Seller	Schedules1-3.2.3 & 3.3.3 of PJM Operating Agreement
Reconciliation for Transmission Losses			Seller	Schedules 1-3.2.5 & 3.4.2 of PJM Operating Agreement
Reactive Services			Seller	Schedule 3.2.3B of PJM Operating Agreement
Emergency Energy			Seller	Schedule 1-3.2.6, 3.3.4, 3.5.1 & 4.3 of PJM Operating Agreement

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.:				
Credits:	**Day-ahead**	**Balancing**	**Total**	**Reference**
FTR Auction			Seller	Schedule 1-7.3.8 of PJM Operating Agreement
Auction Revenue Rights			Seller	Schedule 1-7.4 of PJM Operating Agreement
Real-Time Economic Load Response Program			Buyer	Sections describing PJM's Economic Load Response Programs in PJM Operating Agreement
Day-Ahead Economic Load Response Program			Buyer	Sections describing PJM's Economic Load Response Programs in PJM Operating Agreement
Emergency Load Response Program			Buyer	Sections describing PJM's Emergency Load Response Programs in PJM Operating Agreement

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

PJM OPEN ACCESS TRANSMISSION TARIFF:		
Charges:	**Total**	**Reference**
PJM Scheduling, System Control and Dispatch Service	Seller	Schedules 1 and 9 of PJM OATT
Transmission Owner Scheduling, System Control and Dispatch Service	Seller	Schedule 1A of PJM OATT
Reactive Supply and Voltage Control from Generation Sources Service	Seller	Schedule 2 of PJM OATT
Black Start Service	Seller	Schedule 6A of PJM OATT
North American Electric Reliability Corporation (NERC)	Seller	Schedules 1 and 9 of PJM OATT
Reliability First Corporation (RFC)	Seller	Schedules 1 and 9 of PJM OATT
Network Integration Transmission Service	Buyer	Section 34, Attachments H-1 through H-15, Attachment H-A, and TOAs Section 5.4
Firm Point-to-Point Transmission Service	Seller	Section 13.7, Schedule 7, and TOAs Section 5.4
Non-Firm Point-to-Point Transmission Service	Seller	Sections 14.5 & 27A, Schedule 8 of PJM OATT
Reconciliation for PJM Scheduling, System Control and Dispatch Service	Seller	Schedules 1 and 9 of PJM OATT
Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service	Seller	Schedule 1A of PJM OATT
Energy Imbalance	Seller	Schedule 4 of PJM OATT
Expansion Cost Recovery	Buyer	Schedule 13 of PJM OATT
Transmission Enhancement Charges	Buyer	Schedule 12 of PJM OATT
Generation Deactivation	Seller	Part V of PJM OATT
Charges:	**Total**	**Reference**

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

RPM Auction	Seller	Attachment DD of PJM OATT
Locational Reliability	Seller	Attachment DD of PJM OATT
Non-Unit Specific Capacity Transaction	Seller	Attachment DD of PJM OATT
Demand Resource and ILR Compliance Penalty	Buyer	Attachment DD of PJM OATT
Capacity Resource Deficiency	Seller	Attachment DD of PJM OATT
Generation Resource Rating Test Failure	Seller	Attachment DD of PJM OATT
Qualifying Transmission Upgrade Compliance Penalty	Seller	Attachment DD of PJM OATT
Peak Season Maintenance Compliance Penalty	Seller	Attachment DD of PJM OATT

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

Credits:	Total	Reference
Transmission Owner Scheduling, System Control and Dispatch	Buyer	Schedule 1A of PJM OATT
Reactive Supply and Voltage Control from Generation Sources	Buyer	Schedule 2 of PJM OATT
Black Start Service	Seller	Schedule 6A of PJM OATT
Network Integration Transmission Service	Buyer	Section 34, Attachments H-1 through H-15, Attachment H-A, and TOAs Section 5.4
Firm Point-to-Point Transmission Service	Buyer	Section 13.7, Schedule 7, and TOAs Section 5.4
Non-Firm Point-to-Point Transmission Service	Buyer	Sections 14.5 & 27A, Schedule 8 of PJM OATT
Expansion Integration	Buyer	Schedule 13 of PJM OATT
Other Supporting Facilities	Buyer	Schedules 7 & 8 and Attachments F, F-1, H-5A, H-6A, H-8A and H-9 of PJM OATT
Energy Imbalance	Seller	Schedule 4 of PJM OATT
Expansion Cost Recovery	Buyer	Schedule 13 of PJM OATT
Transmission Enhancement Credits	Buyer	Schedule 12 of PJM OATT
Generation Deactivation	Seller	Part V of PJM OATT
RPM Auction	Seller	Attachment DD of PJM OATT
Interruptible Load for Reliability	Buyer	Attachment DD of PJM OATT
Capacity Transfer Rights	Seller	Attachment DD of PJM OATT
Incremental Capacity Transfer Rights	Seller	Attachment DD of PJM OATT
Non-Unit Specific Capacity Transaction	Seller	Attachment DD of PJM OATT
Demand Resource and ILR Compliance Penalty	Buyer	Attachment DD of PJM OATT

EXHIBIT D
SAMPLE PJM INVOICE (Continued)

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY

FOR PERIOD: MM/DD/YYYY **TO** MM/DD/YYYY

Credits:	**Total**	**Reference**
Generation Resource Rating Test Failure	Seller	Attachment DD of PJM OATT
Qualifying Transmission Upgrade Compliance Penalty	Seller	Attachment DD of PJM OATT
Peak Season Maintenance Compliance Penalty	Seller	Attachment DD of PJM OATT

PECO Exhibit No. JAB-3

Schedule 12-C Appendix C						
Transmission Enhancement Charge (TEC) Adjustments - Monthly						
Zone or MTF	Monthly TEC Adjustment Years 1-4 Without PATH	Monthly TEC Adjustment Years 1-4 PATH Only	**Total Monthly TEC Adjustment Years 1 through 4**	Monthly TEC Adjustment Years 5-10 Without Path	Monthly TEC Adjustment Years 5-10 Path Only	**Total Monthly TEC Adjustment Years 5 through 10**
AE	-$24,860.09	$47,899.66	**$23,039.57**	-$10,418.79	$20,074.61	**$9,655.82**
AEP	-$2,444,812.18	-$174,489.11	**-$2,619,301.30**	-$1,024,614.00	-$73,127.90	**-$1,097,741.90**
APS	$954,922.88	$52,440.01	**$1,007,362.89**	$400,205.53	$21,977.46	**$422,182.99**
ATSI	-$1,093,902.38	-$72,438.56	**-$1,166,340.94**	-$458,451.45	-$30,358.80	**-$488,810.25**
BGE	$1,281,971.91	-$2,640.98	**$1,279,330.93**	$537,270.87	-$1,106.83	**$536,164.04**
ComEd	-$2,608,103.66	-$221,693.57	**-$2,829,797.23**	-$1,093,049.01	-$92,911.16	**-$1,185,960.17**
ConEd	-$70,904.37	-$4,688.81	**-$75,593.18**	-$29,715.83	-$1,965.07	**-$31,680.89**
Dayton	-$375,384.08	-$34,767.87	**-$410,151.95**	-$157,322.42	-$14,571.12	**-$171,893.54**
Duke OH/KY	-$302,715.79	-$20,247.63	**-$322,963.42**	-$126,867.35	-$8,485.73	**-$135,353.07**
Duquesne	-$318,588.72	-$28,822.02	**-$347,410.74**	-$133,519.65	-$12,079.23	**-$145,598.88**
Delmarva DE	-$157,754.97	$37,622.55	**-$120,132.43**	-$66,114.67	$15,767.50	**-$50,347.17**
Delmarva MD	-$97,639.85	$22,956.13	**-$74,683.72**	-$40,920.59	$9,620.85	**-$31,299.74**
Delmarva VA	-$13,369.07	$3,188.35	**-$10,180.71**	-$5,602.94	$1,336.23	**-$4,266.71**
Dominion	$2,548,417.01	-$29,708.12	**$2,518,708.88**	$1,068,034.50	-$12,450.59	**$1,055,583.90**
EKPC	-$88,156.35	-$3,920.00	**-$92,076.35**	-$36,946.08	-$1,642.86	**-$38,588.94**
HTP	$67,459.71	-$392.30	**$67,067.41**	$28,272.18	-$164.41	**$28,107.76**
JCPL	$684,836.11	$113,570.16	**$798,406.27**	$287,012.91	$47,596.94	**$334,609.85**
MedEd	-$290,626.73	$14,498.19	**-$276,128.54**	-$121,800.86	$6,076.15	**-$115,724.70**
Neptune	$63,553.63	$10,067.97	**$73,621.60**	$26,635.15	$4,219.46	**$30,854.61**
PECO	-$766,990.16	$132,927.71	**-$634,062.44**	-$321,443.45	$55,709.64	**-$265,733.81**
Penelec	-$224,425.28	-$30,009.25	**-$254,434.53**	-$94,056.01	-$12,576.79	**-$106,632.80**
PEPCO DC	$787,856.55	$9,072.91	**$796,929.46**	$330,188.49	$3,802.43	**$333,990.92**
PEPCO MD	$1,145,526.02	$13,215.00	**$1,158,741.03**	$480,086.78	$5,538.37	**$485,625.15**
PEPCO SMECO	$273,479.45	$3,154.91	**$276,634.36**	$114,614.48	$1,322.21	**$115,936.69**
PPL PPLEU	-$786,877.08	$20,174.85	**-$766,702.23**	-$329,778.00	$8,455.23	**-$321,322.78**
PPL UGI	-$40.31	$0.00	**-$40.31**	-$16.89	$0.00	**-$16.89**
PSEG	$1,713,725.35	$135,477.48	**$1,849,202.83**	$718,217.54	$56,778.24	**$774,995.77**
Rockland	$63,940.65	$4,698.27	**$68,638.92**	$26,797.35	$1,969.03	**$28,766.38**
East Coast Power	$79,461.78	$2,854.08	**$82,315.86**	$33,302.21	$1,196.14	**$34,498.35**

PECO Exhibit No. JAB-4

Calculation of PJM Bill Credits PECO Will Receive Under the Settlement

"Black Box" Settlement Credit

SOURCE:

FERC Docket No. EL05-121-009, Offer of Settlement
June 15, 2016
Appendix A, Attachment C

Schedule 12-C Appendix C						
Transmission Enhancement Charge (TEC) Adjustments - Monthly						
Zone or MTF	Monthly TEC Adjustment Years 1-4 Without PATH	Monthly TEC Adjustment Years 1-4 PATH Only	**Total Monthly TEC Adjustment Years 1 through 4**	Monthly TEC Adjustment Years 5-10 Without Path	Monthly TEC Adjustment Years 5-10 Path Only	**Total Monthly TEC Adjustment Years 5 through 10**
PECO	-$766,990.16	$132,927.71	**-$634,062.44**	-$321,443.45	$55,709.64	**-$265,733.81**

Total Monthly Adj Sum, Years 1-4	$ (30,434,997.12)
Total Monthly Adj Sum, Years 5-10	$ (19,132,834.32)
Total "Black Box" Settlement Credit	**$ (49,567,831.44)**

"Transitional" Credit

SOURCE:

PJM, "Current Recovery Charge Transitional Period Summary"
July 31, 2018

Total Transitional Period Aggregate Differences (January 2016 - June 2018)	$ (31,707,893.11)
Total Transitional Period Interest (January 2016 - June 2018)	$ (1,704,045.45)
Monthly Current Recovery Charge Transitional Period Charge - 1108A (July 2018 - June 2019)	$ (2,784,328.21)

Total Transitional Period Aggregate Differences Plus Interest	$ (33,411,938.56)
Total Transitional Credit	$ (33,411,938.56)

Total "Black Box" Settlement Credit	$ (49,567,831.44)
Total Transitional Credit	$ (33,411,938.56)
Total Expected Credit:	**$ (82,979,770.00)**

PECO Exhibit No. JAB-5

PECO EGS Shopping Statistics (excluding Unaccounted-For Energy)

YEAR	EGS Usage	Default Usage	Total Usage	EGS %	Default %				
1/1/2003	3,460,077,974	35,884,666,922	39,344,744,897	8.8%	91.2%				
1/1/2004	4,874,098,226	35,354,593,032	40,228,691,258	12.1%	87.9%				
1/1/2005	2,256,160,787	39,191,835,282	41,447,996,070	5.4%	94.6%				
1/1/2006	828,990,063	39,587,707,105	40,416,697,168	2.1%	97.9%				
1/1/2007	648,355,773	40,858,680,659	41,507,036,431	1.6%	98.4%	[redacted]	378,207,534	23,834,230,384	24,212,437,918
1/1/2008	528,840,851	40,756,335,749	41,285,176,601	1.3%	98.7%		471,567,956	40,158,467,951	40,630,035,907
1/1/2009	414,295,060	39,560,600,153	39,974,895,213	1.0%	99.0%		459,712,965	40,923,663,367	41,383,376,332
1/1/2010	505,130,870	42,286,726,581	42,791,857,451	1.2%	98.8%		11,722,746,680	30,474,244,033	42,196,990,713
1/1/2011	22,940,362,490	18,661,761,485	41,602,123,975	55.1%	44.9%		13,032,235,135	135,390,605,735	148,422,840,870
1/1/2012	26,249,927,504	14,081,888,264	40,331,815,767	65.1%	34.9%		8.8%	**91.2%**	
1/1/2013	27,606,595,915	13,105,583,049	40,712,178,964	67.8%	32.2%				
1/1/2014	27,982,223,924	12,428,028,611	40,410,252,535	69.2%	30.8%				
1/1/2015	28,198,011,260	12,711,369,252	40,909,380,511	68.9%	31.1%				
1/1/2016	28,489,999,682	12,397,313,914	40,887,313,595	69.7%	30.3%				
1/1/2017	28,082,858,392	11,927,276,247	40,010,134,639	70.2%	29.8%				
1/1/2018	11,258,228,414	5,057,736,610	16,315,965,024	69.0%	31.0%				

PECO Exhibit No. JAB-6

Calculation of Pre-2011 PJM Bill Credits Under the Settlement

PJM Transmission Enhancement Zonal Cost Allocation using Prior Method

(Source: PJM Data Provided During Settlement Negotiations at Docket No. EL05-121-009)

June - December 2007	$ 208,012.42			
January - May 2008	$ 526,829.62			
June - September 2008	$ 817,664.26			
October - December 2008	$ 646,431.10			
January - May 2009	$ 1,621,701.26			
June 2009	$ 428,639.74			
July - December 2009	$ 3,108,908.31			
January - May 2010	$ 3,032,901.90			
June 2010	$ 1,065,591.01	2007-2010 Total	% of 2007-2015 Total	
July - December 2010	$ 6,402,033.17	$ 17,858,712.79	12.3%	
January - May 2011	$ 7,110,547.21			
June 2011	$ 1,492,843.91			
July - December 2011	$ 8,959,813.02			
January - April 2012	$ 6,103,190.94			
May 2012	$ 1,517,579.79			
June - 2012	$ 1,911,374.47			
June - December 2012	$ 11,475,732.98			
January - May 2013	$ 10,600,044.98			
June 2013	$ 2,015,829.61			
July - December 2013	$ 12,190,738.42			
January - May 2014	$ 12,007,357.98			
June 2014	$ 2,658,748.06			
July - December 2014	$ 16,065,782.06			
January 2015	$ 2,771,091.65	2011-2015 Total:		
Feb-Dec 2015	$ 30,482,008.15	$ 127,362,683.24		
TOTAL	$ 145,221,396.03	$ 145,221,396.03		

RTEP "Black Box" Settlement: Allocation Factor Development

From PECO Exhibit JAB-4:	
Total "Black Box" Settlement Credit	$ (49,567,831.44)
2007-2010 PJM Transmission Enhancement Zonal Cost Allocation using Prior Method	$ (6,095,642.17)
From PECO Exhibit JAB-5:	
PECO Default Service Usage %	91.2%
RTEP Credit to be Retained by PECO	**$ (5,560,415.64)**

PECO Exhibit No. JAB-7

PECO
An Exelon Company

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

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November 7, 2018

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

SUBJECT: Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment, PECO Energy Electric Tariff No. 5, Supplement No. 76 Effective December 1, 2018, Docket No. P-2014-2409362

Dear Secretary Chiavetta:

This filing contains PECO Energy Company's (PECO) semiannual adjustment to the Non-Bypassable Transmission Service Charge (NBT), effective December 1, 2018. This filing is being made in accordance with PECO's Tariff approved in Docket No. P-2014-2409362

The following attachments are included in support of this filing:

Attachment 1 – Revised tariff pages for NBT;
Attachment 2 – NBT Calculation for Residential - Rates R & RH;
Attachment 3 – NBT Calculation for C&I Rate GS;
Attachment 4 – NBT Calculation for C&I Rates HT, PD, EP;
Attachment 5 – NBT Calculation for Street Lighting - Rates SLE, SLS, POL, AL, TLCL.

This adjustment to the NBT is the first to reflect the impact of approved Regional Transmission Expansion Plan ("RTEP") credits being refunded to the PECO Zone by PJM, pursuant to the Settlement Agreement under FERC Docket No. EL05-121-009. Credits received by PECO since July of this year, as well as over 90% of projected refunds expected over the upcoming six-month period, will be returned to customers via this adjustment. The NBT will continue to reflect RTEP credits that PJM will refund through 2025 as specified in the Settlement.

Per the Settlement, the PECO Zone will receive $79.5M of total credits, including receipt of approximately $56M of this amount by the end of June 2019. As discussed with the Commission this past October, PECO will retain $5.5 million of the total credits over the NBT filing periods from December 1, 2018 through November 30, 2019. Retaining this credit permits recovery of overpaid RTEP costs previously absorbed by PECO from 2007 through 2010. As a result, PECO will refund approximately $74M to customers through 2025.

Should the Commission need to initiate any related proceeding, PECO requests that the NBT tariff rates specified in this filing not be suspended by the Commission, but rather that such rates be placed into effect, subject to refund.

Thank you for your assistance in this matter. Please direct any questions regarding the above to Richard Schlesinger, Manager, Retail Rates at (215) 841-5771.

Sincerely,

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

Copies to: K. G. Sophy, Director, Office of Special Assistants
P. T. Diskin, Director, Bureau of Technical Utility Services
K. A. Monaghan, Director, Bureau of Audits
R. A. Kanaskie, Director, Bureau of Investigation & Enforcement
Office of Consumer Advocate
Office of Small Business Advocate
McNees, Wallace & Nurick

Attachment 1

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued November 7, 2018 Effective December 1, 2018

ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Non-Bypassable Transmission Charge (NBT) – 6th Revised Page No. 41
Reflects semiannual adjustment for Non-Bypassable Transmission Charge pursuant to Order at Docket No. R-2010-2161575.

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Rate R - Residence Service - 29th Revised Page No. 48
The Variable Distribution Service Charge is decreased to a change in the Non-Bypassable Transmission Charge (NBT).

Rate RH - Residential Heating Service – 29th Revised Page No. 49
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate GS - General Service – 30th Revised Page No. 53
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate SL-E Street Lighting Customer Owned Facilities – 14th Revised Page No. 62
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate TLCL - Traffic Lighting Constant Load Service – 16th Revised Page No. 64
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

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NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362.

Applicability: The surcharge shall be assessed to all distribution customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential, Small C&I and Street Lighting class rate schedules as described below.

For Rates PD, HT, and EP (Large C&I class), a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT. Customer's PLC will be computed to the nearest kilowatt. The NBT shall be recovered through a separate charge listed on customers' bills.

The surcharge shall be calculated on a semi-annual basis using the formula below:

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where;

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

> Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges, Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362.

E – The estimated over or under recovery from the applicable reconciliation period.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate

R= ($0 00151) per kilowatthour **(D)**
RH= ($0.00151) per kilowatthour **(D)**
Small C&I = ($0.53) per billed kW **(D)**
Large C&I = ($0.38) per kW based on the PJM PLC **(D)**
Street Lighting = $.00009 per kilowatt hour **(D)**

(D) Denotes Decrease

RATE R RESIDENCE SERVICE

AVAILABILITY.
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37 1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS. Standard single phase secondary service

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $8.45
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.92

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.06243 per kWh **(D)**

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, SMART METER COST RECOVERY SURCHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS Standard.

(D) Denotes Decrease

RATE R H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Wood, solar, wind, water, and biomass systems may be used to supply a portion of the heating requirements in conjunction with service provided hereunder. Any customer system of this type that produces electric energy may not be operated concurrently with service provided by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered.

CURRENT CHARACTERISTICS. Standard single phase secondary service

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $8.45
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.92

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.06243 per kWh for all kWh. **(D)**
WINTER MONTHS. (October through May)
$0.04431 per kWh for all kWh **(D)**

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE. The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, SMART METER COST RECOVERY SURCHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE. Where a portion of the service provided is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS. Standard.

(D) Denotes Decrease

RATE-GS GENERAL SERVICE

AVAILABILITY.
Service through a single metering installation for offices, professional, commercial or industrial establishments, governmental agencies, and other applications outside the scope of the Residence Service rate schedules. For service configurations that are nominally 120/208 volts, 3 phase, 4 wires and the service capacity exceeds 750 kVa for transformers located either inside or outside the building, the only rate option available to the customer will be Rate HT. For service configurations that are nominally 277/480 volts, 3 phase, 4 wires and capacity exceeds either 750 kVa for transformers located inside the building or 1,500 kVa for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$ 14.28 for single-phase service without demand measurement, or
$ 18.19 for single-phase service with demand measurement, or
$ 43.53 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$6.93 per kW of billed demand **(D)**
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00167 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, SMART METER COST RECOVERY SURCHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows:
(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
(b) For customers with demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, (ii) 40% of the maximum contract demand; or (iii) the maximum measured demand from the prior year. These customers will be identified according to the process listed in Tariff Rule 22.

If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 1.2 kilowatts.
For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.
The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus a charge of $8.31 per KW of billing demand. In addition to the above, for customers in Procurement Class 3/4 charges will be assessed on PJM's reliability pricing model.

(D) Denotes Decrease

RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the utilization facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $7.16 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE: $0.00862 per kWh (D)
ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2

* The service location charge includes an Energy Efficiency Program Surcharge of $0 05 per location

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE. The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location shall comprise each lighting installation and must be separately connected to a delivery point on the Company's secondary circuit.

DETERMINATION OF BILLING DEMAND.
The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of wattages of all Service Locations in service shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.
The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 6 Service. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.
1. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
   The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities.
   b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90 degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such utilization facilities.
   Except as provided in Paragraph 4 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided.
   c. Service to Group of Streetlights:
      AERIAL SUPPLY
      When the customer requests service to a group of streetlights supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the streetlights. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all streetlight locations.

      UNDERGROUND SUPPLY
      When groups of streetlights are supplied from underground distribution facilities the customer is responsible for the supporting poles or posts and the supply conductors to each streetlight from the designated delivery point. If the customer requests an underground supply to a group of streetlights and the designated delivery point is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.
2. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

(D) Denotes Decrease

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.
Standard single phase secondary service.

RATE TABLE.
SERVICE LOCATION CHARGE: $3.62 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.01549 per kWh (as defined below)* **(D)**
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of $.00063 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours. The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

SPECIAL TERMINATION RIGHTS
Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider. In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer. The customer may then, at its discretion, notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days. If the customer has not removed its facilities within 30 days, then PECO may, at its sole discretion and upon 72-hour notice, physically remove the customer facility as a means of terminating service to that facility. Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL. In addition, the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs, use of truck or other equipment, fuel costs, and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals. PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage.

TERM OF CONTRACT.
The initial contract term for each signal light installation and constant load device shall be for at least one year.

PAYMENT TERMS.
Standard.

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SUPPLEMENT NO. 75 to
ELECTRIC PA. P.U.C. NO. 5

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PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued November 7, 2018 Effective December 1, 2018

ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101

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LIST OF CHANGES MADE BY THIS SUPPLEMENT

Non-Bypassable Transmission Charge (NBT) – 6th Revised Page No. 41
Reflects semiannual adjustment for Non-Bypassable Transmission Charge pursuant to Order at Docket No. R-2010-2161575

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Rate R - Residence Service - 29th Revised Page No. 48
The Variable Distribution Service Charge is decreased to a change in the Non-Bypassable Transmission Charge (NBT)

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Rate RH - Residential Heating Service – 29th Revised Page No. 49
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

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Rate GS - General Service – 30th Revised Page No. 53
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

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Rate SL-E Street Lighting Customer Owned Facilities – 14th Revised Page No. 62
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

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Rate TLCL - Traffic Lighting Constant Load Service – 16th Revised Page No. 64
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

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Reflects semiannual adjustment for Transmission Service Charge pursuant to Order at Docket No. R-2010-2161575 ¶

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NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362

Applicability The surcharge shall be assessed to all distribution customers The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential Small C&I and Street Lighting class rate schedules as described below

For Rates PD, HT and EP (Large C&I class) a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT Customer's PLC will be computed to the nearest kilowatt The NBT shall be recovered through a separate charge listed on customers bills

The surcharge shall be calculated on a semi-annual basis using the formula below

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff These costs shall include the following

> Regional Transmission Expansion Plan charges Expansion Cost Recovery charges Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362

E – The estimated over or under recovery from the applicable reconciliation period

I – Interest on any over or under recovery balance Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period

n – rate class where 1 = residential 1a = RH 2 = small C&I 3 = large C&I 4 = street lighting

Residential – Rates R RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT PD EP (reconciled as a group)
Street Lighting – SLE SLS POL AL TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period For the Large C&I class (Rates PD HT and EP) the PJM PLC shall be used to calculate the NBT The application period will be the period when rates will be in effect

T – The currently effective gross receipts tax rate

Filings and Reconciliations The Company shall submit filings 15 days prior to the start of the application period beginning June 1 2015 Thereafter the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1 September 1) The annual reconciliation statement will be made by December 31 each year

Current Non-Bypassable Transmission Rate

R= ($0 00151) per kilowatthour (D)
RH= ($0 00151) per kilowatthour (D)
Small C&I = ($0 53) per billed kW (D)
Large C&I = ($0 38) per kW based on the PJM PLC (D)
Street Lighting = $ 00009 per kilowatt hour (D)

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RATE R RESIDENCE SERVICE

AVAILABILITY
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not) for the domestic requirements of its members when such service is supplied through one meter Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements

Each dwelling unit connected after May 10 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply Centrally supplied master metered heating cooling or water heating service may be provided if such supply will result in energy conservation

The term "residence service" includes service to (a) the separate dwelling unit in an apartment house or condominium but not the halls basement, or other portions of such building common to more than one such unit (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis (c) the premises owned by a church and primarily designated or set aside for and actually occupied and used as the dwelling place of a priest rabbi pastor rector nun or other functioning Church Divine and the resident associates (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain stock dairy poultry garden truck or other agricultural products

The term does NOT include service to (a) Premises institutional in character including Clubs Fraternities Orphanages or Homes (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly (c) a premises containing a residence unit but primarily devoted to a professional or other office studio or other gainful pursuit (d) farms operated principally to sell prepare or process products produced by others or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2 1969) (e) electric furnaces or welding apparatus other than a transformer type 'limited input' arc welder with an input not to exceed 37 1/2 amperes at 240 volts

CURRENT CHARACTERISTICS Standard single phase secondary service

MONTHLY RATE TABLE
FIXED DISTRIBUTION SERVICE CHARGE $8 45
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS $1 92

VARIABLE DISTRIBUTION SERVICE CHARGE
All kWhs $0 06243 per kWh (D)

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ENERGY SUPPLY CHARGE
Refer to the Generation Supply Adjustment Procurement Class 1

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

MINIMUM CHARGE The minimum charge per month will be the Fixed Distribution Service Charge

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS SMART METER COST RECOVERY SURCHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

PAYMENT TERMS Standard

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RATE R H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources All space heating installations must meet Company requirements This rate schedule is not available for commercial institutional or industrial establishments

Wood solar wind water and biomass systems may be used to supply a portion of the heating requirements in conjunction with service provided hereunder Any customer system of this type that produces electric energy may not be operated concurrently with service provided by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider

Each dwelling unit connected after May 10 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered

CURRENT CHARACTERISTICS Standard single phase secondary service

MONTHLY RATE TABLE
FIXED DISTRIBUTION SERVICE CHARGE $8 45
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS $1 92

VARIABLE DISTRIBUTION SERVICE CHARGE
SUMMER MONTHS (June through September)
$0 06243 per kWh for all kWh (D)
WINTER MONTHS (October through May)
$0 04431 per kWh for all kWh (D)

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ENERGY SUPPLY CHARGE
Refer to the Generation Supply Adjustment Procurement Class 1

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

MINIMUM CHARGE The minimum charge per month will be the Fixed Distribution Service Charge

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS SMART METER COST RECOVERY SURCHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE Where a portion of the service provided is used for commercial purposes the appropriate general service rate is applicable to all service or at the option of the customer the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only

PAYMENT TERMS. Standard

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RATE-GS GENERAL SERVICE

AVAILABILITY.
Service through a single metering installation for offices professional commercial or industrial establishments governmental agencies and other applications outside the scope of the Residence Service rate schedules For service configurations that are nominally 120/208 volts 3 phase 4 wires and the service capacity exceeds 750 kVa for transformers located either inside or outside the building the only rate option available to the customer will be Rate HT For service configurations that are nominally 277/480 volts 3 phase 4 wires and capacity exceeds either 750 kVa for transformers located inside the building or 1 500 kVa for transformers located outside the building the only rate option availab e to the customer will be Rate HT

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE
$ 14 28 for single-phase service without demand measurement or
$ 18 19 for single-phase service with demand measurement or
$ 43 53 for polyphase service

VARIABLE DISTRIBUTION SERVICE CHARGE
$6 93 per kW of billed demand (D)
($0 0006) per kWh for all kWh

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ENERGY EFFICIENCY CHARGE $0 00167 per kWh

ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS SMART METER COST RECOVERY SURCHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

DETERMINATION OF DEMAND.
The billing demand may be measured where consumption exceeds 1 100 kilowatt-hours per month for three consecutive months or where load tests indicate a demand of five or more kilowatts or where the customer requests demand measurement Measured demands will be determined to the nearest 0 1 of a kilowatt but will not be less than 1 2 kilowatts and will be adjusted for power factor in accordance with the Rules and Regulations

For those customers with demand measurement the billing demand will be determined as follows

(a)For customers with demand up to 500 kW the billing demand shall be the measured demand with a minimum billing demand of 1 2 kW

(b)For customers with demand greater than 500 kW the billing demand shall be the greater of (i) the measured demand (ii) 40% of the maximum contract demand or (iii) the maximum measured demand from the prior year These customers will be identified according to the process listed in Tariff Rule 22

If a measured demand customer has less than 1 100 monthly kilowatt-hours of use the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours whichever is less but not less than 1 2 kilowatts

For those customers without demand measurement the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours The computed demand will be determined to the nearest 0 1 of a kilowatt but will not be less than 1 2 kilowatts

MINIMUM CHARGE.
The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge plus a charge of $8 31 per KW of billing demand In addition to the above for customers in Procurement Class 3/4 charges will be assessed on PJM s reliability pricing model

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Tariff Electric Pa. P.U.C. No. 5
Fourteenth Revised Page No. 62
PECO Energy Company Supersedes Thirteenth Revised Page No. 62

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RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY

To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets highways bridges, parks or similar places including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the utilization facilities as defined in Terms and Conditions in this Base Rate are installed owned and maintained by a governmental agency

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated This rate is not available to commercial or industrial customers All facilities and their installation shall be approved by the Company

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE $7 16 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE $0.00862 per kWh (D)
ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Class 2

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* The service location charge includes an Energy Efficiency Program Surcharge of $0 05 per location

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE

SERVICE LOCATION

A Service Location shall comprise each lighting installation and must be separately connected to a delivery point on the Company's secondary circuit

DETERMINATION OF BILLING DEMAND

The wattage expressed to the nearest tenth of a watt of a Service Location shall be composed of manufacturer's rating of its lamps ballasts transformers individual controls and other load components required for its operation The aggregate of wattages of all Service Locations in service shall constitute the billing demand for the month

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions Paragraph 6 Service The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month

TERMS AND CONDITIONS

1 Ownership of Utilization Facilities

a Service Locations Supplied from Aerial Circuits customer shall provide own and maintain the Utilization Facilities comprising the brackets hangers luminaries lamps, ballasts transformers individual controls conductors molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location

The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities

b Service Locations Supplied from Underground Circuits customer shall provide own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90 degree pipe bend brackets or hangers luminaries lamps ballasts transformers individual controls conductors and conduits from the lamp receptacles to sidewalk level or in special cases such as Federally and State financed limited access highways to a delivery point designated by the Company on its secondary voltage circuit and shall assume all costs of installing such utilization facilities

Except as provided in Paragraph 4 Supply Facilities the Company shall own conduit from the distribution circuit to the 90 degree pipe bend shall own conductors from its distribution system to the designated delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided

c Service to Group of Streetlights

AERIAL SUPPLY

When the customer requests service to a group of streetlights supplied from aerial distribution facilities the customer is responsible for providing the support poles or posts for the streetlights The Company will provide a service nominally 100 feet to the customer's first supporting structure The customer is responsible for installing supply conductors from the first supporting structure to all streetlight locations

UNDERGROUND SUPPLY

When groups of streetlights are supplied from underground distribution facilities the customer is responsible for the supporting poles or posts and the supply conductors to each streetlight from the designated delivery point If the customer requests an underground supply to a group of streetlights and the designated delivery point is a secondary terminal pole the customer will install own maintain all cable including the cable on the pole

2 Standards of Construction for Utilization Facilities Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work

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RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.

To any municipality using the Company's standard service for (a) electric traffic signal lights installed owned and maintained by the municipality and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the municipality

To any non-municipal non-residential customer using the Company s standard service for unmetered small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the non-municipal customer which are electrically separate from any other facilities whether municipally-owned or non-municipally-owned that are receiving service from PECO as a separate account

To any non-municipal non-residential customer using the Company s standard service for unmetered small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the non-municipal customer which are electrically integrated with any other facilities whether municipally-owned or non-municipally-owned that are receiving service from PECO as a separate account but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate

CURRENT CHARACTERISTICS

Standard single phase secondary service

RATE TABLE.

SERVICE LOCATION CHARGE $3 62 PER LOCATION

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VARIABLE DISTRIBUTION SERVICE CHARGE $0 01549 per kWh (as defined below)* (D)

*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of $ 00063 per kWh

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ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Class 2

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE Transmission Service Charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY NON-BYPASSABLE TRANSMISSION CHARGE CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE

SPECIAL RULES AND REGULATIONS

The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices so that the Company may forthwith revise its estimate of the energy used

The Company shall not be liable for damage to person or property arising accruing or resulting from the attachment of the signal equipment to its poles wires or fixtures The customer shall be responsible to determine the amount location and sufficiency of illumination including conducting all studies of luminosity lighting location and traffic

SPECIAL TERMINATION RIGHTS

Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account Rate or Rider In the event of non-payment of bills for service to such a Rate TLCL facility PECO will provide a termination notice to the customer The customer may then at its discretion notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days If the customer has not removed its facilities within 30 days then PECO may at its sole discretion and upon 72-hour notice physically remove the customer facility as a means of terminating service to that facility Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals Notwithstanding any removal of such facilities by either the customer of PECO the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL In addition the customer shall pay to PECO its full cost of removing the facilities including direct and indirect labor costs use of truck or other equipment fuel costs and costs of storing the customer equipment all at PECO s normal rates for such work at such time as it may perform such removals PECO shall not be liable for damage if any to the customer equipment that occurs during removal or storage

TERM OF CONTRACT

The initial contract term for each signal light installation and constant load device shall be for at least one year

PAYMENT TERMS

Standard

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Attachment 2

PECO - Electric
December 2018 Non-Bypassable Transmission Charge (NBT
Semi-Annual Rate Calculation

NBT 1: Rates R, RH

					Amount
(1)	C	=	Projected Recoverable Transmission Costs	$	4,113,708
(2)	E	=	Experienced & Estimated Net Over/(Under)		
		a.	Over/(Under)	$	13,379,104
		b.	Interest	$	411,840
				$	13,790,944
(3)			Net Recoverable (C - E)	$	(9,677,236)
(4)	S	=	Projected Sales (kWh) for Computation Period		6,790,170,505
(5)	T	=	Pennsylvania gross receipts tax rate		5.90%
(6)			**NBT = [(C+E+I)/S]/(1-T)**		**($0.00151)**

PECO - December 2018
NBT
C-Factor Calculation

NBT 1: Rates R, RH

C-Factor Month		Projected Transmission Costs [a] (1)	Projected Sales (kWh) (2)
Dec-18 (est)	$	665,946	1,230,111,833
Jan-19 (est)	$	673,710	1,437,191,726
Feb-19 (est)	$	669,828	1,281,040,446
Mar-19 (est)	$	689,238	1,106,639,516
Apr-19 (est)	$	697,002	910,578,727
May-19 (est)	$	717,985	824,608,257
Total	$	4,113,708	6,790,170,505

Estimated Recovery C-Factor **$0.00061** per kWh

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement of over the period 12/1/18-5/13/19 *$ (12,994,084.26)*

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual NBT Costs [(a)] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [(b)] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [(b)] (10)
Balance										
Dec-17	$ 3,675,182	1,133,467,227	$ 0 00326	$ 3,766,702	3,964	$ -	$ 3,766,702	$ 91,519	$ (0.00049)	$ (562,497)
Jan-18	$ 3,374,819	1 575,927,973	$ 0 00326	$ 5,120,181	3,729	$ -	$ 5,120,181	$ 1,745,362	$ (0.00049)	$ (764,617)
Feb-18	$ 3,376,838	1 212,575,533	$ 0.00326	$ 3,939 413	3,733	$ -	$ 3,939,413	$ 562,575	$ (0.00049)	$ (588,288)
Mar-18	$ 3,371,530	1 038 006 090	$ 0 00326	$ 3,369 169	3,737	$ -	$ 3,369,169	$ (2,361)	$ (0.00049)	$ (503,132)
Apr-18	$ 3,377,270	991 600 624	$ 0 00326	$ 3 216 555	3,740	$ -	$ 3,216,555	$ (160,715)	$ (0.00049)	$ (480,341)
May-18	$ 3,312,114	839 825 543	$ 0 00326	$ 2 722 237	3,741	$ -	$ 2,722,237	$ (589,877)	$ (0.00049)	$ (406,523)
Jun-18	$ 3,332,286	1 014 619 014	$ 0 00326	$ 3 176 111	3,740	$ -	$ 3,176,111	$ (156,175)	$ (0.00028)	$ (270,601)
Jul-18	$ 3,331,778	1,397 738 875	$ 0 00326	$ 4 551 707	3,740	$ -	$ 4,551,707	$ 1,219,929	$ (0.00028)	$ (387,801)
Aug-18	$ 109,517	1 450 945,593	$ 0.00326	$ 4 726 218	3,742	$ -	$ 4 726,218	$ 4,616,701	$ (0.00028)	$ (402,669)
Sep-18	$ 458,179	1,422,280,375	$ 0.00326	$ 4,633,816	3,744	$ -	$ 4,633 816	$ 4 175 637	$ (0 00028)	$ (394 796)
Oct-18	$ 678,179	991,186,851	$ 0.00326	$ 3,228,365	3,748	$ -	$ 3,228 365	$ 2 550 186	$ (0 00028)	$ (275,053)
Nov-18 (est)	$ 662,729	839,148,959	$ 0.00326	$ 2,637,056	3,742	$ -	$ 2,637,056	$ 1,974,327	$ (0 00028)	$ (224,674)

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018

(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
Interest Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual Sales (kWh) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [(a)] (7)	Total Interest Owed (Interest Recoup (8) = (5) + (7)
Balance								
Dec-17	1,133,467,227	$ 91,519	6%	9/12	$ 4,118	$ (0.00002)	$ (21,624)	$ (17
Jan-18	1,575,927,973	$ 1,745,362	6%	8/12	$ 69,814	$ (0.00002)	$ (29,394)	$ 40
Feb-18	1,212,575,533	$ 562,575	6%	7/12	$ 19,690	$ (0.00002)	$ (22,616)	$ (2
Mar-18	1,038,006,090	$ (2,361)	6%	6/12	$ (71)	$ (0.00002)	$ (19,342)	$ (19
Apr-18	991,600,624	$ (160,715)	6%	5/12	$ (4,018)	$ (0.00002)	$ (18,466)	$ (22
May-18	839,825,543	$ (589,877)	6%	4/12	$ (11,798)	$ (0.00002)	$ (15,628)	$ (27
Jun-18	1,014,619,014	$ (156,175)	6%	9/12	$ (7,028)	$ (0.00001)	$ (11,704)	$ (18
Jul-18	1,397,738,875	$ 1,219,929	6%	8/12	$ 48,797	$ (0.00001)	$ (16,772)	$ 32
Aug-18	1,450,945,593	$ 4,616,701	6%	7/12	$ 161,585	$ (0.00001)	$ (17,415)	$ 144
Sep-18	1,422,280,375	$ 4,175,637	6%	6/12	$ 125,269	$ (0.00001)	$ (17,075)	$ 108
Oct-18	991,186,851	$ 2,550,186	6%	5/12	$ 63,755	$ (0.00001)	$ (11,896)	$ 51
Nov-18 (est)	839,148,959	$ 1,974,327	6%	4/12	$ 39,487	$ (0.00001)	$ (9,717)	$ 29

(a) Interest Revenues are allocated on a percentage basis.

Net Int

Attachment 3

PECO Exhibit No. JAB-7

PECO - Electric
December 2018 Non-Bypassable Transmission Charge (NBT
Semi-Annual Rate Calculation

NBT 2: Rate GS

					Amount	$
(1)	C	=	Projected Recoverable Transmission Costs	$	2,038,889	
(2)	E	=	Experienced & Estimated Net Over/(Under)			
		a.	Over/(Under)	$	7,511,229	
		b.	Interest	$	216,970	
				$	7,728,199	
(3)			Net Recoverable (C - E)	$	(5,689,310)	
(4)	S	=	Projected Sales (kW) for Computation Period		11,448,430	
(5)	T	=	Pennsylvania gross receipts tax rate		5.90%	
(6)			**NBT = [(C+E+I)/S]/(1-T)**		**($0.53)**	

PECO - December 2018
NBT
C-Factor Calculation

NBT 2: Rate GS

C-Factor Month		Projected Transmission Costs [a]	Projected Sales (kW)
		(1)	(2)
Dec-18 (est)	$	330,065	2,127,284
Jan-19 (est)	$	333,913	2,139,622
Feb-19 (est)	$	331,989	2,010,562
Mar-19 (est)	$	341,609	1,878,495
Apr-19 (est)	$	345,457	1,696,431
May-19 (est)	$	355,857	1,596,036
Total	$	2,038,889	11,448,430

Estimated Recovery C-Factor **$0.18** per kW

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement of over the period 12/1/18-5/13/19 *$ (6,440,295.14)*

PECO - December 2018
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) [b] (2)	C-Factor Rate (3)	C-Factor Revenue [c] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [c] (10)	T Col Re (11) =
Balance											
Dec-17	$ 1,712,725	1,791,291	$ 0.89	$ 2,545,084	1,847	$ -	$ 2,545,084	$ 832,359	$ (0.39)	$ (1,111,741)	$ 1
Jan-18	$ 1,680,299	2,044,817	$ 0.89	$ 2,058,786	1,857	$ -	$ 2,058,786	$ 378,487	$ (0.39)	$ (899,317)	$ 1
Feb-18	$ 1,679,531	1,956,242	$ 0.89	$ 1,997,647	1,857	$ -	$ 1,997,647	$ 318,117	$ (0.39)	$ (872,611)	$ 1
Mar-18	$ 1,675,994	1,850,464	$ 0.89	$ 1,863,971	1,857	$ -	$ 1,863,971	$ 187,977	$ (0.39)	$ (814,218)	$ 1
Apr-18	$ 1,676,352	1,876,864	$ 0.89	$ 1,892,893	1,856	$ -	$ 1,892,893	$ 216,541	$ (0.39)	$ (826,852)	$ 1
May-18	$ 1,643,578	1,914,650	$ 0.89	$ 1,911,240	1,857	$ -	$ 1,911,240	$ 267,662	$ (0.39)	$ (834,866)	$ 1
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$ 1
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$ 1
Aug-18	$ 54,280	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 2,105,818	$ (0.11)	$ (262,883)	$ 1
Sep-18	$ 226,910	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 2,017,004	$ (0.11)	$ (273,083)	$ 1
Oct-18	$ 335,332	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 1,623,167	$ (0.11)	$ (238,348)	$ 1
Nov-18 (est)	$ 328,536	1,655,212	$ 0.91	$ 1,841,821	1,855	$ -	$ 1,841,821	$ 1,513,284	$ (0.11)	$ (224,149)	$ 1

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) Correction made to September actual sales on 11-2-2018 (cell reference error); Modified from $2,590,611 to $2,181,146
(c) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
Interest Calculation

NBT 2: Rate GS

E-Factor Period	Actual Sales (kW) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [(a)] (7)	Total Interest Owed/ (Interest Recouped) (8) = (5) + (7)
Balance								
Dec-17	1,791,291	$ 832,359	6%	9/12	$ 37,456	$ (0.01)	$ (35,905)	$ 1,55
Jan-18	2,044,817	$ 378,487	6%	8/12	$ 15,139	$ (0.01)	$ (29,045)	$ (13,90
Feb-18	1,956,242	$ 318,117	6%	7/12	$ 11,134	$ (0.01)	$ (28,182)	$ (17,04
Mar-18	1,850,464	$ 187,977	6%	6/12	$ 5,639	$ (0.01)	$ (26,296)	$ (20,65
Apr-18	1,876,864	$ 216,541	6%	5/12	$ 5,414	$ (0.01)	$ (26,704)	$ (21,29
May-18	1,914,650	$ 267,662	6%	4/12	$ 5,353	$ (0.01)	$ (26,963)	$ (21,61
Jun-18	1,986,924	$ (41,600)	6%	9/12	$ (1,872)	$ (0.00)	(7,635)	$ (9,50
Jul-18	2,050,527	$ 528,090	6%	8/12	$ 21,124	$ (0.00)	(10,327)	$ 10,79
Aug-18	2,089,410	$ 2,105,818	6%	7/12	$ 73,704	$ (0.00)	(10,225)	$ 63,47
Sep-18	2,181,146	$ 2,017,004	6%	6/12	$ 60,510	$ (0.00)	(10,622)	$ 49,88
Oct-18	1,866,353	$ 1,623,167	6%	5/12	$ 40,579	$ (0.00)	(9,271)	$ 31,30
Nov-18 (est)	1,655,212	$ 1,513,284	6%	4/12	$ 30,266	$ (0.00)	(8,719)	$ 21,54

(a) Interest Revenues are allocated on a percentage basis.

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Attachment 4

PECO - Electric
December 2018 Non-Bypassable Transmission Charge (NBT)
Semi-Annual Rate Calculation

NBT 3: Rates HT, PD, EP

					Amount	$/
(1)	C	=	Projected Recoverable Transmission Costs	$	2,818,217	
(2)	E	=	Experienced & Estimated Net Over/(Under)			
		a.	Over/(Under)	$	7,916,798	
		b.	Interest	$	221,625	
				$	8,138,423	
(3)			Net Recoverable (C - E)	$	(5,320,206)	
(4)	S	=	Projected PLC Sales (kW) for Computation Period		15,073,392	
(5)	T	=	Pennsylvania gross receipts tax rate		5.90%	
(6)			**NBT = [(C+E+I)/S]/(1-T)**		**($0.38)**	

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
C-Factor Calculation

NBT 3: Rates HT, PD, EP

C-Factor Month		Projected Transmission Costs [a] (1)	Projected PLC Sales (kW) (2)
Dec-18 (est)	$	456,226	2,512,232
Jan-19 (est)	$	461,545	2,512,232
Feb-19 (est)	$	458,885	2,512,232
Mar-19 (est)	$	472,183	2,512,232
Apr-19 (est)	$	477,502	2,512,232
May-19 (est)	$	491,877	2,512,232
Total	$	2,818,217	15,073,392

Estimated Recovery C-Factor **$0.19** per kW

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement of over the period 12/1/18-5/13/19 *$ (8,901,981.16)*

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) +
Balance											
Dec-17	$ 2,393,977	2,483,117	$ 0.95	$ 2,438,168	2 582	$ -	$ 2,438 168	$ 44,191	$ (0.17)	$ (438,000)	$ 2,000,1
Jan-18	$ 2,318,012	2,244,738	$ 0.95	$ 2,152,222	2 562	$ -	$ 2 152,222	$ (165,790)	$ (0.17)	$ (386,632)	$ 1,765,5
Feb-18	$ 2,316,504	2,649,856	$ 0.95	$ 2,510,884	2,561	$ -	$ 2,510 884	$ 194,380	$ (0.17)	$ (451,063)	$ 2,059,8
Mar-18	$ 2,312,161	2,434,209	$ 0.95	$ 2,343,686	2,563	$ -	$ 2,343,686	$ 31,525	$ (0.17)	$ (421,027)	$ 1,922,6
Apr-18	$ 2,315,846	2,555,401	$ 0.95	$ 2,429,607	2,564	$ -	$ 2,429 607	$ 113,761	$ (0.17)	$ (436,462)	$ 1,993,1
May-18	$ 2,270,076	2,542,035	$ 0.95	$ 2,450,185	2,564	$ -	$ 2,450,185	$ 180 109	$ (0.17)	$ (440,159)	$ 2,010,0
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2 562	$ -	$ 2,019 542	$ (262,830)	$ (0 02)	$ (43,665)	$ 1,975,8
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0 02)	$ (52,784)	$ 2,388,4
Aug-18	$ 75,052	2,593,177	$ 0.96	$ 2,502,678	2 564	$ -	$ 2 502 678	$ 2,427,625	$ (0.02)	$ (54,111)	$ 2,448,5
Sep-18	$ 314,003	2,590,611	$ 0 96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 2 184,008	$ (0 02)	$ (54,010)	$ 2,444,0
Oct-18	$ 464,357	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 1,701,886	$ (0.02)	$ (46,837)	$ 2,119,4
Nov-18 (est)	$ 454,056	2,540,450	$ 0.96	$ 2,020,218	2,564	$ -	$ 2,020,218	$ 1,566,162	$ (0.02)	$ (43,680)	$ 1,976,5
											Total

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
Interest Calculation

NBT 3: Rates HT, PD, EP

E-Factor Period	Actual Sales (kW) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [(a)] (7)	Total Interest Owed/ (Interest Recouped) (8) = (5) + (7)
Balance								
Dec-17	2,483,117	$ 44,191	6%	9/12	$ 1,989	$ (0.01)	$ (13,818)	$ (11,830
Jan-18	2,244,738	$ (165,790)	6%	8/12	$ (6,632)	$ (0.01)	$ (12,198)	$ (18,829
Feb-18	2,649,856	$ 194,380	6%	7/12	$ 6,803	$ (0.01)	$ (14,230)	$ (7,427
Mar-18	2,434,209	$ 31,525	6%	6/12	$ 946	$ (0.01)	$ (13,283)	$ (12,337
Apr-18	2,555,401	$ 113,761	6%	5/12	$ 2,844	$ (0.01)	$ (13,770)	$ (10,926
May-18	2,542,035	$ 180,109	6%	4/12	$ 3,602	$ (0.01)	$ (13,886)	$ (10,284
Jun-18	2,185,507	$ (262,830)	6%	9/12	$ (11,827)	$ (0.00)	$ (1,066)	$ (12,894
Jul-18	2,482,563	$ 158,599	6%	8/12	$ 6,344	$ (0.00)	$ (1,289)	$ 5,055
Aug-18	2,593,177	$ 2,427,625	6%	7/12	$ 84,967	$ (0.00)	$ (1,321)	$ 83,646
Sep-18	2,590,611	$ 2,184,008	6%	6/12	$ 65,520	$ (0.00)	$ (1,319)	$ 64,201
Oct-18	2,240,870	$ 1,701,886	6%	5/12	$ 42,547	$ (0.00)	$ (1,144)	$ 41,404
Nov-18 (est)	2,540,450	$ 1,566,162	6%	4/12	$ 31,323	$ (0.00)	$ (1,067)	$ 30,257

(a) Interest Revenues are allocated on a percentage basis.

Net Interes

Attachment 5

PECO Exhibit No. JAB-7

PECO - Electric
December 2018 Non-Bypassable Transmission Charge (NBT)
Semi-Annual Rate Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

					Amount
(1)	C	=	Projected Recoverable Transmission Costs	$	6,345
(2)	E	=	Experienced & Estimated Net Over/(Under)		
		a.	Over/(Under)	$	(1,823)
		b.	Interest	$	(105)
				$	(1,929)
(3)			Net Recoverable (C - E)		8,273
(4)	S	=	Projected Sales (kWh) for Computation Period		94,419,479
(5)	T	=	Pennsylvania gross receipts tax rate		5.90%
(6)			**TSC = [(C+E+I)/S]/(1-T)**		**$0.00009**

PECO - December 2018
NBT
C-Factor Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

C-Factor Month		Projected Transmission Costs [a] (1)	Projected Sales (kWh) (2)
Dec-18 (est)	$	1,027	14,883,737
Jan-19 (est)	$	1,039	15,934,079
Feb-19 (est)	$	1,033	15,909,045
Mar-19 (est)	$	1,063	15,882,144
Apr-19 (est)	$	1,075	16,003,012
May-19 (est)	$	1,107	15,807,463
Total	$	6,345	94,419,479

Estimated Recovery C-Factor **$0.00007** per kWh

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement of *$ (20,041.37)*

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7
Balance											
Dec-17	$ 5,649	15,424,796	$ 0 00042	$ 5,787	6	$ -	$ 5,787	$ 139	$ (0.00005)	$ (659)	$ 5,12
Jan-18	$ 5,250	14,862,566	$ 0.00042	$ 4,952	6	$ -	$ 4 952	$ (297)	$ (0.00005)	$ (564)	$ 4 38
Feb-18	$ 5,239	14,393,798	$ 0.00042	$ (2,524)	6	$	$ (2,524)	$ (7,763)	$ (0.00005)	$ 288	$ (2,23
Mar-18	$ 5,215	14,761,820	$ 0.00042	$ (2,394)	6	$	$ (2,394)	$ (7,608)	$ (0.00005)	$ 273	$ (2,12
Apr-18	$ 5,214	10,068,025	$ 0.00042	$ (2,805)	6	$ -	$ (2,805)	$ (8,019)	$ (0.00005)	$ 320	$ (2,48
May-18	$ 5,108	15,914,380	$ 0.00042	$ (2,329)	6	$ -	$ (2,329)	$ (7,437)	$ (0.00005)	$ 265	$ (2,06
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$ (67
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5 030	$ (113)	$ 0.00026	$ 3 744	$ 8,77
Aug-18	$ 169	13 523 553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 4,523	$ 0 00026	$ 3,492	$ 8,18
Sep-18	$ 706	17,917,376	$ 0 00035	$ 5,581	6	$ -	$ 5,581	$ 4,875	$ 0.00026	$ 4,154	$ 9,73
Oct-18	$ 1,045	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ 3,192	$ 0.00026	$ 3,153	$ 7,39
Nov-18 (est)	$ 1,022	15,003,817	$ 0.00035	$ 2,844	6	$ -	$ 2,844	$ 1,822	$ 0.00026	$ 2,116	$ 4,96

Total R

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO Exhibit No. JAB-7

PECO - December 2018
NBT
Interest Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

E-Factor Period	Actual Sales (kWh) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [a] (7)	Total Interest Owed/ (Interest Recouped) (8) = (5) + (7)
Balance								
Dec-17	15,424,796	$ 139	6%	9/12	$ 6	$ (0.00000)	$ (21)	$ (15)
Jan-18	14,862,566	$ (297)	6%	8/12	$ (12)	$ (0.00000)	$ (18)	$ (30)
Feb-18	14,393,798	$ (7,763)	6%	7/12	$ (272)	$ (0.00000)	$ 9	$ (263)
Mar-18	14,761,820	$ (7,608)	6%	6/12	$ (228)	$ (0.00000)	$ 9	$ (220)
Apr-18	10,068,025	$ (8,019)	6%	5/12	$ (200)	$ (0.00000)	$ 10	$ (190)
May-18	15,914,380	$ (7,437)	6%	4/12	$ (149)	$ (0.00000)	$ 8	$ (140)
Jun-18	15,798,654	$ (5,529)	6%	9/12	$ (249)	$ 0.00001	$ (8)	$ (257)
Jul-18	16,216,415	$ (113)	6%	8/12	$ (5)	$ 0.00001	$ 104	$ 100
Aug-18	13,523,553	$ 4,523	6%	7/12	$ 158	$ 0.00001	$ 97	$ 256
Sep-18	17,917,376	$ 4,875	6%	6/12	$ 146	$ 0.00001	$ 116	$ 262
Oct-18	14,232,798	$ 3,192	6%	5/12	$ 80	$ 0.00001	$ 88	$ 168
Nov-18 (est)	15,003,817	$ 1,822	6%	4/12	$ 36	$ 0.00001	$ 59	$ 95

(a) Interest Revenues are allocated on a percentage basis.

Net Interest

PECO Exhibit No. JAB-8

Post-2010 PJM Bill Adjustments, E-Factor Component, Supplement No. 76

Tariff Rate Class	Allocation of Monthly NSPL Average MW			
	Aug-18 (for July)	Sep-18 (for Aug)	Oct-18 (for Sept)	Nov-18 (est - for Oct)
GS	22.7%	22.7%	22.7%	22.7%
RH	5.6%	5.6%	5.6%	5.6%
SLE	0.0%	0.0%	0.0%	0.0%
R	40.2%	40.2%	40.2%	40.2%
PD	1.0%	1.0%	1.0%	1.0%
POL	0.0%	0.0%	0.0%	0.0%
OP	0.0%	0.0%	0.0%	0.0%
HT	29.2%	29.3%	29.2%	29.2%
SLS	0.0%	0.0%	0.0%	0.0%
TL	0.1%	0.1%	0.1%	0.1%
AL	0.0%	0.0%	0.0%	0.0%
EP	1.2%	1.2%	1.2%	1.2%

	Aug-18 (for July)	Sep-18 (for Aug)	Oct-18 (for Sept)	Nov-18 (est - for Oct)	Totals
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,784,328.21)	$ (2,922,068.55)	$ (2,884,503.01)	$ (2,903,512.71)	$ (11,494,412.48)
NBT 1 (R, RH)	$ (1,275,761.71)	$ (1,339,099.31)	$ (1,322,735.00)	$ (1,330,418.44)	$ (5,268,014.46)
NBT 2 (GS)	$ (632,311.51)	$ (663,180.07)	$ (654,038.25)	$ (659,531.99)	$ (2,609,061.83)
NBT 3 (HT, PD, EP)	$ (874,286.55)	$ (917,724.57)	$ (905,692.37)	$ (911,510.31)	$ (3,609,213.81)
NBT 4 (SLE, POL, SLS, TL, AL)	$ (1,968.43)	$ (2,064.60)	$ (2,037.39)	$ (2,051.96)	$ (8,122.39)
Check	*$ (2,784,328.21)*	*$ (2,922,068.55)*	*$ (2,884,503.01)*	*$ (2,903,512.71)*	*$ (11,494,412.48)*

	Aug-18 (for July)	Sep-18 (for Aug)	Oct-18 (for Sept)	Nov-18 (est - for Oct)	Totals
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,302,649.64)	$ (2,385,194.42)	$ (2,362,682.21)	$ (2,374,074.31)	$ (9,424,600.58)
NBT 1 (R, RH)	$ (1,055,059.62)	$ (1,093,065.46)	$ (1,083,445.73)	$ (1,087,824.49)	$ (4,319,395.29)
NBT 2 (GS)	$ (522,923.94)	$ (541,333.44)	$ (535,719.51)	$ (539,270.23)	$ (2,139,247.11)
NBT 3 (HT, PD, EP)	$ (723,038.18)	$ (749,110.26)	$ (741,848.16)	$ (745,301.79)	$ (2,959,298.39)
NBT 4 (SLE, POL, SLS, TL, AL)	$ (1,627.90)	$ (1,685.27)	$ (1,668.82)	$ (1,677.80)	$ (6,659.79)
Check	*$ (2,302,649.64)*	*$ (2,385,194.42)*	*$ (2,362,682.21)*	*$ (2,374,074.31)*	*$ (9,424,600.58)*

Total RTEP Credit by Group	Aug-18 (for July)	Sep-18 (for Aug)	Oct-18 (for Sept)	Nov-18 (est - for Oct)	Totals	*Check*
NBT 1 (R, RH)	$ (2,330,821.33)	$ (2,432,164.76)	$ (2,406,180.73)	$ (2,418,242.93)	**$ (9,587,409.75)**	$ (9,587,409.75)
NBT 2 (GS)	$ (1,155,235.46)	$ (1,204,513.51)	$ (1,189,757.75)	$ (1,198,802.22)	**$ (4,748,308.94)**	$ (4,748,308.94)
NBT 3 (HT, PD, EP)	$ (1,597,324.74)	$ (1,666,834.83)	$ (1,647,540.53)	$ (1,656,812.11)	**$ (6,568,512.20)**	$ (6,568,512.20)
NBT 4 (SLE, POL, SLS, TL, AL)	$ (3,596.33)	$ (3,749.87)	$ (3,706.21)	$ (3,729.76)	**$ (14,782.17)**	$ (14,782.17)
					$ (20,919,013.06)	

NBT Update: 11-2-18 (est)

December-17

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1847.4	22.0%	1,712,725
RH	482.4	5.7%	447,264
SLE		0.0%	-
R	3481.7	41.4%	3,227,918
PD	79.3	0.9%	73,495
POL		0.0%	-
OP		0.0%	-
HT	2376.5	28.3%	2,203,256
SLS		0.0%	-
TL	6.1	0.1%	5,649
AL		0.0%	-
EP	126.4	1.5%	117,227
Total	8,399.7	100.00%	7,787,533
NSPL Total Check	8399.7		
RTEP	$ 7,763,699.96		
Expansion Recovery	$ -		
Generation Deactivation	$ 23,833.28		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,787,533.24		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,964		3,675,182
NBT 2	1,847		1,712,725
NBT 3	2,582		2,393,977
NBT 4	6		5,649
Check	-		-
	Revenues		Sales
R	2,546,945		853,435,837
RH	835,181		280,031,390
OP	-		-
SCI	1,485,055		1,791,291
LCI	2,110,892		2,483,117
SL	5,428		15,424,796
Total	6,983,502		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,983,502	6,642,843
Monthly Costs		7,787,533	7,787,533
Monthly Over/(Under)		(804,032)	(1,144,690)
Cum Revenues		174,414,374	166,944,042
Cum Costs		152,674,951	152,674,951
Cum Over/Under		21,739,423	14,269,091
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(470,977)	2,142,010	GOOD
NBT 2	(279,382)	4,104,814	GOOD
NBT 3	(393,809)	2,217,794	GOOD
NBT 4	(521)	3,580	GOOD
Total	(1,144,690)	8,468,199	

January-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1856.8	22.8%	1,680,299
RH	454.6	5.6%	411,393
SLE	0.0	0.0%	-
R	3274.8	40.2%	2,963,426
PD	79.7	1.0%	72,163
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2384.3	29.2%	2,157,573
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,250
AL	0.0	0.0%	-
EP	97.6	1.2%	88,276
Total	8153.6	100.00%	7,378,380
NSPL Total Check	8153.6		
RTEP	$ 7,353,991.74		
Expansion Recovery	$ -		
Generation Deactivation	$ 24,388.14		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,378,379.88		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,729		3,374,819
NBT 2	1,857		1,680,299
NBT 3	2,562		2,318,012
NBT 4	6		5,250
Check	-		-
	Revenues		Sales
R	3,226,390		1,106,269,907
RH	1,371,027		469,658,066
OP	-		-
SCI	1,201,301		2,044,817
LCI	1,863,328		2,244,738
SL	4,644		14,862,566
Total	7,666,691		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		7,666,691	7,285,011
Monthly Costs		7,378,380	7,378,380
Monthly Over/(Under)		288,311	(93,369)
Cum Revenues		182,081,065	174,229,053
Cum Costs		160,053,331	160,053,331
Cum Over/Under		22,027,734	14,175,722
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	980,744	3,122,755	GOOD
NBT 2	(520,830)	3,583,984	GOOD
NBT 3	(552,422)	1,665,373	GOOD
NBT 4	(862)	2,718	GOOD
Total	(93,369)	8,374,830	

February-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1856.8	22.8%	1,679,531
RH	456.1	5.6%	412,538
SLE	0.0	0.0%	-
R	3277.3	40.2%	2,964,300
PD	79.7	1.0%	72,089
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2383.8	29.2%	2,156,180
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,239
AL	0.0	0.0%	-
EP	97.6	1.2%	88,235
Total	8,157.1	100.00%	7,378,112
NSPL Total Check	8157.1		
RTEP	$ 7,353,991.74		
Expansion Recovery	$ -		
Generation Deactivation	$ 24,120.14		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,378,111.88		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,733		3,376,838
NBT 2	1,857		1,679,531
NBT 3	2,561		2,316,504
NBT 4	6		5,239
Check	-		-
	Revenues		Sales
R	2,528,790		867,247,341
RH	1,008,414		345,328,192
OP	-		-
SCI	1,165,627		1,956,242
LCI	2,173,847		2,649,856
SL	(2,367)		14,393,798
Total	6,874,311		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,874,311	6,533,745
Monthly Costs		7,378,112	7,378,112
Monthly Over/(Under)		(503,801)	(844,367)
Cum Revenues		188,955,376	180,762,798
Cum Costs		167,431,443	167,431,443
Cum Over/Under		21,523,933	13,331,355
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(25,713)	3,097,041	GOOD
NBT 2	(554,494)	3,029,490	GOOD
NBT 3	(256,684)	1,408,689	GOOD
NBT 4	(7,475)	(4,757)	GOOD
Total	(844,367)	7,530,463	

March-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1857.5	22.8%	1,675,994
RH	457.4	5.6%	412,670
SLE	0.0	0.0%	-
R	3279.3	40.2%	2,958,861
PD	79.6	1.0%	71,823
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2385.4	29.2%	2,152,319
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,215
AL	0.0	0.0%	-
EP	97.6	1.2%	88,019
Total	8,162.5	100.00%	7,364,899
NSPL Total Check	8162.5		
RTEP	$ 7,353,991.74		
Expansion Recovery	$ -		
Generation Deactivation	$ 10,907.69		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,364,899.43		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,737		3,371,530
NBT 2	1,857		1,675,994
NBT 3	2,563		2,312,161
NBT 4	6		5,215
Check	-		-
	Revenues		Sales
R	2,223,627		763,150,796
RH	801,554		274,855,294
OP	-		-
SCI	1,087,626		1,850,464
LCI	2,029,092		2,434,209
SL	(2,245)		14,761,820
Total	6,139,655		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,139,655	5,836,328
Monthly Costs		7,364,899	7,364,899
Monthly Over/(Under)		(1,225,245)	(1,528,572)
Cum Revenues		195,095,031	186,599,126
Cum Costs		174,796,343	174,796,343
Cum Over/Under		20,298,688	11,802,783
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(505,493)	2,591,549	GOOD
NBT 2	(626,241)	2,403,249	GOOD
NBT 3	(389,502)	1,019,187	GOOD
NBT 4	(7,336)	(12,093)	GOOD
Total	(1,528,572)	6,001,892	

April-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1856.3	22.7%	1,676,352
RH	458.0	5.6%	413,626
SLE	0.0	0.0%	-
R	3281.8	40.2%	2,963,644
PD	79.7	1.0%	71,970
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2387.2	29.2%	2,155,783
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,214
AL	0.0	0.0%	-
EP	97.6	1.2%	88,093
Total	8,166.4	100.00%	7,374,682
NSPL Total Check	8166.4		
RTEP	$ 7,353,991.74		
Expansion Recovery	$ -		
Generation Deactivation	$ 20,690.00		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,374,681.74		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,740		3,377,270
NBT 2	1,856		1,676,352
NBT 3	2,564		2,315,846
NBT 4	6		5,214
Check	-		-
	Revenues		Sales
R	2,152,683		739,271,899
RH	735,465		252,328,725
OP	-		-
SCI	1,104,502		1,876,864
LCI	2,103,480		2,555,401
SL	(2,630)		10,068,025
Total	6,093,501		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,093,501	5,792,914
Monthly Costs		7,374,682	7,374,682
Monthly Over/(Under)		(1,281,181)	(1,581,768)
Cum Revenues		201,188,532	192,392,040
Cum Costs		182,171,024	182,171,024
Cum Over/Under		19,017,507	10,221,016
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(641,056)	1,950,492	GOOD
NBT 2	(610,311)	1,792,939	GOOD
NBT 3	(322,702)	696,485	GOOD
NBT 4	(7,699)	(19,792)	GOOD
Total	(1,581,768)	4,420,124	

May-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1856.6	22.7%	1,643,578
RH	458.4	5.6%	405,784
SLE	0.0	0.0%	-
R	3283.0	40.2%	2,906,330
PD	79.2	1.0%	70,117
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2387.5	29.2%	2,113,601
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,108
AL	0.0	0.0%	-
EP	97.6	1.2%	86,359
Total	8,168.0	100.00%	7,230,877
NSPL Total Check	8168.0		
RTEP	$ 7,209,275.29		
Expansion Recovery	$ -		
Generation Deactivation	$ 21,601.99		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,230,877.28		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,741		3,312,114
NBT 2	1,857		1,643,578
NBT 3	2,564		2,270,076
NBT 4	6		5,108
Check	-		-
	Revenues		Sales
R	1,969,805		676,700,805
RH	474,496		163,124,738
OP	-		-
SCI	1,115,208		1,914,650
LCI	2,121,296		2,542,035
SL	(2,184)		15,914,380
Total	5,678,620		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		5,678,620	5,400,050
Monthly Costs		7,230,877	7,230,877
Monthly Over/(Under)		(1,552,257)	(1,830,827)
Cum Revenues		206,867,152	197,792,090
Cum Costs		189,401,902	189,401,902
Cum Over/Under		17,465,250	8,390,189
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(996,400)	954,092	GOOD
NBT 2	(567,205)	1,225,734	GOOD
NBT 3	(260,050)	436,434	GOOD
NBT 4	(7,172)	(26,964)	GOOD
Total	(1,830,827)	2,589,297	

June-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1857.0	22.7%	1,654,618
RH	458.1	5.6%	408,188
SLE	0.0	0.0%	-
R	3281.8	40.2%	2,924,097
PD	78.7	1.0%	70,079
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2385.3	29.2%	2,125,373
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,142
AL	0.0	0.0%	-
EP	97.6	1.2%	86,919
Total	8,164.2	100.00%	7,274,417
NSPL Total Check	8164.2		
RTEP	$ 7,265,697.26		
Expansion Recovery	$ -		
Generation Deactivation	$ 8,719.88		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,274,417.14		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,740		3,332,286
NBT 2	1,857		1,654,618
NBT 3	2,562		2,282,371
NBT 4	6		5,142
Check	-		-
	Revenues		Sales
R	2,609,893		861,031,494
RH	465,352		153,587,520
OP	-		-
SCI	1,497,428		1,986,924
LCI	2,098,629		2,185,507
SL	(726)		15,798,654
Total	6,670,576		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,670,576	6,297,425
Monthly Costs		7,274,417	7,274,417
Monthly Over/(Under)		(603,841)	(976,992)
Cum Revenues		213,537,727	204,089,515
Cum Costs		196,676,319	196,676,319
Cum Over/Under		16,861,409	7,413,197
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	(426,777)	527,316	GOOD
NBT 2	(237,903)	987,831	GOOD
NBT 3	(306,495)	129,940	GOOD
NBT 4	(5,817)	(32,781)	GOOD
Total	(976,992)	1,612,305	

July-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1856.1	22.7%	1,653,524
RH	457.9	5.6%	407,932
SLE	0.0	0.0%	-
R	3282.0	40.2%	2,923,846
PD	78.6	1.0%	70,005
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2386.2	29.2%	2,125,772
SLS	0.0	0.0%	-
TL	5.8	0.1%	5,143
AL	0.0	0.0%	-
EP	97.6	1.2%	86,905
Total	8164.1	100.00%	7,273,127
NSPL Total Check	8164.1		
RTEP	$ 7,265,697.26		
Expansion Recovery	$ -		
Generation Deactivation	$ 7,429.27		
RTEP "Transitional Period" Settlement (EL05-121-009)			
RTEP "Black Box" Settlement (EL05-121-009)			
Total Cost	$ 7,273,126.53		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,740		3,331,778
NBT 2	1,856		1,653,524
NBT 3	2,562		2,282,682
NBT 4	6		5,143
Check	-		-
	Revenues		Sales
R	3,829,064		1,214,198,425
RH	578,092		183,540,450
OP	-		-
SCI	2,025,277		2,050,527
LCI	2,536,884		2,482,563
SL	9,435		16,216,415
Total	8,978,752		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		8,978,752	8,477,289
Monthly Costs		7,273,127	7,273,127
Monthly Over/(Under)		1,705,625	1,204,163
Cum Revenues		222,516,479	212,566,805
Cum Costs		203,949,445	203,949,445
Cum Over/Under		18,567,034	8,617,360
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	832,128	1,359,444	GOOD
NBT 2	262,589	1,250,420	GOOD
NBT 3	105,815	235,755	GOOD
NBT 4	3,630	(29,151)	GOOD
Total	1,204,163	2,816,468	

August-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1854.4	22.7%	54,280
RH	458.0	5.6%	13,405
SLE	0.0	0.0%	-
R	3283.5	40.2%	96,112
PD	78.6	1.0%	2,301
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2387.9	29.2%	69,896
SLS	0.0	0.0%	-
TL	5.8	0.1%	169
AL	0.0	0.0%	-
EP	97.6	1.2%	2,855
Total	8,165.8	100.00%	239,019
NSPL Total Check	8165.8		
RTEP	$ 5,303,576.42		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,420.08		
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,784,328.21)	*PJM BLI 1108A, 7/2018 PJM Bill*	
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,302,649.64)	*PJM BLI 1115, 7/2018 PJM Bill*	
Total Cost	$ 239,018.65		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,742		109,517
NBT 2	1,854		54,280
NBT 3	2,564		75,052
NBT 4	6		169
Check	-		-
	Revenues		Sales
R	3,991,693		1,265,448,464
RH	584,432		185,497,129
OP	-		-
SCI	2,005,303		2,089,410
LCI	2,600,686		2,593,177
SL	8,801		13,523,553
Total	9,190,914.85		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		9,190,915	8,677,515
Monthly Costs		239,019	239,019
Monthly Over/(Under)		8,951,896	8,438,497
Cum Revenues		231,707,394	221,244,320
Cum Costs		204,188,464	204,188,464
Cum Over/Under		27,518,930	17,055,856
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	4,214,032	5,573,477	GOOD
NBT 2	1,842,935	3,093,354	GOOD
NBT 3	2,373,514	2,609,269	GOOD
NBT 4	8,016	(21,135)	GOOD
Total	8,438,497	11,254,964	

September-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1854.3	22.7%	226,910
RH	458.2	5.6%	56,069
SLE	0.0	0.0%	-
R	3286.1	40.2%	402,110
PD	78.4	1.0%	9,600
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2390.1	29.3%	292,467
SLS	0.0	0.0%	-
TL	5.8	0.1%	706
AL	0.0	0.0%	-
EP	97.6	1.2%	11,937
Total	8,170.5	100.00%	999,799
NSPL Total Check	8170.5		
RTEP	$ 6,284,636.84		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,424.67		
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,922,068.55)	*PJM BLI 1108A, 8/2018 PJM Bill*	
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,385,194.42)	*PJM BLI 1115, 8/2018 PJM Bill*	
Total Cost	$ 999,798.54		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,744		458,179
NBT 2	1,854		226,910
NBT 3	2,566		314,003
NBT 4	6		706
Check	-		-
	Revenues		Sales
R	3,906,081		1,238,070,971
RH	580,577		184,209,404
OP	-		-
SCI	2,083,112		2,181,146
LCI	2,595,837		2,590,611
SL	10,469		17,917,376
Total	9,176,075.47		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		9,176,075	8,663,587
Monthly Costs		999,799	999,799
Monthly Over/(Under)		8,176,277	7,663,788
Cum Revenues		240,883,470	229,907,907
Cum Costs		205,188,262	205,188,262
Cum Over/Under		35,695,207	24,719,645
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	3,780,841	9,354,318	GOOD
NBT 2	1,743,920	4,837,275	GOOD
NBT 3	2,129,998	4,739,267	GOOD
NBT 4	9,029	(12,106)	GOOD
Total	7,663,788	18,918,753	

October-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1853.2	22.7%	335,332
RH	458.7	5.6%	83,001
SLE	0.0	0.0%	-
R	3289.2	40.2%	595,178
PD	78.2	1.0%	14,148
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2390.5	29.2%	432,558
SLS	0.0	0.0%	-
TL	5.8	0.1%	1,045
AL	0.0	0.0%	-
EP	97.6	1.2%	17,652
Total	8,173.1	100.00%	1,478,912
NSPL Total Check	8173.1		
RTEP	$ 6,702,929.70		
Expansion Recovery	$ -		
Generation Deactivation	$ 23,167.41		
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,884,503.01)	*PJM BLI 1108A, 9/2018 PJM Bill*	
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,362,682.21)	*PJM BLI 1115, 9/2018 PJM Bill*	
Total Cost	$ 1,478,911.89		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,748		678,179
NBT 2	1,853		335,332
NBT 3	2,566		464,357
NBT 4	6		1,045
Check	-		-
	Revenues		Sales
R	2,669,917		846,484,441
RH	455,923		144,702,410
OP	-		-
SCI	1,818,150		1,866,353
LCI	2,251,076		2,240,870
SL	7,946		14,232,798
Total	7,203,013		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		7,203,013	6,800,258
Monthly Costs		1,478,912	1,478,912
Monthly Over/(Under)		5,724,101	5,321,346
Cum Revenues		248,086,482	236,708,165
Cum Costs		206,667,174	206,667,174
Cum Over/Under		41,419,308	30,040,990
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	2,275,133	11,629,451	GOOD
NBT 2	1,384,818	6,222,093	GOOD
NBT 3	1,655,049	6,394,316	GOOD
NBT 4	6,345	(5,761)	GOOD
Total	5,321,346	24,240,098	

November-18

Rate Class	NSPL AVG MW	Allocation	Allocated Cost
GS	1855.3	22.7%	328,536
RH	458.2	5.6%	81,141
SLE	0.0	0.0%	-
R	3284.3	40.2%	581,587
PD	78.6	1.0%	13,921
POL	0.0	0.0%	-
OP	0.0	0.0%	-
HT	2387.9	29.2%	422,860
SLS	0.0	0.0%	-
TL	5.8	0.1%	1,022
AL	0.0	0.0%	-
EP	97.6	1.2%	17,275
Total	8,167.6	100.00%	1,446,343
NSPL Total Check			
RTEP	$ 6,702,929.70		
Expansion Recovery	$ -		
Generation Deactivation	$ 21,000.00		
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,903,512.71)	*PJM BLI 1108A, 10/2018 PJM Bill*	
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,374,074.31)	*PJM BLI 1115, 10/2018 PJM Bill*	
Total Cost	$ 1,446,342.68		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,742		662,729
NBT 2	1,855		328,536
NBT 3	2,564		454,056
NBT 4	6		1,022
Check	-		-
	Revenues		Sales
R	2,082,760		684,447,603
RH	470,550		154,701,356
OP	-		-
SCI	1,709,833		1,655,212
LCI	2,099,332		2,540,450
SL	5,334		15,003,817
Total	6,367,809		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		6,367,809	6,011,551
Monthly Costs		1,446,343	1,446,343
Monthly Over/(Under)		4,921,466	4,565,208
Cum Revenues		254,454,291	242,719,716
Cum Costs		208,113,517	208,113,517
Cum Over/Under		46,340,774	34,606,199
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	1,749,653	13,379,104	GOOD
NBT 2	1,289,135	7,511,229	GOOD
NBT 3	1,522,482	7,916,798	GOOD
NBT 4	3,938	(1,823)	GOOD
Total	4,565,208	28,805,307	

PECO - December 2018
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)
Balance													**$ 2,612,988**
Dec-17	$ 3,675,182	1,133,467,227	$ 0.00326	$ 3,766,702	3,964	$ -	$ 3,766,702	$ 91,519	$ (0.00049)	$ (562,497)	$ 3,204,205	$ (470,977)	$ 2,142,010
Jan-18	$ 3,374,819	1,575,927,973	$ 0.00326	$ 5,120,181	3,729	$ -	$ 5,120,181	$ 1,745,362	$ (0.00049)	$ (764,617)	$ 4,355,564	$ 980,744	$ 3,122,755
Feb-18	$ 3,376,838	1,212,575,533	$ 0.00326	$ 3,939,413	3,733	$ -	$ 3,939,413	$ 562,575	$ (0.00049)	$ (588,288)	$ 3,351,125	$ (25,713)	$ 3,097,041
Mar-18	$ 3,371,530	1,038,006,090	$ 0.00326	$ 3,369,169	3,737	$ -	$ 3,369,169	$ (2,361)	$ (0.00049)	$ (503,132)	$ 2,866,037	$ (505,493)	$ 2,591,549
Apr-18	$ 3,377,270	991,600,624	$ 0.00326	$ 3,216,555	3,740	$ -	$ 3,216,555	$ (160,715)	$ (0.00049)	$ (480,341)	$ 2,736,214	$ (641,056)	$ 1,950,492
May-18	$ 3,312,114	839,825,543	$ 0.00326	$ 2,722,237	3,741	$ -	$ 2,722,237	$ (589,877)	$ (0.00049)	$ (406,523)	$ 2,315,714	$ (996,400)	$ 954,092
Jun-18	$ 3,332,286	1,014,619,014	$ 0.00326	$ 3,176,111	3,740	$ -	$ 3,176,111	$ (156,175)	$ (0.00028)	$ (270,601)	$ 2,905,509	$ (426,777)	$ 527,316
Jul-18	$ 3,331,778	1,397,738,875	$ 0.00326	$ 4,551,707	3,740	$ -	$ 4,551,707	$ 1,219,929	$ (0.00028)	$ (387,801)	$ 4,163,906	$ 832,128	$ 1,359,444
Aug-18	$ 109,517	1,450,945,593	$ 0.00326	$ 4,726,218	3,742	$ -	$ 4,726,218	$ 4,616,701	$ (0.00028)	$ (402,669)	$ 4,323,549	$ 4,214,032	$ 5,573,477
Sep-18	$ 458,179	1,422,280,375	$ 0.00326	$ 4,633,816	3,744	$ -	$ 4,633,816	$ 4,175,637	$ (0.00028)	$ (394,796)	$ 4,239,020	$ 3,780,841	$ 9,354,318
Oct-18	$ 678,179	991,186,851	$ 0.00326	$ 3,228,365	3,748	$ -	$ 3,228,365	$ 2,550,186	$ (0.00028)	$ (275,053)	$ 2,953,312	$ 2,275,133	$ 11,629,451
Nov-18 (est)	$ 662,729	839,148,959	$ 0.00326	$ 2,637,056	3,742	$ -	$ 2,637,056	$ 1,974,327	$ (0.00028)	$ (224,674)	$ 2,412,381	$ 1,749,653	$ 13,379,104
												Total Recovery E-Factor	**$ 13,379,104**

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period		Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)		C-Factor Rate (3)		C-Factor Revenue [b] (4)	NSPL AVE MW (5)		Working Capital $0.00 per MW/mo (6) = (5) * $0		Adjusted C-Factor Revenue (7) = (4) - (6)		C-Factor Over/(Under) Recovery (8) = (7) - (1)		E-Factor Rate (9)		E-Factor Revenue [b] (10)		Total Collected Revenue (11) = (10) + (7)		Over/(Under) Recovery (12) = (11) - (1)		Cumulative Over/(Under) Recovery (13)	Starting Balance (Last Updated)
Balance																							**$**	**2,612,988**	6/15/2018
Dec-17	$	3,675,182	1,133,467,227	$	0.00326	$	3,766,702	3,964	$	-	$	3,766,702	$	91,519	$	(0.00049)	$	(562,497)	$	3,204,205	$	(470,977)	$	2,142,010	
Jan-18	$	3,374,819	1,575,927,973	$	0.00326	$	5,120,181	3,729	$	-	$	5,120,181	$	1,745,362	$	(0.00049)	$	(764,617)	$	4,355,564	$	980,744	$	3,122,755	
Feb-18	$	3,376,838	1,212,575,533	$	0.00326	$	3,939,413	3,733	$	-	$	3,939,413	$	562,575	$	(0.00049)	$	(588,288)	$	3,351,125	$	(25,713)	$	3,097,041	
Mar-18	$	3,371,530	1,038,006,090	$	0.00326	$	3,369,169	3,737	$	-	$	3,369,169	$	(2,361)	$	(0.00049)	$	(503,132)	$	2,866,037	$	(505,493)	$	2,591,549	
Apr-18	$	3,377,270	991,600,624	$	0.00326	$	3,216,555	3,740	$	-	$	3,216,555	$	(160,715)	$	(0.00049)	$	(480,341)	$	2,736,214	$	(641,056)	$	1,950,492	
May-18	$	3,312,114	839,825,543	$	0.00326	$	2,722,237	3,741	$	-	$	2,722,237	$	(589,877)	$	(0.00049)	$	(406,523)	$	2,315,714	$	(996,400)	$	954,092	
Jun-18	$	3,332,286	1,014,619,014	$	0.00326	$	3,176,111	3,740	$	-	$	3,176,111	$	(156,175)	$	(0.00028)	$	(270,601)	$	2,905,509	$	(426,777)	$	527,316	
Jul-18	$	3,331,778	1,397,738,875	$	0.00326	$	4,551,707	3,740	$	-	$	4,551,707	$	1,219,929	$	(0.00028)	$	(387,801)	$	4,163,906	$	832,128	$	1,359,444	
Aug-18	$	2,440,338	1,450,945,593	$	0.00326	$	4,726,218	3,742	$	-	$	4,726,218	$	2,285,880	$	(0.00028)	$	(402,669)	$	4,323,549	$	1,883,211	$	3,242,655	
Sep-18	$	2,890,343	1,422,280,375	$	0.00326	$	4,633,816	3,744	$	-	$	4,633,816	$	1,743,473	$	(0.00028)	$	(394,796)	$	4,239,020	$	1,348,676	$	4,591,332	
Oct-18	$	3,084,359	991,186,851	$	0.00326	$	3,228,365	3,748	$	-	$	3,228,365	$	144,006	$	(0.00028)	$	(275,053)	$	2,953,312	$	(131,048)	$	4,460,284	
Nov-18 (est)	$	3,080,972	839,148,959	$	0.00326	$	2,637,056	3,742	$	-	$	2,637,056	$	(443,916)	$	(0.00028)	$	(224,674)	$	2,412,381	$	(668,590)	$	3,791,694	
																						Total Recovery E-Factor	**$**	**3,791,694**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) [b] (2)	C-Factor Rate (3)	C-Factor Revenue [c] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [c] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 4,384,196**	6/15/2018
Dec-17	$ 1,712,725	1,791,291	$ 0.89	$ 2,545,084	1,847	$ -	$ 2,545,084	$ 832,359	$ (0.39)	$ (1,111,741)	$ 1,433,343	$ (279,382)	$ 4,104,814	
Jan-18	$ 1,680,299	2,044,817	$ 0.89	$ 2,058,786	1,857	$ -	$ 2,058,786	$ 378,487	$ (0.39)	$ (899,317)	$ 1,159,469	$ (520,830)	$ 3,583,984	
Feb-18	$ 1,679,531	1,956,242	$ 0.89	$ 1,997,647	1,857	$ -	$ 1,997,647	$ 318,117	$ (0.39)	$ (872,611)	$ 1,125,037	$ (554,494)	$ 3,029,490	
Mar-18	$ 1,675,994	1,850,464	$ 0.89	$ 1,863,971	1,857	$ -	$ 1,863,971	$ 187,977	$ (0.39)	$ (814,218)	$ 1,049,753	$ (626,241)	$ 2,403,249	
Apr-18	$ 1,676,352	1,876,864	$ 0.89	$ 1,892,893	1,856	$ -	$ 1,892,893	$ 216,541	$ (0.39)	$ (826,852)	$ 1,066,041	$ (610,311)	$ 1,792,939	
May-18	$ 1,643,578	1,914,650	$ 0.89	$ 1,911,240	1,857	$ -	$ 1,911,240	$ 267,662	$ (0.39)	$ (834,866)	$ 1,076,374	$ (567,205)	$ 1,225,734	
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$ 1,416,715	$ (237,903)	$ 987,831	
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$ 1,916,113	$ 262,589	$ 1,250,420	
Aug-18	$ 54,280	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 2,105,818	$ (0.11)	$ (262,883)	$ 1,897,215	$ 1,842,935	$ 3,093,354	
Sep-18	$ 226,910	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 2,017,004	$ (0.11)	$ (273,083)	$ 1,970,830	$ 1,743,920	$ 4,837,275	
Oct-18	$ 335,332	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 1,623,167	$ (0.11)	$ (238,348)	$ 1,720,150	$ 1,384,818	$ 6,222,093	
Nov-18 (est)	$ 328,536	1,655,212	$ 0.91	$ 1,841,821	1,855	$ -	$ 1,841,821	$ 1,513,284	$ (0.11)	$ (224,149)	$ 1,617,672	$ 1,289,135	$ 7,511,229	
												Total Recovery E-Factor	**$ 7,511,229**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) Correction made to September actual sales on 11-2-2018 (cell reference error); Modified from $2,590,611 to $2,181,146
(c) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [(a)]	Actual Sales (kW) [(b)]	C-Factor Rate	C-Factor Revenue [(c)]	NSPL AVE MW	Working Capital $0.00 per MW/mo	Adjusted C-Factor Revenue	C-Factor Over/(Under) Recovery	E-Factor Rate	E-Factor Revenue [(c)]	Total Collected Revenue	Over/(Under) Recovery	Cumulative Over/(Under) Recovery	*Starting Balance (Last Updated)*
	(1)	(2)	(3)	(4)	(5)	(6) = (5) * $0	(7) = (4) - (6)	(8) = (7) - (1)	(9)	(10)	(11) = (10) + (7)	(12) = (11) - (1)	(13)	
Balance													**$ 4,384,196**	6/15/2018
Dec-17	$ 1,712,725	1,791,291	$ 0.89	$ 2,545,084	1,847	$ -	$ 2,545,084	$ 832,359	$ (0.39)	$ (1,111,741)	$ 1,433,343	$ (279,382)	$ 4,104,814	
Jan-18	$ 1,680,299	2,044,817	$ 0.89	$ 2,058,786	1,857	$ -	$ 2,058,786	$ 378,487	$ (0.39)	$ (899,317)	$ 1,159,469	$ (520,830)	$ 3,583,984	
Feb-18	$ 1,679,531	1,956,242	$ 0.89	$ 1,997,647	1,857	$ -	$ 1,997,647	$ 318,117	$ (0.39)	$ (872,611)	$ 1,125,037	$ (554,494)	$ 3,029,490	
Mar-18	$ 1,675,994	1,850,464	$ 0.89	$ 1,863,971	1,857	$ -	$ 1,863,971	$ 187,977	$ (0.39)	$ (814,218)	$ 1,049,753	$ (626,241)	$ 2,403,249	
Apr-18	$ 1,676,352	1,876,864	$ 0.89	$ 1,892,893	1,856	$ -	$ 1,892,893	$ 216,541	$ (0.39)	$ (826,852)	$ 1,066,041	$ (610,311)	$ 1,792,939	
May-18	$ 1,643,578	1,914,650	$ 0.89	$ 1,911,240	1,857	$ -	$ 1,911,240	$ 267,662	$ (0.39)	$ (834,866)	$ 1,076,374	$ (567,205)	$ 1,225,734	
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$ 1,416,715	$ (237,903)	$ 987,831	
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$ 1,916,113	$ 262,589	$ 1,250,420	
Aug-18	$ 1,209,516	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 950,582	$ (0.11)	$ (262,883)	$ 1,897,215	$ 687,699	$ 1,938,119	
Sep-18	$ 1,431,423	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 812,490	$ (0.11)	$ (273,083)	$ 1,970,830	$ 539,407	$ 2,477,526	
Oct-18	$ 1,525,089	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 433,409	$ (0.11)	$ (238,348)	$ 1,720,150	$ 195,061	$ 2,672,586	
Nov-18 (est)	$ 1,527,338	1,655,212	$ 0.91	$ 1,841,821	1,855	$ -	$ 1,841,821	$ 314,482	$ (0.11)	$ (224,149)	$ 1,617,672	$ 90,333	$ 2,762,920	
												Total Recovery E-Factor	**$ 2,762,920**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) Correction made to September actual sales on 11-2-2018 (cell reference error); Modified from $2,590,611 to $2,181,146
(c) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 2,611,604**	6/15/2018
Dec-17	$ 2,393,977	2,483,117	$ 0.95	$ 2,438,168	2,582	$ -	$ 2,438,168	$ 44,191	$ (0.17)	$ (438,000)	$ 2,000,168	$ (393,809)	$ 2,217,794	
Jan-18	$ 2,318,012	2,244,738	$ 0.95	$ 2,152,222	2,562	$ -	$ 2,152,222	$ (165,790)	$ (0.17)	$ (386,632)	$ 1,765,590	$ (552,422)	$ 1,665,373	
Feb-18	$ 2,316,504	2,649,856	$ 0.95	$ 2,510,884	2,561	$ -	$ 2,510,884	$ 194,380	$ (0.17)	$ (451,063)	$ 2,059,821	$ (256,684)	$ 1,408,689	
Mar-18	$ 2,312,161	2,434,209	$ 0.95	$ 2,343,686	2,563	$ -	$ 2,343,686	$ 31,525	$ (0.17)	$ (421,027)	$ 1,922,659	$ (389,502)	$ 1,019,187	
Apr-18	$ 2,315,846	2,555,401	$ 0.95	$ 2,429,607	2,564	$ -	$ 2,429,607	$ 113,761	$ (0.17)	$ (436,462)	$ 1,993,145	$ (322,702)	$ 696,485	
May-18	$ 2,270,076	2,542,035	$ 0.95	$ 2,450,185	2,564	$ -	$ 2,450,185	$ 180,109	$ (0.17)	$ (440,159)	$ 2,010,026	$ (260,050)	$ 436,434	
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2,562	$ -	$ 2,019,542	$ (262,830)	$ (0.02)	$ (43,665)	$ 1,975,876	$ (306,495)	$ 129,940	
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0.02)	$ (52,784)	$ 2,388,497	$ 105,815	$ 235,755	
Aug-18	$ 75,052	2,593,177	$ 0.96	$ 2,502,678	2,564	$ -	$ 2,502,678	$ 2,427,625	$ (0.02)	$ (54,111)	$ 2,448,566	$ 2,373,514	$ 2,609,269	
Sep-18	$ 314,003	2,590,611	$ 0.96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 2,184,008	$ (0.02)	$ (54,010)	$ 2,444,001	$ 2,129,998	$ 4,739,267	
Oct-18	$ 464,357	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 1,701,886	$ (0.02)	$ (46,837)	$ 2,119,406	$ 1,655,049	$ 6,394,316	
Nov-18 (est)	$ 454,056	2,540,450	$ 0.96	$ 2,020,218	2,564	$ -	$ 2,020,218	$ 1,566,162	$ (0.02)	$ (43,680)	$ 1,976,538	$ 1,522,482	$ 7,916,798	
												Total Recovery E-Factor	**$ 7,916,798**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	Starting Balance (Last Updated)
Balance													**$ 2,611,604**	6/15/2018
Dec-17	$ 2,393,977	2,483,117	$ 0.95	$ 2,438,168	2,582	$ -	$ 2,438,168	$ 44,191	$ (0.17)	$ (438,000)	$ 2,000,168	$ (393,809)	$ 2,217,794	
Jan-18	$ 2,318,012	2,244,738	$ 0.95	$ 2,152,222	2,562	$ -	$ 2,152,222	$ (165,790)	$ (0.17)	$ (386,632)	$ 1,765,590	$ (552,422)	$ 1,665,373	
Feb-18	$ 2,316,504	2,649,856	$ 0.95	$ 2,510,884	2,561	$ -	$ 2,510,884	$ 194,380	$ (0.17)	$ (451,063)	$ 2,059,821	$ (256,684)	$ 1,408,689	
Mar-18	$ 2,312,161	2,434,209	$ 0.95	$ 2,343,686	2,563	$ -	$ 2,343,686	$ 31,525	$ (0.17)	$ (421,027)	$ 1,922,659	$ (389,502)	$ 1,019,187	
Apr-18	$ 2,315,846	2,555,401	$ 0.95	$ 2,429,607	2,564	$ -	$ 2,429,607	$ 113,761	$ (0.17)	$ (436,462)	$ 1,993,145	$ (322,702)	$ 696,485	
May-18	$ 2,270,076	2,542,035	$ 0.95	$ 2,450,185	2,564	$ -	$ 2,450,185	$ 180,109	$ (0.17)	$ (440,159)	$ 2,010,026	$ (260,050)	$ 436,434	
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2,562	$ -	$ 2,019,542	$ (262,830)	$ (0.02)	$ (43,665)	$ 1,975,876	$ (306,495)	$ 129,940	
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0.02)	$ (52,784)	$ 2,388,497	$ 105,815	$ 235,755	
Aug-18	$ 1,672,377	2,593,177	$ 0.96	$ 2,502,678	2,564	$ -	$ 2,502,678	$ 830,300	$ (0.02)	$ (54,111)	$ 2,448,566	$ 776,189	$ 1,011,944	
Sep-18	$ 1,980,838	2,590,611	$ 0.96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 517,174	$ (0.02)	$ (54,010)	$ 2,444,001	$ 463,163	$ 1,475,107	
Oct-18	$ 2,111,898	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 54,346	$ (0.02)	$ (46,837)	$ 2,119,406	$ 7,509	$ 1,482,616	
Nov-18 (est)	$ 2,110,868	2,540,450	$ 0.96	$ 2,020,218	2,564	$ -	$ 2,020,218	$ (90,650)	$ (0.02)	$ (43,680)	$ 1,976,538	$ (134,330)	$ 1,348,286	
												Total Recovery E-Factor	**$ 1,348,286**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

E-Factor Period	Actual NBT Costs [a]	Actual Sales (kWh)	C-Factor Rate	C-Factor Revenue [b]	NSPL AVE MW	Working Capital $0.00 per MW/mo	Adjusted C-Factor Revenue	C-Factor Over/(Under) Recovery	E-Factor Rate	E-Factor Revenue [b]	Total Collected Revenue	Over/(Under) Recovery	Cumulative Over/(Under) Recovery	*Starting Balance (Last Updated)*
	(1)	(2)	(3)	(4)	(5)	(6) = (5) * $0	(7) = (4) - (6)	(8) = (7) - (1)	(9)	(10)	(11) = (10) + (7)	(12) = (11) - (1)	(13)	
Balance													**$ 4,101**	6/15/2018
Dec-17	$ 5,649	15,424,796	$ 0.00042	$ 5,787	6	$ -	$ 5,787	$ 139	$ (0.00005)	$ (659)	$ 5,128	$ (521)	$ 3,580	
Jan-18	$ 5,250	14,862,566	$ 0.00042	$ 4,952	6	$ -	$ 4,952	$ (297)	$ (0.00005)	$ (564)	$ 4,388	$ (862)	$ 2,718	
Feb-18	$ 5,239	14,393,798	$ 0.00042	$ (2,524)	6	$ -	$ (2,524)	$ (7,763)	$ (0.00005)	$ 288	$ (2,237)	$ (7,475)	$ (4,757)	
Mar-18	$ 5,215	14,761,820	$ 0.00042	$ (2,394)	6	$ -	$ (2,394)	$ (7,608)	$ (0.00005)	$ 273	$ (2,121)	$ (7,336)	$ (12,093)	
Apr-18	$ 5,214	10,068,025	$ 0.00042	$ (2,805)	6	$ -	$ (2,805)	$ (8,019)	$ (0.00005)	$ 320	$ (2,485)	$ (7,699)	$ (19,792)	
May-18	$ 5,108	15,914,380	$ 0.00042	$ (2,329)	6	$ -	$ (2,329)	$ (7,437)	$ (0.00005)	$ 265	$ (2,063)	$ (7,172)	$ (26,964)	
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$ (675)	$ (5,817)	$ (32,781)	
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5,030	$ (113)	$ 0.00026	$ 3,744	$ 8,774	$ 3,630	$ (29,151)	
Aug-18	$ 169	13,523,553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 4,523	$ 0.00026	$ 3,492	$ 8,185	$ 8,016	$ (21,135)	
Sep-18	$ 706	17,917,376	$ 0.00035	$ 5,581	6	$ -	$ 5,581	$ 4,875	$ 0.00026	$ 4,154	$ 9,735	$ 9,029	$ (12,106)	
Oct-18	$ 1,045	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ 3,192	$ 0.00026	$ 3,153	$ 7,390	$ 6,345	$ (5,761)	
Nov-18 (est)	$ 1,022	15,003,817	$ 0.00035	$ 2,844	6	$ -	$ 2,844	$ 1,822	$ 0.00026	$ 2,116	$ 4,960	$ 3,938	$ (1,823)	
												Total Recovery E-Factor	**$ (1,823)**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - December 2018
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, POL, AL, TLCL

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 4,101**	6/15/2018
Dec-17	$ 5,649	15,424,796	$ 0.00042	$ 5,787	6	$ -	$ 5,787	$ 139	$ (0.00005)	$ (659)	$ 5,128	$ (521)	$ 3,580	
Jan-18	$ 5,250	14,862,566	$ 0.00042	$ 4,952	6	$ -	$ 4,952	$ (297)	$ (0.00005)	$ (564)	$ 4,388	$ (862)	$ 2,718	
Feb-18	$ 5,239	14,393,798	$ 0.00042	$ (2,524)	6	$ -	$ (2,524)	$ (7,763)	$ (0.00005)	$ 288	$ (2,237)	$ (7,475)	$ (4,757)	
Mar-18	$ 5,215	14,761,820	$ 0.00042	$ (2,394)	6	$ -	$ (2,394)	$ (7,608)	$ (0.00005)	$ 273	$ (2,121)	$ (7,336)	$ (12,093)	
Apr-18	$ 5,214	10,068,025	$ 0.00042	$ (2,805)	6	$ -	$ (2,805)	$ (8,019)	$ (0.00005)	$ 320	$ (2,485)	$ (7,699)	$ (19,792)	
May-18	$ 5,108	15,914,380	$ 0.00042	$ (2,329)	6	$ -	$ (2,329)	$ (7,437)	$ (0.00005)	$ 265	$ (2,063)	$ (7,172)	$ (26,964)	
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$ (675)	$ (5,817)	$ (32,781)	
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5,030	$ (113)	$ 0.00026	$ 3,744	$ 8,774	$ 3,630	$ (29,151)	
Aug-18	$ 3,765	13,523,553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 927	$ 0.00026	$ 3,492	$ 8,185	$ 4,419	$ (24,732)	
Sep-18	$ 4,456	17,917,376	$ 0.00035	$ 5,581	6	$ -	$ 5,581	$ 1,125	$ 0.00026	$ 4,154	$ 9,735	$ 5,279	$ (19,453)	
Oct-18	$ 4,751	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ (514)	$ 0.00026	$ 3,153	$ 7,390	$ 2,639	$ (16,814)	
Nov-18 (est)	$ 4,752	15,003,817	$ 0.00035	$ 2,844	6	$ -	$ 2,844	$ (1,908)	$ 0.00026	$ 2,116	$ 4,960	$ 208	$ (16,606)	
												Total Recovery E-Factor	**$ (16,606)**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

Non-Bypassable Transmission		Forecasted: Dec 18-$	Forecasted: Jan 19-$	Forecasted: Feb 19-$	Forecasted: Mar 19-$	Forecasted: Apr 19-$	Forecasted: May 19-$	Forecasted: Total	6 mo Average
Transm Enhancement (non-PECO zone RTEP)		$ 4,330,891	$ 4,330,891	$ 4,330,891	$ 4,330,891	$ 4,330,891	$ 4,359,737	$ 26,014,190	$ 4,335,698
Transm Enhancement (PECO zone RTEP)		$ 1,865,562	$ 1,865,562	$ 1,865,562	$ 1,865,562	$ 1,865,562	$ 1,865,562	$ 11,193,371	$ 1,865,562
RTEP "Transitional Period" Settlement (EL05-121-009)		$ (2,869,082)	$ (2,858,487)	$ (2,863,785)	$ (2,837,299)	$ (2,826,705)	$ (2,816,111)	$ (17,071,468)	$ (2,845,245)
RTEP "Black Box" Settlement (EL05-121-009)		$ (2,353,441)	$ (2,347,092)	$ (2,350,266)	$ (2,334,394)	$ (2,328,045)	$ (2,321,696)	$ (14,034,934)	$ (2,339,156)
PECO 2007-2010 RTEP "Black Box" Credit Retention (EL05-121-009)	$ 5,500,000	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 2,750,000	$ 458,333
Expansion Recovery Cost (Schedule 13) Payments ended in 2015.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Deactivation		$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 126,000	$ 21,000
Total Cost		**$ 1,453,264**	**$ 1,470,207**	**$ 1,461,735**	**$ 1,504,093**	**$ 1,521,036**	**$ 1,566,825**	**$ 8,977,159**	$ 1,496,193
NBT Costs									
NBT 1	45.82%	$ 665,946	$ 673,710	$ 669,828	$ 689,238	$ 697,002	$ 717,985	$ 4,113,708	$ 685,618
NBT 2	22.71%	$ 330,065	$ 333,913	$ 331,989	$ 341,609	$ 345,457	$ 355,857	$ 2,038,889	$ 339,815
NBT 3	31.39%	$ 456,226	$ 461,545	$ 458,885	$ 472,183	$ 477,502	$ 491,877	$ 2,818,217	$ 469,703
NBT 4	0.07%	$ 1,027	$ 1,039	$ 1,033	$ 1,063	$ 1,075	$ 1,107	$ 6,345	$ 1,057
	100%								

NSPL Allocation supporting NBT Costs	
Actuals from 12/2017 Forward	**NSPL Total**
- NBT 1	18,713
- NBT 2	9,275
- NBT 3	12,820
- NBT 4	29
Total	40,838
- NBT 1 Share of Total	45.82%
- NBT 2 Share of Total	22.71%
- NBT 3 Share of Total	31.39%
- NBT 4 Share of Total	0.07%

Source for Projected Monthly Expense Outside PECO Zone:
PJM Transmission Cost Information Calculator as of 11/1/2018
http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

Projected Annual Expense to be recovered from PECO customers for PECO TO: **$22,386,742**

Generation Deactivation:
PECO assumes PJM will continue collecting for Dominion Generation resources Yorktown 1 and Yorktown 2 thru this period.

FERC # EL05-121-009 Settlement *(relates to FERC Order 494)*
Based on new PJM cost allocation method for RTEP facilities >=500kV and PJM recast of prior RTEP periods back to 2007
PECO expects "Transitional" refunds thru 6/30/2018 and "Black Box" refunds through 12/31/2025.
PECO is retaining $5.5M of the "Black Box" refund over twelve months, from 12/2018 through 11/2019.

PECO Exhibit No. JAB-9

PECO
An Exelon Company

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

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dick.webster@peco-energy.com

May 15, 2019

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

SUBJECT: Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment, PECO Energy Electric Tariff No. 6, Supplement No. 13, Effective June 1, 2019, Docket No. P-2014-2409362

Dear Secretary Chiavetta:

This filing contains PECO Energy Company's (PECO) semiannual adjustment to the Non-Bypassable Transmission Service Charge (NBT), effective June 1, 2019. This filing is being made in accordance with PECO's Tariff approved in Docket No. P-2014-2409362.

The following attachments are included in support of this filing:

Attachment 1 – Revised tariff pages for NBT;
Attachment 2 – NBT Calculation for Residential - Rates R & RH;
Attachment 3 – NBT Calculation for C&I Rate GS;
Attachment 4 – NBT Calculation for C&I Rates HT, PD, EP;
Attachment 5 – NBT Calculation for Street Lighting - Rates SLE, SLS, SLC, POL, AL, TLCL.

Please note the addition of Rate SLC to the NBT Calculation for Street Lighting (Attachment 5), effective July 1, 2019 pursuant to PECO's 2018 electric distribution rate case at Docket No. R-2018-3000164.

This adjustment to the NBT is the second to reflect the impact of approved Regional Transmission Expansion Plan ("RTEP") credits being refunded to the PECO Zone by PJM, pursuant to the Settlement Agreement under FERC Docket # EL05-121-009. The NBT will continue to reflect RTEP credits that PJM will refund through 2025 as specified in the Settlement.

As discussed with the Commission in October of 2018, PECO is retaining $5.5 million of the total credits over the NBT filing periods from December 1, 2018 through November 30, 2019. Retaining this credit permits recovery of overpaid RTEP costs previously absorbed by PECO from 2007 through 2010. Note the Commission initiated a proceeding, see Docket No. M-2018-3005860, in response to several stakeholder interventions regarding the $5.5 million credit. Similar to PECO's request when filing its prior NBT adjustment, PECO requests that the NBT tariff rates specified in this filing not be suspended by the Commission, but rather that such rates be placed into effect, subject to refund.

Thank you for your assistance in this matter. Please direct any questions regarding the above to Richard Schlesinger, Manager, Retail Rates at (215) 841-5771.

Sincerely,

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

Copies to: K. G. Sophy, Director, Office of Special Assistants
P. T. Diskin, Director, Bureau of Technical Utility Services
K. A. Monaghan, Director, Bureau of Audits
R. A. Kanaskie, Director, Bureau of Investigation & Enforcement
Office of Consumer Advocate
Office of Small Business Advocate
McNees, Wallace & Nurick

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued May 15, 2019 | Effective June 1, 2019

ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Non-Bypassable Transmission Charge (NBT) - 2nd Revised Page No. 43
Reflects semiannual adjustment for Non-Bypassable Transmission Charge pursuant to Order at Docket No. P-2014-2409362.

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Rate R - Residence Service - 3rd -Revised Page No. 49
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate RH - Residential Heating Service - 3rd Revised Page No. 50
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate GS - General Service - 3rd Revised Page No. 54
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate SL-E Street Lighting Customer Owned Facilities - 2nd Revised Page No. 63
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate SL-C Smart Lighting Control Lighting Customer Owned Facilities - 2nd Revised Page No. 65
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

Rate TLCL - Traffic Lighting Constant Load Service - 2nd Revised Page No. 68
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT).

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NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362.

Applicability: The surcharge shall be assessed to all distribution customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential, Small C&I and Street Lighting class rate schedules as described below.

For Rates PD, HT, and EP (Large C&I class), a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT. Customer's PLC will be computed to the nearest kilowatt. The NBT shall be recovered through a separate charge listed on customers' bills.

The surcharge shall be calculated on a semi-annual basis using the formula below:

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where;

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

> Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges, Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362.

E – The estimated over or under recovery from the applicable reconciliation period.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate:

R= $.00083 per kilowatthour **(I)**
RH= $.00083 per kilowatthour **(I)**
Small C&I = $0.30 per billed kW **(I)**
Large C&I = $0.27 per kW based on the PJM PLC **(I)**
Street Lighting = $.00002 per kilowatt hour **(D)**

(D) Denotes Decrease
(I) Denotes Increase

RATE R RESIDENCE SERVICE

AVAILABILITY.
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and is served through the same meter as the dwelling unit; (g) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and requires separate metering service as a result of wiring restrictions or legal requirements.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37 1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $9.97
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.94

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.06475 per kWh **(I)**

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

(I) Denotes Increase

RATE R H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered.

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $9.97
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.94

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.06475 per kWh for all kWh. (I)
WINTER MONTHS. (October through May)
$0.04798 per kWh for all kWh (I)

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE. The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE. Where a portion of the service provided is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS. Standard.

(I) Denotes Increase

RATE-GS GENERAL SERVICE

AVAILABILITY.
Service through a single metering installation for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$ 14.49 for single-phase service without demand measurement, or
$ 18.47 for single-phase service with demand measurement, or
$ 44.21 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$7.93 per kW of billed demand (I)
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00223 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows:
(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
For customers with demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, (ii) 40% of the maximum contract demand; or (iii) the maximum measured demand from the prior year.

If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus a charge of $7.10 per KW of billing demand. In addition to the above, for customers in Procurement Class 3/4 charges will be assessed on PJM's reliability pricing model.

(I) – Denotes Increase

RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.

To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$6.68 per Service Location (as defined below) *	
VARIABLE DISTRIBUTION CHARGE:	$0.01696 per kWh	(D)

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

* The service location charge includes an Energy Efficiency Program Surcharge of $0.03 per location

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.

A Service Location is the Point of Delivery on the Company's secondary circuit. that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer

2. Ownership of Utilization Facilities.

   a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.

   The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities.

   b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.

   Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

   c. Service to Group of Utilization Facilities:

      AERIAL SUPPLY

      When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

      UNDERGROUND SUPPLY

      When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

D Denotes Decrease

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.

Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to.
   a. Measurement of energy usage at the individual Utilization Facility level.
   b. Customer control of the lamp's burning hours.
   c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
   d. Ability of customer to dim the lights (LED only).

(B) Provides energy usage to the Company as described below under Data Requirements.

(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$5.66 per Service Location (as defined below)	
VARIABLE DISTRIBUTION CHARGE:	$0.03213 per kWh	**(D)**

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.

A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.

The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:

(A) Manufacturer-rated wattage
(B) Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
(C) Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.

Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.

1 Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.
If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

D Denotes Decrease

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.

To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.

To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.

To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.

Standard single phase secondary service.

RATE TABLE.

SERVICE LOCATION CHARGE: $3.67 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.01625 per kWh (as defined below)* **(D)**

*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of $0.00047 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SPECIAL RULES AND REGULATIONS.

The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours. The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

SPECIAL TERMINATION RIGHTS

Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider. In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer. The customer may then, at its discretion, notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days If the customer has not removed its facilities within 30 days, then PECO may, at its sole discretion and upon 72-hour notice, physically remove the customer facility as a means of terminating service to that facility. Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals. Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL. In addition, the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs, use of truck or other equipment, fuel costs, and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals. PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage.

TERM OF CONTRACT.

The initial contract term for each signal light installation and constant load device shall be for at least one year.

PAYMENT TERMS.

Standard.

(D) Denotes Decrease

Supplement No. 13 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 19101

For List of Communities Served, See Page 4.

Issued May 15, 2019 **Effective June 1, 2019**

ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Non-Bypassable Transmission Charge (NBT) - 2nd Revised Page No. 43
Reflects semiannual adjustment for Non-Bypassable Transmission Charge pursuant to Order at Docket No. P-2014-2409362

Rate R - Residence Service - 3rd Revised Page No. 49
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate RH - Residential Heating Service - 3rd Revised Page No. 50
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate GS - General Service - 3rd Revised Page No. 54
The Variable Distribution Service Charge is increased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate SL-E Street Lighting Customer Owned Facilities - 2nd Revised Page No. 63
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate SL-C Smart Lighting Control Lighting Customer Owned Facilities - 2nd Revised Page No. 65
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

Rate TLCL - Traffic Lighting Constant Load Service - 2nd Revised Page No. 68
The Variable Distribution Service Charge is decreased due to a change in the Non-Bypassable Transmission Charge (NBT)

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Reflects semiannual adjustment for Transmission Service Charge pursuant to Order at Docket No. R-2010-2161575 ¶
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Supplement No. 13 to
Tariff Electric Pa. P.U.C. No. 6
Thirteenth Revised Page No. 2
PECO Energy Company Supersedes Twelfth Revised Page No. 2

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NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362

Applicability The surcharge shall be assessed to all distribution customers The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential Small C&I and Street Lighting class rate schedules as described below

For Rates PD HT and EP (Large C&I class) a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT Customer's PLC will be computed to the nearest kilowatt The NBT shall be recovered through a separate charge listed on customers bills

The surcharge shall be calculated on a semi annual basis using the formula below

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff These costs shall include the following

> Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362

E – The estimated over or under recovery from the applicable reconciliation period

I – Interest on any over or under recovery balance Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period

n – rate class where 1 = residential 1a = RH 2 = small C&I 3 = large C&I 4 = street lighting

Residential – Rates R RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT PD EP (reconciled as a group)
Street Lighting – SLE SLC SLS POL AL TLCL (reconciled as a group)

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S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period For the Large C&I class (Rates PD HT and EP) the PJM PLC shall be used to calculate the NBT The application period will be the period when rates will be in effect

T – The currently effective gross receipts tax rate

Filings and Reconciliations The Company shall submit filings 15 days prior to the start of the application period beginning June 1 2015 Thereafter the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1) The annual reconciliation statement will be made by December 31 each year

Current Non-Bypassable Transmission Rate

R= $ 00083 per kilowatthour (I)
RH = $ 00083 per kilowatthour (I)
Small C&I = $0 30 per billed kW (I)
Large C&I = $0 27 per kW based on the PJM PLC (I)
Street Lighting = $ 00002 per kilowatt hour (D)

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RATE R RESIDENCE SERVICE

AVAILABILITY

Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply Centrally supplied master metered heating cooling or water heating service may be provided if such supply will result in energy conservation

The term "residence service" includes service to (a) the separate dwelling unit in an apartment house or condominium but not the halls basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as the dwelling place of a priest rabbi, pastor rector nun or other functioning Church Divine, and the resident associates (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) A detached garage located on the same premises as the customer's dwelling unit that is utilized solely for the domestic requirements of the dwelling unit s members and is served through the same meter as the dwelling unit (g) A detached garage located on the same premises as the customer's dwelling unit that is utilized solely for the domestic requirements of the dwelling unit s members and requires separate metering service as a result of wiring restrictions or legal requirements

The term does NOT include service to (a) Premises institutional in character including Clubs Fraternities Orphanages or Homes (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly (c) a premises containing a residence unit but primarily devoted to a professional or other office studio or other gainful pursuit (d) electric furnaces or welding apparatus other than a transformer type 'limited input' arc welder with an input not to exceed 37 1/2 amperes at 240 volts

CURRENT CHARACTERISTICS Standard single phase secondary service

MONTHLY RATE TABLE
FIXED DISTRIBUTION SERVICE CHARGE $9 97
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS $1 94

VARIABLE DISTRIBUTION SERVICE CHARGE
All kWhs $0.08475 per kWh (I)

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ENERGY SUPPLY CHARGE
Refer to the Generation Supply Adjustment Procurement Class 1

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

MINIMUM CHARGE The minimum charge per month will be the Fixed Distribution Service Charge

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) FEDERAL TAX ADJUSTMENT CREDIT (FTAC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

PAYMENT TERMS Standard

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RATE R H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not) for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources All space heating installations must meet Company requirements This rate schedule is not available for commercial institutional or industrial establishments

Each dwelling unit connected after May 10 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered

CURRENT CHARACTERISTICS Standard single phase secondary service

MONTHLY RATE TABLE
FIXED DISTRIBUTION SERVICE CHARGE $9 97
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS $1 94

VARIABLE DISTRIBUTION SERVICE CHARGE
SUMMER MONTHS (June through September)
$0.06475 per kWh for all kWh (I)
WINTER MONTHS (October through May)
$0.04798 per kWh for all kWh (I)

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ENERGY SUPPLY CHARGE
Refer to the Generation Supply Adjustment Procurement Class 1

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

MINIMUM CHARGE The minimum charge per month will be the Fixed Distribution Service Charge

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) FEDERAL TAX ADJUSTMENT CREDIT (FTAC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE Where a portion of the service provided is used for commercial purposes the appropriate general service rate is applicable to all service or at the option of the customer the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only

PAYMENT TERMS. Standard

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RATE-GS GENERAL SERVICE

AVAILABILITY.
Service through a single metering installation for offices professional, commercial or industrial establishments governmental agencies farms and other applications outside the scope of the Residence Service rate schedules

For service configurations that are nominally 120/208 volts 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1 500 kVA for transformers outside the building the customer may request service at 277/480 volts 3-phase 4-wires from transformers located outside the building Otherwise the only rate option available to the customer will be Rate HT

For service configurations that are nominally 277/480 volts 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1 500 kVA for transformers located outside the building the only rate option available to the customer will be Rate HT

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE
$ 14 49 for single-phase service without demand measurement or
$ 18 47 for single-phase service with demand measurement or
$ 44 21 for polyphase service

VARIABLE DISTRIBUTION SERVICE CHARGE
$7 93 per kW of billed demand (I)
($0 0006) per kWh for all kWh

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ENERGY EFFICIENCY CHARGE $0 00223 per kWh

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ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service Charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) FEDERAL TAX ADJUSTMENT CREDIT (FTAC) NUCLEAR DECOMMISSIONING COST ADJUSTMENT NON-BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE

DETERMINATION OF DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement Measured demands will be determined to the nearest 0 1 of a kilowatt but will not be less than 1 2 kilowatts and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows
(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand with a minimum billing demand of 1 2 kW
For customers with demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand (ii) 40% of the maximum contract demand or (iii) the maximum measured demand from the prior year

If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less but not less than 1 2 kilowatts

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours The computed demand will be determined to the nearest 0 1 of a kilowatt but will not be less than 1 2 kilowatts

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge plus a charge of $7 10 per KW of billing demand In addition to the above for customers in Procurement Class 3/4 charges will be assessed on PJM s reliability pricing model

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RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY

To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets highways bridges parks or similar places including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate are installed owned and maintained by a governmental agency

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated This rate is not available to commercial or industrial customers All facilities and their installation shall be approved by the Company

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE	$6 68 per Service Location (as defined below) *	
VARIABLE DISTRIBUTION CHARGE	$0 01696 per kWh	(D)

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ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Class 2

* The service location charge includes an Energy Efficiency Program Surcharge of $0 03 per location

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TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS NON BYPASSABLE TRANSMISSION CHARGE PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE

SERVICE LOCATION

A Service Location is the Point of Delivery on the Company s secondary circuit that connects to one or more Utilization Facilities A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions Paragraph 1 Service The wattage expressed to the nearest tenth of a watt of a Service Location shall be composed of manufacturer's rating of its lamps ballasts transformers individual controls and other load components required for its operation The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month

TERMS AND CONDITIONS

1. Service Lighting service will be operated on all-night every-night lighting schedules under which lights normally are turned on after sunset and off before sunrise with approximately 4 100 annual operating hours (average monthly burning hours = 341 11 hours) Extended lighting service during all daylight hours will be supplied for lamps specified by the customer

2. Ownership of Utilization Facilities

   a Service Locations Supplied from Aerial Circuits customer shall provide own and maintain the Utilization Facilities defined as the brackets hangers luminaires lamps/LED array(s) ballasts/drivers transformers individual controls conductors molding and supporting insulators between the lamp receptacles and line wires of the Company s distribution facilities and any other components as required for the operation of each Service Location

   The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities

   b Service Locations Supplied from Underground Circuits customer shall provide own and maintain the Utilization Facilities defined as brackets or hangers luminaires, lamps/LED array(s) ballasts/drivers transformers, individual controls and conductors and shall assume all costs of installing such Utilization Facilities Customer shall also provide, own and maintain the supporting pole or post foundation with 90 degree pipe bend and conduits from the luminaires to sidewalk level, or in special cases such as Federally and State financed limited access highways to a Service Location designated by the Company on its secondary voltage circuit

   Except as provided in Paragraph 5 Supply Facilities the Company shall own conduit from the distribution circuit to the 90 degree pipe bend shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided

   c Service to Group of Utilization Facilities

   AERIAL SUPPLY

   When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities the customer is responsible for providing the support poles or posts for the Utilization Facilities The Company will provide a service nominally 100 feet to the customer's first supporting structure The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities

   UNDERGROUND SUPPLY

   When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole the customer will install own maintain all cable including the cable on the pole

3. Standards of Construction for Utilization Facilities Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY

Any governmenta agency for outdoor l ghting provided for the safety and convenience of the pub ic of streets highways, bridges parks or similar places, that compl es w th each of the following conditions

(A) Installs a Smart Light ng Control Module approved by the Company that has capabil ties inc ud ng but not necessarily limited to
  a Measurement of energy usage at the individual Utilization Facility level
  b Customer control of the lamp's burning hours
  c Data showing failure of the lamp to burn, such as customer notification that customer can provide to Company upon request
  d Ability of customer to dim the lights (LED only)

(B) Provides energy usage to the Company as described below under Data Requirements

(C) Installs owns and maintains all Utilization Facilities as defined in the Terms and Conditions of this Base Rate (All facilities and their installation shall be approved by the Company)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated This rate is not available to commercial or industrial customers

Customers may take service under the rate beginning on July 1 2019 The below listed pricing will be revised as needed based on applicable surcharge adjustments prior to the SL-C effective service date of July 1 2019

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE	$5 66 per Service Location (as defined below)
VARIABLE DISTRIBUTION CHARGE	$0 03213 per kWh (D)

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ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Class 2

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE The Transmission Service charge shall apply

STATE TAX ADJUSTMENT CLAUSE FEDERAL TAX ADJUSTMENT CREDIT (FTAC) PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS NON-BYPASSABLE TRANSMISSION CHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE

SERVICE LOCATION

A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.

The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified

(A) Manufacturer-rated wattage
(B) Annual burning hours if different than the standard 4 100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
(C) Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light

DETERMINATION OF ENERGY BILLED.

Upon acceptance of the required data the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage adjusted based on the provided dimming percentage/factor and the provided burning hours during the calendar month

The Company may at any time and without prior notice request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light by calendar month for up to the past 12 months to verify the continued accuracy of Company billing

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer

TERMS AND CONDITIONS

1 Service For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module lighting service will be operated on all-night every-night lighting schedules under which lights normally are turned on after sunset and off before sunrise with approximately 4 100 annual operating hours (average monthly burning hours = 341 11 hours) Extended lighting service during all daylight hours will be supplied for lamps specified by the customer
If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage the burning hours provided by the customer will be used instead of the standard 4 100 annual operating hours

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RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.

To any municipality using the Company's standard service for (a) electric traffic signal lights installed owned and maintained by the municipality and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the municipality.

To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the non-municipal customer which are electrically separate from any other facilities whether municipally-owned or non-municipally-owned that are receiving service from PECO as a separate account

To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1 2 kW owned and maintained by the non-municipal customer which are electrically integrated with any other facilities whether municipally-owned or non-municipally-owned that are receiving service from PECO as a separate account but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate

CURRENT CHARACTERISTICS

Standard single phase secondary service

RATE TABLE.

SERVICE LOCATION CHARGE $3 67 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE $0 01525 per kWh (as defined below)* (D)

*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of $0 00047 per kWh

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ENERGY SUPPLY CHARGE Refer to the Generation Supply Adjustment Procurement Class 2

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE Transmission Service Charge shall apply

STATE TAX ADJUSTMENT CLAUSE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) FEDERAL TAX ADJUSTMENT CREDIT (FTAC) PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE

SPECIAL RULES AND REGULATIONS

The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used

The Company shall not be liable for damage to person or property arising accruing or resulting from the attachment of the signal equipment to its poles wires or fixtures The customer shall be responsible to determine the amount, location and sufficiency of illumination including conducting all studies of luminosity lighting location and traffic

SPECIAL TERMINATION RIGHTS

Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer The customer may then at its discretion notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days If the customer has not removed its facilities within 30 days, then PECO may at its sole discretion and upon 72-hour notice physically remove the customer facility as a means of terminating service to that facility Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL In addition the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs use of truck or other equipment fuel costs and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage

TERM OF CONTRACT

The initial contract term for each signal light installation and constant load device shall be for at least one year

PAYMENT TERMS

Standard

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PECO - Electric
June 2019 Non-Bypassable Transmission Charge (NBT)
Semi-Annual Rate Calculation

NBT 1: Rates R, RH

					Amount
(1)	C	=	Projected Recoverable Transmission Costs	$	10,254,345
(2)	E	=	Experienced & Estimated Net Over/(Under)		
		a.	Over/(Under)	$	4,846,300
		b.	Interest	$	134,729
				$	4,981,029
(3)			Net Recoverable (C - E)	$	5,273,316
(4)	S	=	Projected Sales (kWh) for Computation Period		6,764,101,969
(5)	T	=	Pennsylvania gross receipts tax rate		5.90%
(6)			**NBT = [(C+E+I)/S]/(1-T)**		**$0.00083**

PECO - June 2019
NBT
C-Factor Calculation

NBT 1: Rates R, RH

C-Factor Month		Projected Transmission Costs [a] (1)	Projected Sales (kWh) (2)
Jun-19 (est)	$	640,002	1,010,829,136
Jul-19 (est)	$	1,919,695	1,342,965,867
Aug-19 (est)	$	1,923,662	1,439,759,360
Sep-19 (est)	$	1,923,662	1,194,254,392
Oct-19 (est)	$	1,923,662	900,103,211
Nov-19 (est)	$	1,923,662	876,190,002
Total	$	10,254,345	6,764,101,969

Estimated Recovery C-Factor **$0.00152** per kWh

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement over the period 6/1/19-11/30/2019: *$ (6,322,018.97)*

PECO - June 2019
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)
Balance										
Jun-18	$ 3,332,286	1,014,619,014	$ 0.00326	$ 3,176,111	3,740	$ -	$ 3,176,111	$ (156,175)	$ (0.00028)	$ (270,601)
Jul-18	$ 3,331,778	1,397,738,875	$ 0.00326	$ 4,551,707	3,740	$ -	$ 4,551,707	$ 1,219,929	$ (0.00028)	$ (387,801)
Aug-18	$ 109,517	1,450,945,593	$ 0.00326	$ 4,726,218	3,742	$ -	$ 4,726,218	$ 4,616,701	$ (0.00028)	$ (402,669)
Sep-18	$ 458,179	1,422,280,375	$ 0.00326	$ 4,633,816	3,744	$ -	$ 4,633,816	$ 4,175,637	$ (0.00028)	$ (394,796)
Oct-18	$ 678,179	991,186,851	$ 0.00326	$ 3,228,365	3,748	$ -	$ 3,228,365	$ 2,550,186	$ (0.00028)	$ (275,053)
Nov-18	$ 483,760	910,689,634	$ 0.00326	$ 2,964,740	3,751	$ -	$ 2,964,740	$ 2,480,980	$ (0.00028)	$ (252,593)
Dec-18	$ 509,563	1,216,785,091	$ 0.00061	$ (444,104)	3,755	$ -	$ (444,104)	$ (953,667)	$ (0.00197)	$ 1,444,368
Jan-19	$ 408,585	1,351,486,380	$ 0.00061	$ 815,528	3,907	$ -	$ 815,528	$ 406,942	$ (0.00197)	$ (2,652,359)
Feb-19	$ 410,496	1,313,879,327	$ 0.00061	$ 792,177	3,912	$ -	$ 792,177	$ 381,681	$ (0.00197)	$ (2,576,416)
Mar-19	$ 421,933	1,137,162,861	$ 0.00061	$ 685,118	3,915	$ -	$ 685,118	$ 263,185	$ (0.00197)	$ (2,228,225)
Apr-19	$ 429,262	887,424,700	$ 0.00061	$ 533,900	3,919	$ -	$ 533,900	$ 104,638	$ (0.00197)	$ (1,736,416)
May-19 (est)	$ 474,192	1,136,237,999	$ 0.00061	$ 440,025	3,860	$ -	$ 440,025	$ (34,167)	$ (0.00197)	$ (1,431,102)

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018
(b) C Factor and E Factor Revenues are allocated on a percentage basis

PECO - June 2019
NBT
Interest Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual Sales (kWh) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [a] (7)	Total Interest Ow (Interest Reco (8) = (5) + (
Balance								
Jun-18	1,014,619,014	$ (156,175)	6%	9/12	$ (7,028)	$ (0.00001)	$ (11,704)	$ (
Jul-18	1,397,738,875	$ 1,219,929	6%	8/12	$ 48,797	$ (0.00001)	$ (16,772)	$
Aug-18	1,450,945,593	$ 4,616,701	6%	7/12	$ 161,585	$ (0.00001)	$ (17,415)	$ 1
Sep-18	1,422,280,375	$ 4,175,637	6%	6/12	$ 125,269	$ (0.00001)	$ (17,075)	$ 1
Oct-18	991,186,851	$ 2,550,186	6%	5/12	$ 63,755	$ (0.00001)	$ (11,896)	$
Nov-18	910,689,634	$ 2,480,980	6%	4/12	$ 49,620	$ (0.00001)	$ (10,925)	$
Dec-18	1,216,785,091	$ (953,667)	6%	9/12	$ (42,915)	$ (0.00006)	$ 44,461	$
Jan-19	1,351,486,380	$ 406,942	6%	8/12	$ 16,278	$ (0.00006)	$ (81,646)	$ (
Feb-19	1,313,879,327	$ 381,681	6%	7/12	$ 13,359	$ (0.00006)	$ (79,308)	$ (
Mar-19	1,137,162,861	$ 263,185	6%	6/12	$ 7,896	$ (0.00006)	$ (68,590)	$ (
Apr-19	887,424,700	$ 104,638	6%	5/12	$ 2,616	$ (0.00006)	$ (53,451)	$ (
May-19 (est)	1,136,237,999	$ (34,167)	6%	4/12	$ (683)	$ (0.00006)	$ (44,053)	$ (

(a) Interest Revenues are allocated on a percentage basis.

Net I

PECO - Electric
June 2019 Non-Bypassable Transmission Charge (NBT)
Semi-Annual Rate Calculation

NBT 2: Rate GS

				Amount
(1)	C	=	Projected Recoverable Transmission Costs	$ 5,134,891
(2)	E	=	Experienced & Estimated Net Over/(Under)	
		a.	Over/(Under)	$ 1,764,262
		b.	Interest	$ 44,602
				$ 1,808,864
(3)			Net Recoverable (C - E)	$ 3,326,027
(4)	S	=	Projected Sales (kW) for Computation Period	11,715,804
(5)	T	=	Pennsylvania gross receipts tax rate	5.90%
(6)			**NBT = [(C+E+I)/S]/(1-T)**	**$0.30**

PECO - June 2019
NBT
C-Factor Calculation

NBT 2: Rate GS

C-Factor Month		Projected Transmission Costs [a] (1)	Projected Sales (kW) (2)
Jun-19 (est)	$	320,483	1,973,174
Jul-19 (est)	$	961,292	2,104,066
Aug-19 (est)	$	963,279	2,185,446
Sep-19 (est)	$	963,279	1,991,673
Oct-19 (est)	$	963,279	1,769,697
Nov-19 (est)	$	963,279	1,691,748
Total	$	5,134,891	11,715,804

Estimated Recovery C-Factor **$0.44** per kW

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement over the period 6/1/19-11/30/2019: *$ (3,165,767.68)*

PECO - June 2019
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	C R (11)
Balance											
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$
Aug-18	$ 54,280	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 2,105,818	$ (0.11)	$ (262,883)	$
Sep-18	$ 226,910	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 2,017,004	$ (0.11)	$ (273,083)	$
Oct-18	$ 335,332	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 1,623,167	$ (0.11)	$ (238,348)	$
Nov-18	$ 239,051	1,651,642	$ 0.91	$ 1,880,839	1,854	$ -	$ 1,880,839	$ 1,641,788	$ (0.11)	$ (228,897)	$
Dec-18	$ 251,761	1,803,223	$ 0.18	$ (177,067)	1,855	$ -	$ (177,067)	$ (428,827)	$ (0.66)	$ 652,311	$
Jan-19	$ 205,567	2,107,561	$ 0.18	$ 409,369	1,966	$ -	$ 409,369	$ 203,802	$ (0.66)	$ (1,508,108)	$
Feb-19	$ 206,297	1,775,693	$ 0.18	$ 352,867	1,966	$ -	$ 352,867	$ 146,570	$ (0.66)	$ (1,299,955)	$
Mar-19	$ 211,808	2,206,236	$ 0.18	$ 387,680	1,965	$ -	$ 387,680	$ 175,872	$ (0.66)	$ (1,428,206)	$
Apr-19	$ 215,384	2,073,416	$ 0.18	$ 366,954	1,966	$ -	$ 366,954	$ 151,571	$ (0.66)	$ (1,351,853)	$
May-19 (est)	$ 236,946	1,936,295	$ 0.18	$ 352,816	1,929	$ -	$ 352,816	$ 115,870	$ (0.66)	$ (1,299,768)	$

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.

(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
Interest Calculation

NBT 2: Rate GS

E-Factor Period	Actual Sales (kW) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [a] (7)	Total Interest Owed/ (Interest Recoupe (8) = (5) + (7)
Balance								
Jun-18	1,986,924	$ (41,600)	6%	9/12	$ (1,872)	$ (0.00)	$ (7,635)	$ (9,
Jul-18	2,050,527	$ 528,090	6%	8/12	$ 21,124	$ (0.00)	$ (10,327)	$ 10,
Aug-18	2,089,410	$ 2,105,818	6%	7/12	$ 73,704	$ (0.00)	$ (10,225)	$ 63,
Sep-18	2,181,146	$ 2,017,004	6%	6/12	$ 60,510	$ (0.00)	$ (10,622)	$ 49,
Oct-18	1,866,353	$ 1,623,167	6%	5/12	$ 40,579	$ (0.00)	$ (9,271)	$ 31,
Nov-18	1,651,642	$ 1,641,788	6%	4/12	$ 32,836	$ (0.00)	$ (8,903)	$ 23,
Dec-18	1,803,223	$ (428,827)	6%	9/12	$ (19,297)	$ (0.02)	18,843	$ (
Jan-19	2,107,561	$ 203,802	6%	8/12	$ 8,152	$ (0.02)	(43,563)	$ (35,
Feb-19	1,775,693	$ 146,570	6%	7/12	$ 5,130	$ (0.02)	(37,551)	$ (32,
Mar-19	2,206,236	$ 175,872	6%	6/12	$ 5,276	$ (0.02)	(41,255)	$ (35,
Apr-19	2,073,416	$ 151,571	6%	5/12	$ 3,789	$ (0.02)	(39,050)	$ (35,
May-19 (est)	1,936,295	$ 115,870	6%	4/12	$ 2,317	$ (0.02)	(37,545)	$ (35,

(a) Interest Revenues are allocated on a percentage basis.

Net Inte

PECO - Electric
une 2019 Non-Bypassable Transmission Charge (NBT)
Semi-Annual Rate Calculation

NBT 3: Rates HT, PD, EP

				Amount
(1)	C =	Projected Recoverable Transmission Costs	$	7,135,380
(2)	E =	Experienced & Estimated Net Over/(Under)		
		a. Over/(Under)	$	3,128,599
		b. Interest	$	69,325
			$	3,197,924
(3)		Net Recoverable (C - E)	$	3,937,456
(4)	S =	Projected PLC Sales (kW) for Computation Period		15,529,106
(5)	T =	Pennsylvania gross receipts tax rate		5.90%
(6)		**NBT = [(C+E+I)/S]/(1-T)**		**$0.27**

PECO - June 2019
NBT
C-Factor Calculation

NBT 3: Rates HT, PD, EP

C-Factor Month		Projected Transmission Costs [a]	Projected PLC Sales (kW)
		(1)	(2)
Jun-19 (est)	$	445,339	2,588,184
Jul-19 (est)	$	1,335,800	2,588,184
Aug-19 (est)	$	1,338,560	2,588,184
Sep-19 (est)	$	1,338,560	2,588,184
Oct-19 (est)	$	1,338,560	2,588,184
Nov-19 (est)	$	1,338,560	2,588,184
Total	$	7,135,380	15,529,106

Estimated Recovery C-Factor **$0.46** per kW

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement over the period 6/1/19-11/30/2019: *$ (4,399,111.16)*

PECO - June 2019
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collect Reven (11) = (10
Balance											
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2,562	$ -	$ 2,019,542	$ (262,830)	$ (0.02)	$ (43,665)	$ 1,975
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0.02)	$ (52,784)	$ 2,388
Aug-18	$ 75,052	2,593,177	$ 0.96	$ 2,502,678	2,564	$ -	$ 2,502,678	$ 2,427,625	$ (0.02)	$ (54,111)	$ 2,448
Sep-18	$ 314,003	2,590,611	$ 0.96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 2,184,008	$ (0.02)	$ (54,010)	$ 2,444
Oct-18	$ 464,357	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 1,701,886	$ (0.02)	$ (46,837)	$ 2,119
Nov-18	$ 330,935	2,175,513	$ 0.96	$ 2,107,105	2,566	$ -	$ 2,107,105	$ 1,776,170	$ (0.02)	$ (45,558)	$ 2,06
Dec-18	$ 348,195	2,716,889	$ 0.19	$ (650,390)	2,566	$ -	$ (650,390)	$ (998,585)	$ (0.53)	$ 1,827,044	$ 1,170
Jan-19	$ 286,111	2,455,299	$ 0.19	$ 414,282	2,736	$ -	$ 414,282	$ 128,171	$ (0.53)	$ (1,163,780)	$ (749
Feb-19	$ 287,081	2,302,036	$ 0.19	$ 416,077	2,736	$ -	$ 416,077	$ 128,996	$ (0.53)	$ (1,168,824)	$ (752
Mar-19	$ 294,615	2,252,714	$ 0.19	$ 491,568	2,734	$ -	$ 491,568	$ 196,952	$ (0.53)	$ (1,380,888)	$ (889
Apr-19	$ 299,421	2,738,028	$ 0.19	$ 518,025	2,734	$ -	$ 518,025	$ 218,605	$ (0.53)	$ (1,455,212)	$ (937
May-19 (est)	$ 329,059	2,440,080	$ 0.19	$ 552,607	2,678	$ -	$ 552,607	$ 223,548	$ (0.53)	$ (1,552,356)	$ (999
											Tot

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
Interest Calculation

NBT 3: Rates HT, PD, EP

E-Factor Period	Actual Sales (kW) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [a] (7)	Total Interest Owed/ (Interest Recoupe (8) = (5) + (7)
Balance								
Jun-18	2,185,507	$ (262,830)	6%	9/12	$ (11,827)	$ (0.00)	$ (1,066)	$ (12,8
Jul-18	2,482,563	$ 158,599	6%	8/12	$ 6,344	$ (0.00)	$ (1,289)	$ 5,0
Aug-18	2,593,177	$ 2,427,625	6%	7/12	$ 84,967	$ (0.00)	$ (1,321)	$ 83,6
Sep-18	2,590,611	$ 2,184,008	6%	6/12	$ 65,520	$ (0.00)	$ (1,319)	$ 64,2
Oct-18	2,240,870	$ 1,701,886	6%	5/12	$ 42,547	$ (0.00)	$ (1,144)	$ 41,4
Nov-18	2,175,513	$ 1,776,170	6%	4/12	$ 35,523	$ (0.00)	$ (1,112)	$ 34,4
Dec-18	2,716,889	$ (998,585)	6%	9/12	$ (44,936)	$ (0.01)	$ 51,147	$ 6,2
Jan-19	2,455,299	$ 128,171	6%	8/12	$ 5,127	$ (0.01)	$ (32,579)	$ (27,4
Feb-19	2,302,036	$ 128,996	6%	7/12	$ 4,515	$ (0.01)	$ (32,720)	$ (28,2
Mar-19	2,252,714	$ 196,952	6%	6/12	$ 5,909	$ (0.01)	$ (38,657)	$ (32,7
Apr-19	2,738,028	$ 218,605	6%	5/12	$ 5,465	$ (0.01)	$ (40,738)	$ (35,2
May-19 (est)	2,440,080	$ 223,548	6%	4/12	$ 4,471	$ (0.01)	$ (43,457)	$ (38,9

(a) Interest Revenues are allocated on a percentage basis.

Net Inte

PECO - Electric

une 2019 Non-Bypassable Transmission Charge (NBT)

Semi-Annual Rate Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

						Amount
(1)	C	=	Projected Recoverable Transmission Costs		$	15,055
(2)	E	=	Experienced & Estimated Net Over/(Under)			
			a. Over/(Under)		$	12,979
			b. Interest		$	474
					$	13,453
(3)			Net Recoverable (C - E)		$	1,603
(4)	S	=	Projected Sales (kWh) for Computation Period			95,209,774
(5)	T	=	Pennsylvania gross receipts tax rate			5.90%
(6)			**TSC = [(C+E+I)/S]/(1-T)**			**$0.00002**

PECO - June 2019
NBT
C-Factor Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

C-Factor Month	Projected Transmission Costs [a] (1)		Projected Sales (kWh) (2)
Jun-19 (est)	$	940	13,307,516
Jul-19 (est)	$	2,819	17,491,611
Aug-19 (est)	$	2,824	16,700,889
Sep-19 (est)	$	2,824	18,065,163
Oct-19 (est)	$	2,824	14,144,659
Nov-19 (est)	$	2,824	15,499,935
Total	$	15,055	95,209,774

Estimated Recovery C-Factor **$0.00016** per kWh

(a) Projected costs account for estimated net refund per FERC # EL05-121-009 Settlement over the period 6/1/19-11/30/2019: $ (9,282.02)

PECO - June 2019
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

E-Factor Period	Actual NBT Costs [(a)] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [(b)] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [(b)] (10)	Total Collecte Revenu (11) = (10)
Balance											
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5,030	$ (113)	$ 0.00026	$ 3,744	$ 8
Aug-18	$ 169	13,523,553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 4,523	$ 0.00026	$ 3,492	$ 8
Sep-18	$ 706	17,917,376	$ 0.00035	$ 5,581	6	$ -	$ 5,581	$ 4,875	$ 0.00026	$ 4,154	$ 9
Oct-18	$ 1,045	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ 3,192	$ 0.00026	$ 3,153	$ 7
Nov-18	$ 744	15,170,848	$ 0.00035	$ 5,006	6	$ -	$ 5,006	$ 4,261	$ 0.00026	$ 3,726	$ 8
Dec-18	$ 784	14,483,787	$ 0.00007	$ 5,727	6	$ -	$ 5,727	$ 4,944	$ 0.00002	$ 1,646	$ 7
Jan-19	$ 592	14,935,391	$ 0.00007	$ 974	6	$ -	$ 974	$ 382	$ 0.00002	$ 280	$ 1
Feb-19	$ 595	14,693,317	$ 0.00007	$ 1,119	6	$ -	$ 1,119	$ 524	$ 0.00002	$ 322	$ 1
Mar-19	$ 613	14,904,323	$ 0.00007	$ 1,134	6	$ -	$ 1,134	$ 520	$ 0.00002	$ 326	$ 1
Apr-19	$ 624	15,067,267	$ 0.00007	$ 1,183	6	$ -	$ 1,183	$ 559	$ 0.00002	$ 340	$ 1
May-19 (est)	$ 702	14,875,822	$ 0.00007	$ 1,252	6	$ -	$ 1,252	$ 551	$ 0.00002	$ 360	$ 1
											Tot

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018

(b) C Factor and E Factor Revenues are allocated on a percentage basis

PECO - June 2019
NBT
Interest Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

E-Factor Period	Actual Sales (kWh) (1)	C-Factor Over/(Under) Recovery (2)	Interest Rate (3)	Interest Time Factor (4)	Interest Owed/ (Interest Recouped) (5) = (2) * (3) * (4)	Interest Factor Rate (6)	Interest Factor Revenues [(a)] (7)	Total Interest Owed/ (Interest Recouped (8) = (5) + (7)
Balance								
Jun-18	15,798,654	$ (5,529)	6%	9/12	$ (249)	$ 0.00001	$ (8)	$ (25
Jul-18	16,216,415	$ (113)	6%	8/12	$ (5)	$ 0.00001	$ 104	$ 10
Aug-18	13,523,553	$ 4,523	6%	7/12	$ 158	$ 0.00001	$ 97	$ 25
Sep-18	17,917,376	$ 4,875	6%	6/12	$ 146	$ 0.00001	$ 116	$ 26
Oct-18	14,232,798	$ 3,192	6%	5/12	$ 80	$ 0.00001	$ 88	$ 16
Nov-18	15,170,848	$ 4,261	6%	4/12	$ 85	$ 0.00001	$ 104	$ 18
Dec-18	14,483,787	$ 4,944	6%	9/12	$ 222	$ 0.00000	$ 95	$ 31
Jan-19	14,935,391	$ 382	6%	8/12	$ 15	$ 0.00000	$ 16	$ 3
Feb-19	14,693,317	$ 524	6%	7/12	$ 18	$ 0.00000	$ 19	$ 3
Mar-19	14,904,323	$ 520	6%	6/12	$ 16	$ 0.00000	$ 19	$ 3
Apr-19	15,067,267	$ 559	6%	5/12	$ 14	$ 0.00000	$ 20	$ 3
May-19 (est)	14,875,822	$ 551	6%	4/12	$ 11	$ 0.00000	$ 21	$ 3

(a) Interest Revenues are allocated on a percentage basis.

Net Intere

PECO Exhibit No. JAB-10

Post-2010 PJM Bill Adjustments, E-Factor Component, Supplement No. 13

Tariff Rate Class	Allocation of Monthly NSPL Average MW					
	Dec-18 (for Nov)	Jan-19 (for Dec)	Feb-19 (for Jan)	March-19 (for Feb)	April-19 (for March)	May-19 (est - for April)
GS	22.7%	22.8%	22.8%	22.8%	22.8%	22.8%
RH	5.6%	5.8%	5.8%	5.8%	5.8%	5.7%
SLE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
R	40.3%	39.6%	39.6%	39.6%	39.6%	39.8%
PD	1.0%	1.0%	1.0%	1.0%	0.9%	1.0%
POL	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
OP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
HT	29.2%	29.6%	29.6%	29.6%	29.6%	29.5%
SLS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TL	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
AL	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
EP	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%

	Dec-18 (for Nov)	Jan-19 (for Dec)	Feb-19 (for Jan)	March-19 (for Feb)	April-19 (for March)	May-19 (est - for April)	Totals
RTEP "Transitional Period" Settlement (EL05-121-009)	$ (2,869,081.64)	$ (2,858,487.46)	$ (2,867,308.82)	$ (2,839,648.62)	$ (2,828,584.54)	$ (2,819,250.55)	$ (17,082,361.63)
Projected (Supplement 76)	$ (2,869,081.64)	$ (2,858,487.46)	$ (2,863,784.55)	$ (2,837,299.10)	$ (2,826,704.92)	$ (2,816,110.74)	$ (17,071,468.41)
Variance for E-Factor	$ -	$ -	$ (3,524.27)	$ (2,349.52)	$ (1,879.62)	$ (3,139.81)	$ (10,893.22)
NBT 1 (R, RH)	$ -	$ -	$ (1,599.50)	$ (1,067.14)	$ (854.09)	$ (1,430.37)	$ (4,951.10)
NBT 2 (GS)	$ -	$ -	$ (803.84)	$ (535.70)	$ (428.54)	$ (714.73)	$ (2,482.81)
NBT 3 (HT, PD, EP)	$ -	$ -	$ (1,118.61)	$ (745.13)	$ (595.75)	$ (992.59)	$ (3,452.08)
NBT 4 (SLE, POL, SLS, TL, AL)	$ -	$ -	$ (2.32)	$ (1.55)	$ (1.24)	$ (2.12)	$ (7.23)
Check	*$ -*	*$ -*	*$ (3,524.27)*	*$ (2,349.52)*	*$ (1,879.62)*	*$ (3,139.81)*	*$ (10,893.22)*

	Dec-18 (for Nov)	Jan-19 (for Dec)	Feb-19 (for Jan)	March-19 (for Feb)	April-19 (for March)	May-19 (est - for April)	Totals
RTEP "Black Box" Settlement (EL05-121-009)	$ (2,353,440.52)	$ (2,347,091.66)	$ (2,352,378.11)	$ (2,335,801.95)	$ (2,329,171.49)	$ (2,323,577.84)	$ (14,041,461.57)
Projected (Supplement 76)	$ (2,353,440.52)	$ (2,347,091.66)	$ (2,350,266.09)	$ (2,334,393.94)	$ (2,328,045.08)	$ (2,321,696.22)	$ (14,034,933.51)
Variance for E-Factor	$ -	$ -	$ (2,112.02)	$ (1,408.01)	$ (1,126.41)	$ (1,881.62)	$ (6,528.06)
NBT 1 (R, RH)	$ -	$ -	$ (958.55)	$ (639.51)	$ (511.83)	$ (857.19)	$ (2,967.08)
NBT 2 (GS)	$ -	$ -	$ (481.72)	$ (321.03)	$ (256.81)	$ (428.32)	$ (1,487.89)
NBT 3 (HT, PD, EP)	$ -	$ -	$ (670.36)	$ (446.54)	$ (357.02)	$ (594.84)	$ (2,068.75)
NBT 4 (SLE, POL, SLS, TL, AL)	$ -	$ -	$ (1.39)	$ (0.93)	$ (0.74)	$ (1.27)	$ (4.33)
Check	*$ -*	*$ -*	*$ (2,112.02)*	*$ (1,408.01)*	*$ (1,126.41)*	*$ (1,881.62)*	*$ (6,528.06)*

Total RTEP Credit by Group	Dec-18 (for Nov)	Jan-19 (for Dec)	Feb-19 (for Jan)	March-19 (for Feb)	April-19 (for March)	May-19 (est - for April)	Totals	*Check*
NBT 1 (R, RH)	$ -	$ -	$ (2,558.05)	$ (1,706.65)	$ (1,365.92)	$ (2,287.56)	**$ (7,918.18)**	$ (7,918.18)
NBT 2 (GS)	$ -	$ -	$ (1,285.56)	$ (856.73)	$ (685.36)	$ (1,143.06)	**$ (3,970.70)**	$ (3,970.70)
NBT 3 (HT, PD, EP)	$ -	$ -	$ (1,788.98)	$ (1,191.67)	$ (952.76)	$ (1,587.42)	**$ (5,520.83)**	$ (5,520.83)
NBT 4 (SLE, POL, SLS, TL, AL)	$ -	$ -	$ (3.71)	$ (2.48)	$ (1.98)	$ (3.38)	**$ (11.56)**	$ (11.56)
							$ (17,421.28)	

NBT Update: 5-6-19 (est)

Rate Class	June-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1857.0	22.7%	$ 1,654,618
RH	458.1	5.6%	$ 408,188
SLE	0.0	0.0%	$ -
R	3281.8	40.2%	$ 2,924,097
PD	78.7	1.0%	$ 70,079
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2385.3	29.2%	$ 2,125,373
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 5,142
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 86,919
Total	8,164.2	100.00%	$ 7,274,417
NSPL Total Check	8164.2		
RTEP	$ 7,265,697.26		
Expansion Recovery	$ -		
Generation Deactivation	$ 8,719.88		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)			
RTEP "Black Box" Settlement (FERC #EL05-121-009)			
Total Cost	$ 7,274,417.14		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,740		$ 3,332,286
NBT 2	1,857		$ 1,654,618
NBT 3	2,562		$ 2,282,371
NBT 4	6		$ 5,142
Check	-		$ -
	Revenues		Sales
R	$ 2,609,893		861,031,494
RH	$ 465,352		153,587,520
OP	$ -		-
SCI	$ 1,497,428		1,986,924
LCI	$ 2,098,629		2,185,507
SL	$ (726)		15,798,654
Total	$ 6,670,576		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 6,670,576	$ 6,297,425
Monthly Costs		$ 7,274,417	$ 7,274,417
Monthly Over/(Under)		$ (603,841)	$ (976,992)
Cum Revenues		$ 213,537,727	$ 204,089,515
Cum Costs		$ 196,676,319	$ 196,676,319
Cum Over/Under		$ 16,861,409	$ 7,413,197
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (426,777)	$ 527,316	GOOD
NBT 2	$ (237,903)	$ 987,831	GOOD
NBT 3	$ (306,495)	$ 129,940	GOOD
NBT 4	$ (5,817)	$ (32,781)	GOOD
Total	$ (976,992)	$ 1,612,305	

Rate Class	July-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1856.1	22.7%	$ 1,653,524
RH	457.9	5.6%	$ 407,932
SLE	0.0	0.0%	$ -
R	3282.0	40.2%	$ 2,923,846
PD	78.6	1.0%	$ 70,005
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2386.2	29.2%	$ 2,125,772
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 5,143
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 86,905
Total	8164.1	100.00%	$ 7,273,127
NSPL Total Check	8164.1		
RTEP	$ 7,265,697.26		
Expansion Recovery	$ -		
Generation Deactivation	$ 7,429.27		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)			
RTEP "Black Box" Settlement (FERC #EL05-121-009)			
Total Cost	$ 7,273,126.53		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,740		$ 3,331,778
NBT 2	1,856		$ 1,653,524
NBT 3	2,562		$ 2,282,682
NBT 4	6		$ 5,143
Check	-		$ -
	Revenues		Sales
R	$ 3,829,064		1,214,198,425
RH	$ 578,092		183,540,450
OP	$ -		-
SCI	$ 2,025,277		2,050,527
LCI	$ 2,536,884		2,482,563
SL	$ 9,435		16,216,415
Total	$ 8,978,752		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 8,978,752	$ 8,477,289
Monthly Costs		$ 7,273,127	$ 7,273,127
Monthly Over/(Under)		$ 1,705,625	$ 1,204,163
Cum Revenues		$ 222,516,479	$ 212,566,805
Cum Costs		$ 203,949,445	$ 203,949,445
Cum Over/Under		$ 18,567,034	$ 8,617,360
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 832,128	$ 1,359,444	GOOD
NBT 2	$ 262,589	$ 1,250,420	GOOD
NBT 3	$ 105,815	$ 235,755	GOOD
NBT 4	$ 3,630	$ (29,151)	GOOD
Total	$ 1,204,163	$ 2,816,468	

Rate Class	August-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1854.4	22.7%	$ 54,280
RH	458.0	5.6%	$ 13,405
SLE	0.0	0.0%	$ -
R	3283.5	40.2%	$ 96,112
PD	78.6	1.0%	$ 2,301
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2387.9	29.2%	$ 69,896
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 169
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 2,855
Total	8,165.8	100.00%	$ 239,019
NSPL Total Check	8165.8		
RTEP	$ 5,303,576.42		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,420.08		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,784,328.21)	*PJM BLI 1108A, 7/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,302,649.64)	*PJM BLI 1115, 7/2018 PJM Bill*	
Total Cost	$ 239,018.65		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,742		$ 109,517
NBT 2	1,854		$ 54,280
NBT 3	2,564		$ 75,052
NBT 4	6		$ 169
Check	-		$ -
	Revenues		Sales
R	$ 3,991,693		1,265,448,464
RH	$ 584,432		185,497,129
OP	$ -		-
SCI	$ 2,005,303		2,089,410
LCI	$ 2,600,686		2,593,177
SL	$ 8,801		13,523,553
Total	$ 9,190,915		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 9,190,915	$ 8,677,515
Monthly Costs		$ 239,019	$ 239,019
Monthly Over/(Under)		$ 8,951,896	$ 8,438,497
Cum Revenues		$ 231,707,394	$ 221,244,320
Cum Costs		$ 204,188,464	$ 204,188,464
Cum Over/Under		$ 27,518,930	$ 17,055,856
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 4,214,032	$ 5,573,477	GOOD
NBT 2	$ 1,842,935	$ 3,093,354	GOOD
NBT 3	$ 2,373,514	$ 2,609,269	GOOD
NBT 4	$ 8,016	$ (21,135)	GOOD
Total	$ 8,438,497	$ 11,254,964	

Rate Class	September-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1854.3	22.7%	$ 226,910
RH	458.2	5.6%	$ 56,069
SLE	0.0	0.0%	$ -
R	3286.1	40.2%	$ 402,110
PD	78.4	1.0%	$ 9,600
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2390.1	29.3%	$ 292,467
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 706
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 11,937
Total	8,170.5	100.00%	$ 999,799
NSPL Total Check	8170.5		
RTEP	$ 6,284,636.84		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,424.67		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,922,068.55)	*PJM BLI 1108A, 8/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,385,194.42)	*PJM BLI 1115, 8/2018 PJM Bill*	
Total Cost	$ 999,798.54		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,744		$ 458,179
NBT 2	1,854		$ 226,910
NBT 3	2,566		$ 314,003
NBT 4	6		$ 706
Check	-		$ -
	Revenues		Sales
R	$ 3,906,081		1,238,070,971
RH	$ 580,577		184,209,404
OP	$ -		-
SCI	$ 2,083,112		2,181,146
LCI	$ 2,595,837		2,590,611
SL	$ 10,469		17,917,376
Total	$ 9,176,075		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 9,176,075	$ 8,663,587
Monthly Costs		$ 999,799	$ 999,799
Monthly Over/(Under)		$ 8,176,277	$ 7,663,788
Cum Revenues		$ 240,883,470	$ 229,907,907
Cum Costs		$ 205,188,262	$ 205,188,262
Cum Over/Under		$ 35,695,207	$ 24,719,645
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 3,780,841	$ 9,354,318	GOOD
NBT 2	$ 1,743,920	$ 4,837,275	GOOD
NBT 3	$ 2,129,998	$ 4,739,267	GOOD
NBT 4	$ 9,029	$ (12,106)	GOOD
Total	$ 7,663,788	$ 18,918,753	

Rate Class	October-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1853.2	22.7%	$ 335,332
RH	458.7	5.6%	$ 83,001
SLE	0.0	0.0%	$ -
R	3289.2	40.2%	$ 595,178
PD	78.2	1.0%	$ 14,148
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2390.5	29.2%	$ 432,558
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 1,045
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 17,652
Total	8,173.1	100.00%	$ 1,478,912
NSPL Total Check	8173.1		
RTEP	$ 6,702,929.70		
Expansion Recovery	$ -		
Generation Deactivation	$ 23,167.41		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,884,503.01)	*PJM BLI 1108A, 9/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,362,682.21)	*PJM BLI 1115, 9/2018 PJM Bill*	
Total Cost	$ 1,478,911.89		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,748		$ 678,179
NBT 2	1,853		$ 335,332
NBT 3	2,566		$ 464,357
NBT 4	6		$ 1,045
Check	-		$ -
	Revenues		Sales
R	$ 2,669,917		846,484,441
RH	$ 455,923		144,702,410
OP	$ -		-
SCI	$ 1,818,150		1,866,353
LCI	$ 2,251,076		2,240,870
SL	$ 7,946		14,232,798
Total	$ 7,203,013		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 7,203,013	$ 6,800,258
Monthly Costs		$ 1,478,912	$ 1,478,912
Monthly Over/(Under)		$ 5,724,101	$ 5,321,346
Cum Revenues		$ 248,086,482	$ 236,708,165
Cum Costs		$ 206,667,174	$ 206,667,174
Cum Over/Under		$ 41,419,308	$ 30,040,990
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 2,275,133	$ 11,629,451	GOOD
NBT 2	$ 1,384,818	$ 6,222,093	GOOD
NBT 3	$ 1,655,049	$ 6,394,316	GOOD
NBT 4	$ 6,345	$ (5,761)	GOOD
Total	$ 5,321,346	$ 24,240,098	

Rate Class	November-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1853.8	22.7%	$ 239,051
RH	459.1	5.6%	$ 59,208
SLE	0.0	0.0%	$ -
R	3292.3	40.3%	$ 424,552
PD	78.1	1.0%	$ 10,071
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2390.7	29.2%	$ 308,285
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 744
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 12,579
Total	8,177.4	100.00%	$ 1,054,490
NSPL Total Check	8177.4		
RTEP	$ 6,309,657.39		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,420.08		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,903,512.71)	*PJM BLI 1108A, 10/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,374,074.31)	*PJM BLI 1115, 10/2018 PJM Bill*	
Total Cost	$ 1,054,490.45		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,751		$ 483,760
NBT 2	1,854		$ 239,051
NBT 3	2,566		$ 330,935
NBT 4	6		$ 744
Check	-		$ -
	Revenues		Sales
R	$ 2,281,206		723,657,062
RH	$ 589,381		187,032,572
OP	$ -		-
SCI	$ 1,746,056		1,651,642
LCI	$ 2,189,622		2,175,513
SL	$ 9,389		15,170,848
Total	$ 6,815,654		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 6,815,654	$ 6,434,367
Monthly Costs		$ 1,054,490	$ 1,054,490
Monthly Over/(Under)		$ 5,761,164	$ 5,379,877
Cum Revenues		$ 254,902,137	$ 243,142,532
Cum Costs		$ 207,721,665	$ 207,721,665
Cum Over/Under		$ 47,180,472	$ 35,420,867
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 2,228,387	$ 13,857,838	GOOD
NBT 2	$ 1,412,891	$ 7,634,984	GOOD
NBT 3	$ 1,730,612	$ 8,124,928	GOOD
NBT 4	$ 7,987	$ 2,226	GOOD
Total	$ 5,379,877	$ 29,619,975	

Rate Class	December-18 NSPL AVG MW	Allocation	Allocated Cost
GS	1855.1	22.7%	$ 251,761
RH	460.0	5.6%	$ 62,431
SLE	0.0	0.0%	$ -
R	3294.7	40.3%	$ 447,132
PD	78.0	1.0%	$ 10,592
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2390.1	29.2%	$ 324,365
SLS	0.0	0.0%	$ -
TL	5.8	0.1%	$ 784
AL	0.0	0.0%	$ -
EP	97.6	1.2%	$ 13,239
Total	8,181.3	100.00%	$ 1,110,303
NSPL Total Check	8181.3		
RTEP	$ 6,309,657.39		
Expansion Recovery	$ -		
Generation Deactivation	$ 23,167.41		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,869,081.64)	*PJM BLI 1108A, 11/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,353,440.52)	*PJM BLI 1115, 11/2018 PJM Bill*	
Total Cost	$ 1,110,302.64		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,755		$ 509,563
NBT 2	1,855		$ 251,761
NBT 3	2,566		$ 348,195
NBT 4	6		$ 784
Check	-		$ -
	Revenues		Sales
R	$ 844,916		905,071,168
RH	$ 265,313		311,713,923
OP	$ -		-
SCI	$ 525,066		1,803,223
LCI	$ 1,304,783		2,716,889
SL	$ 7,936		14,483,787
Total	$ 2,948,014		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ 2,948,014	$ 2,659,536
Monthly Costs		$ 1,110,303	$ 1,110,303
Monthly Over/(Under)		$ 1,837,712	$ 1,549,233
Cum Revenues		$ 257,850,151	$ 245,802,068
Cum Costs		$ 208,831,967	$ 208,831,967
Cum Over/Under		$ 49,018,184	$ 36,970,100
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ 490,701	$ 14,348,539	GOOD
NBT 2	$ 223,484	$ 7,858,468	GOOD
NBT 3	$ 828,459	$ 8,953,386	GOOD
NBT 4	$ 6,590	$ 8,815	GOOD
Total	$ 1,549,233	$ 31,169,208	

Rate Class	January-19 NSPL AVG MW	Allocation	Allocated Cost
GS	1965.6	22.8%	$ 205,567
RH	497.6	5.8%	$ 52,042
SLE	0.0	0.0%	$ -
R	3409.2	39.6%	$ 356,543
PD	82.8	1.0%	$ 8,659
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2553.0	29.6%	$ 266,994
SLS	0.0	0.0%	$ -
TL	5.7	0.1%	$ 592
AL	0.0	0.0%	$ -
EP	100.0	1.2%	$ 10,457
Total	8613.9	100.00%	$ 900,856
NSPL Total Check	8613.9		
RTEP	$ 6,084,015.03		
Expansion Recovery	$ -		
Generation Deactivation	$ 22,420.08		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,858,487.46)	*PJM BLI 1108A, 12/2018 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,347,091.66)	*PJM BLI 1115, 12/2018 PJM Bill*	
Total Cost	$ 900,855.99		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,907		$ 408,585
NBT 2	1,966		$ 205,567
NBT 3	2,736		$ 286,111
NBT 4	6		$ 592
Check	-		$ -
	Revenues		Sales
R	$ (1,497,850)		992,367,478
RH	$ (540,914)		359,118,902
OP	$ -		-
SCI	$ (1,213,924)		2,107,561
LCI	$ (831,113)		2,455,299
SL	$ 1,350		14,935,391
Total	$ (4,082,451)		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ (4,082,451)	$ (3,683,814)
Monthly Costs		$ 900,856	$ 900,856
Monthly Over/(Under)		$ (4,983,307)	$ (4,584,670)
Cum Revenues		$ 253,767,700	$ 242,118,254
Cum Costs		$ 209,732,823	$ 209,732,823
Cum Over/Under		$ 44,034,877	$ 32,385,430
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (2,245,416)	$ 12,103,122	GOOD
NBT 2	$ (1,304,307)	$ 6,554,161	GOOD
NBT 3	$ (1,035,609)	$ 7,917,778	GOOD
NBT 4	$ 662	$ 9,477	GOOD
Total	$ (4,584,670)	$ 26,584,538	

Rate Class	February-19 NSPL AVG MW	Allocation	Allocated Cost
GS	1965.9	22.8%	$ 206,297
RH	498.7	5.8%	$ 52,332
SLE	0.0	0.0%	$ -
R	3413.1	39.6%	$ 358,165
PD	82.4	1.0%	$ 8,648
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2553.3	29.6%	$ 267,941
SLS	0.0	0.0%	$ -
TL	5.7	0.1%	$ 595
AL	0.0	0.0%	$ -
EP	100.0	1.2%	$ 10,493
Total	8,619.0	100.00%	$ 904,470
NSPL Total Check	8619.0		
RTEP	$ 6,100,989.51		
Expansion Recovery	$ -		
Generation Deactivation	$ 23,167.41		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,867,308.82)	*PJM BLI 1108A, 1/2019 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,352,378.11)	*PJM BLI 1115, 1/2019 PJM Bill*	
Total Cost	$ 904,469.99		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,912		$ 410,496
NBT 2	1,966		$ 206,297
NBT 3	2,736		$ 287,081
NBT 4	6		$ 595
Check	-		$ -
	Revenues		Sales
R	$ (1,391,342)		923,289,472
RH	$ (589,048)		390,589,855
OP	$ -		-
SCI	$ (1,046,375)		1,775,693
LCI	$ (834,715)		2,302,036
SL	$ 1,551		14,693,317
Total	$ (3,859,929.00)		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ (3,859,929)	$ (3,482,633)
Monthly Costs		$ 904,470	$ 904,470
Monthly Over/(Under)		$ (4,764,399)	$ (4,387,103)
Cum Revenues		$ 249,907,771	$ 238,635,621
Cum Costs		$ 210,637,293	$ 210,637,293
Cum Over/Under		$ 39,270,478	$ 27,998,328
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (2,194,735)	$ 9,908,387	GOOD
NBT 2	$ (1,153,385)	$ 5,400,776	GOOD
NBT 3	$ (1,039,828)	$ 6,877,950	GOOD
NBT 4	$ 846	$ 10,323	GOOD
Total	$ (4,387,103)	$ 22,197,436	

Rate Class	March-19 NSPL AVG MW	Allocation	Allocated Cost
GS	1965.4	22.8%	$ 211,808
RH	499.6	5.8%	$ 53,844
SLE	0.0	0.0%	$ -
R	3415.5	39.6%	$ 368,089
PD	82.2	1.0%	$ 8,859
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2551.5	29.6%	$ 274,981
SLS	0.0	0.0%	$ -
TL	5.7	0.1%	$ 613
AL	0.0	0.0%	$ -
EP	100.0	1.2%	$ 10,776
Total	8,619.9	100.00%	$ 928,970
NSPL Total Check	8619.9		
RTEP	$ 6,084,015.03		
Expansion Recovery	$ -		
Generation Deactivation	$ 20,405.73		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,839,648.62)	*PJM BLI 1108A, 2/2019 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,335,801.95)	*PJM BLI 1115, 2/2019 PJM Bill*	
Total Cost	$ 928,970.19		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,915		$ 421,933
NBT 2	1,965		$ 211,808
NBT 3	2,734		$ 294,615
NBT 4	6		$ 613
Check	-		$ -
	Revenues		Sales
R	$ (1,235,705)		820,612,971
RH	$ (477,044)		316,549,890
OP	$ -		-
SCI	$ (1,149,608)		2,206,236
LCI	$ (986,161)		2,252,714
SL	$ 1,571		14,904,323
Total	$ (3,846,947.00)		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ (3,846,947)	$ (3,471,494)
Monthly Costs		$ 928,970	$ 928,970
Monthly Over/(Under)		$ (4,775,917)	$ (4,400,464)
Cum Revenues		$ 246,060,824	$ 235,164,127
Cum Costs		$ 211,566,264	$ 211,566,264
Cum Over/Under		$ 34,494,560	$ 23,597,864
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (1,965,040)	$ 7,943,347	GOOD
NBT 2	$ (1,252,334)	$ 4,148,442	GOOD
NBT 3	$ (1,183,936)	$ 5,694,014	GOOD
NBT 4	$ 846	$ 11,169	GOOD
Total	$ (4,400,464)	$ 17,796,972	

Rate Class	April-19 NSPL AVG MW	Allocation	Allocated Cost
GS	1966.4	22.8%	$ 215,384
RH	500.9	5.8%	$ 54,868
SLE	0.0	0.0%	$ -
R	3418.1	39.6%	$ 374,394
PD	81.9	0.9%	$ 8,969
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2551.7	29.6%	$ 279,499
SLS	0.0	0.0%	$ -
TL	5.7	0.1%	$ 624
AL	0.0	0.0%	$ -
EP	100.0	1.2%	$ 10,952
Total	8,624.8	100.00%	$ 944,690
NSPL Total Check	8624.8		
RTEP	$ 6,084,015.03		
Expansion Recovery	$ -		
Generation Deactivation	$ 18,430.98		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,828,584.54)	*PJM BLI 1108A, 3/2019 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,329,171.49)	*PJM BLI 1115, 3/2019 PJM Bill*	
Total Cost	$ 944,689.98		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,919		$ 429,262
NBT 2	1,966		$ 215,384
NBT 3	2,734		$ 299,421
NBT 4	6		$ 624
Check	-		$ -
	Revenues		Sales
R	$ (1,024,912)		681,505,214
RH	$ (309,803)		205,919,486
OP	$ -		-
SCI	$ (1,088,149)		2,073,416
LCI	$ (1,039,239)		2,738,028
SL	$ 1,639		15,067,267
Total	$ (3,460,464)		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ (3,460,464)	$ (3,123,078)
Monthly Costs		$ 944,690	$ 944,690
Monthly Over/(Under)		$ (4,405,154)	$ (4,067,768)
Cum Revenues		$ 242,600,360	$ 232,041,050
Cum Costs		$ 212,510,954	$ 212,510,954
Cum Over/Under		$ 30,089,406	$ 19,530,096
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (1,631,778)	$ 6,311,570	GOOD
NBT 2	$ (1,200,282)	$ 2,948,160	GOOD
NBT 3	$ (1,236,607)	$ 4,457,407	GOOD
NBT 4	$ 899	$ 12,068	GOOD
Total	$ (4,067,768)	$ 13,729,204	

Rate Class	May-19 (est) NSPL AVG MW	Allocation	Allocated Cost
GS	1928.7	22.8%	$ 236,946
RH	486.0	5.7%	$ 59,707
SLE	0.0	0.0%	$ -
R	3373.8	39.8%	$ 414,485
PD	80.9	1.0%	$ 9,940
POL	0.0	0.0%	$ -
OP	0.0	0.0%	$ -
HT	2498.4	29.5%	$ 306,935
SLS	0.0	0.0%	$ -
TL	5.7	0.1%	$ 702
AL	0.0	0.0%	$ -
EP	99.2	1.2%	$ 12,184
Total	8,472.7	100.00%	$ 1,040,898
NSPL Total Check			
RTEP	$ 6,162,058.23		
Expansion Recovery	$ -		
Generation Deactivation	$ 21,668.62		
RTEP "Transitional Period" Settlement (FERC #EL05-121-009)	$ (2,819,250.55)	*PJM BLI 1108A, 4/2019 PJM Bill*	
RTEP "Black Box" Settlement (FERC #EL05-121-009)	$ (2,323,577.84)	*PJM BLI 1115, 4/2019 PJM Bill*	
Total Cost	$ 1,040,898.46		
Check	$ -		
NBT Costs	NSPL AVG		
NBT 1	3,860		$ 474,192
NBT 2	1,929		$ 236,946
NBT 3	2,678		$ 329,059
NBT 4	6		$ 702
Check	-		$ -
	Revenues		Sales
R	$ (867,266)		841,083,894
RH	$ (232,766)		295,154,105
OP	$ -		-
SCI	$ (1,046,224)		1,936,295
LCI	$ (1,108,614)		2,440,080
SL	$ 1,735		14,875,822
Total	$ (3,253,135)		
Summary		w/GRT	wo/GRT & Int
Monthly Revenues		$ (3,253,135)	$ (2,936,166)
Monthly Costs		$ 1,040,898	$ 1,040,898
Monthly Over/(Under)		$ (4,294,033)	$ (3,977,064)
Cum Revenues		$ 239,347,225	$ 229,104,884
Cum Costs		$ 213,551,852	$ 213,551,852
Cum Over/Under		$ 25,795,373	$ 15,553,032
Cumulative O/(U) (no interest)	Monthly	Filing Period	Period Check
NBT 1	$ (1,465,269)	$ 4,846,300	GOOD
NBT 2	$ (1,183,897)	$ 1,764,262	GOOD
NBT 3	$ (1,328,808)	$ 3,128,599	GOOD
NBT 4	$ 911	$ 12,979	GOOD
Total	$ (3,977,064)	$ 9,752,140	

PECO - June 2019
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 954,092**	12/15/2018
Jun-18	$ 3,332,286	1,014,619,014	$ 0.00326	$ 3,176,111	3,740	$ -	$ 3,176,111	$ (156,175)	$ (0.00028)	$ (270,601)	$ 2,905,509	$ (426,777)	$ 527,316	
Jul-18	$ 3,331,778	1,397,738,875	$ 0.00326	$ 4,551,707	3,740	$ -	$ 4,551,707	$ 1,219,929	$ (0.00028)	$ (387,801)	$ 4,163,906	$ 832,128	$ 1,359,444	
Aug-18	$ 109,517	1,450,945,593	$ 0.00326	$ 4,726,218	3,742	$ -	$ 4,726,218	$ 4,616,701	$ (0.00028)	$ (402,669)	$ 4,323,549	$ 4,214,032	$ 5,573,477	
Sep-18	$ 458,179	1,422,280,375	$ 0.00326	$ 4,633,816	3,744	$ -	$ 4,633,816	$ 4,175,637	$ (0.00028)	$ (394,796)	$ 4,239,020	$ 3,780,841	$ 9,354,318	
Oct-18	$ 678,179	991,186,851	$ 0.00326	$ 3,228,365	3,748	$ -	$ 3,228,365	$ 2,550,186	$ (0.00028)	$ (275,053)	$ 2,953,312	$ 2,275,133	$ 11,629,451	
Nov-18	$ 483,760	910,689,634	$ 0.00326	$ 2,964,740	3,751	$ -	$ 2,964,740	$ 2,480,980	$ (0.00028)	$ (252,593)	$ 2,712,147	$ 2,228,387	$ 13,857,838	
Dec-18	$ 509,563	1,216,785,091	$ 0.00061	$ (444,104)	3,755	$ -	$ (444,104)	$ (953,667)	$ (0.00197)	$ 1,444,368	$ 1,000,265	$ 490,701	$ 14,348,539	
Jan-19	$ 408,585	1,351,486,380	$ 0.00061	$ 815,528	3,907	$ -	$ 815,528	$ 406,942	$ (0.00197)	$ (2,652,359)	$ (1,836,831)	$ (2,245,416)	$ 12,103,122	
Feb-19	$ 410,496	1,313,879,327	$ 0.00061	$ 792,177	3,912	$ -	$ 792,177	$ 381,681	$ (0.00197)	$ (2,576,416)	$ (1,784,239)	$ (2,194,735)	$ 9,908,387	
Mar-19	$ 421,933	1,137,162,861	$ 0.00061	$ 685,118	3,915	$ -	$ 685,118	$ 263,185	$ (0.00197)	$ (2,228,225)	$ (1,543,107)	$ (1,965,040)	$ 7,943,347	
Apr-19	$ 429,262	887,424,700	$ 0.00061	$ 533,900	3,919	$ -	$ 533,900	$ 104,638	$ (0.00197)	$ (1,736,416)	$ (1,202,516)	$ (1,631,778)	$ 6,311,570	
May-19 (est)	$ 474,192	1,136,237,999	$ 0.00061	$ 440,025	3,860	$ -	$ 440,025	$ (34,167)	$ (0.00197)	$ (1,431,102)	$ (991,077)	$ (1,465,269)	$ 4,846,300	
												Total Recovery E-Factor	**$ 4,846,300**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 1: Rates R, RH

E-Factor Period	Actual NBT Costs [(a)] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [(b)] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [(b)] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 954,092**	12/15/2018
Jun-18	$ 3,332,286	1,014,619,014	$ 0.00326	$ 3,176,111	3,740	$ -	$ 3,176,111	$ (156,175)	$ (0.00028)	$ (270,601)	$ 2,905,509	$ (426,777)	$ 527,316	
Jul-18	$ 3,331,778	1,397,738,875	$ 0.00326	$ 4,551,707	3,740	$ -	$ 4,551,707	$ 1,219,929	$ (0.00028)	$ (387,801)	$ 4,163,906	$ 832,128	$ 1,359,444	
Aug-18	$ 109,517	1,450,945,593	$ 0.00326	$ 4,726,218	3,742	$ -	$ 4,726,218	$ 4,616,701	$ (0.00028)	$ (402,669)	$ 4,323,549	$ 4,214,032	$ 5,573,477	
Sep-18	$ 458,179	1,422,280,375	$ 0.00326	$ 4,633,816	3,744	$ -	$ 4,633,816	$ 4,175,637	$ (0.00028)	$ (394,796)	$ 4,239,020	$ 3,780,841	$ 9,354,318	
Oct-18	$ 678,179	991,186,851	$ 0.00326	$ 3,228,365	3,748	$ -	$ 3,228,365	$ 2,550,186	$ (0.00028)	$ (275,053)	$ 2,953,312	$ 2,275,133	$ 11,629,451	
Nov-18	$ 483,760	910,689,634	$ 0.00326	$ 2,964,740	3,751	$ -	$ 2,964,740	$ 2,480,980	$ (0.00028)	$ (252,593)	$ 2,712,147	$ 2,228,387	$ 13,857,838	
Dec-18	$ 509,563	1,216,785,091	$ 0.00061	$ (444,104)	3,755	$ -	$ (444,104)	$ (953,667)	$ (0.00197)	$ 1,444,368	$ 1,000,265	$ 490,701	$ 14,348,539	
Jan-19	$ 408,585	1,351,486,380	$ 0.00061	$ 815,528	3,907	$ -	$ 815,528	$ 406,942	$ (0.00197)	$ (2,652,359)	$ (1,836,831)	$ (2,245,416)	$ 12,103,122	
Feb-19	$ 413,054	1,313,879,327	$ 0.00061	$ 792,177	3,912	$ -	$ 792,177	$ 379,123	$ (0.00197)	$ (2,576,416)	$ (1,784,239)	$ (2,197,293)	$ 9,905,829	
Mar-19	$ 423,640	1,137,162,861	$ 0.00061	$ 685,118	3,915	$ -	$ 685,118	$ 261,478	$ (0.00197)	$ (2,228,225)	$ (1,543,107)	$ (1,966,747)	$ 7,939,083	
Apr-19	$ 430,628	887,424,700	$ 0.00061	$ 533,900	3,919	$ -	$ 533,900	$ 103,273	$ (0.00197)	$ (1,736,416)	$ (1,202,516)	$ (1,633,144)	$ 6,305,939	
May-19 (est)	$ 476,480	1,136,237,999	$ 0.00061	$ 440,025	3,860	$ -	$ 440,025	$ (36,455)	$ (0.00197)	$ (1,431,102)	$ (991,077)	$ (1,467,557)	$ 4,838,382	
												Total Recovery E-Factor	**$ 4,838,382**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 1,225,734**	12/15/2018
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$ 1,416,715	$ (237,903)	$ 987,831	
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$ 1,916,113	$ 262,589	$ 1,250,420	
Aug-18	$ 54,280	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 2,105,818	$ (0.11)	$ (262,883)	$ 1,897,215	$ 1,842,935	$ 3,093,354	
Sep-18	$ 226,910	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 2,017,004	$ (0.11)	$ (273,083)	$ 1,970,830	$ 1,743,920	$ 4,837,275	
Oct-18	$ 335,332	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 1,623,167	$ (0.11)	$ (238,348)	$ 1,720,150	$ 1,384,818	$ 6,222,093	
Nov-18	$ 239,051	1,651,642	$ 0.91	$ 1,880,839	1,854	$ -	$ 1,880,839	$ 1,641,788	$ (0.11)	$ (228,897)	$ 1,651,942	$ 1,412,891	$ 7,634,984	
Dec-18	$ 251,761	1,803,223	$ 0.18	$ (177,067)	1,855	$ -	$ (177,067)	$ (428,827)	$ (0.66)	$ 652,311	$ 475,244	$ 223,484	$ 7,858,468	
Jan-19	$ 205,567	2,107,561	$ 0.18	$ 409,369	1,966	$ -	$ 409,369	$ 203,802	$ (0.66)	$ (1,508,108)	$ (1,098,739)	$ (1,304,307)	$ 6,554,161	
Feb-19	$ 206,297	1,775,693	$ 0.18	$ 352,867	1,966	$ -	$ 352,867	$ 146,570	$ (0.66)	$ (1,299,955)	$ (947,088)	$ (1,153,385)	$ 5,400,776	
Mar-19	$ 211,808	2,206,236	$ 0.18	$ 387,680	1,965	$ -	$ 387,680	$ 175,872	$ (0.66)	$ (1,428,206)	$ (1,040,526)	$ (1,252,334)	$ 4,148,442	
Apr-19	$ 215,384	2,073,416	$ 0.18	$ 366,954	1,966	$ -	$ 366,954	$ 151,571	$ (0.66)	$ (1,351,853)	$ (984,898)	$ (1,200,282)	$ 2,948,160	
May-19 (est)	$ 236,946	1,936,295	$ 0.18	$ 352,816	1,929	$ -	$ 352,816	$ 115,870	$ (0.66)	$ (1,299,768)	$ (946,952)	$ (1,183,897)	$ 1,764,262	
												Total Recovery E-Factor	**$ 1,764,262**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.

(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 2: Rate GS

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 1,225,734**	12/15/2018
Jun-18	$ 1,654,618	1,986,924	$ 0.91	$ 1,613,018	1,857	$ -	$ 1,613,018	$ (41,600)	$ (0.11)	$ (196,304)	$ 1,416,715	$ (237,903)	$ 987,831	
Jul-18	$ 1,653,524	2,050,527	$ 0.91	$ 2,181,615	1,856	$ -	$ 2,181,615	$ 528,090	$ (0.11)	$ (265,502)	$ 1,916,113	$ 262,589	$ 1,250,420	
Aug-18	$ 54,280	2,089,410	$ 0.91	$ 2,160,098	1,854	$ -	$ 2,160,098	$ 2,105,818	$ (0.11)	$ (262,883)	$ 1,897,215	$ 1,842,935	$ 3,093,354	
Sep-18	$ 226,910	2,181,146	$ 0.91	$ 2,243,914	1,854	$ -	$ 2,243,914	$ 2,017,004	$ (0.11)	$ (273,083)	$ 1,970,830	$ 1,743,920	$ 4,837,275	
Oct-18	$ 335,332	1,866,353	$ 0.91	$ 1,958,498	1,853	$ -	$ 1,958,498	$ 1,623,167	$ (0.11)	$ (238,348)	$ 1,720,150	$ 1,384,818	$ 6,222,093	
Nov-18	$ 239,051	1,651,642	$ 0.91	$ 1,880,839	1,854	$ -	$ 1,880,839	$ 1,641,788	$ (0.11)	$ (228,897)	$ 1,651,942	$ 1,412,891	$ 7,634,984	
Dec-18	$ 251,761	1,803,223	$ 0.18	$ (177,067)	1,855	$ -	$ (177,067)	$ (428,827)	$ (0.66)	$ 652,311	$ 475,244	$ 223,484	$ 7,858,468	
Jan-19	$ 205,567	2,107,561	$ 0.18	$ 409,369	1,966	$ -	$ 409,369	$ 203,802	$ (0.66)	$ (1,508,108)	$ (1,098,739)	$ (1,304,307)	$ 6,554,161	
Feb-19	$ 207,583	1,775,693	$ 0.18	$ 352,867	1,966	$ -	$ 352,867	$ 145,284	$ (0.66)	$ (1,299,955)	$ (947,088)	$ (1,154,671)	$ 5,399,491	
Mar-19	$ 212,665	2,206,236	$ 0.18	$ 387,680	1,965	$ -	$ 387,680	$ 175,015	$ (0.66)	$ (1,428,206)	$ (1,040,526)	$ (1,253,191)	$ 4,146,300	
Apr-19	$ 216,069	2,073,416	$ 0.18	$ 366,954	1,966	$ -	$ 366,954	$ 150,885	$ (0.66)	$ (1,351,853)	$ (984,898)	$ (1,200,967)	$ 2,945,332	
May-19 (est)	$ 238,089	1,936,295	$ 0.18	$ 352,816	1,929	$ -	$ 352,816	$ 114,727	$ (0.66)	$ (1,299,768)	$ (946,952)	$ (1,185,041)	$ 1,760,292	
												Total Recovery E-Factor	**$ 1,760,292**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.

(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													$ 436,434	12/15/2018
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2,562	$ -	$ 2,019,542	$ (262,830)	$ (0.02)	$ (43,665)	$ 1,975,876	$ (306,495)	$ 129,940	
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0.02)	$ (52,784)	$ 2,388,497	$ 105,815	$ 235,755	
Aug-18	$ 75,052	2,593,177	$ 0.96	$ 2,502,678	2,564	$ -	$ 2,502,678	$ 2,427,625	$ (0.02)	$ (54,111)	$ 2,448,566	$ 2,373,514	$ 2,609,269	
Sep-18	$ 314,003	2,590,611	$ 0.96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 2,184,008	$ (0.02)	$ (54,010)	$ 2,444,001	$ 2,129,998	$ 4,739,267	
Oct-18	$ 464,357	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 1,701,886	$ (0.02)	$ (46,837)	$ 2,119,406	$ 1,655,049	$ 6,394,316	
Nov-18	$ 330,935	2,175,513	$ 0.96	$ 2,107,105	2,566	$ -	$ 2,107,105	$ 1,776,170	$ (0.02)	$ (45,558)	$ 2,061,547	$ 1,730,612	$ 8,124,928	
Dec-18	$ 348,195	2,716,889	$ 0.19	$ (650,390)	2,566	$ -	$ (650,390)	$ (998,585)	$ (0.53)	$ 1,827,044	$ 1,176,654	$ 828,459	$ 8,953,386	
Jan-19	$ 286,111	2,455,299	$ 0.19	$ 414,282	2,736	$ -	$ 414,282	$ 128,171	$ (0.53)	$ (1,163,780)	$ (749,498)	$ (1,035,609)	$ 7,917,778	
Feb-19	$ 287,081	2,302,036	$ 0.19	$ 416,077	2,736	$ -	$ 416,077	$ 128,996	$ (0.53)	$ (1,168,824)	$ (752,746)	$ (1,039,828)	$ 6,877,950	
Mar-19	$ 294,615	2,252,714	$ 0.19	$ 491,568	2,734	$ -	$ 491,568	$ 196,952	$ (0.53)	$ (1,380,888)	$ (889,321)	$ (1,183,936)	$ 5,694,014	
Apr-19	$ 299,421	2,738,028	$ 0.19	$ 518,025	2,734	$ -	$ 518,025	$ 218,605	$ (0.53)	$ (1,455,212)	$ (937,186)	$ (1,236,607)	$ 4,457,407	
May-19 (est)	$ 329,059	2,440,080	$ 0.19	$ 552,607	2,678	$ -	$ 552,607	$ 223,548	$ (0.53)	$ (1,552,356)	$ (999,749)	$ (1,328,808)	$ 3,128,599	
												Total Recovery E-Factor	**$ 3,128,599**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 3: Rates PD, HT, EP

E-Factor Period	Actual NBT Costs [(a)] (1)	Actual Sales (kW) (2)	C-Factor Rate (3)	C-Factor Revenue [(b)] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [(b)] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ 436,434**	12/15/2018
Jun-18	$ 2,282,371	2,185,507	$ 0.96	$ 2,019,542	2,562	$ -	$ 2,019,542	$ (262,830)	$ (0.02)	$ (43,665)	$ 1,975,876	$ (306,495)	$ 129,940	
Jul-18	$ 2,282,682	2,482,563	$ 0.96	$ 2,441,281	2,562	$ -	$ 2,441,281	$ 158,599	$ (0.02)	$ (52,784)	$ 2,388,497	$ 105,815	$ 235,755	
Aug-18	$ 75,052	2,593,177	$ 0.96	$ 2,502,678	2,564	$ -	$ 2,502,678	$ 2,427,625	$ (0.02)	$ (54,111)	$ 2,448,566	$ 2,373,514	$ 2,609,269	
Sep-18	$ 314,003	2,590,611	$ 0.96	$ 2,498,012	2,566	$ -	$ 2,498,012	$ 2,184,008	$ (0.02)	$ (54,010)	$ 2,444,001	$ 2,129,998	$ 4,739,267	
Oct-18	$ 464,357	2,240,870	$ 0.96	$ 2,166,243	2,566	$ -	$ 2,166,243	$ 1,701,886	$ (0.02)	$ (46,837)	$ 2,119,406	$ 1,655,049	$ 6,394,316	
Nov-18	$ 330,935	2,175,513	$ 0.96	$ 2,107,105	2,566	$ -	$ 2,107,105	$ 1,776,170	$ (0.02)	$ (45,558)	$ 2,061,547	$ 1,730,612	$ 8,124,928	
Dec-18	$ 348,195	2,716,889	$ 0.19	$ (650,390)	2,566	$ -	$ (650,390)	$ (998,585)	$ (0.53)	$ 1,827,044	$ 1,176,654	$ 828,459	$ 8,953,386	
Jan-19	$ 286,111	2,455,299	$ 0.19	$ 414,282	2,736	$ -	$ 414,282	$ 128,171	$ (0.53)	$ (1,163,780)	$ (749,498)	$ (1,035,609)	$ 7,917,778	
Feb-19	$ 288,870	2,302,036	$ 0.19	$ 416,077	2,736	$ -	$ 416,077	$ 127,207	$ (0.53)	$ (1,168,824)	$ (752,746)	$ (1,041,617)	$ 6,876,161	
Mar-19	$ 295,807	2,252,714	$ 0.19	$ 491,568	2,734	$ -	$ 491,568	$ 195,761	$ (0.53)	$ (1,380,888)	$ (889,321)	$ (1,185,128)	$ 5,691,033	
Apr-19	$ 300,373	2,738,028	$ 0.19	$ 518,025	2,734	$ -	$ 518,025	$ 217,652	$ (0.53)	$ (1,455,212)	$ (937,186)	$ (1,237,560)	$ 4,453,473	
May-19 (est)	$ 330,646	2,440,080	$ 0.19	$ 552,607	2,678	$ -	$ 552,607	$ 221,960	$ (0.53)	$ (1,552,356)	$ (999,749)	$ (1,330,395)	$ 3,123,078	
												Total Recovery E-Factor	**$ 3,123,078**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

E-Factor Period	Actual NBT Costs [a] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [b] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [b] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ (26,964)**	12/15/2018
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$ (675)	$ (5,817)	$ (32,781)	
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5,030	$ (113)	$ 0.00026	$ 3,744	$ 8,774	$ 3,630	$ (29,151)	
Aug-18	$ 169	13,523,553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 4,523	$ 0.00026	$ 3,492	$ 8,185	$ 8,016	$ (21,135)	
Sep-18	$ 706	17,917,376	$ 0.00035	$ 5,581	6	$ -	$ 5,581	$ 4,875	$ 0.00026	$ 4,154	$ 9,735	$ 9,029	$ (12,106)	
Oct-18	$ 1,045	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ 3,192	$ 0.00026	$ 3,153	$ 7,390	$ 6,345	$ (5,761)	
Nov-18	$ 744	15,170,848	$ 0.00035	$ 5,006	6	$ -	$ 5,006	$ 4,261	$ 0.00026	$ 3,726	$ 8,731	$ 7,987	$ 2,226	
Dec-18	$ 784	14,483,787	$ 0.00007	$ 5,727	6	$ -	$ 5,727	$ 4,944	$ 0.00002	$ 1,646	$ 7,373	$ 6,590	$ 8,815	
Jan-19	$ 592	14,935,391	$ 0.00007	$ 974	6	$ -	$ 974	$ 382	$ 0.00002	$ 280	$ 1,254	$ 662	$ 9,477	
Feb-19	$ 595	14,693,317	$ 0.00007	$ 1,119	6	$ -	$ 1,119	$ 524	$ 0.00002	$ 322	$ 1,441	$ 846	$ 10,323	
Mar-19	$ 613	14,904,323	$ 0.00007	$ 1,134	6	$ -	$ 1,134	$ 520	$ 0.00002	$ 326	$ 1,460	$ 846	$ 11,169	
Apr-19	$ 624	15,067,267	$ 0.00007	$ 1,183	6	$ -	$ 1,183	$ 559	$ 0.00002	$ 340	$ 1,523	$ 899	$ 12,068	
May-19 (est)	$ 702	14,875,822	$ 0.00007	$ 1,252	6	$ -	$ 1,252	$ 551	$ 0.00002	$ 360	$ 1,612	$ 911	$ 12,979	
												Total Recovery E-Factor	**$ 12,979**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

PECO - June 2019
NBT
E-Factor Calculation

NBT 4: Rates SLE, SLS, SLC*, POL, AL, TLCL

**Rate SLC will be effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164.*

E-Factor Period	Actual NBT Costs [(a)] (1)	Actual Sales (kWh) (2)	C-Factor Rate (3)	C-Factor Revenue [(b)] (4)	NSPL AVE MW (5)	Working Capital $0.00 per MW/mo (6) = (5) * $0	Adjusted C-Factor Revenue (7) = (4) - (6)	C-Factor Over/(Under) Recovery (8) = (7) - (1)	E-Factor Rate (9)	E-Factor Revenue [(b)] (10)	Total Collected Revenue (11) = (10) + (7)	Over/(Under) Recovery (12) = (11) - (1)	Cumulative Over/(Under) Recovery (13)	*Starting Balance (Last Updated)*
Balance													**$ (26,964)**	12/15/2018
Jun-18	$ 5,142	15,798,654	$ 0.00035	$ (387)	6	$ -	$ (387)	$ (5,529)	$ 0.00026	$ (288)	$ (675)	$ (5,817)	$ (32,781)	
Jul-18	$ 5,143	16,216,415	$ 0.00035	$ 5,030	6	$ -	$ 5,030	$ (113)	$ 0.00026	$ 3,744	$ 8,774	$ 3,630	$ (29,151)	
Aug-18	$ 169	13,523,553	$ 0.00035	$ 4,692	6	$ -	$ 4,692	$ 4,523	$ 0.00026	$ 3,492	$ 8,185	$ 8,016	$ (21,135)	
Sep-18	$ 706	17,917,376	$ 0.00035	$ 5,581	6	$ -	$ 5,581	$ 4,875	$ 0.00026	$ 4,154	$ 9,735	$ 9,029	$ (12,106)	
Oct-18	$ 1,045	14,232,798	$ 0.00035	$ 4,237	6	$ -	$ 4,237	$ 3,192	$ 0.00026	$ 3,153	$ 7,390	$ 6,345	$ (5,761)	
Nov-18	$ 744	15,170,848	$ 0.00035	$ 5,006	6	$ -	$ 5,006	$ 4,261	$ 0.00026	$ 3,726	$ 8,731	$ 7,987	$ 2,226	
Dec-18	$ 784	14,483,787	$ 0.00007	$ 5,727	6	$ -	$ 5,727	$ 4,944	$ 0.00002	$ 1,646	$ 7,373	$ 6,590	$ 8,815	
Jan-19	$ 592	14,935,391	$ 0.00007	$ 974	6	$ -	$ 974	$ 382	$ 0.00002	$ 280	$ 1,254	$ 662	$ 9,477	
Feb-19	$ 599	14,693,317	$ 0.00007	$ 1,119	6	$ -	$ 1,119	$ 520	$ 0.00002	$ 322	$ 1,441	$ 842	$ 10,319	
Mar-19	$ 616	14,904,323	$ 0.00007	$ 1,134	6	$ -	$ 1,134	$ 518	$ 0.00002	$ 326	$ 1,460	$ 844	$ 11,163	
Apr-19	$ 626	15,067,267	$ 0.00007	$ 1,183	6	$ -	$ 1,183	$ 557	$ 0.00002	$ 340	$ 1,523	$ 897	$ 12,060	
May-19 (est)	$ 705	14,875,822	$ 0.00007	$ 1,252	6	$ -	$ 1,252	$ 547	$ 0.00002	$ 360	$ 1,612	$ 907	$ 12,967	
												Total Recovery E-Factor	**$ 12,967**	

(a) Actual NBT Costs account for RTEP refunds per FERC # EL05-121-009 Settlement, beginning with PJM billing in August 2018.
(b) C Factor and E Factor Revenues are allocated on a percentage basis.

Non-Bypassable Transmission		Forecasted: Jun 19-$	Forecasted: Jul 19-$	Forecasted: Aug 19-$	Forecasted: Sep 19-$	Forecasted: Oct 19-$	Forecasted: Nov 19-$	Forecasted: Total	6 mo Average
Transm Enhancement (non-PECO zone RTEP)		$ 4,089,361	$ 4,089,361	$ 4,089,361	$ 4,089,361	$ 4,089,361	$ 4,089,361	$ 24,536,164	$ 4,089,361
Transm Enhancement (PECO zone RTEP)		$ 1,962,281	$ 1,962,281	$ 1,962,281	$ 1,962,281	$ 1,962,281	$ 1,962,281	$ 11,773,687	$ 1,962,281
RTEP "Transitional Period" Settlement (EL05-121-009)		$ (2,807,610)	$ -	$ -	$ -	$ -	$ -	$ (2,807,610)	$ (467,935)
RTEP "Black Box" Settlement (EL05-121-009)		$ (2,316,602)	$ (2,311,370)	$ (2,302,650)	$ (2,302,650)	$ (2,302,650)	$ (2,302,650)	$ (13,838,570)	$ (2,306,428)
PECO 2007-2010 RTEP "Black Box" Credit Retention (EL05-121-009)	$ 5,500,000	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 458,333	$ 2,750,000	$ 458,333
Expansion Recovery Cost (Schedule 13) Payments ended in 2015.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Deactivation		$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 126,000	$ 21,000
Total Cost		**$ 1,406,764**	**$ 4,219,605**	**$ 4,228,325**	**$ 4,228,325**	**$ 4,228,325**	**$ 4,228,325**	**$ 22,539,671**	$ 3,756,612
NBT Costs									
NBT 1	45.49%	$ 640,002	$ 1,919,695	$ 1,923,662	$ 1,923,662	$ 1,923,662	$ 1,923,662	$ 10,254,345	$ 1,709,058
NBT 2	22.78%	$ 320,483	$ 961,292	$ 963,279	$ 963,279	$ 963,279	$ 963,279	$ 5,134,891	$ 855,815
NBT 3	31.66%	$ 445,339	$ 1,335,800	$ 1,338,560	$ 1,338,560	$ 1,338,560	$ 1,338,560	$ 7,135,380	$ 1,189,230
NBT 4	0.07%	$ 940	$ 2,819	$ 2,824	$ 2,824	$ 2,824	$ 2,824	$ 15,055	$ 2,509
	100%								

NSPL Allocation supporting NBT Costs	
Actuals from 12/2017 Forward	**NSPL Total**
- NBT 1	19,407
- NBT 2	9,718
- NBT 3	13,505
- NBT 4	28
Total	42,659
- NBT 1 Share of Total	45.49%
- NBT 2 Share of Total	22.78%
- NBT 3 Share of Total	31.66%
- NBT 4 Share of Total	0.07%

Source for Projected Monthly Expense Outside PECO Zone:
PJM Transmission Cost Information Calculator as of 5/1/2019
http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

Projected Annual Expense to be recovered from PECO customers for PECO TO: **$23,547,374**

Generation Deactivation:
PECO assumes PJM will continue collecting for Dominion Generation resources Yorktown 1 and Yorktown 2 thru this period.

FERC # EL05-121-009 Settlement *(relates to FERC Order 494)*
Based on new PJM cost allocation method for RTEP facilities >=500kV and PJM recast of prior RTEP periods back to 2007
PECO expects "Transitional" refunds thru 6/30/2018 and "Black Box" refunds through 12/31/2025.
PECO is retaining $5.5M of the "Black Box" refund over twelve months, from 12/2018 through 11/2019.

PECO ENERGY COMPANY
STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE

v.

PECO ENERGY COMPANY

DOCKET NOS. M-2018-3005860
C-2018-3006242

REBUTTAL TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: CALCULATION OF PECO ENERGY COMPANY'S NON-BYPASSABLE TRANSMISSION CHARGE RATES EFFECTIVE AS OF DECEMBER 1, 2018 AND JUNE 1, 2019

DATED: OCTOBER 4, 2019

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REBUTTAL TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your 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 marked as PECO Statement No. 1 and accompanying PECO Exhibit Nos. JAB-1 through JAB-10. 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 the direct testimony of the Office of Consumer Advocate's ("OCA") witness Karl Richard Pavlovic, Ph.D. My testimony is divided into two parts.

First, I will address Dr. Pavlovic's testimony that "PECO should retain no [Regional Transmission Expansion Plan (RTEP)] credits" because "PECO has provided no support for its claim that it did not otherwise recover PECO zone RTEP charges through its transmission rate during the period June 2007 through December 2010."[1] Specifically, I will address Dr. Pavlovic's statements regarding Account 561.8 of the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts[2] and his contention that "transmission revenues" generated by PECO's "transmission rates"[3] recovered all of the costs recorded in that account, including PECO zone RTEP charges,.[4] I will identify the errors in Dr. Pavlovic's testimony and explain why the "transmission revenues" and "transmission rates" he relies upon are not relevant and do not support requiring PECO to refund $5.5 million of pre-2011 bill credits it received under the settlement approved by the FERC at Docket No. EL05-121-009 ("Settlement").

Second, I will respond to Dr. Pavlovic's contention that PECO's calculation of the portion of the total PJM net bill credit adjustments relating to pre-2011 transmission charges is a "highly speculative estimate."[5] As discussed in my

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1 Direct Testimony of Karl Richard Pavlovic on behalf of the Office of Consumer Advocate (August 5, 2019), identified as OCA Statement No. 1 (hereafter, "OCA St. No. 1"), p. 3, lines 14-15 ("PECO has not demonstrated that it was unable to recover any portion of its PECO zone RTEP charges during the period June 2007 through December 2010") and lines 19-20 ("Therefore, PECO should retain no PECO zone RTEP credits for the period June 2007 through December 2010") and p. 8, line 16 – p. 9, line 2 ("I conclude that PECO has provided no support for its claim that it did not otherwise recover PECO zone RTEP charges through its transmission rate during the June 2007 through December 2010 period. I further conclude that PECO should retain no RTEP credits for that period.").

2 OCA St. No. 1, p. 6, lines 2-6 ("As a matter of the cost-based ratemaking principles underlying PECO's FERC approved transmission rates, it is not correct. PECO records its PECO zone RTEP charges to FERC Account 561.8. Account 561.8 is functionalized in the FERC Uniform System of Accounts as a transmission operating expense. This means that PECO's transmission rate included a provision for RTEP charges as transmission operating expenses.").

3 *Id.*, p. 6, line 18 – p. 8, line 13.

4 *Id.*, p. 8, line 16 – p. 9, line 2 (quoted in footnote 1, *supra*).

5 *Id.*, p. 3, lines 16-18 ("PECO's calculation of the PECO Zone RTEP credits that PECO seeks to retain is a highly speculative estimate that is not based in any way on PECO's billed RTEP charges during the period June 2007 through December 2010.") and p. 12, lines 3-8 ("The $5,560,416 that PECO seeks to retain is a highly speculative estimated number that is not based on and supported by the RTEP charges actually billed to and paid by PECO as the default service provider in the PECO zone during the June 2007 through December 2010 period.").

Direct Testimony, PECO used time-segmented "black box" RTEP reallocation amounts for the PECO Zone provided by PJM during the negotiations leading to the Settlement[6], and PECO's calculations are reasonable.

II. DR. PAVLOVIC'S STATEMENTS REGARDING ACCOUNT 561.8 AND "TRANSMISSION REVENUES" GENERATED BY PECO'S "TRANSMISSION RATES" DO NOT PROVIDE A VALID BASIS FOR REQUIRING PECO TO REFUND TO RETAIL CUSTOMERS PJM BILL CREDITS FOR PRE-2011 RTEP CHARGES

4. Q. Mr. Bisti, Dr. Pavlovic summarizes a portion of your Direct Testimony, stating that "from January 2011 through December 2015 the PECO zone RTEP charges billed to PECO were recovered from retail customers, first, through PECO's separate tariffed Transmission Service Charge and later through its tariffed Nonbypassable Transmission Charge."[7] Is Dr. Pavlovic's summary accurate?

A. Dr. Pavlovic's statement is accurate but leaves out an important fact. Both PECO's Transmission Service Charge ("TSC"), which did not become effective until January 1, 2011, and its Non-Bypassable Transmission Charge ("NBT"), which went into effect as of June 1, 2015, are fully reconcilable adjustment clauses established under Section 1307 of the Public Utility Code ("Code"). As such, PECO recovers qualifying transmission costs under those clauses on a dollar-for-dollar basis. Costs and revenues are reconciled, and

[6] PECO St. No. 1, p. 14, lines 6-9 ("The Company used time-segmented "black box" RTEP reallocation amounts for the PECO Zone provided by PJM during the settlement negotiations at FERC Docket No. EL05-121-009 to determine the portion of RTEP charges paid by PECO during the historical period.").

[7] OCA St. 1, p. 5, lines 7-10.

over or under-recoveries are refunded or recouped, respectively, so that PECO recovers its actual cost to obtain transmission service, neither more nor less.

5. Q. How did PECO recover its cost to obtain transmission service on behalf of retail customers before the TSC was implemented?

A. On January 1, 1999, PECO's retail rates were functionally "unbundled" into distribution, transmission and generation components pursuant to its Commission-approved Restructuring Plan. Beginning on that date, PECO had the obligation to offer and furnish "Provider Of Last Resort" ("POLR") generation service, as required by Section 2807(e)(1) of the Code,[8] to customers that did not, or could not, shop with an electric generation supplier. In addition, PECO had to obtain and furnish transmission service to deliver the energy it supplied to PECO's PJM zone, where that energy could then be distributed by PECO to POLR customers' premises. Because PECO's retail rates had been unbundled, the cost of providing POLR service included two components: a generation price, which remained capped until January 1, 2011, and a transmission component, to recover the cost of bringing that generation into the PECO zone.[9] PECO's "price to compare" ("PTC") for

[8] After PECO's generation rate caps expired on January 1, 2011, PECO began to furnish "default service" to non-shopping customers under a "commission-approved competitive procurement plan" pursuant to Section 2807(e)(3.1) of the Code and the Commission's regulations on default service (52 Pa. Code §§ 54.181 – 54.189) instead of POLR service at the capped generation price established by its Restructuring Plan. PECO's TSC was implemented at the same time PECO began to provide default service under its first Commission-approved default service program at generation prices that were no longer subject to the generation rate cap (PECO St. No. 1, p. 7, line 10 – p. 8, line 12).

[9] The statutory caps on PECO's transmission and distribution rates that had initially been extended pursuant to its Restructuring Plan and further extended in the PECO/Unicom merger settlement expired on December 31, 2006. *See Application of PECO Energy Co. for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code et al.*, Docket Nos. R-00973953 and P-00971265 (Opinion and Order entered May 14, 1998), pp. 3-4, 8; *Application of PECO Energy Co. Pursuant to Chapters 11, 19, 21, 22 and 28 of the Pub. Util.*

POLR service was the sum of these two components.[10] As I explained in my Direct Testimony,[11] until PECO's fully-reconcilable TSC was implemented on January 1, 2011, PECO recovered the cost of obtaining transmission service for POLR customers through the transmission component of its retail base rates in the PTC charged to POLR customers. However, as explained in more detail below, the transmission component of PECO's retail rates did not include the PJM charges at issue in this proceeding. Indeed, during the period 2007-2010, the at-issue PJM charges were not included for recovery in *any* rate charged to *any* person or entity.

6. Q. Is PECO refunding to retail customers the PJM bill credits for RTEP charges billed after PECO implemented its TSC on January 1, 2011?

A. Yes. PECO is refunding all post-2010 PJM bill credits through its NBT rates (approximately, $77.5 million), as I explained in my Direct Testimony.[12]

Code for Approval of (1) a Plan of Corporate Restructuring, Including the Creation of a Holding Company and (2) the Merger of the Newly Formed Holding Company and Unicom Corp., Docket No. A-00110550F0147 (Opinion and Order entered June 22, 2000), pp. 8, 26.

10 What is now known as the PTC for default service was referred to at the time of restructuring as a "shopping credit" for POLR service.

11 PECO St. No. 1, p. 7, lines 10-17 ("PECO's base rates in effect at the time PJM initiated RTEP charges were established in PECO's 1989 base rate case and were subsequently unbundled effective January 1, 1999, in conjunction with PECO's Commission-approved Restructuring Plan. The 1989 base rates did not provide for the recovery of any RTEP charges because PECO was not yet incurring those charges. PECO therefore absorbed all RTEP charges without recovering those costs from customers while the 1989 base rates were effective.").

12 *Id.*, pp. 15-19.

7. Q. **Why is it appropriate to refund *post*-2010 PJM bill credits to retail customers?**

A. As I noted above, after January 1, 2011, PECO implemented a TSC (and as of June 1, 2015, an NBT). The terms of those adjustment clauses provide for full reconciliation of the revenues those clauses recover to the costs PECO actually incurs to obtain transmission service for retail customers.[13] Therefore, increases in qualifying transmission costs above the level used to establish the TSC (from January 1, 2011 to May 31, 2015) and the NBT (from and after June 1, 2015) are included in the "E" factor of the clause formula and recovered from retail customers following the end of each rate adjustment period, when a reconciliation is calculated. In the same way, if qualifying transmission costs fall below the level used to set PECO's TSC or NBT rate, the over-recovery is reflected in a subsequent calculation to reduce charges to customers in order to match revenues recovered with costs actually incurred.

[13] Under the TSC, PECO recovered the cost of obtaining transmission service to deliver generation to its zone to supply default service customers. After June 1, 2015, with the Commission's approval, PECO began to obtain transmission service for *both* default service customers and "shopping" customers and, therefore, also began to recover the cost of obtaining that transmission service from *all* of its retail customers under the NBT charge. PECO St. No. 1, p. 9, lines 3-16.

8. Q. Was the transmission component of the rate for POLR service that PECO charged prior to January 1, 2011 subject to reconciliation like the TSC and NBT?

A. No, it was not. The transmission component of PECO's retail base rates was not subject to reconciliation, nor was it subject to refund or recoupment like the TSC and NBT.

9. Q. Dr. Pavlovic contends that the way RTEP charges were recorded by PECO for accounting purposes is relevant to how PECO may have recovered those costs before January 1, 2011.[14] What does he offer as the basis for his position?

A. Dr. Pavlovic makes three related contentions. First, he reiterates that PECO records PJM charges in FERC Account No. 561.8.[15] Second, he states that Account 561.8 is functionalized in the FERC Uniform System of Accounts as a "transmission operating expense."[16] Third, based solely on these two facts, he contends that PECO's "transmission rate" included a "provision for RTEP charges" during the 2007 to 2010 period.[17]

[14] OCA St. No. 1, p. 6, lines 2-6 (quoted in footnote 2, *supra*).

[15] *Id.*, p. 6, lines 3-4 (quoted in footnote 2, *supra*).

[16] *Id.*, p. 6, lines 4-5 (quoted in footnote 2, *supra*).

[17] *Id.*, p. 6, lines 5-6 (quoted in footnote 2, *supra*).

10. Q. Does Dr. Pavlovic identify what "transmission rate" he is referring to at page 6, line 5, of his Direct Testimony?

A. No, he does not. However, in light of his testimony following that statement, it appears he is referring to the FERC-approved "transmission rate" for Network Integration Transmission Service ("NITS") that PECO charges to Load Serving Entities ("LSEs") to move power on their behalf on PECO's transmission system.[18]

11. Q. Do you agree with Dr. Pavlovic's analysis and conclusion?

A. No, I do not. Dr. Pavlovic's conclusion is not correct because it is based on three principal errors. First, Dr. Pavlovic inaccurately implies that the manner in which PECO recorded these costs for accounting purposes determined the manner in which they are recovered for ratemaking purposes. Second, Dr. Pavlovic ignores important differences in the kinds of transmission costs PECO incurs, which reflect relevant distinctions in the nature of the transmission service PECO obtains for its customers as opposed to the transmission service PECO provides to other LSEs. Third, Dr. Pavlovic improperly commingles revenues from two different kinds of transmission service and, in so doing, introduces issues that are not relevant to this case.

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[18] OCA St. No. 1, p. 7, lines 8-14 (stating that if a utility believes its "transmission rate" was inadequate to recover its "transmission capital costs or operating expenses" then "[t]here are two possible courses of action: (1) a utility can construct a transmission revenue requirement that includes all current costs and apply to the FERC for approval of a new stated transmission rate that will recover its transmission costs; or (2) a utility can apply to the FERC for approval of a transmission formula rate that on an annual basis will adjust rates to recover all its costs. In either case, all that is required is an application to the FERC under Section 205 of the Federal Power Act which a transmission utility may do at a time of its own election."). Dr. Pavlovic's response to PECO-OCA-II-6 (attached hereto as PECO Exhibit No. JAB-1R) also clarifies that page 6 of his direct testimony refers to PECO's transmission rate charged to LSEs.

This proceeding pertains specifically to the transmission component of retail rates that PECO charged for retail POLR service, subject to the jurisdiction of the Commission, before implementing the fully reconcilable TSC.

12. Q. Can you please explain Dr. Pavlovic's first error relating to how costs are recorded?

A. The fact that PECO recorded RTEP costs in Account No. 561.8 for accounting purposes does not support Dr. Pavlovic's conclusion that those costs were recovered in PECO's "transmission" rates. PECO's NITS rate was established by a 1998 FERC Settlement at Docket No. ER97-3189-000 ("1998 Settlement").[19] This occurred before PJM began imposing RTEP charges and even before FERC established Account 561.8.[20] Contrary to Dr. Pavlovic's contention, the terms of the 1998 Settlement specifically prevented PECO from recovering *any* costs recorded in Account 561 via PECO's NITS rate.[21] The 1998 Settlement terms remained in effect after FERC established more detailed sub-accounts to replace FERC Account 561, including but not limited to FERC

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19 PECO St. No. 1, p. 10, lines 3-13 ("Network Integration Transmission Service ("NITS") is the mechanism by which PECO and other transmission owners recover their annual transmission costs and revenue requirements from PJM network customers. For the period of January 1, 2007 through December 31, 2010, PECO recovered its cost of providing network service in its transmission zone through a stated rate. PECO's stated FERC transmission rate was fixed at $20,942 per megawatt-year in 1998 based on a black box settlement approved by the FERC at Docket No. ER97-3189-000. PJM RTEP costs did not exist at the time the 1998 settlement was approved.").

20 *Accounting and Financial Reporting For Public Utilities Including RTOs*, FERC Docket No. RM04-12-000 (Order No. 668 issued Dec. 16, 2005), pp. 30-33 (creating three new subaccounts, including Account 561.8, to provide greater transparency for the payments made by public utilities to regional transmission organizations).

21 The 1998 FERC Settlement (pp. 2-3) (attached hereto as PECO Exhibit No. JAB-2R) removed *all* costs recorded in FERC Account No. 561 from PECO's annual revenue requirement used to establish its stated NITS rate. As evidenced by Dr. Pavlovic's response to PECO-OCA-II-4 (attached hereto as PECO Exhibit No. JAB-3R), Dr. Pavlovic assumed incorrectly that the adjustment to PECO's annual transmission revenue requirement removed from Account No. 561 only Scheduling, System Control and Dispatch Service expenses.

Account 561.8, effective as of January 1, 2006. Given that the associated PECO NITS rate and related 1998 Settlement terms were still in effect between 2007 and 2010, PECO could not and did not recover any RTEP costs recorded in FERC Account 561.8 through its NITS rate, regardless of the manner in which FERC functionalizes that account.

13. Q. What is Dr. Pavlovic's second error involving differences in transmission service?

A. Dr. Pavlovic disregards differences in the nature of "transmission service" that are relevant to this case. PECO provides transmission to other entities, including other LSEs, to move power on their behalf within or across the PJM-designated PECO zone using transmission facilities owned by PECO. The costs PECO incurs for that service, including the fixed costs of PECO-owned transmission facilities, are recovered in PECO's wholesale NITS rate from the entities that receive that service.[22]

However, PECO, in its capacity as an LSE, was (and still is) a user of transmission service provided by others. As I previously explained, after PECO's retail rates were unbundled on January 1, 1999, PECO obtained transmission service from transmission owners to move generation *to* the PECO zone to supply the energy needs of its POLR customers. Until January 1, 2011, the wholesale LSE transmission-related costs that PECO incurred had to be recovered in the transmission component of its unbundled retail base

[22] This concept is also explained in my Direct Testimony (PECO St. No. 1, p. 10, line 8 – p. 11, line 6).

rates charged to POLR customers. The pre-2011 RTEP charges to which pre-2011 PJM bill credits relate were imposed on PECO in its capacity as an LSE to recover costs incurred by other transmission owners that owned and operated transmission facilities outside the PECO zone. As I previously testified, and undisputed by Dr. Pavlovic, these RTEP charges "were not, and could not, be a part of PECO's network service rate."[23] Dr. Pavlovic either disregards or confuses the important distinction between these two kinds of transmission costs that PECO incurred during the 2007-2010 period.

14. Q. What is Dr. Pavlovic's error involving commingling of funds?

A. Dr. Pavlovic contends that pre-2011 Settlement credits should be refunded to retail customers through PECO's reconcilable NBT rate because "PECO has not demonstrated that it was unable to recover any portion of its PECO zone RTEP charges during the period June 2007 through December 2010."[24] In support of this argument, Dr. Pavlovic compared PECO's "transmission revenues" reported in PECO's FERC Form 1 during the period 2007-2009 to the Company's "transmission revenue requirement" for providing NITS.[25] He derived the revenue requirement from information relating to the 1998

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[23] PECO St. No. 1, p. 11, lines 4-6.

[24] *See* footnote 1*, supra*.

[25] OCA St. No. 1, p. 8, lines 1-8 ("The annual revenue requirement underlying PECO's $20,924 per megawatt-year 1998 transmission rate referenced by Witness Bisti was $151,703,000. The transmission revenues PECO reported in its FERC Form 1 Reports for 2007, 2008 and 2009 range from $197,140,504 in 2007 to $193,610,760 in 2009. PECO's reported transmission revenues for each of those years were, thus, approximately $40 million dollars more than its transmission revenue requirement. This would have been more than enough to cover the PECO zone RTEP charges for that period as estimated by PJM in the EL05-121-009 settlement, the highest of which was approximately $5.2 million in 2009.").

Settlement establishing PECO's NITS rate, which FERC approved more than nine years before the period he used to derive his "transmission revenues." Based on that comparison, Dr. Pavlovic alleged that PECO's reported "transmission revenues" exceeded its "transmission revenue requirement" and, therefore, produced revenues "more than enough to cover" RTEP charges paid by PECO between 2007 and 2010.[26]

The commingling error in Dr. Pavlovic's analysis grows out of his second error, which I explained in my prior answer. Dr. Pavlovic commingles the revenue requirement PECO recovers under the wholesale "transmission rate" (that is, its NITS rate), charged to LSEs for transmission service PECO provides using PECO-owned facilities in the PECO zone, with the retail "transmission" component included in PECO's PTC charged to POLR customers. PECO's wholesale revenue requirement to furnish network transmission service to other entities and the "transmission revenues" it obtained under its NITS rates for that service are not relevant to the retail rate issues in this case. This case involves costs PECO incurred in its capacity as an LSE to obtain wholesale transmission service on behalf of POLR customers and the recovery of those costs from POLR customers under the applicable retail POLR rate. As I previously demonstrated, PECO's retail POLR rate during the period 2007-2010 could not have included a provision

[26] *See* footnote 25*, supra*, and OCA St. No. 1, p. 8, lines 10-13 ("Unfortunately, in its 2010 FERC Form 1 PECO did not report transmission revenues, but it seems unlikely that they would not have been sufficient to cover the 2010 PECO zone RTEP charges of approximately $10.5 million as estimated by PJM in the EL05-121-009 settlement.").

for RTEP costs because the transmission component of PECO's retail base rates was established before RTEP charges existed.

Dr. Pavlovic's third error is also demonstrated by his statement that, if PECO was not recovering RTEP charges during the 2007-2010 period, it should have sought FERC approval under Section 205 of the Federal Power Act either to increase its "stated" FERC rate or to implement a "formula" adjustment mechanism to reflect annual changes in its costs.[27] Under either alternative, PECO would be asking FERC to increase its rate for network service. As I stated above, PECO's wholesale revenue requirement and corresponding NITS rate are not relevant to the retail rate issues in this case. PECO incurred RTEP costs during the 2007-2010 period in its capacity as an LSE, and PECO's pre-2011 base retail rates did not include cost recovery of those RTEP costs from POLR service customers. Therefore, as I stated in my Direct Testimony, it is not reasonable to require PECO to include the pre-2011 billing adjustments at issue in this case in its calculation of NBT charges, regardless of PECO's actions with respect to its wholesale transmission revenue requirement.[28]

[27] *See* footnote 19*, supra*.

[28] PECO St. No. 1, p. 19, lines 13-17 ("The 2018 Settlement before the FERC that required PJM to make retrospective billing adjustments does not provide any valid basis for a single-issue, line-item adjustment to PECO's pre-2011 base rates. Such an adjustment is particularly inappropriate given that PECO's pre-2011 base rates did not reflect any RTEP charges.").

III. PECO'S ESTIMATE OF THE PORTION OF THE SETTLEMENT BILL CREDITS THAT RELATES TO THE 2007-2010 PERIOD IS REASONABLE, BASED ON DATA PROVIDED BY PJM, AND NOT A "HIGHLY SPECULATIVE ESTIMATE"

15. Q. Do you agree with Dr. Pavlovic's contention that PECO's $5.5 million estimate of Settlement credits that relate to transmission service for the 2007-2010 period is "highly speculative" because it is not based on actual PJM charges paid by the Company?[29]

A. No. As explained in my Direct Testimony,[30] for the "historical period" (2007-2016), the total amount of RTEP charges that were reallocated, and the corresponding billing adjustments, under the Settlement are based on a "black box" settlement and not actual PJM invoices paid by PECO and other LSEs in each PJM transmission zone. However, PJM provided time-segmented amounts of RTEP reallocated costs under the Settlement for the PECO Zone that were used as the basis for Settlement negotiations. PECO used those time-segmented amounts to calculate its pre-2011 bill credits under the Settlement. Using the same time-segmentation that was employed by the parties and PJM to negotiate the Settlement is reasonable and not speculative, as Dr. Pavlovic contends.

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[29] *See* footnote 6*, supra*.

[30] PECO St. No. 1, p. 13, lines 4-12 ("For the 'historical period,' from the initiation of RTEP charges in 2007 to January 1, 2016, the total amounts that were reallocated and the corresponding billing adjustments are based on a "black box" settlement. A new Schedule 12-C, Appendix C ("Appendix C"), was added to the [PJM Open Access Transmission Tariff] to implement the Settlement effective as of January 1, 2016 and continuing through December 31, 2025. Appendix C reflects the parties' agreement to identify the total amounts PJM would collect from, or credit to, LSEs in each responsible transmission zone and does not specify any underlying billing determinants as the basis for the agreed upon total.").

Dr. Pavlovic notably does not offer an alternative methodology. Instead, he highlights that PECO's estimate is not supported by the RTEP charges actually billed to and paid by PECO during the 2007-2010 period. The Settlement does not furnish a detailed itemization by transmission owner that ties the related PJM billing adjustments back to the original PJM billing periods and associated line item charges, and it is not reasonable to expect such an itemization given the "black box" nature of the Settlement. However, in the absence of such information, Dr. Pavlovic concludes that the "historical period" amount that relates to billing periods from 2007-2010 must be deemed to be zero.[31] That is not a reasonable conclusion.

16. Q. Do PJM's invoices to PECO for RTEP charges during the historical period support Dr. Pavlovic's conclusion?

A. No. Based on the available PJM invoices for 2008-2016 (which were provided to the OCA in discovery), PECO updated its original calculation of the percentage of RTEP charges paid by PECO during the 2007-2010 period and reallocated under the Settlement. That analysis demonstrates that PECO could have claimed that it was entitled to retain as much as $8.1 million of the PJM bill credits. As shown on PECO Exhibit No. JAB-4R, approximately 18.4% of the total RTEP charges invoiced by PJM from 2008 through 2016 were paid by PECO during the July 2008-December 2010 period. Applying the 18.4% factor along with the Company's updated default service load

[31] OCA St. No. 1, p. 3, lines 19-20 ("PECO should retain no PECO zone RTEP credits for the period June 2007 through December 2010.").

percentage for the pre-2011 period calculated in PECO Exhibit No. JAB-5R (88.5%) to PECO's total "black box" PJM bill credit for the historical period ($49,567,831.44) results in an increase to PECO's Settlement credits that relate to pre-2011 bill adjustments from approximately $5.5 million to $8.1 million. While PECO is not increasing its request regarding the amount of the pre-2011 Settlement amount to be excluded from the Company's NBT rate calculations, the foregoing calculation based on actual PJM invoices further supports the reasonableness of PECO's $5.5 million estimate. I cannot agree with Dr. Pavlovic's contention that this analysis, or the conclusions that I reach from it, are "highly speculative."

IV. CONCLUSION

17. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

PECO EXHIBIT NO. JAB-1R

PECO Energy Company (PECO)
Docket Nos. M-2018-3005860, C-2018-3006242

Response of the Office of Consumer Advocate to Interrogatories of PECO Energy Company (PECO)
Set II

PECO-OCA-II-6: Reference Dr. Pavlovic's Direct Testimony at page 6, lines 1-6. With specific reference to Dr. Pavlovic's statement that "PECO's transmission rate included a provision for RTEP charges as transmission operating expenses," please state whether the "transmission rate" to which Dr. Pavlovic is referring is: (a) PECO's "transmission rate" charged to Load Serving Entities; or (2) the "transmission rate" included in PECO's distribution rates charges to retail distribution customers in Pennsylvania. Please set forth the factual basis, and provide all analyses and/or studies that support Dr. Pavlovic's response to this interrogatory.

RESPONSE: Dr. Pavlovic's Direct Testimony at page 6, lines 1-6 refers to PECO's 1998 PJM OATT Attachment H-7 transmission revenue requirement and stated rate charged to Load Serving Entities. See response to PECO-OCA-II-4, (1) – (4).

Response prepared by: Dr. Karl Pavlovic

PECO EXHIBIT NO. JAB-2R

PECO Exhibit No. JAB-2R

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March 16, 1998

FILED
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FEDERAL ENERGY REGULATORY COMMISSION

VIA HAND DELIVERY

Mr. David Boergers
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: PECO Energy Company, Docket No. ER97-3189-005

Dear Mr. Boergers:

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.602 (1997), PECO Energy Company ("PECO Energy") hereby submits for filing an original and fourteen (14) copies of a Settlement Agreement which resolves the outstanding issue in the above docketed proceeding. A separate Explanatory Statement is attached to the Settlement Agreement.

The Settlement Agreement should be referred to the Honorable Michel Levant, the Presiding Administrative Law Judge in this case.

Description

The history of the proceeding is briefly described in the Settlement Agreement. The terms and conditions of the Settlement Agreement are set forth in Articles II-III. As more fully explained in the Explanatory Statement, the Settlement Agreement affects PECO Energy's rate for Reactive Supply and Voltage Control from Generation Sources Service, as well as rates for firm and non-firm transmission service in the PECO Energy service territory under the Pennsylvania-New Jersey-Maryland Open Access Transmission Tariff. The Settlement Agreement also addresses the treatment of costs associated with Account No. 561.

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Comment Period

In accordance with Rule 602(f), comments on this Settlement Agreement shall be filed on or before April 6, 1998, which is the 20th day after the date of submission of the Settlement Agreement to the Commission. The final day for filing reply comments is April 15, 1998, which is the 30th day after submission of the Settlement Agreement to the Commission. Pursuant to the Commission's regulations, failure to file comments will be deemed a waiver of the right to file comments.

Service

As required by Rule 602(d), a copy of this letter of transmittal, together with all attachments and enclosures, is being served on all participants on the restricted service list in accordance with Rule 2010.

Respectfully submitted,

Glen S. Bernstein

Enclosure

cc: The Honorable Michel Levant
Service List

SETTLEMENT AGREEMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PECO Energy Company) Docket No. ER97-3189-005

SETTLEMENT AGREEMENT

This Settlement Agreement is made and entered into by and between PECO Energy Company ("PECO Energy"), PJM Interconnection, LLC ("PJM LLC"), Allegheny Electric Cooperative, Inc. ("Allegheny"), and PJM Industrial Customer Coalition ("PJMICC") (collectively referred to as "the Parties"), pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.602 (1997), to dispose of the matter at issue in this proceeding.

I. INTRODUCTION

1. On November 25, 1997, the Commission issued an order addressing proposals to restructure the Pennsylvania-New Jersey-Maryland Interconnection ("PJM"), including proposed changes to the PJM region-wide transmission tariff. Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997). In that order, the Commission set certain issues for hearing, including PECO Energy's charge for Reactive Supply and Voltage Control from Generation Sources Service.

2. A prehearing conference was held on December 10, 1997, at which Presiding Administrative Law Judge ("ALJ") Michel Levant adopted a procedural schedule for this proceeding. ALJ Levant adopted a restricted service list on December 31, 1997.

3. Thereafter, the active participants in this proceeding engaged in settlement negotiations, and ultimately reached an agreement in principle aimed at disposing of the case. This Settlement Agreement is the result of those negotiations.

4. In light of the parties' agreement in principle, on February 12, 1998 PECO Energy filed an Unopposed Motion to Suspend the procedural schedule. Chief Administrative Law Judge Curtis L. Wagner, in the absence of ALJ Levant, granted that motion on February 13, 1998.

5. Subject in every particular way to the conditions set forth in this Settlement Agreement, PECO Energy, PJM LLC, Allegheny and PJMICC have agreed as follows:

II. THE SETTLEMENT

6. Reactive Supply and Voltage Control from Generation Sources Service.

PECO Energy's charges for Reactive Supply and Voltage Control from Generation Sources Service shall be as follows:

monthly rate:	$0.100/kW-month
weekly rate:	$0.0231/kW-week
daily rate:	$0.00329/kW-day
hourly rate:	$0.137/MWh

A new Schedule 2 to the PJM Open Access Transmission Tariff ("PJM Tariff") is included as Attachment A hereto. This revised schedule makes no change in the rates of the other Regional Transmission Owners ("RTOs") that are incorporated in Schedule 2 of the PJM Tariff. It only adds PECO Energy's new rates to the schedule and recalculates the pool-wide rate accordingly. Furthermore, in some instances the table also shows the PECO Energy rate as the pool-wide rate because there are no stated rates for the other RTOs. However, that is intended as a placeholder; ultimately, the pool-wide rate will be the weighted average of all the RTO rates.

7. Unbundling of Scheduling Services Costs.

a. FERC Trial Staff has requested PECO Energy to remove all FERC Account No. 561 costs from its revenue requirement in accordance with general Commission policy requiring the unbundling of ancillary services costs, including the costs of Scheduling, System Control and Dispatch Service. Accordingly, PECO Energy's current transmission revenue requirement in Attachment H-7 of the PJM Tariff shall be reduced by $2,766,000 to reflect costs associated with FERC Account No. 561 that currently are included in PECO Energy's transmission revenue requirement. Due to this reduction, PECO Energy's transmission revenue requirement shall be $151,703,000. A new Attachment H-7 to the PJM Tariff is included as Attachment B-1 hereto.

b. In reaching this agreement, the parties hereto specifically acknowledge that, were PECO Energy offering service under a company-specific (as opposed to a PJM-wide) open access transmission tariff, these Account No. 561 costs properly would be recoverable as part of Scheduling, System Control and Dispatch Service. However, the Parties hereto also acknowledge that, as of the time of this Settlement Agreement, there has been no final Commission decision on the treatment of ancillary services, including Scheduling, System Control and Dispatch Service, under the PJM Tariff. Accordingly, if the Commission finds in any proceeding involving PJM or the RTOs that the Account No. 561 costs referenced in Paragraph 7(a) hereof are properly recovered in the base transmission rates included in the PJM Tariff, Paragraph 7(a) of the Settlement Agreement shall be modified, and PECO Energy may file with the Commission to recover these costs through base transmission rates. The Parties will not contest the recovery of these Account No. 561 costs in PECO Energy's base transmission rates. The base transmission rates contained in Attachment B-2 to this Settlement Agreement are adjusted to include these Account No. 561 costs.

c. By entering into this Settlement Agreement, PECO Energy neither waives nor otherwise relinquishes the right to seek recovery of the Account No. 561 costs referenced in Paragraph 7(a) under the PJM Tariff by any appropriate means under the Federal Power Act.

8. Firm Point-to-Point Transmission Rates - PECO Zone.

a. PECO Energy's charges for Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service shall be as follows:

monthly rate:	$2.189/kW-month
weekly rate:	$0.5051/kW-week
daily rate: (on-peak)	$0.1010/kW-day
daily rate: (off-peak)	$0.0722/kW-day

Off-peak daily charges shall apply on weekends, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Peak hours are from 7 a.m. to 11 p.m., Monday through Friday (except for the holidays listed above). All other hours are off-peak. A new Schedule 7 to the PJM Tariff is included as Attachment C-1 hereto. This revised schedule makes no change in the rates of the other RTOs that are incorporated in Schedule 7 of the PJM Tariff. It only adds PECO Energy's new rates to the schedule and recalculates the pool-wide rate accordingly. A new weighted average PJM-wide rate has also been offered. Finally, the second page of Schedule 7 as presented in Attachment C-1 is the same as the second page of Schedule 7 in the existing PJM Open Access Transmission Tariff on file with the FERC. By including that page, the parties do not intend to suggest any changes thereto, but are merely indicating the parties' understanding that the second page remains as is.

b. In reaching this agreement, the parties agree that if the Commission finds that the Account No. 561 costs referenced in Paragraph 7(a) hereof are properly recovered in base transmission rates, PECO Energy may file for the following charges for Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service:

monthly rate:	$2.229/kW-month
weekly rate:	$0.5143/kW-week
daily rate: (on-peak)	$0.1029/kW-day
daily rate: (off-peak)	$0.0735/kW-day

An alternate Schedule 7 reflecting the retention of FERC Account No. 561 costs in base transmission rates is included as Attachment C-2 hereto.

9. Non-Firm Point-to-Point Transmission Rates - PECO Zone

a. PECO Energy's charges for Non-Firm Point-to-Point Transmission Service shall be up to the following:

monthly rate:	\$2.189/kW-month
weekly rate:	\$0.5051/kW-week
daily rate: (on-peak)	\$0.1010/kW-day
daily rate: (off-peak)	\$0.0722kW-day
hourly rate: (on-peak)	\$6.31/MWh
hourly rate: (off-peak)	\$3.01/MWh

Off-peak daily charges shall apply on weekends, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Peak hours are from 7 a.m. to 11 p.m., Monday through Friday (except for the holidays already listed above). All other hours are off-peak. A new Schedule 8 to the PJM Tariff is included as Attachment D-1 hereto. This revised schedule makes no change in the rates of the other RTOs that are incorporated in Schedule 8 of the PJM Tariff. It only adds PECO Energy's new rates to the schedule and recalculates the pool-wide rate accordingly. A new weighted average PJM-wide rate has also been offered. Finally, the second page of Schedule 8 as presented in Attachment D-1 is the same as the second page of Schedule 8 in the existing PJM Open Access Transmission Tariff on file with the FERC. By including that page, the parties do not intend to suggest any changes thereto, but are merely indicating the parties' understanding that the second page remains as is.

b. In reaching this agreement, the parties agree that if the Commission finds that the Account No. 561 costs referenced in Paragraph 7(a) hereof are properly recovered in base transmission rates, PECO Energy may file for the following charges for Non-Firm Point-to-Point Transmission Service:

monthly rate:	\$2.229/kW-month
weekly rate:	\$0.5143/kW-week
daily rate: (on-peak)	\$0.1029/kW-day
daily rate: (off-peak)	\$0.0735/kW-day
hourly rate: (on-peak)	\$6.43/MWh
hourly rate: (off-peak)	\$3.05/MWh

An alternate Schedule 8 reflecting the retention of Account No. 561 costs in base transmission rates is included as Attachment D-2 hereto. Finally, the second page of Schedule 8 as presented in Attachment D-2 is the same as the second page of Schedule 8 in the existing PJM Open Access Transmission Tariff on file with the FERC. By including that page, the parties do not intend to suggest any changes thereto, but are merely indicating the parties' understanding that the second page remains as is.

III. GENERAL PROVISIONS

10. The making and carrying out of this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party that any allegation or contention made in this proceeding is true or valid, nor does the Settlement Agreement establish any principles or constitute an agreement as to any principle, issue, or any method of cost of service determination, or design of rate schedules or terms or conditions of service, or the application of any rule of law.

11. The Parties shall cooperate in securing Commission approval of this Settlement Agreement. If the Commission does not approve this Settlement Agreement without condition, modification, or further proceedings, the Settlement Agreement shall be deemed withdrawn, shall not be binding on the parties, and shall not be part of the record of this proceeding.

12. The discussions that have produced this Settlement Agreement have been conducted with the explicit understanding and agreement, pursuant to Commission Rule 602(e) that all offers of settlement and discussions related thereto are and shall be privileged, shall be without prejudice to the positions of any party presenting such offer or participating in such discussions, and are not to be used in any manner in connection with this proceeding or otherwise, except as necessary for the enforcement of the terms of this Settlement Agreement consistent with the Commission's rules and regulations.

13. This Settlement Agreement supersedes any and all previous understandings, oral or written, pertaining to the subject matter contained in this Settlement Agreement. No party may rely upon any oral or written representation or oral or written information prior to execution of the Settlement Agreement made or given by any representative of any other party (or anyone on its behalf). Parol or extrinsic evidence shall not be used to vary or contradict the express terms of this Settlement Agreement, and any and all prior drafts and/or versions or notes related thereto shall not be used by the parties to explain or interpret the Settlement Agreement. The deletion of or change in language contained in previous drafts and/or versions shall be of no value in interpreting or construing the executed Settlement Agreement.

This Settlement Agreement is entered into this 13th day of March, 1998, by and among PECO Energy, PJM LLC, Allegheny and the PJMICC, and is entered into by their duly authorized representatives.

PECO ENERGY

By: [signature]

Title: ATTORNEY

PJM LLC

By: Barry Spector / RPC

Title: ATTORNEY

ALLEGHENY

By: Robert Weinberg / RPC

Title: ATTORNEY

PJMICC

By: David Kleppinger / RPC

Title: ATTORNEY

ATTACHMENT A

SCHEDULE 2

Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

The charges for such service will be based on the rates set forth below for Network Customers in each Zone and a pool-wide rate for Point-To-Point Transmission Service:

Zone	Capacity MW	Capacity Weighting	Monthly Zone Rate ($/kW-mo)	Weekly Zone Rate ($/kW-w)	Daily Zone Rate ($/MW-d)	Hourly Zone Rate ($/MWh)
AE	2,326	0.0422	0.290			
BG&E	6,716	0.1219	0.147			
Delmarva	2,923	0.0531	0.226			
JCPL	4,836	0.0878	0.279			
MetEd	2,300	0.0417	0.232			
Penelec	2,878	0.0522	0.286			
PECO	9,001	0.1634	0.100	0.0231	3.29	0.137
PPL	6,867	0.1246	0.120			
Pepco	6,746	0.1224	0.210			
PSE&G	10,502	0.1907	0.080			
Pool-Wide Rate:	55,095	1.0000	0.100	0.0231	3.29	0.137

ATTACHMENT B-1

ATTACHMENT H-7

Annual Transmission Rates -- PECO Energy Company
for Network Integration Transmission Service

1. The annual transmission revenue requirement is $151,703,000 and the rate for Network Integration Transmission Service is $20,942 per megawatt per year, which reflects the facilities recorded in FERC Form 1 as transmission for PECO Energy Company and its subsidiaries. Service utilizing other facilities will be provided at rates determined on a case-by-case basis.

2. The rate in (1) shall be effective until amended by the Regional Transmission Owner(s) within the zone or modified by the Commission.

3. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Regional Transmission Owners for any amounts payable by them as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT B-2

ATTACHMENT H-7

Annual Transmission Rates -- PECO Energy Company for Network Integration Transmission Service

1. The annual transmission revenue requirement is $154,469,000 and the rate for Network Integration Transmission Service is $26,743 per megawatt per year, which reflects the facilities recorded in FERC Form 1 as transmission for PECO Energy Company and its subsidiaries. Service utilizing other facilities will be provided at rates determined on a case-by-case basis.

2. The rate in (1) shall be effective until amended by the Regional Transmission Owner(s) within the zone or modified by the Commission.

3. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Regional Transmission Owners for any amounts payable by them as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT C-1

Attachment C - 1

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily Charge	Off-Peak Daily Charge
Border of PJM Control Area	22.311	1.859	0.4291	0.0858	0.0722
AE Zone	21.319	1.777	0.4100	0.0820	
BG&E Zone	17.029	1.419	0.3275	0.0655	
Delmarva Zone	22.996	1.916	0.4422	0.0884	
JCPL Zone	29.569	2.464	0.5686	0.1137	
MetEd Zone	13.425	1.119	0.2582	0.0516	
Penelec Zone	11.015	0.918	0.2118	0.0424	
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone	25.779	2.148	0.4958	0.0992	
Pepco Zone	21.091	1.758	0.4056	0.0811	
PSE&G Zone	23.531	1.961	0.4525	0.0905	

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any day during such week. Off-peak daily charges shall apply on weekends and NERC holidays.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion and Losses:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT C-2

Attachment C - 2

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily Charge	Off-Peak Daily Charge
Border of PJM Control Area	22.381	1.865	0.4304	0.0861	0.0735
AE Zone	21.319	1.777	0.4100	0.0820	
BG&E Zone	17.029	1.419	0.3275	0.0655	
Delmarva Zone	22.996	1.916	0.4422	0.0884	
JCPL Zone	29.569	2.464	0.5686	0.1137	
MetEd Zone	13.425	1.119	0.2582	0.0516	
Penelec Zone	11.015	0.918	0.2118	0.0424	
PECO Zone	26.743	2.229	0.5143	0.1029	0.0735
PPL Zone	25.779	2.148	0.4958	0.0992	
Pepco Zone	21.091	1.758	0.4056	0.0811	
PSE&G Zone	23.531	1.961	0.4525	0.0905	

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any day during such week. Off-peak daily charges shall apply on weekends and NERC holidays.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion and Losses:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT D-1

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily Charge ($/kW)	Off-Peak Daily Charge ($/kW)	Hourly On-Peak Charge ($/MWh)	Hourly Off-Peak Charge ($/MWh)
Border of PJM Control Area	1.859	0.4291	0.0858	.0722	5.36	3.01
AE Zone	1.777	0.4100	0.0820		5.12	
BG&E Zone	1.419	0.3275	0.0655		4.09	
Delmarva Zone	1.916	0.4422	0.0884		5.53	
JCPL Zone	2.464	0.5686	0.1137		7.11	
MetEd Zone	1.119	0.2582	0.0516		3.23	
Penelec Zone	0.918	0.2118	0.0424		2.65	
PECO Zone	2.189	0.5051	0.1010	0.0722	6.31	3.01
PPL Zone	2.148	0.4958	0.0992		6.20	
Pepco Zone	1.758	0.4056	0.0811		5.07	
PSE&G Zone	1.961	0.4525	0.0905		5.66	

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any day during such week. Off-peak daily charges shall apply on weekends and NERC holidays. Peak hours are 7 a.m. to 11 p.m. (prevailing time) Monday through Friday, excluding NERC holidays. All other hours are off-peak.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to a point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion and Losses:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall pay the higher of any applicable Redispatch Cost as calculated pursuant to Attachment K or the applicable rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT D-2

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily Charge ($/kW)	Off-Peak Daily Charge ($/kW)	Hourly On-Peak Charge ($/MWh)	Hourly Off-Peak Charge ($/MWh)
Border of PJM Control Area	1.865	0.4304	0.0861	.0735	5.38	3.05
AE Zone	1.777	0.4100	0.0820		5.12	
BG&E Zone	1.419	0.3275	0.0655		4.09	
Delmarva Zone	1.916	0.4422	0.0884		5.53	
JCPL Zone	2.464	0.5686	0.1137		7.11	
MetEd Zone	1.119	0.2582	0.0516		3.23	
Penelec Zone	0.918	0.2118	0.0424		2.65	
PECO Zone	2.229	0.5143	0.1029	0.0735	6.43	3.05
PPL Zone	2.148	0.4958	0.0992		6.20	
Pepco Zone	1.758	0.4056	0.0811		5.07	
PSE&G Zone	1.961	0.4525	0.0905		5.66	

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any day during such week. Off-peak daily charges shall apply on weekends and NERC holidays. Peak hours are 7 a.m. to 11 p.m. (prevailing time) Monday through Friday, excluding NERC holidays. All other hours are off-peak.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

    The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to a point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion and Losses:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall pay the higher of any applicable Redispatch Cost as calculated pursuant to Attachment K or the applicable rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

EXPLANATORY STATEMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PECO Energy Company) Docket No. ER97-3189-005

EXPLANATORY STATEMENT
IN SUPPORT OF SETTLEMENT

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.602 (1997), PECO Energy Company ("PECO Energy") hereby submits this Explanatory Statement in support of the concurrently filed Settlement Agreement ("Settlement"). The Settlement includes as appendices rate schedules under the Pennsylvania-New Jersey-Maryland ("PJM") Open Access Transmission Tariff ("PJM Tariff"). These rate schedules are necessary to implement the terms of the Settlement.

I. INTRODUCTION

The Settlement represents the result of negotiations among PECO Energy, Commission Trial Staff ("Staff"), and active intervenors. If accepted, the Settlement will provide for resolution of the issue set for hearing in this proceeding. PECO Energy urges the Presiding Administrative Law Judge, after an appropriate comment period, to certify the Settlement to the Commission, and for the Commission to accept the Settlement, without condition or modification.

II. BACKGROUND

This proceeding arises out of the restructuring of the PJM Interconnection consistent with the requirements of Order No. 888.[1/] On November 25, 1997, the Commission issued an order in

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1/ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities: Recovery of Stranded Costs by Public Utilities
(continued...)

Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997), ("PJM Order"), approving, subject to certain modifications, a plan for restructuring the PJM Interconnection proposed in Docket No. ER97-3189-0000 by the "Supporting Companies."2/

In the PJM Order, the Commission ordered implementation of a revised pool-wide transmission tariff to be effective on January 1, 1998. The Commission also set certain issues for hearing, including PECO Energy's charge for Reactive Supply and Voltage Control from Generation Sources Service, and assigned Docket No. ER97-3189-005 to that proceeding. On December 23, 1997, the Commission issued an order deferring implementation of the revised tariff until April 1, 1998. Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,379 (1997).

The parties and Staff have participated in numerous settlement discussions in order to reach settlement in this proceeding. The Settlement resolves all issues in this case.

1/(...continued)

and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21540 (May 10, 1996), FERC Stats. & Regs., Regulation Preambles ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12274 (March 4, 1997), FERC Stats. & Regs., Regulation Preambles ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 62 Fed. Reg. 61,688 (December 9, 1997), 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

2/ The "Supporting Companies" are composed of: Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company (the three immediate preceding utilities being subsidiaries of General Public Utilities Corp.), Pennsylvania Power & Light Company, Potomac Electric Company, and Public Service Electric and Gas Company.

III. RATES FOR SERVICE

A. Reactive Supply and Voltage Control from Generation Sources Service

The revised rates for Reactive Supply and Voltage Control from Generation Sources Service are included in Attachment A to the Settlement (which is Schedule 2 to the PJM Tariff). The rates will supersede the rate for Reactive Supply and Voltage Control from Generation Sources Service from PECO Energy included in the PJM Tariff. For the pool-wide rate associated with monthly, weekly, daily, and hourly service, for which the other PJM companies do not currently have rates on file, PECO Energy has included the PECO Energy rate.

B. Unbundling Scheduling Services Costs

In accordance with general Commission policy, Staff requested PECO Energy to remove all Account No. 561 costs from PECO Energy's base transmission rates. This change is reflected in new Attachment H-7, Schedule 7, and Schedule 8 to the PJM Tariff, which are included at Attachments B-1, C-1, and D-1 to the Settlement, respectively.

In reaching this agreement, the parties to the Settlement specifically acknowledge that were PECO Energy operating under a company-specific open access transmission tariff, Account No. 561 costs properly would be recoverable under Schedule 1. The parties also acknowledge that, at the time of the Settlement, there has been no final Commission decision on the treatment of ancillary services under the PJM Tariff, including costs included in Account No. 561. Accordingly, in the event the Commission rules that Account No. 561 costs may be recovered in the base transmission rates included in the PJM Tariff, the parties agree that PECO Energy may file with the Commission to recover these costs through base rates, and the parties will not contest PECO Energy's recovery of such costs. Attachments B-2, C-2, and D-2 include for informational purposes PECO Energy's transmission revenue requirement and rates for firm and non-firm transmission service that are adjusted to include Account No. 561 costs.

IV. CONCLUSION

PECO Energy urges the Presiding Administrative Law Judge to certify the Settlement to the Commission, and the Commission to accept the Settlement, without condition or notification.

Respectfully submitted,

Vilna Waldron Gaston /GSB

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Attorneys for PECO Energy Company

Dated: March 16, 1998

PECO EXHIBIT NO. JAB-3R

PECO Energy Company (PECO)
Docket Nos. M-2018-3005860, C-2018-3006242

Response of the Office of Consumer Advocate to
Interrogatories of PECO Energy Company (PECO)
Set II

PECO-OCA-II-4: Reference Dr. Pavlovic's Direct Testimony at page 6, lines 1-6. Is it Dr. Pavlovic's position that PECO's distribution base rates charged to retail distribution customers during the years 2007 through 2010 were established based on a revenue requirement that included as a recoverable expense the RTEP charges that were billed by PJM during those years? If Dr. Pavlovic's answer is in the affirmative, please provide the factual basis upon which he relies for his answer.

RESPONSE: The factual bases for Dr. Pavlovic's testimony at page 6, lines 1-6 together with the testimony at page 5, lines 13-20 are:

(1) On March 16, 1998, PECO submitted, in FERC Docket ER97-3189-005, a Settlement Agreement which, inter alia, removed Scheduling, System Control and Dispatch Service costs recorded in FERC Account No. 561 from PECO's then current transmission revenue requirement in Attachment H-7 of PJM's OATT tariff, resulting in an annual transmission revenue requirement of $151,703,000 and a stated transmission rate of $20,942 per megawatt per year and a stated transmission rate of $20,942 per megawatt per year. See PECO-OCA-II-4 Attachment A, Section I.7.a.

(2) On December 16, 1998, the FERC by letter order approved the settlement effective April 1, 1998. See PECO-OCA-II-4 Attachment B.

(3) FERC Account No. 561 consists of the following subaccounts.

561.1 Load dispatch – Reliability

561.2 Load dispatch – Monitor and operate transmission system

561.3 Load dispatch – Transmission service and scheduling

561.4 Scheduling, system control and dispatch services

561.5 Reliability planning and standards development

561.6 Transmission service studies

561.7 Generation interconnection studies

561.8 Reliability planning and standards development services

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PECO Energy Company (PECO)
Docket Nos. M-2018-3005860, C-2018-3006242

Response of the Office of Consumer Advocate to Interrogatories of PECO Energy Company (PECO)
Set II

(4) On or about June 2007 PECO began recording RTEP charges to FERC Account No. 561.8. See PECO response to OCA-IV-2.

(5) Under Section 205 of the Federal Power Act, PECO may at a time of its own election file an application with the FERC to modify its transmission rate.

(6) PECO did not petition for a change in its 1998 PJM OATT Attachment H-7 transmission revenue requirement and stated rate until May 1, 2017 in FERC Docket No. ER17-1519-000.

(7) On April 29, 1998, PECO submitted to the PaPUC a Settlement Agreement resolving all issues regarding PECO's Application for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code. See PECO-OCA-II-4 Attachment C.

(8) On May 14, 1998, the PaPUC issued a Final Order approving the May 29, 1998 Settlement Agreement effective January 1, 1999. See PECO-OCA-II-4 Attachment D.

(9) Sections III.A and III.B. of the May 29, 1998 Settlement Agreement, inter alia, (a) provided for unbundled Distribution and Transmission rates, (b) capped the combined Distribution and Transmission rates, and (c) provided for changes in Transmission rates to be offset by corresponding inverse changes to Distribution rates. See PECO-OCA-II-4 Attachment C.

(10) The May 29, 1998 Settlement Agreement Compliance Tariff, Tariff Electric Pa. P.U.C. No. 3 effective January 1, 1999, provides for transmission charges to be billed to those customers receiving default PLR service who had not obtained transmission service on their own. See PECO-OCA-II-4 Attachment E.

Response prepared by: Dr. Karl Pavlovic

PECO EXHIBIT NO. JAB-4R

PJM Billing Date	Billing Period	Amount Billed	2008-2010 Total	% of 2008-2015 Total
Jul-08	Jun-08	$ 357,549.47		
Aug-08	Jul-08	$ 260,499.10		
Sep-08	Aug-08	$ 260,636.65		
Oct-08	Sep-08	$ 391,784.08		
Nov-08	Oct-08	$ 395,065.78		
Dec-08	Nov-08	$ 397,334.22		
Jan-09	Dec-08	$ 397,404.93		
Feb-09	Jan-09	$ 493,762.98		
Mar-09	Feb-09	$ 494,009.05		
Apr-09	Mar-09	$ 495,382.84		
May-09	Apr-09	$ 499,014.66		
Jun-09	May-09	$ 499,167.83		
Jul-09	Jun-09	$ 689,912.48		
Aug-09	Jul-09	$ 717,428.41		
Sep-09	Aug-09	$ 717,468.20		
Oct-09	Sep-09	$ 717,528.57		
Nov-09	Oct-09	$ 717,615.57		
Dec-09	Nov-09	$ 717,730.79		
Jan-10	Dec-09	$ 717,826.73		
Feb-10	Jan-10	$ 811,120.32		
Mar-10	Feb-10	$ 811,184.71		
Apr-10	Mar-10	$ 810,950.72		
May-10	Apr-10	$ 811,044.88		
Jun-10	May-10	$ 811,091.86		
Jul-10	Jun-10	$ 1,253,477.70		
Aug-10	Jul-10	$ 1,255,019.54		
Sep-10	Aug-10	$ 1,255,204.95		
Oct-10	Sep-10	$ 1,255,078.80		
Nov-10	Oct-10	$ 1,254,408.70		
Dec-10	Nov-10	$ 1,256,411.20		
Jan-11	Dec-10	$ 1,241,981.85	$ 22,764,097.57	18.4%
Feb-11	Jan-11	$ 1,317,110.30		
Mar-11	Feb-11	$ 1,005,126.75		
Apr-11	Mar-11	$ 944,107.65		
May-11	Apr-11	$ 902,742.76		
Jun-11	May-11	$ 874,786.68		
Jul-11	Jun-11	$ 877,246.46		
Aug-11	Jul-11	$ 859,360.09		
Sep-11	Aug-11	$ 844,334.95		
Oct-11	Sep-11	$ 815,182.34		
Nov-11	Oct-11	$ 792,383.84		
Dec-11	Nov-11	$ 780,468.50		
Jan-12	Dec-11	$ 770,656.61		
Feb-12	Jan-12	$ 818,658.16		

Total "Black Box" Settlement Credit	$ (49,567,831.44)
2008-2010 PJM Transmission Enhancement *(11/07 - 5/08 excluded; PJM bills unavailable)*	$ (9,134,846.85)
PECO Default Service Usage % for same period	88.4%
Pre-2011 RTEP Credit Amount	**$ (8,075,035.16)**

PJM Billing Date	Billing Period	Amount Billed	
Mar-12	Feb-12	$ 810,145.63	
Apr-12	Mar-12	$ 798,901.90	
May-12	Apr-12	$ 786,065.92	
Jun-12	May-12	$ 773,632.65	
Jul-12	Jun-12	$ 965,992.74	
Aug-12	Jul-12	$ 968,180.83	
Sep-12	Aug-12	$ 944,205.67	
Oct-12	Sep-12	$ 936,006.01	
Nov-12	Oct-12	$ 928,746.14	
Dec-12	Nov-12	$ 918,669.79	
Jan-13	Dec-12	$ 913,003.46	
Feb-13	Jan-13	$ 1,142,052.50	
Mar-13	Feb-13	$ 1,111,063.05	
Apr-13	Mar-13	$ 1,101,110.76	
May-13	Apr-13	$ 1,090,892.21	
Jun-13	May-13	$ 1,084,836.22	
Jul-13	Jun-13	$ 936,855.80	
Aug-13	Jul-13	$ 940,442.51	
Sep-13	Aug-13	$ 1,067,378.93	
Oct-13	Sep-13	$ 1,069,428.11	
Nov-13	Oct-13	$ 1,068,866.55	
Dec-13	Nov-13	$ 1,064,746.37	
Jan-14	Dec-13	$ 1,057,567.81	
Feb-14	Jan-14	$ 1,402,255.13	
Mar-14	Feb-14	$ 1,395,429.04	
Apr-14	Mar-14	$ 1,391,523.70	
May-14	Apr-14	$ 1,392,238.30	
Jun-14	May-14	$ 1,394,672.50	
Jul-14	Jun-14	$ 1,387,147.54	
Aug-14	Jul-14	$ 1,395,582.70	
Sep-14	Aug-14	$ 1,397,216.74	
Oct-14	Sep-14	$ 1,409,148.75	
Nov-14	Oct-14	$ 1,407,745.87	
Dec-14	Nov-14	$ 1,407,709.90	
Jan-15	Dec-14	$ 1,523,842.70	
Feb-15	Jan-15	$ 1,993,864.25	
Mar-15	Feb-15	$ 1,985,902.15	
Apr-15	Mar-15	$ 1,981,733.63	
May-15	Apr-15	$ 1,984,983.70	
Jun-15	May-15	$ 1,985,854.18	
Jul-15	Jun-15	$ 5,678,904.90	
Aug-15	Jul-15	$ 5,693,757.89	
Sep-15	Aug-15	$ 5,693,757.89	
Oct-15	Sep-15	$ 5,693,757.89	
Nov-15	Oct-15	$ 5,693,757.89	
Dec-15	Nov-15	$ 5,693,757.89	2011-2015 Total

PJM Billing Date	Billing Period	Amount Billed	
Jan-16	Dec-15	$ 5,693,757.89	$ 100,759,259.67

PECO EXHIBIT NO. JAB-5R

PECO EGS Shopping Statistics (excluding Unaccounted-For Energy and disaggregated by NBT Rate Class)

YEAR	Class	EGS Usage	Default Usage	Total Usage	EGS %	Default %
1/1/2003	NBT 1 (Residential)	1,076,141,150	12,425,203,977	13,501,345,127	8.0%	92.0%
1/1/2003	NBT 2 (Small C&I)	1,601,677,456	7,374,261,423	8,975,938,879	17.8%	82.2%
1/1/2003	NBT 3 (Large C&I)	782,058,673	15,872,203,627	16,654,262,301	4.7%	95.3%
1/1/2003	NBT 4 (Lighting)	200,695	212,997,894	213,198,589	0.1%	99.9%
1/1/2004	NBT 1 (Residential)	2,246,967,596	11,509,079,186	13,756,046,782	16.3%	83.7%
1/1/2004	NBT 2 (Small C&I)	1,836,582,395	7,337,679,427	9,174,261,822	20.0%	80.0%
1/1/2004	NBT 3 (Large C&I)	790,175,570	16,301,414,671	17,091,590,241	4.6%	95.4%
1/1/2004	NBT 4 (Lighting)	372,666	206,419,748	206,792,414	0.2%	99.8%
1/1/2005	NBT 1 (Residential)	363,437,120	14,237,626,971	14,601,064,092	2.5%	97.5%
1/1/2005	NBT 2 (Small C&I)	1,382,113,440	8,078,519,154	9,460,632,594	14.6%	85.4%
1/1/2005	NBT 3 (Large C&I)	510,501,945	16,669,902,489	17,180,404,434	3.0%	97.0%
1/1/2005	NBT 4 (Lighting)	108,282	205,786,668	205,894,950	0.1%	99.9%
1/1/2006	NBT 1 (Residential)	67,543,475	13,867,436,808	13,934,980,283	0.5%	99.5%
1/1/2006	NBT 2 (Small C&I)	726,897,156	8,386,653,639	9,113,550,796	8.0%	92.0%
1/1/2006	NBT 3 (Large C&I)	34,532,339	17,103,907,561	17,138,439,900	0.2%	99.8%
1/1/2006	NBT 4 (Lighting)	17,093	229,709,096	229,726,190	0.0%	100.0%
1/1/2007	NBT 1 (Residential)	44,731,286	14,595,015,733	14,639,747,020	0.3%	99.7%
1/1/2007	NBT 2 (Small C&I)	590,093,332	8,154,514,652	8,744,607,983	6.7%	93.3%
1/1/2007	NBT 3 (Large C&I)	13,527,292	17,895,760,433	17,909,287,725	0.1%	99.9%
1/1/2007	NBT 4 (Lighting)	3,863	213,389,841	213,393,703	0.0%	100.0%
1/1/2008	NBT 1 (Residential)	32,796,506	14,467,816,314	14,500,612,821	0.2%	99.8%
1/1/2008	NBT 2 (Small C&I)	491,510,019	8,120,085,001	8,611,595,020	5.7%	94.3%
1/1/2008	NBT 3 (Large C&I)	4,534,062	17,961,241,629	17,965,775,691	0.0%	100.0%
1/1/2008	NBT 4 (Lighting)	265	207,192,804	207,193,069	0.0%	100.0%
1/1/2009	NBT 1 (Residential)	24,223,236	14,060,242,339	14,084,465,576	0.2%	99.8%
1/1/2009	NBT 2 (Small C&I)	374,520,120	8,018,399,229	8,392,919,349	4.5%	95.5%
1/1/2009	NBT 3 (Large C&I)	15,550,087	17,280,747,266	17,296,297,354	0.1%	99.9%
1/1/2009	NBT 4 (Lighting)	1,616	201,211,318	201,212,935	0.0%	100.0%
1/1/2010	NBT 1 (Residential)	35,191,133	15,393,159,114	15,428,350,247	0.2%	99.8%
1/1/2010	NBT 2 (Small C&I)	395,996,322	8,965,444,379	9,361,440,701	4.2%	95.8%
1/1/2010	NBT 3 (Large C&I)	73,801,664	17,728,627,564	17,802,429,228	0.4%	99.6%
1/1/2010	NBT 4 (Lighting)	141,752	199,495,523	199,637,275	0.1%	99.9%
1/1/2011	NBT 1 (Residential)	2,471,143,422	12,486,078,036	14,957,221,458	16.5%	83.5%
1/1/2011	NBT 2 (Small C&I)	4,994,186,122	4,088,722,155	9,082,908,277	55.0%	45.0%
1/1/2011	NBT 3 (Large C&I)	15,333,003,202	1,999,715,196	17,332,718,398	88.5%	11.5%
1/1/2011	NBT 4 (Lighting)	142,029,744	87,246,098	229,275,842	61.9%	38.1%
1/1/2012	NBT 1 (Residential)	4,065,186,832	10,521,418,349	14,586,605,181	27.9%	72.1%
1/1/2012	NBT 2 (Small C&I)	6,083,064,392	2,802,166,881	8,885,231,273	68.5%	31.5%
1/1/2012	NBT 3 (Large C&I)	15,917,591,260	712,783,752	16,630,375,011	95.7%	4.3%
1/1/2012	NBT 4 (Lighting)	184,085,020	45,519,283	229,604,302	80.2%	19.8%

[redacted]	19,131,295	8,439,559,517	8,458,690,812
	286,714,178	4,736,716,251	5,023,430,428
	2,644,869	10,477,390,950	10,480,035,820
	154	120,862,469	120,862,624
	29,707,184	14,726,700,727	14,756,407,911
	385,258,221	8,491,921,804	8,877,180,025
	44,675,876	17,504,687,415	17,549,363,291
	71,684	200,353,421	200,425,105
	1,253,167,277	13,939,618,575	15,192,785,852
	2,695,091,222	6,527,083,267	9,222,174,489
	7,703,402,433	9,864,171,380	17,567,573,813
	71,085,748	143,370,811	214,456,558
	12,490,950,142	95,172,436,587	107,663,386,728
	11.6%	**88.4%**	

PECO EGS Shopping Statistics (excluding Unaccounted-For Energy and disaggregated by NBT Rate Class)

YEAR	Class	EGS Usage	Default Usage	Total Usage	EGS %	Default %
1/1/2013	NBT 1 (Residential)	5,006,503,323	9,718,300,204	14,724,803,527	34.0%	66.0%
1/1/2013	NBT 2 (Small C&I)	6,340,473,261	2,586,056,919	8,926,530,180	71.0%	29.0%
1/1/2013	NBT 3 (Large C&I)	16,068,123,065	763,254,830	16,831,377,895	95.5%	4.5%
1/1/2013	NBT 4 (Lighting)	191,496,266	37,971,095	229,467,361	83.5%	16.5%
1/1/2014	NBT 1 (Residential)	5,180,929,859	9,394,413,392	14,575,343,251	35.5%	64.5%
1/1/2014	NBT 2 (Small C&I)	6,438,927,939	2,448,474,775	8,887,402,713	72.5%	27.5%
1/1/2014	NBT 3 (Large C&I)	16,168,748,905	550,140,600	16,718,889,505	96.7%	3.3%
1/1/2014	NBT 4 (Lighting)	193,617,221	34,999,845	228,617,065	84.7%	15.3%
1/1/2015	NBT 1 (Residential)	5,342,998,051	9,701,231,256	15,044,229,307	35.5%	64.5%
1/1/2015	NBT 2 (Small C&I)	6,499,905,190	2,458,938,417	8,958,843,607	72.6%	27.4%
1/1/2015	NBT 3 (Large C&I)	16,158,954,370	521,112,471	16,680,066,841	96.9%	3.1%
1/1/2015	NBT 4 (Lighting)	196,153,649	30,087,108	226,240,757	86.7%	13.3%
1/1/2016	NBT 1 (Residential)	5,463,005,612	9,602,842,108	15,065,847,720	36.3%	63.7%
1/1/2016	NBT 2 (Small C&I)	6,626,545,820	2,304,612,989	8,931,158,809	74.2%	25.8%
1/1/2016	NBT 3 (Large C&I)	16,197,648,458	464,919,395	16,662,567,853	97.2%	2.8%
1/1/2016	NBT 4 (Lighting)	202,799,792	24,939,421	227,739,213	89.0%	11.0%
1/1/2017	NBT 1 (Residential)	5,219,517,275	9,144,470,169	14,363,987,444	36.3%	63.7%
1/1/2017	NBT 2 (Small C&I)	6,449,562,626	2,303,199,383	8,752,762,008	73.7%	26.3%
1/1/2017	NBT 3 (Large C&I)	16,215,126,876	456,258,701	16,671,385,577	97.3%	2.7%
1/1/2017	NBT 4 (Lighting)	198,651,615	23,347,994	221,999,610	89.5%	10.5%
1/1/2018	NBT 1 (Residential)	5,216,595,248	10,130,897,539	15,347,492,787	34.0%	66.0%
1/1/2018	NBT 2 (Small C&I)	6,455,006,329	2,482,954,803	8,937,961,131	72.2%	27.8%
1/1/2018	NBT 3 (Large C&I)	16,361,358,841	421,502,121	16,782,860,962	97.5%	2.5%
1/1/2018	NBT 4 (Lighting)	183,841,316	22,132,925	205,974,241	89.3%	10.7%

PECO ENERGY COMPANY
STATEMENT NO. 1-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE

v.

PECO ENERGY COMPANY

DOCKET NOS. M-2018-3005860
C-2018-3006242

REJOINDER TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: RATEMAKING TREATMENT OF PJM TRANSMISSION CHARGES FROM 2007-2010

DATED: NOVEMBER 8, 2019

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REJOINDER TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your 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 marked as PECO Statement No. 1 and accompanying PECO Exhibit Nos. JAB-1 through JAB-10. My background and qualifications are set forth in that statement. I also submitted rebuttal testimony marked as PECO Statement No. 1-R and accompanying PECO Exhibit Nos. JAB-1R through JAB-5R.

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

A. My rejoinder testimony responds to two averments in the surrebuttal testimony of Office of Consumer Advocate ("OCA") witness Karl Richard Pavlovic, Ph.D.[1] First, I will address Dr. Pavlovic's attempt to refute the portion of my rebuttal testimony explaining that PECO's transmission rates in

[1] Surrebuttal Testimony of Karl Richard Pavlovic on behalf of the Pennsylvania Office of Consumer Advocate (Oct. 24, 2019) ("hereafter, "OCA St. No. 1-SR").

effect during the 2007-2010 period did not include any allowance for recovery of Regional Transmission Expansion Plan ("RTEP") charges imposed by PJM Interconnection, L.L.C. ("PJM") and, in fact, did not include any costs recorded in Account 561 of the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts.[2] Second, I will address Dr. Pavlovic's contention that the direct testimony of PECO witness Alan B. Cohn in PECO's 2010 electric base rate case[3] affirms that PECO's electric distribution base rates in effect prior to January 1, 2011 included a component for recovery of RTEP charges imposed by PJM.[4] As I will explain, both of Dr. Pavlovic's contentions are based on clear factual errors and, therefore, are not correct.

II. PECO'S TRANSMISSION RATES IN EFFECT DURING THE 2007-2010 PERIOD DID NOT INCLUDE A COMPONENT FOR RECOVERY OF RTEP CHARGES

4. Q. Mr. Bisti, at pages 8-9 of his surrebuttal testimony, Dr. Pavlovic takes issue with the portion of your rebuttal testimony (PECO St. 1-R, pp. 8-10) explaining that PECO's transmission rates in effect during the 2007-2010 period did not include a component for recovery of PJM RTEP charges. By way of background and for the clarity of the record, what were the relevant statements in that portion of your testimony?

A. The portion of my rebuttal testimony relevant to this issue states as follows:

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[2] OCA St. No. 1-SR, p. 8, line 18, through p. 9, line 6.

[3] *Pa. P.U.C. v. PECO Energy Co.*, Docket No. R-2010-216575.

[4] OCA St. No. 1-SR, p. 6, line 15, through p. 7, line 6.

> PECO's NITS [Network Integration Transmission Service] rate was established by a 1998 FERC Settlement at Docket No. ER97-3189-000 ("1998 Settlement"). This occurred before PJM began imposing RTEP charges and even before FERC established Account 561.8. Contrary to Dr. Pavlovic's contention, the terms of the 1998 Settlement specifically prevented PECO from recovering any costs recorded in Account 561 via PECO's NITS rate.[21]
>
> [21] The 1998 FERC Settlement (pp. 2-3) (attached hereto as PECO Exhibit No. JAB-2R) removed all costs recorded in FERC Account No. 561 from PECO's annual revenue requirement used to establish its stated NITS rate. As evidenced by Dr. Pavlovic's response to PECO-OCA-II-4 (attached hereto as PECO Exhibit No. JAB-3R), Dr. Pavlovic assumed incorrectly that the adjustment to PECO's annual transmission revenue requirement removed from Account No. 561 only Scheduling, System Control and Dispatch Service expenses.

5. Q. Your rebuttal testimony (footnote 21 at page 9, quoted above) explains that "all costs recorded in FERC Account No. 561" were removed from the annual revenue requirement used to establish PECO's stated NITS rate. What was that amount?

A. The amount removed from PECO's revenue requirement in accordance with the terms of the 1998 Settlement was $2,766,000, as shown in the Settlement Agreement (PECO Ex. JAB-2R, ¶ 7.a.).

6. Q. Why does Dr. Pavlovic disagree with your rebuttal testimony?

A. Dr. Pavlovic identified amounts PECO recorded in FERC Account 561, as reported in PECO's FERC Form 1 filed for the years 1997, 1998 and 1999, in the amounts of $4,608,393, $5,681,472 and $5,857,840, respectively. Based upon those data, Dr. Pavlovic argues that: (1) the amount of $2,766,000 removed from PECO's revenue requirement pursuant to the 1998 Settlement did not eliminate all of the costs recorded in Account 561; (2) additional costs recorded in Account 561 remained in PECO's NITS rate; and (3) the remaining costs were sufficient to allow PECO to recover RTEP charges in subsequent years once PJM actually did begin to impose such charges.[5]

7. Q. Are Dr. Pavlovic's analysis and conclusions correct?

A. No, they are not. Contrary to Dr. Pavlovic's position, after PECO removed the $2,766,000 amount from the revenue requirement adopted in the 1998 Settlement, the Company's NITS rate no longer included for recovery any costs recorded in Account 561. First, Dr. Pavlovic misconstrues the nature and purpose of the proceeding that led to the 1998 Settlement and, therefore, he draws erroneous conclusions from the terms of that settlement and from the Account 561 cost data that he relies upon. Second, Dr. Pavlovic errs by overlooking another important fact that I pointed out in my rebuttal testimony, namely, that RTEP charges were not even being imposed at the time the 1998 Settlement was approved by the FERC.

8. Q. What was the nature and purpose of the proceeding that culminated in the 1998 Settlement?

A. The proceeding that led to the 1998 Settlement was not a transmission rate case and did not reestablish PECO's transmission revenue requirement based on contemporaneous cost data. That proceeding (FERC Docket No. ER-97-3190-0000) was initiated to restructure PJM, establish PJM as an Independent System Operator ("ISO") and provide operational control of the regional transmission system to PJM as the ISO. In its Order in that proceeding (81

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5 *Id.*, p. 8, line 18, through p. 10, line 12.

FERC ¶ 61,257 (1997)), the FERC directed PJM to implement a PJM-wide Open-Access Transmission Tariff that included service over PECO's transmission facilities and, therefore, incorporated the revenue requirement of PECO's transmission facilities in PJM's open access rates for the PECO Zone.[6] The FERC-approved PJM tariff adopted PECO's revenue requirement of $154,469,000 from PECO's company-specific open-access tariff[7] then in effect, which had previously been accepted by the FERC.[8] The transmission rates established in that prior proceeding were based on costs recorded by PECO in 1994 and not 1997, 1998 or 1999, as Dr. Pavlovic erroneously assumed. The higher costs PECO recorded in the years 1997-1999 simply demonstrate that PECO was incurring costs in those years that exceeded the costs reflected in its then-existing NITS rate.

9. Q. What was the total amount of costs PECO actually recorded in Account 561 in 1994?

A. As shown in PECO's FERC Form 1 for 1994 (provided as PECO Exhibit No. JAB-2RJ), the entire amount recorded by PECO in FERC Account 561 in 1994 was $2,766,069, which is materially the same amount PECO removed from its transmission rates pursuant to the 1998 Settlement.[9] Consequently,

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6 *See* PECO Energy Company Compliance Filing filed at FERC Docket No. ER97-3189 on December 12, 1997 (provided as PECO Exhibit No. JAB-1RJ).

7 *See id.*, p. 3.

8 *PECO Energy Co.*, 74 FERC ¶ 61,336 (1996).

9 The costs PECO recorded in 1994 were consistent with the level of such costs PECO was incurring at that time, as evidenced by data in PECO's FERC Form 1 for 1992 and 1993 (provided as PECO Exhibit Nos. JAB-3RJ and JAB-4RJ, respectively), showing that PECO recorded $2,122,373 and $2,288,962 in Account 561 in the two years preceding 1994.

PECO's transmission rates adopted by the 1998 Settlement did not include any expense recorded in Account 561.

10. Q. Is there any other reason why Dr. Pavlovic's analysis and conclusion are incorrect?

A. Yes, as I stated above and as I explained in my rebuttal testimony,[10] PJM was not imposing RTEP charges when the 1998 Settlement was approved by the FERC. And, therefore, it was also not imposing RTEP charges when the rates and revenue requirement were adopted in PECO's last transmission rate case prior to the 1998 PJM restructuring proceeding.

III. DR. PAVLOVIC MISSTATED AND MISCHARACTERIZED THE TESTIMONY OF PECO WITNESS COHN IN THE COMPANY'S 2010 RATE CASE

11. Q. Mr. Bisti, in your rebuttal testimony, did you explain how the transmission component of PECO's retail base rates in effect during the 2007-2010 period had been established?

A. Yes. I explained that the transmission component of PECO's base rates in effect following PECO's restructuring proceeding through 2010 did not include the PJM RTEP charges at issue in this proceeding. In fact, during the 2007-2010 period, PJM RTEP charges were not included for recovery in any rate charged by PECO for either retail service or FERC-regulated transmission service.[11]

[10] PECO St. 1-R, p. 9, lines 10-11.

[11] *Id.*, p. 4, line 5, through p. 5, line 9.

12. Q. Does Dr. Pavlovic dispute that portion of your rebuttal testimony?

A. Yes. Dr. Pavlovic contends that my statements are refuted by the direct testimony of PECO witness Cohn in PECO's 2010 electric base rate case, which was identified as PECO Statement No. 9.[12] Dr. Pavlovic states that "PECO Witness Cohn explained that PECO removed transmission costs from base rates and placed them in the [Transmission Service Charge ("TSC")] rider"[13] and Dr. Pavlovic also states that the costs allegedly "removed from base rates" included "RTEP Charges."[14] Based on his characterization of Mr. Cohn's testimony, Dr. Pavlovic concluded that PECO's base rates in effect prior to January 1, 2010 included, and were recovering, PJM RTEP charges even though those rates had been established well before PJM began to impose RTEP charges.

13. Q. Has Dr. Pavlovic correctly described and characterized Mr. Cohn's testimony in PECO's 2010 electric base rate case?

A. No, he has not. In fact, the discussion in Dr. Pavlovic's surrebuttal testimony leaves out some very significant parts of Mr. Cohn's testimony that make it clear Mr. Cohn did not say what Dr. Pavlovic attributes to him. Specifically, as Mr. Cohn testified regarding recovery of PJM transmission charges, the "base rates" he was referring to were not PECO's existing base rates in effect when it filed its 2010 electric rate case. Rather, Mr. Cohn was referring to

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[12] Dr. Pavlovic provided a copy of Mr. Cohn's direct testimony as OCA Exhibit KRP-4SR.

[13] OCA St. 1-SR, p. 6, lines 17-19.

[14] *Id.*, p. 7, lines 1-6.

PECO's *proposed* base rates, effective in 2011, for which it was seeking approval in that case.[15] PECO included in its proposed base rate revenue requirement estimates of the charges PJM would be imposing during the future test year (calendar year 2010) employed in that case. In parallel with its base rate increase proposal, PECO also asked the Pennsylvania Public Utility Commission ("Commission") to approve its TSC as "an alternative cost recovery method" that would recover the PJM costs PECO had included, on a pro forma basis, in developing its proposed base rates. Mr. Cohn then explained that because PECO was offering two alternatives for recovering all of the estimated future test year PJM transmission charges – in its proposed base rates or through the TSC automatic adjustment clause – the estimates of PJM costs included in PECO's proposed base rate revenue requirement would have to be adjusted to remove those amounts if the Commission approved the TSC:

> If the TSC Rider is approved, the Company will recover the transmission costs charged to it by PJM under that rider and, accordingly, those costs would not be included in base rates established at the conclusion of this case.[16]

Thus, when Mr. Cohn stated that "Exhibit ABC-7 shows, by category, the PJM costs that PECO will remove from base rates and recover through the TSC"[17] he was referring to the projected PJM costs that PECO included in developing the revenue requirement underlying its proposed rates. This point is also established

15 OCA Exhibit KRP-4SR, p. 24.

16 *Id*.

17 *Id.*, p. 25.

by PECO Exhibit ABC-7 (which is part of OCA Exhibit KRP-4SR). That exhibit clearly shows that the "Regional Transmission Expansion Plan charges" PECO was removing from the proposed base rate revenue requirement consisted of "estimated 2010 payments" – not previously experienced costs embedded in PECO's then-existing base rates.

14. Q. In addition to mischaracterizing Mr. Cohn's testimony in PECO's 2010 electric base rate case, is there any other reason why Dr. Pavlovic's contention that PECO was recovering RTEP charges in its base rates prior to 2011 is incorrect?

A. Yes. Once again, Dr. Pavlovic has ignored or overlooked the fact that PECO's base rates in effect from 2007 through 2010 did not provide for the recovery of RTEP charges because PECO was not yet incurring those charges at the time those base rates were established in PECO's 1989 base rate case, as I explained in my direct testimony.[18]

IV. CONCLUSION

15. Q. Does this complete your rejoinder testimony at this time?

A. Yes, it does.

[18] PECO St. No. 1, p. 7, lines 11-17.

PECO EXHIBIT NO. JAB-1RJ

PECO Exhibit No. JAB-1RJ

ORIGINAL

PECO ENERGY

FILED OFFICE OF THE SECRETARY
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FEDERAL ENERGY REGULATORY COMMISSION

PECO Energy Company
2301 Market Street
PO Box 8699
Philadelphia, PA 19101-8699
215 841 4000

215 841 4236

12 December 1997

Ms. Lois D. Cashell, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: PECO Energy Company, Docket No. ER97-3189-005

Dear Ms. Cashell:

PECO Energy Company ("PECO" or "the Company") hereby submits for filing with the Federal Energy Regulatory Commission ("Commission") a recomputation of its transmission rate in compliance with the Commission's 25 November 1997 Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control over Jurisdictional Facilities, and Denying Rehearings, Pennsylvania-New Jersey-Maryland Interconnection, *et al.*, 81 FERC ¶ 61,257 ("PJM Order").

PECO makes this compliance filing without waiver of its right to seek rehearing of the PJM Order or to obtain appellate relief therefrom. Nor should anything stated herein be construed as agreement or acquiescence by PECO in any aspect of that order, including the making of this compliance filing. In addition, PECO further clarifies that it is not a proponent of any rate filing in the Docket No. ER97-3189-000 or in the above-referenced sub-docket. Rather, the rate filing at issue herein was both made by the Supporting Companies[1] and ordered by the Commission without PECO's consent.

[1] The Supporting Companies are Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company (the three immediately preceding utilities being subsidiaries of General Public Utilities Corp.), Pennsylvania Power & Light Company, Potomac Electric Power Company and Public Service Electric and Gas Company.

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DEC 15 1997

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Communications

Please address all correspondence in connection with this filing to:

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Background and Reason for Filing:

PECO, directly or through subsidiaries, owns electric transmission facilities which have been operated as part of a power pool for many years under the Pennsylvania-New Jersey-Maryland Interconnection Agreement dated 26 September 1956 and more recently under the Operating Agreement of the PJM Interconnection, L.L.C. dated 31 March 1997. On 2 June 1997 the Supporting Companies, a group of regional transmission owners not including PECO, tendered for filing with the Commission a plan for restructuring of the PJM Interconnection. PECO and others protested the Supporting Companies' plan and proposed alternatives.

In the PJM Order, the Commission stated: "We are directing PJM-OI to implement Supporting Companies' proposal prospectively, effective January 1, 1998, subject to further modification in accordance with our findings herein." PJM Order, mimeo at 13-14. Among the elements of the Supporting Companies' plan is a regional open-access transmission tariff which, with certain modifications, the Commission ordered to be implemented as a tariff of the PJM Interconnection, LLC. That tariff, both as tendered for filing by the Supporting Companies and as it is to be modified pursuant to the PJM Order, encompasses service over PECO's transmission facilities, and hence incorporates the revenue requirement of PECO's transmission facilities into its rates. Ordering paragraph (F) of the PJM Order directs each regional transmission owner including PECO to make a compliance filing for the purpose of accomplishing two specific changes to the rate development as tendered by the Supporting Companies: billing determinants and non-firm revenue crediting. The instant filing is in response to that directive.

Description of Revisions

The Commission's pro forma tariff contemplates that the revenue requirement of the transmission provider should be set forth in Attachment H. The Supporting Companies drafted their proposed tariff with a separate sheet in the form of Attachment H for each regional transmission owner. PECO's revenue requirement as stated in Attachment H-7 is $154,469,000. That numerical value was taken by the Supporting Companies from PECO's company-specific open-access tariff previously accepted for filing by the Commission. See PECO Energy Company, 74 FERC ¶ 61,336 (1996), and Allegheny Power System, Inc. et al., 80 FERC ¶ 61,143 (1997). Inasmuch as the Supporting Companies are proposing to charge for network integration transmission service using a set rate, rather than a load ratio allocation, they then divided this annual revenue requirement by PECO's 12CP load for 1995 (5776 MW) to create a network service rate.

One of the two elements to be addressed in this compliance filing is identified in the Commission's directive: "each RTO that provided for crediting of non-firm revenues to its revenue requirement in developing its rates is hereby ordered to revise its rates to exclude those revenues from its revenue requirement." PJM Order, mimeo at 102. After preliminary investigation, PECO has determined that any non-firm revenues it might be entitled to add back into its revenue requirement based on the test year would be insignificant at best. Accordingly, PECO hereby waives the right to seek any increase in its transmission revenue requirement based on such revenues.

The second element of the compliance filing follows the Commission's directive that "each RTO is hereby ordered to revise its rates to comply with the requirements that the billing determinants for network customers reflect the same figures that are used for FTRs". PJM Order, mimeo at 102. PECO notes that under the Supporting Companies' plan Fixed Transmission Rights ("FTRs") are a species of rights which rebate to transmission customers some congestion charges which might otherwise be imposed. Although not all FTRs are geographically equivalent, a network customer can receive as many MW worth of FTRs as the customer's annual peak load. Thus, absent the effects of load shifting between suppliers, a network customer would be expected to receive the same MW level of FTRs every month of the year.

For calculating the network customer's transmission charge, however, the Supporting Companies proposed to multiply the set rate by the customer's monthly peak load. For firm point-to-point customers, on the other hand, both the MW level of FTRs and the transmission charge would be based on the reservation level during the month. In the PJM Order the Commission concluded that network customers, like point-to-point customers, should be charged for transmission service using billing determinants equal to the MW value of the FTRs. Consequently, the Commission directed the PJM-OI to modify the tariff to reflect that change. For consistency between billing determinants and rates, the Commission observed: "This change will also require a corresponding change to the divisor used to develop the unit charge. As noted earlier, the divisor will reflect the average of 12 monthly peaks rather than the annual peak. However, the network service 'peaks' will reflect the monthly FTR MW rather than the actual network monthly load MW." PJM Order, mimeo at 59, n. 127.

The development of a revised unit charge, i.e. the network service rate in Attachment H of the Tariff, was assigned not to the PJM-OI, but to the individual RTOs. The change necessary to comply with the Commission's directive is straightforward. The divisor employed by the Supporting Companies to develop their originally-filed rate was PECO's 1995 12CP load. The new divisor must be PECO's 12CP FTR MW, which as explained above happens to be equal to PECO's annual peak load, which is 7,244 MW in August, 1995. Thus the rate is recomputed as follows: $154,469,000 /7,244 MW = $21,324 per MW per year. Attachment H-7 to the Supporting Companies' tariff filing has been modified accordingly.

PECO wishes however to call the Commission's attention to an unusual circumstance surrounding this filing. The compliance herein, which deals with the rate computation, was ordered to be prepared by PECO and submitted 15 December 1997, while the compliance filing of the revised tariff was ordered to be prepared by the PJM Office of the Interconnection (PJM-IO) and submitted 31 December 1997. Consequently, in making this submission PECO cannot control and in fact does not even know whether or not the two revisions are (or will be) consistent, notwithstanding that they are being made specifically for the purpose of achieving consistency. Hence, in the interests of reasonability and fairness, PECO reserves the right to withdraw this filing and substitute a different one in the event that the PJM OI makes no change to the tariff calculation or makes a change inconsistent with PECO's interpretations as described herein.

<u>Compliance With The Commission's Filing Requirements</u>

In accordance with the requirements of 18 C.F.R. § 35.7, an original and six copies of the following documents are submitted in connection with this filing:

1. This letter of transmittal;

2. Revised Attachment H-7 ("Annual Transmission Rates – PECO Energy Company – for Network Integration Transmission Service) to the Open Access Transmission Tariff of the PJM Interconnection, LLC filed by the Supporting Companies (Attachment A);

3. A redline version of Attachment H-7 showing changes from the previously filed text (Attachment B); and

4. A form of Notice of Filing suitable for publication in the Federal Register (Attachment C)

PECO also encloses a diskette containing electronic copies of clean and redlined copies of the revised tariff page and the form of Notice of Filing.

Copies of this compliance filing are being served on the other PJM Regional Transmission Owners and those persons on the Restricted Service List expected to be entered in this case.[2]

Respectfully submitted,

Robert N. Spencer

Robert N. Spencer, Director
Interconnection Arrangements

[2] In accordance with the discussions at the December 10, 1997 pre-hearing conference in the above-referenced sub-docket, the Restricted Service List is presently composed of those persons in attendance at the conference: PECO, Commission Staff, the PJM Interconnection, L.L.C., the PJM Industrial Customers Coalition and Allegheny Electric Cooperative.

ATTACHMENT A

CLEAN VERSION OF REVISED TARIFF PAGE

ATTACHMENT H-7

Annual Transmission Rates – PECO Energy Company for Network Integration Transmission Service

1. The annual transmission revenue requirement is $154,469,000 and the rate for Network Integration Transmission Service is $21,324 per megawatt per year, which reflects the facilities recorded in FERC Form 1, as transmission for PECO Energy Company and its subsidiaries. Service utilizing other facilities will be provided at rates determined on a case-by-case basis.

2. The rate in (1) shall be effective until amended by the Regional Transmission Owner(s) within the Zone or modified by the Commission.

3. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Regional Transmission Owners for any amounts payable by them as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

Revised: 12 December, 1997
Effective: 1 January 1998

PECO Exhibit No. JAB-1RJ

ATTACHMENT B

REDLINED VERSION OF REVISED TARIFF PAGE

ATTACHMENT H-7

Annual Transmission Rates – PECO Energy Company for Network Integration Transmission Service

1. The annual transmission revenue requirement is $154,469,000 and the rate for Network Integration Transmission Service is $21,324~~26,743~~ per megawatt per year, which reflects the facilities recorded in FERC Form 1, as transmission for PECO Energy Company and its subsidiaries. Service utilizing other facilities will be provided at rates determined on a case-by-case basis.

2. The rate in (1) shall be effective until amended by the Regional Transmission Owner(s) within the Zone or modified by the Commission.

3. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Regional Transmission Owners for any amounts payable by them as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT C

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PECO Energy Company,	)))	**Docket No. ER97-3189-005**

NOTICE OF FILING

(December ____, 1997)

Take notice that on December 15, 1997, PECO Energy Company, in compliance with the 25 November 1997 order of the Federal Energy Regulatory Commission in Pennsylvania-New Jersey-Maryland Interconnection, *et al.*, 81 FERC ¶ 61,257, filed clean and redlined versions of a revised Attachment H-7 to the "PJM Open Access Transmission Tariff" filed by the "Supporting Companies" at Docket ER97-3189-000. The "Supporting Companies" are Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power & Light Company, Potomac Electric Power Company and Public Service Electric and Gas Company.

Copies of this compliance are being served on the other PJM Regional Transmission Owners, the PJM Interconnection, L.L.C. and other persons on the Restricted Service List expected to be entered in this case in accordance with the December 10, 1997 pre-hearing conference.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedures (18 C.F.R. § 385.211 and 18 C.F.R. § 385.214). All such motions or protests should be filed on or before _____, 1997. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Hon. Lois D. Cashell
Secretary

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing document are being served upon the representatives of other PJM Regional Transmission Owners, the PJM Interconnection, L.L.C. and other persons on the Restricted Service List expected to be entered in the proceeding at Docket No. ER97-3189-005.

Dated at Philadelphia, PA this 12th day of December, 1997.

Vilna Waldron Gaston

PECO EXHIBIT NO. JAB-2RJ

Check appropriate box:

☐ Original signed form

☒ Conformed copy

PECO Exhibit No. JAB-2R

Form Approved
OMB No. 1902-0021
(Expires 7/31/95)

FERC Form No. 1: ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature

Exact Legal Name of Respondent (Company)	Year of Report
PECO Energy Company	Dec. 31, 1994

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
PECO Energy Company	(1) x An Original (2) A Resubmission	12/31/94	Dec. 31, 1994

ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$223,612	$161,879
54	(542) Maintenance of Structures	52,573	255,515
55	(543) Maintenance of Reservoirs, Dams, and Waterways	148,094	270,810
56	(544) Maintenance of Electric Plant	1,259,902	1,824,778
57	(545) Maintenance of Miscellaneous Hydraulic Plant	529,648	166,221
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	$2,213,829	$2,679,203
59	TOTAL Power Production Expenses-Hydraulic Power(Enter total of lines 50 and 58)	$4,819,537	$6,572,038
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	$915,138	$964,591
63	(547) Fuel	6,002,047	3,698,131
64	(548) Generation Expenses	580,941	883,233
65	(549) Miscellaneous Other Power Generation Expenses	1,225,977	2,257,836
66	(550) Rents	172,357	172,357
67	TOTAL Operation (Enter Total of lines 62 thru 66)	$8,896,460	$7,976,148
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	$1,288,734	$643,786
70	(552) Maintenance of Structures	813,356	896,155
71	(553) Maintenance of Generating and Electric Plant	3,854,622	5,111,558
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	196,528	70,962
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	$6,153,240	$6,722,461
74	TOTAL Power Production Expenses--Other Power (Enter Total of lines 67 and 73)	$15,049,700	$14,698,609
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$169,556,684	$160,392,439
77	(556) System Control and Load Dispatching	9,412,714	7,900,933
78	(557) Other Expenses	(33,483,769)	(19,301,531)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$145,485,629	$148,991,841
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$1,092,714,937	$1,105,113,887
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$1,450,695	$713,525
84	(561) Load Dispatching	2,766,069	2,288,962
85	(562) Station Expenses	564,335	821,847
86	(563) Overhead Lines Expenses	507,548	306,438
87	(564) Underground Lines Expenses	144,553	305,494
88	(565) Transmission of Electricity by Others	0	0
89	(566) Miscellaneous Transmission Expenses	2,683,517	3,664,697
90	(567) Rents	6,150,499	5,567,867
91	TOTAL Operation (Enter Total of lines 83 thru 90)	$14,267,216	$13,668,830
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$593	$408,992
94	(569) Maintenance of Structures	133,954	392,121
95	(570) Maintenance of Station Equipment	10,482,145	9,173,546
96	(571) Maintenance of Overhead Lines	5,127,768	4,325,921
97	(572) Maintenance of Underground Lines	930,592	1,301,909
98	(573) Maintenance of Miscellaneous Transmission Plant	722,607	0
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$17,397,659	$15,602,489
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$31,664,875	$29,271,319
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$5,657,311	$5,070,317

PECO EXHIBIT NO. JAB-3RJ

PECO Exhibit No. JAB-3RJ

Check appropriate box:

☐ Original signed form

☒ Conformed copy

Form Approved
OMB No. 1902-0021
(Expires 7/31/95)

FERC Form No. 1: ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3,4(a), 304 and 309, and 18 CFR141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
PHILADELPHIA ELECTRIC COMPANY	Dec. 31, 1992

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	198,586	271,114
53	(542) Maintenance of Structures	177,555	89,756
54	(543) Maintenance of Reservoirs, Dams, and Waterways	230,477	317,399
55	(544) Maintenance of Electric Plant	1,716,688	1,370,119
56	(545) Maintenance of Miscellaneous Hydraulic Plant	742,367	273,482
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	3,065,673	2,321,870
58	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 49 and 57)	5,962,736	4,626,695
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	953,075	1,067,196
62	(547) Fuel	2,167,643	5,718,677
63	(548) Generation Expenses	971,844	1,354,034
64	(549) Miscellaneous Other Power Generation Expenses	1,988,998	1,725,858
65	(550) Rents	172,357	172,357
66	TOTAL Operation (Enter total of lines 61 thru 65)	6,253,917	10,038,122
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	661,506	610,601
69	(552) Maintenance of Structures	1,116,219	675,836
70	(553) Maintenance of Generating and Electric Plant	4,237,463	3,581,818
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	41,379	40,107
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	6,056,567	4,908,362
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66 and 72)	12,310,484	14,946,484
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	218,778,544	199,213,060
76	(556) System Control and Load Dispatching	7,903,122	7,539,187
77	(557) Other Expenses	57,135,596	37,674,41
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	283,817,262	244,426,65[illegible]
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73, and 78)	1,157,594,174	1,141,458,217
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	769,789	2,746,439
83	(561) Load Dispatching	2,122,373	2,197,374
84	(562) Station Expenses	979,544	1,402,486
85	(563) Overhead Line Expenses	471,441	473,986
86	(564) Underground Line Expenses	339,076	393,907
87	(565) Transmission of Electricity by Others	-	-
88	(566) Miscellaneous Transmission Expenses	3,107,525	2,994,782
89	(567) Rents	6,154,505	6,357,060
90	TOTAL Operation (Enter Total of lines 82 thru 89)	13,944,253	16,566,034
91	Maintenance		
92	(568) Maintenance Supervision and Engineering	461,474	718,462
93	(569) Maintenance of Structures	424,495	217,982
94	(570) Maintenance of Station Equipment	8,794,696	5,525,710
95	(571) Maintenance of Overhead Lines	4,694,736	4,352,777
96	(572) Maintenance of Underground Lines	1,249,986	1,337,648
97	(573) Maintenance of Miscellaneous Transmission Plant	86,618	22,300
98	TOTAL Maintenance (Enter Total of lines 92 thru 97)	15,712,005	12,174,879
99	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	29,656,258	28,740,913
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering	4,745,126	7,109,356

PECO EXHIBIT NO. JAB-4RJ

Check appropriate box:

☐ Original signed form

☒ Conformed copy

PECO Exhibit No. JAB-4RJ

Form Approved
OMB No. 1902-0021
(Expires 7/31/95)

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
PECO Energy Company	Dec. 31, 19 93

FERC FORM NO. 1 (REVISED 12-93)

PECO Exhibit No. JAB-4RJ

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	161,879	198,586
54	(542) Maintenance of Structures	255,515	177,555
55	(543) Maintenance of Reservoirs, Dams, and Waterways	270,810	230,477
56	(544) Maintenance of Electric Plant	1,824,778	1,716,688
57	(545) Maintenance of Miscellaneous Hydraulic Plant	166,221	742,367
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,679,203	3,065,673
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	6,572,038	5,962,736
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	964,591	953,075
63	(547) Fuel	3,698,131	2,167,643
64	(548) Generation Expenses	883,233	971,844
65	(549) Miscellaneous Other Power Generation Expenses	2,257,836	1,988,998
66	(550) Rents	172,357	172,357
67	TOTAL Operation (Enter total of lines 62 thru 66)	7,976,148	6,253,917
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	643,786	661,506
70	(552) Maintenance of Structures	896,155	1,116,219
71	(553) Maintenance of Generating and Electric Plant	5,111,558	4,237,463
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	70,962	41,379
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	6,722,461	6,056,567
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	14,698,609	12,310,484
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	160,392,439	218,778,544
77	(556) System Control and Load Dispatching	7,900,933	7,903,122
78	(557) Other Expenses	(19,301,531)	57,135,596
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	148,991,841	283,817,262
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	1,105,113,887	1,157,594,174
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	713,525	769,789
84	(561) Load Dispatching	2,288,962	2,122,373
85	(562) Station Expenses	821,847	979,544
86	(563) Overhead Line Expenses	306,438	471,441
87	(564) Underground Line Expenses	305,494	339,076
88	(565) Transmission of Electricity by Others	-	-
89	(566) Miscellaneous Transmission Expenses	3,664,697	3,107,525
90	(567) Rents	5,567,867	6,154,505
91	TOTAL Operation (Enter Total of lines 83 thru 90)	13,668,830	13,944,253
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	408,992	461,474
94	(569) Maintenance of Structures	392,121	424,495
95	(570) Maintenance of Station Equipment	9,173,546	8,794,696
96	(571) Maintenance of Overhead Lines	4,325,921	4,694,736
97	(572) Maintenance of Underground Lines	1,301,909	1,249,986
98	(573) Maintenance of Miscellaneous Transmission Plant	-	86,618
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	15,602,489	15,712,005
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	29,271,319	29,656,258
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	5,070,317	4,745,126

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE	:	
	:	
v.	:	**DOCKET NOS. M-2018-3005860**
	:	**C-2018-3006242**
PECO ENERGY COMPANY	:	

VERIFICATION

I, Joseph A. Bisti, hereby state that I am a Principal Regulatory and Rates Specialist at PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed in PECO Hearing Exhibit No. 1, which is attached hereto as Appendix A, 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.

Dated: November 13, 2019

Joseph A Bisti

Joseph A. Bisti

APPENDIX A

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

OFFICE OF CONSUMER ADVOCATE	:	
	:	
v.	:	**Docket Nos. M-2018-3005860**
	:	**C-2018-3006342**
PECO ENERGY COMPANY	:	

<u>LIST OF PECO ENERGY COMPANY'S TESTIMONY & EXHIBITS</u>

- **PECO Energy Co. Statement No. 1:** **Direct Testimony of Joseph A. Bisti**
  - **Exhibit No. JAB-1:** **Supplement No. 8 to Tariff Electric-Pa PUC No. 4, Effective January 1, 2011**
  - **Exhibit No. JAB-2:** **PECO Energy Company Default Service Program Request for Proposals For Full Requirements Products (2009)**
  - **Exhibit No. JAB-3:** **Schedule 12-C Appendix C to the Settlement (FERC Docket No. EL05-121-009)**
  - **Exhibit No. JAB-4:** **Calculation of PJM Bill Credits PECO will Receive Under the Settlement (FERC Docket No. EL05-121-009)**
  - **Exhibit No. JAB-5:** **PECO EGS Shopping Statistics (Excluding Unaccounted-For Energy 2003-2018)**
  - **Exhibit No. JAB-6:** **Calculation of Pre-2011 PJM Bill Credits Under the Settlement (FERC Docket No. EL05-121-009)**
  - **Exhibit No. JAB-7:** **Non-Bypassable Transmission Service Charge Semiannual Adjustment, PECO Energy Electric Tariff No. 5, Supplement No. 76, Effective December 1, 2018**
  - **Exhibit No. JAB-8:** **Post-2010 PJM Bill Adjustments, E-Factor Component, Supplement No. 76**

- □ **Exhibit No. JAB-9:** **Non-Bypassable Transmission Service Charge Semiannual Adjustment, PECO Energy Electric Tariff No. 6, Supplement No. 13, Effective June 1, 2019**
- □ **Exhibit No. JAB-10:** **Post-2010 PJM Bill Adjustments, E-Factor Component, Supplement No. 13**

■ **PECO Energy Co. Statement No. 1-R:** **Rebuttal Testimony of Joseph A. Bisti**

- □ **Exhibit No. JAB-1R:** **Response of the OCA to Interrogatories of PECO Energy Company Set II, No. 6**
- □ **Exhibit No. JAB-2R:** **Settlement Agreement, FERC Docket No. ER97-3189-005**
- □ **Exhibit No. JAB-3R:** **Response of the OCA to Interrogatories of PECO Energy Company Set II, No. 4**
- □ **Exhibit No. JAB-4R:** **Pre-2011 RTEP Credit Amount**
- □ **Exhibit No. JAB-5R:** **PECO EGS Shopping Statistics (Excluding Unaccounted-For Energy and Disaggregated by NBT Rate Class)**

■ **PECO Energy Co. Statement No. 1-RJ:** **Rejoinder Testimony of Joseph A. Bisti**

- □ **Exhibit No. JAB-1RJ:** **PECO Compliance Filing (FERC Docket No. ER97-3189-005)**
- □ **Exhibit No. JAB-2RJ:** **PECO FERC Form No. 1 December 31, 1994 (Excerpt)**
- □ **Exhibit No. JAB-3RJ:** **PECO FERC Form No. 1 December 31, 1992 (Excerpt)**
- □ **Exhibit No. JAB-4RJ:** **PECO FERC Form No. 1 December 31, 1993 (Excerpt)**