OCA HEARING EXHIBIT NO. 1

EXHIBIT
OCA 1
PENGAD 800-631-6989

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

LIST OF THE OFFICE OF CONSUMER ADVOCATE'S

TESTIMONY & EXHIBITS

- **OCA Statement No. 1:** — **Direct Testimony of Dr. Karl Richard Pavlovic**
  - **Exhibit KRP-1:** — **Qualifications of Dr. Karl Richard Pavlovic**
  - **Exhibit KRP-2:** — **PECO Response to OCA Interrogatory I-2-a, Attachment OCA-I-2-a-i (PECO Allocation Methodology for $5.5 Million in RTEP Credits)**
  - **Exhibit KRP-3:** — **PECO Response to OCA Interrogatory I-1-c, Attachment I-1-c (PECO Calculation of RTEP Credits Expected to be Received under the FERC Settlement)**
  - **Exhibit KRP-4:** — **PECO Response to OCA Interrogatory I-2-a, Attachment OCA-I-2-a-ii (PECO Workpapers for the Default Service Load Percentage Calculation)**
  - **Exhibit KRP-5:** — **PECO Response to OCA Interrogatory I-2-a, Attachment OCA-I-2-a-iii (PECO Postage Stamp Worksheet)**
  - **Exhibit KRP-6:** — **OATT Attachment H-7 (Annual Transmission Rates – PECO Energy Company – For Network Integration Transmission Service)**
- **OCA Statement No. 1-SR:** — **Surrebuttal Testimony of Dr. Karl Richard Pavlovic**

□ **Exhibit KRP-1SR:**	**OCA Response to PECO Set II Interrogatories, Nos. 4 and 7**
□ **Exhibit KRP-2SR:**	**PECO Response to OCA Set V Interrogatory, No. 2**
□ **Exhibit KRP-3SR:**	**PECO Transmission Tariff Timeline**
□ **Exhibit KRP-4SR:**	**Excerpt of PECO Energy Company Statement No. 9, Direct Testimony of Alan B. Cohn and Exhibits ABC-6, ABC-7, and ABC-8 (Docket No. R-2010-2161575)**
□ **Exhibit KRP-5SR:**	**Excerpt of Petition of PECO Energy Company for Approval of its Default Service Program for the period from June 1, 2015 through May 31, 2017, *Opinion and Order*, Docket No. P-2014-2409362 (Dec. 2014)**
□ **Exhibit KRP-6SR:**	**PECO Energy Company, Docket No. ER-97-3189-005, Settlement Agreement**
□ **Exhibit KRP-7SR:**	**PECO 1998 and 1999 FERC Form No. 1**
□ **Exhibit KRP-8SR:**	**PECO Response to OCA V-1, Attachment OCA-V-1-b (Excerpts from FERC Order 668, Docket No. RM04-12-000 (Dec. 2005))**
□ **Exhibit KRP-9SR:**	**Excerpt of PECO Energy Company's Application for Approval of Its Restructuring Plan et al., Docket Nos. R-00973953 and P-00971235 – *Joint Petition for Settlement***
□ **Exhibit KRP-10SR:**	**PECO Response to OCA VI-2-b and Attachment OCA-VI-3-b (Appendix A Tariff Sheets)**
□ **Exhibit KRP-11SR:**	**PECO Exhibit No. JAB-6 (Calculation of Pre-2011 PJM Bill Credits Under the Settlement)**
□ **Exhibit KRP-12SR:**	**PECO Exhibit No. JAB-5 (PECO EGS Shopping Statistics (excluding Unaccounted-For Energy)**

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Office of Consumer Advocate	)	
	)	
v.	)	Docket Nos. M-2018-3005860
	)	C-2018-3006242
PECO Energy Company	)	

DIRECT TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 5, 2019

PENGAD 800-631-6989
EXHIBIT
OCA Statement
1

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Managing Director of and a Senior Consultant with PCMG and Associates LLC ("PCMG"). PCMG is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit KRP-1 to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit KRP-1 also contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the Corporation Commission of the State of Kansas, the Delaware Public Service Commission, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Illinois Commerce Commission, the North Dakota Public Service Commission, the Maine Public Utilities Commission, and the Public Service Commission of the District of Columbia.

Q. PLEASE SUMMARIZE YOUR ELECTRIC REGULATORY EXPERIENCE.

A. For most of my career, I have performed analyses and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Regarding electric regulation, I have testified on: (a) the operational and financial issues with regard to the divestiture of electric generating assets and the subsequent unbundling of retail rates; (b) the procurement of Standard Offer Service ("SOS") electric supply and retail SOS rates; (c) the performance of renewable and energy efficiency programs; (d) "lost revenues" attributable to Demand-Side Management ("DSM") programs; (e) efficient operation of electric transmission and distribution facilities; (f) the need for new transmission and distribution facilities to reliably serve load; and (g) the operating costs and benefits of mergers. Regarding the efficient operation of electric production, transmission and distribution facilities, I served for a number of years as the technical representative of the Office of the People's Counsel of the District of Columbia in monthly meetings of the Productivity Improvement Working Group of the Potomac Electric Power Company and various member working groups within the PJM Regional Transmission Organization.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to PECO's proposal to retain $5.5 million of the Regional Transmission Expansion Plan ("RTEP") credits refunded to the PECO Zone by PJM pursuant to the Settlement Agreement in FERC Docket No. EL05-121-009.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, I find that:

- 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
- 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.
- Therefore, PECO should retain no PECO zone RTEP credits for the period June 2007 through December 2010.

B. PECO HAS NOT DEMONSTRATED ITS CLAIM TO THE PECO ZONE RTEP CREDITS FOR THE JUNE PERIOD 2007 THROUGH DECEMBER 2010.

Q. PLEASE EXPLAIN HOW THIS RTEP CREDIT ISSUE AROSE

A. In FERC Docket EL05-121 numerous parties appealed FERC's original decision to apply RTEP charges across the entire PJM footprint on a "postage stamp" basis. The United States Court of Appeals for the Seventh Circuit remanded the case to FERC in 2009, finding that FERC had not provided a reasonable or articulable basis for using the postage stamp method; and subsequently in 2014 the Seventh Circuit in deciding the second appeal on the same topic found that FERC's proposed method was not reasonable and unsupported.[1] Once again, the Seventh Circuit remanded the case to FERC for the purpose of creating a reasonable basis for allocating these RTEP charges.

Q. PLEASE EXPLAIN THE RTEP CREDITS THAT ARE AT ISSUE IN THIS PROCEEDING

A. The EL05-121-009 Settlement Agreement resolved the dispute about the method of allocating RTEP charges to the PJM transmission zones. The Settlement Agreement resolves the dispute with regard to the allocation of RTEP charges for two periods: (1) the "historical period" defined as the period June 2007 through December 2015[2] and (2) the "going-forward period" defined as January 2016 onward.[3] Under the terms of the settlement, PJM zones that were over allocated RTEP charges are receiving an RTEP

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[1] *Illinois Commerce Comm'n. v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014).
[2] FERC Docket No. EL05-121-009, May 31, 2018 Order on Contested Settlement at 10.
[3] FERC Docket No. EL05-121-009, May 31, 2018 Order on Contested Settlement at 9; see also June 5, 2019 Direct Testimony of Joseph A. Bisti, page 11, line 7 to page 13, line 16.

credit. As explained below, the PECO zone is receiving a credit of $49,567,831 for the historical period, of which PECO seeks to retain $5,560,416 for RTEP charges during the historical period of June 2007 through December 2010.

Q. WHY DOES PECO NOT SEEK TO RETAIN THE PECO ZONE RTEP CREDITS FOR THE HISTORICAL PERIOD OF JANUARY 2011 THROUGH DECEMBER 2015?

A. As PECO Witness Bisti explains, 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.[4] Thus, the PECO zone RTEP charges, while billed to PECO and paid by PECO initially, were paid by PECO ratepayers through these separate mechanisms.

Q. DOES PECO CLAIM THAT, FOR THE HISTORICAL PERIOD PRIOR TO JANUARY 2011, PECO ZONE RTEP CHARGES BILLED TO PECO AS THE DEFAULT SUPPLIER WERE NOT RECOVERED FROM RETAIL CUSTOMERS?

A. Yes. PECO claims that because its transmission rate recovered from its default service customers prior to January 2011 did not specifically provide for recovery of the RTEP charges, PECO zone RTEP charges prior to January 2011 were not recovered from default service customers.[5]

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[4] Bisti Direct, page 7, line 18 to page 10, line 2.
[5] Bisti Direct, page 7, lines 11-17; also page 10, line 3 to page 11, line 11.

Q. IS THAT CORRECT?

A. 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.[6] Account 561.8 is functionalized in the FERC Uniform System of Accounts as a transmission operating expense.[7] This means that PECO's transmission rate included a provision for RTEP charges as transmission operating expenses.

Q. IS IT POSSIBLE THAT PECO ZONE RTEP CHARGES THAT PECO BEGAN TO INCUR IN JUNE 2007 CAUSED ITS TRANSMISSION OPERATING EXPENSES TO EXCEED THE AMOUNT INCLUDED IN THE REVENUE REQUIREMENT UPON WHICH PECO'S TRANSMISSION RATE WAS BASED?

A. Yes, it is possible. However, that is possible for any of the expenses recorded in any of PECO's transmission operating accounts. There is nothing that distinguishes the expenses recorded in Account 561.8 from the expenses recorded in PECO's other transmission operating accounts. And it is not dispositive of whether PECO's transmission rates were at any point in time generating revenue sufficient to recover any given transmission operating expense, including PECO's RTEP charges during the June 2007 through December 2010 period.

Q. HAS PECO PROVIDED DATA AND/OR INFORMATION THAT DEMONSTRATES THAT ITS TRANSMISSION REVENUES WERE

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[6] PECO Response to OCA-IV-2.
[7] 18 CFR Ch. I Account 561.8.

INSUFFICIENT TO RECOVER ALL OR A PORTION OF ITS PECO ZONE RTEP CHARGES?

A. No.

Q. AS A RATEMAKING MATTER, WHAT IS THE APPROPRIATE COURSE OF ACTION WHEN A TRANSMISSION RATE GENERATES INSUFFICIENT REVENUE TO RECOVER A UTILITY'S TRANSMISSION CAPITAL COSTS OR OPERATING EXPENSES?

A. There 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.

Q. DID PECO UNDERTAKE EITHER OF THESE TWO COURSES OF ACTION REGARDING ITS PECO ZONE RTEP CHARGES DURING THE JUNE 2007 THROUGH DECEMBER 2010 PERIOD?

A. To my knowledge, PECO did not.

Q. IS THERE ANY EVIDENCE INDICATING THAT DURING THE PERIOD OF JUNE 2007 THROUGH DECEMBER 2010 PECO'S TRANSMISSION REVENUES WERE GREATER THAN ITS TRANSMISSION REVENUE REQUIREMENT?

A. Yes. The annual revenue requirement underlying PECO's $20,924 per megawatt-year 1998 transmission rate referenced by Witness Bisti[8] was $151,703,000.[9] 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.[10] 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.[11]

Q. WHAT WERE PECO'S TRANSMISSION REVENUES IN 2010?

A. Unfortunately, in its 2010 FERC Form1 PECO did not report transmission revenues,[12] 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.[13]

Q. WHAT DO YOU CONCLUDE REGARDING PECO'S RECOVERY OF PECO ZONE RTEP CHARGES?

A. 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

[8] Bisti Direct, page 10, lines 3-13.
[9] Exhibit KRP-6, page 1, PJM OATT Attachment H-7, PECO Network Integration Transmission Service.
[10] Exhibit KRP-6, pages 2 and 3, PECO 2008 and 2009 FERC Form 1 Reports, page 300, line 22.
[11] See Exhibit KRP-2 and discussion below.
[12] Exhibit KRP-6, page 4, PECO 2010 FERC Form 1 Report, page 300, line 22.
[13] See Exhibit KRP-2 and discussion below.

December 2010 period. I further conclude that PECO should retain no RTEP credits for that period.

C. RTEP CREDITS PECO SEEKS TO RETAIN

Q. HAS PECO PROVIDED ITS CALCULATION OF THE $5,560,416 IN RTEP CREDITS IT PROPOSES TO RETAIN?

A. Yes. Attachments provided in PECO's responses to the OCA's interrogatories include electronic spreadsheets that show the calculation of the $5,560,416 PECO seeks to retain.[14] The attachments are included as Exhibits KRP-2 through KRP-5 to my testimony

Q. CAN YOU EXPLAIN HOW PECO CALCULATED $5,560,416 IN RTEP CREDITS?

A. Yes. The settlement of the historical period is a black box calculation of the credits or collections to and from the PJM zones. The black box settlement calculated for the PECO zone a total of $49,567,831 credits for the historical period.[15] For the reasons I explained above, PECO asserts that it should be allowed to retain the amount of the black box historical period credits that PECO attributes to the original PECO zone RTEP charges for the period June 2007 through December 2010 and calculates that amount in the following steps.

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[14] Response to OCA-I-2-a, Attachment OCA-I-2-a-i; see Exhibit KRP-2; see also Bisti Direct, PECO Exhibit No. JAB-6.

[15] Response to OCA-I-1-c, Attachment OCA-I-1-c; see Exhibit KRP-3; see also Bisti Direct, PECO Exhibit No. JAB-4.

1. From a schedule of estimated PECO zone RTEP charges for the historical period,[16] PECO calculates a percentage for the period June 2007 through December 2010 by dividing the sum of the RTEP charges for the June 2007 through December 2010 period[17] by the sum of the RTEP charges for the entire historical period June 2007 through December 2015.[18] The calculated percentage is 12.3%.[19]
2. PECO multiplies the total PECO zone black box credit ($49,567,831) by 12.3% to calculate the credit amount attributable to the June 2007 through December 2010 period, viz., $6,095,642.[20]
3. Using shopping statistics for the period June 2007 through December 2010, PECO calculates a "PECO Default Service Usage %" by dividing the sum of electric energy it supplied as default service provider by the total electric energy supplied to retail customers for the period, viz., 91.2%.[21]
4. PECO multiplies the $6,095,642 credit amount by the "PECO Default Service Usage %" of 91.2%[22] to calculate the historical period credit amount it seeks to retain, viz. $5,560,416.[23]

Q. IS THE SCHEDULE OF RTEP CHARGES USED IN STEP 1 THE ACTUAL RTEP CHARGES PJM BILLED TO THE PECO ZONE DURING THE HISTORICAL PERIOD?

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[16] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cells B3-B27.
[17] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell C12.
[18] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell C28.
[19] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell D12.
[20] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell G7.
[21] Response to OCA-I-2-a, Attachment OCA-I-2-a-ii_v1, spreadsheet cell I14; see Exhibit KRP-4; see also Bisti Direct, PECO Exhibit No. JAB-5.
[22] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell G10.
[23] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell G12.

A. No. The schedule of RTEP charges used in Step 1 was calculated by PJM by applying settlement "load share" PECO zone allocation percentages to the total RTEP charges for the period June 2007 through January 2015.[24] PECO estimated the PECO zone RTEP charges for the period February 2015 through December 2015 by multiplying the PJM calculated load share PECO zone RTEP charges for January 2015 by 11.[25]

Q. DID OCA REQUEST FROM PECO THE RTEP CHARGES BILLED TO THE PECO ZONE DURING THE HISTORICAL PERIOD?

A. Yes. PECO responded that it did not have that information for the period November 2007 through May 2008.[26]

Q. REGARDING THE CALCULATION OF THE "PECO DEFAULT USAGE %" IN STEP 3, DID PECO PROVIDE THE RTEP CHARGES BILLED TO PECO AS THE DEFAULT SUPPLIER FOR THE PERIOD JUNE 2007 THROUGH DECEMBER 2010?

A. No.

Q. WHY DID PECO CALCULATE THE "PECO DEFAULT USAGE %" APPLIED IN STEP 3?

A. During the June 2007 through December 2010 period, PJM billed PECO zone RTEP charges to the suppliers of electric energy to retail customers.[27] As explained above, PECO

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[24] Response to OCA-I-2-a, Attachment OCA-I-2-a-iii, Postage Stamp Worksheet (1), spreadsheet cells DJ7-DJ30; see Exhibit KRP-5.
[25] Response to OCA-I-2-a, Attachment OCA-I-2-a-i, spreadsheet cell B27.
[26] Response to OCA-II-2-b.
[27] Bisti Direct, page 7, lines 7-9.

seeks to retain only the PECO zone RTEP credits attributable to the RTEP charges it paid as the default service provider.

Q. WHAT DO YOU CONCLUDE REGARDING THE $5,560,416 PECO ZONE RTEP CREDITS PECO SEEKS TO RETAIN?

A. 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.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by PECO.

277125

Exhibit KRP – 1

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on the DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With 33 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

References

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Regulatory Projects and Appearances

1. In re: Application of San Diego Gas & Electric Company for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Increase its Overall Rate of Return, (v) Modify its Adopted Cost of Capital Mechanism Structure, and (vi) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
   CA Public Utilities Commission Application 19-04-017

2. In re: Proposed Amendments to N.J.A.C. 14:9 Adoption of Water and Sewer Uniform System of Accounts (2019) – (Assistance to counsel: water and sewer accounting on behalf of the Division of Rate Counsel)
   NJ Board of Public Utilities Docket Nos. WX19050612 and WX19050613

3. In re: Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (2019) – (Assistance to Counsel: infrastructure replacement accounting)
   NJ Board of Public Utilities Docket No. GE19040522

4. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 19-GREC-06

5. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 19-GREC-05

6. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2019) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
   MD Public Service Commission Case No. 9602

7. In re: PECO Energy Company Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment (2019) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket No. M-2018-3005860

8. In re: PECO Energy Company Transmission Formula Rate Application (2018) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   Federal Energy Regulatory Commission Docket ER17-1519-000

9. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 18-GREC-06

10. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 18-GREC-05

11. In re: The Application of the Potomac Edison Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
   MD Public Service Commission Case No. 9490

12. In re: Rate Applications of Kansas City Power & Light – Missouri and Kansas City Power & Light – Greater Missouri Operations (2018) – (Appearance: consolidated operations, cost of service and rate design on behalf of the Missouri Office of Public Counsel)
   MO Public Service Commission Case Nos. ER-2018-0145 and ER-2018-0146

13. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
   MD Public Service Commission Case No. 9472

14. In re: Mid-Atlantic Interstate Transmission, L.L.C. 2018 Transmission Formula Rate Protocol Filings (2018) - (Analysis and Advice to Counsel: accounting)
   Federal Energy Regulatory Commission Docket ER17-211-000

15. In re: The Gas Company d/b/a Hawaii Gas Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2017-0105

16. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
   ND Public Service Commission Case No. PU-12-813

17. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
   MD Public Service Commission Case No. 9455

18. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

19. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

20. In re: In the matter of the application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9447

21. In re: PJM Interconnection, L.L.C. - PECO Energy Company Transmission Formula Rate Application (2017) - (Analysis and Advice to Counsel: accounting, cost of service and rate design)
    Federal Energy Regulatory Commission Docket ER17-1519-000

22. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) - (Appearance: prudence/used and useful and plant accounting re. accelerated asset replacement program on behalf of the Illinois Citizens Utility Board)
    IL Commerce Commission Docket No. 17-0124

23. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9443

24. In re: PJM Interconnection, L.L.C. - Rockland Electric Company Transmission Rate Application (2017) (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket ER17-856-000

25. In re: PJM Interconnection, L.L.C. - Mid-Atlantic Interstate Transmission, L.L.C. Transmission Formula Rate Application (2016) - (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-211-000

26. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

27. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

28. In re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

29. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

30. In re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Appearance: compliance with statutes and regulations, prudence, cost/benefit, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

31. In re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel: tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

32. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (2016) - (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

33. In re: Emera Maine, Proposed Rate Increase in Rates (2016) - (Analysis and Advice to to Counsel: evaluation of management audit of implementation of Customer Information System on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2015-00360

34. In re: The Merger of the Southern Company and AGL Resources Inc.- Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Appearance: earnings, synergy savings, rates, operations, supply procurement, safety, and reliability on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

35. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Firm Transportation Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-142

36. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-130

37. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Gaz Metro LNG, L.P.; and National Grid LNG (2015-2016) - (Analysis and Advice to Counsel: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-129

38. In re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor Compliance Filing (2015) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-55

39. ENMAX Energy Corporation (EEC) 2015-2016 Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Appearance: cost allocation, rate design, non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

40. In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (2014) - (Advice to Counsel: impact on customers on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities BPU Docket No. EM1406

41. In re: Application of Baltimore Gas and Electric Company For Adjustments To Its Electric and Gas Base Rates (2014) (Analysis and Advice to Counsel in Settlement: earnings, investment tracker, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9355

42. In re: Columbia Gas of Massachusetts CY2013 Targeted Infrastructure Reinvestment Factor Compliance Filing (2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 14-83

43. In re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (2014-2015) - (Analysis and Advice to Counsel: impact on rates and consolidation of rates on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.U-33244

44. In the Matter of the Application of Ohio Power Company to Adopt a Final Implementation Plan for the Retail Stability Rider (2014) - (Analysis and Advice to Counsel: rate design)
    OH Public Utilities Commission Case No. 14-1186-EL-RDR

45. In re: Examination of Long-Term Natural Gas Hedging Proposals (2014-2015) - (Analysis and Advice to Counsel: natural gas procurement on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.R-32975-LPSC, ex parte

46. In re: 2013 Integrated Resource Planning Process for Southwestern Electric Power Company Pursuant to General Order Dated April, 20, 2012 (2014-2015 - (Analysis and Advice to Counsel: IRP design and evaluation on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.I-33013 SWEPCO, ex parte

47. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Adopt an Infrastructure Replacement Surcharge Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9332

48. In the Matter of the Application of Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9331

49. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013-2014) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 13-115

50. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013) - (Appearance: cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

51. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013) - (Appearance: expense tracker design/rates and evaluation on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9316

52. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9299

53. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 11-528

54. ENMAX Energy Corporation (EEC) 2012-2014 Regulated Rate Option Non-Energy Tariff Application (2012-2013) - (Analysis and Advice to Counsel: rate design and non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Application #1608745 Proceeding 2069

55. In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1 and for Other Appropriate Relief (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities Docket No. ER11080469

56. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2011) - (Appearance: investment tracker design/rates, cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1087

57. Electric Transmission Formula Rate Annual Informational Filing of Central Maine Power Company (2011) - (Advice to Counsel: formula transmission rates, cost allocation and rate design on behalf of the Maine Attorney General)
    Federal Energy Regulatory Commission Docket No. ER09-934-000 (2011)

58. Electric Transmission Formula Rate Annual Informational Filing of Bangor Hydro Electric Company (2011) - (Analysis, Report and Advice to Counsel: formula rate on behalf of the Massachusetts Attorney General)
    Federal Energy Regulatory Commission Docket No. ER09-938-000

59. Pennsylvania Public Utility Commission Office of Consumer Advocate Office of Small Business Advocate v. City of Bethlehem – Bureau of Water (2011) - (Appearance: cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania PUC Docket Nos. R-2011-2244756, C-2011-2246910, and C-2011-2248241

60. Southern California Edison Company Transmission Owners Tariff (2011) - (Analysis and Advice to Counsel: depreciation on behalf of M-S-R Public Power Agency)
    Federal Energy Regulatory Commission Docket No. ER11-2061-000

61. In the Matter of the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities under K.S.A. 66-1239 (2011) - (Appearance: advance determination of prudence on behalf of the Kansas Citizens' Utility Ratepayer Board)
    Kansas Corporation Commission Docket No. 11-KCPE-581-PRE

62. Midwest Independent Transmission System Operator, Inc., and Ameren Illinois Company (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Wholesale Distribution Service Customer Group)
    Federal Energy Regulatory Commission Docket No. ER11-2788-000

63. Electric Generation Plant Valuation Study (2010-2012) - (Analysis: generation plant valuation)
    California Department of Water Resources

64. Tampa Electric Company Wholesale Power Tariff (2010-2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Orlando Utilities Commission)
    Federal Energy Regulatory Commission Docket No. ER10-2061-000

65. Pacific Gas & Electric Company, Transmission Owner Tariff (2010-2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Transmission Agency of Northern California)
    Federal Energy Regulatory Commission Docket No. ER10-2026-000

66. Natural Gas Price Forecast Model Consulting (2008-2010) - (line of business development)
    FTI Consulting

67. Impact Evaluation Study of the District of Columbia Department of the Environment's Two-Year Pilot Reliable Energy Trust Fund Programs (2007-2008) - (Appearance: evaluation of implementation and cost effectiveness of energy efficiency, renewable energy, and demand response pilot programs on behalf of the District of Columbia Department of the Environment)
    D.C. Public Service Commission Formal Case No. 945

68. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2007-2008)- Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1053

69. In the Matter of the Investigation of Interconnection Standards in the District of Columbia (2006) - (Analysis and Advice to Counsel: interconnection standards and tariff design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1050

70. In the Matter of the Investigation into the Omnibus Utility Emergency Amendment Act of 2005, Specifically Regarding the Establishment of the Natural Gas Trust Fund Programs (2006) - (Analysis and Advice to Counsel: program design on behalf of the District of Columbia Department of the Environment)
    D.C. Public Service Commission Formal Case No. 1037

71. Emergency Application of the Potomac Electric Power Company For A Certificate of Public Convenience and Necessity To Construct Two 69kV Overhead Transmission Lines and Notice of The Proposed Construction of Two Underground 230kV Transmission Lines (2005-2006) - (Appearance: facilities need on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1044

72. Investigation Into Potomac Electric Power Company's Distribution Service Rates (2003-2005) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1032

73. Investigation of the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating Them Underground in the District of Columbia (2003) - (Analysis and Advice to Counsel: cost/benefit analysis on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1026

74. Guadalupe L. Garcia v. Ann Veneman, Secretary, US Department of Agriculture (2003-2006) - (Appearance: statistical analysis on behalf of the Plaintiff)
    U.S. District Court for the District of Columbia

75. Mirant Corporation, et al., Debtors (2003-2005) - (Analysis and Advice to Counsel: cost of service on behalf of the People's Counsel for the District of Columbia)
    U.S. District Court for the Northern District of Texas

76. Complaint: Office of the People's Counsel of the District of Columbia v. Mirant Americas Energy Marketing, L.P. (2003) - (Analysis and Advice to Counsel: cost of service on behalf of the People's Counsel for the District of Columbia)
    Federal Energy Regulatory Commission

77. Investigation into the Effect of the Bankruptcy of Mirant Corporation on Retail Electric Service in the District of Columbia (2003-2005) - (Appearance: customer and rate impact on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1023

78. Development and Designation of Standard Offer Service in the District of Columbia (2003-2007) - (Appearance: cost of service allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1017

79. Independent Review Panel, Project Management Plan, Ohio River Main Stem Study (2003-2005) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

80. Investigation into Affiliated Activities, Promotional Practices, and Codes of Conduct of Regulated Gas and Electric Companies (2002-2004) - (Analysis and Advice to Counsel: cost allocation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1009

81. Independent Review Panel, Ohio River Main Stem Study, System Investment Plan (2001) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

82. Joint Application of PEPCO and New RC, Inc. for Authorization and Approval of Merger Transaction (2001-2002) - (Appearance: cost allocation and affiliate transactions on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1002

83. Investigation into Explosions Occurring in Underground Distribution Systems of PEPCO (2001-2006) - (Analysis and Advice to Counsel: electric systems operation and planning on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 991

84. Pennsylvania-New Jersey-Maryland Power Pool/PJM LLC (ISO/RTO) (2000-2005) - (Member Working Group technical representation on behalf of The People's Counsel for the District of Columbia)

85. Trans Alaska Pipeline System 1996 Quality Bank Complaint Remand (2000-2008) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

86. Ohio River Main Stem Study, Independent Technical Review (1999) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

87. Investigation of January 1999 Electric Service Interruption (1999-2004) - (Appearance: emergency response evaluation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 982

88. Trans Alaska Pipeline System 1996 Quality Bank Complaint Appeal (1998-2000) - (Analysis and Advice to Counsel: technical record below on behalf of ExxonMobil)
    U.S. Court of Appeals for the District of Columbia

89. Electric Retail Competition Investigation (1997-2006) - (Appearance: electric utility restructuring, electric energy procurement, cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 945

90. Trans Alaska Pipeline System 1996 Quality Bank Complaint (1996-1998) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

91. Trans Alaska Pipeline System 1989 Quality Bank Complaint Remand (1995-1998) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

92. Prudhoe Bay Unit Operating Agreement Hearings (1995) - (Analysis and Advice to Counsel: cost of service on behalf of ExxonMobil)
    Alaska Oil and Gas Conservation Commission

93. Prudhoe Bay Unit Natural Gas Liquids Hearings (1995) - (Analysis and Advice to Counsel: liquids valuation on behalf of ExxonMobil)
    Alaska Department of Natural Resources/Department of Revenue (1995)

94. Potomac Electric Power Co. 3rd Integrated Least-Cost Plan (1995) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 917, Phase II

95. All American Pipeline Quality Bank Complaint (1994-1995) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

96. Trans Alaska Pipeline System 1989 Quality Bank Complaint Appeal (1994-1995) - (Analysis and Advice to Counsel: technical record below on behalf of ExxonMobil)
    U.S. Court of Appeals for the District of Columbia

97. Investigation of the January 1994 Energy Crisis (1994) - (Appearance: emergency response evaluation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 936

98. Washington Gas Light Co. Gas Rate Case (1994) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 934

99. Washington Gas Light Co. 3rd Integrated Least-Cost Plan (1994) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 921

100. Potomac Electric Power Co. Electric Rate Case (1993) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 929

101. Washington Gas Light Co. Gas Rate Case (1993) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 922

102. Trans Alaska Pipeline System Pumpability Complaint (1992) - (Analysis and Advice to Counsel: cost of service and rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

103. Potomac Electric Power Co. 2nd Integrated Least-Cost Plan (1992) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 917

104. Potomac Electric Power Co. Electric Rate Case (1992) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 912

105. Potomac Electric Power Co. Fuel Clause Audit and Productivity Improvement Plan (1991-2005) (Analysis, Participation in Technical Sessions, and Advice to Counsel; electric utility plant investment and operating costs productivity and benefit/cost analysis on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 766

106. Potomac Electric Power Co. Electric Rate Case (1991) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
D.C. Public Service Commission Formal Case No. 905

107. Anchorage Telephone Utility (1991-1995) - (Analysis and Advice to Counsel: cost of service)
Federal Communications Commission

108. Trans Alaska Pipeline System 1989 Quality Bank Complaint (1990-1993) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
Federal Energy Regulatory Commission

109. Telefonica Larga Distancia de Puerto Rico International Service Tariffs (1990-1992) - (Appearance: cost of service and rate design)
Federal Communications Commission

110. Southern Bell Intrastate Depreciation Study (1989-1990) - (Analysis and Advice to Counsel: telecommunications operation)
Florida Public Service Commission

111. Lake Erie Iron Ore Antitrust Litigation: Erie-Western Pennsylvania Port Authority v. Penn Central et al. (1988-1989) - (Analysis and Advice to Counsel: truck operations and damages on behalf of the Norfolk and Western Railroad)
U.S. District Court for the Eastern District of Pennsylvania

112. Unimar International Chapter 11 Reorganization (1988) - (Analysis and Advice to Counsel: cost of service on behalf of Unsecured Creditors)
U.S. Bankruptcy Court for the Western District of Washington at Seattle

113. National Forest Road Cost Analysis System (1986) - (Analysis: cost allocation system design)
U.S. Department of Agriculture, Forest Service

114. Puerto Rico Telephone Company Long Distance Facilities and Service Applications (1985-1990) - (Appearance: cost of service and rate design on behalf of the Puerto Rico Telephone Company)
Federal Communications Commission

115. All American Cable and Radio/AT&T de Puerto Rico International Rate Complaint (1985-1990) - (Appearance: cost of service and rate design on behalf of the Puerto Rico Telephone Company)
Federal Communications Commission

116. Caribbean Telecommunications Facilities Planning Docket (1984-1990) - (Appearance: operations forecast and planning on behalf of the Puerto Rico Telephone Company)
Federal Communications Commission

Exhibit KRP – 2

	A	B	C	D	E	F	G
1	**Attachment OCA-I-2-a-i**						
2	**PJM Transmission Enhancement Zonal Cost Allocation using Prior Method** (from Attachment OCA-I-2-i)					**RTEP "Black Box" Settlement: Allocation Factor Development**	
3	June - December 2007	$ 208,012.42					
4	January - May 2008	$ 526,829.62				**From Attachment OCA-I-1-c:**	
5	June - September 2008	$ 817,664.26				Total "Black Box" Settlement Credit	$ (49,567,831.44)
6	October - December 2008	$ 646,431.10					
7	January - May 2009	$ 1,621,701.26				2007-2010 PJM Transmission Enhancement Zonal Cost Allocation using Prior Method	$ (6,095,642.17)
8	June 2009	$ 428,639.74					
9	July - December 2009	$ 3,108,908.31				**From Attachment OCA-I-2-ii:**	
10	January - May 2010	$ 3,032,901.90				PECO Default Service Usage %	91.2%
11	June 2010	$ 1,065,591.01	2007-2010 Total	% of 2007-2015 Total			
12	July - December 2010	$ 6,402,033.17	$ 17,858,712.79	12.3%		**RTEP Credit to be Retained by PECO**	**$ (5,560,415.64)**
13	January - May 2011	$ 7,110,547.21					
14	June 2011	$ 1,492,843.91					
15	July - December 2011	$ 8,959,813.02					
16	January - April 2012	$ 6,103,190.94					
17	May 2012	$ 1,517,579.79					
18	June - 2012	$ 1,911,374.47					
19	June - December 2012	$ 11,475,732.98					
20	January - May 2013	$ 10,600,044.98					
21	June 2013	$ 2,015,829.61					
22	July - December 2013	$ 12,190,738.42					
23	January - May 2014	$ 12,007,357.98					
24	June 2014	$ 2,658,748.06					
25	July - December 2014	$ 16,065,782.06					
26	January 2015	$ 2,771,091.65	2011-2015 Total:				
27	Feb-Dec 2015	$ 30,482,008.15	$ 127,362,683.24				
28	TOTAL	$ 145,221,396.03	$ 145,221,396.03				

Exhibit KRP-2

Exhibit KRP – 3

Attachment OCA-I-1-c

	A	B	C	D	E	F	G	H
3	"Black Box" Settlement Credit							
5	**SOURCE:**							
6		FERC Docket No. EL05-121-009, Offer of Settlement						
7		June 15, 2016						
8		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 (	$ (49,567,831.44)
Total Transitional Credit	$ (33,411,938.56)
Total Expected Credit:	**$ (82,979,770.00)**

Exhibit KRP-3

Exhibit KRP – 4

	A	B	C	D	E	F	G	H	I	J
1	Attachment OCA-I-2-a-ii_v1									
2	**PECO EGS Shopping Statistics (excluding Unaccounted-For Energy)**									
3										
4	**YEAR**	**EGS Usage**	**Default Usage**	**Total Usage**	**EGS %**	**Default %**				
5	1/1/2003	3,460,077,974	35,884,666,922	39,344,744,897	8.8%	91.2%				
6	1/1/2004	4,874,098,226	35,354,593,032	40,228,691,258	12.1%	87.9%				
7	1/1/2005	2,256,160,787	39,191,835,282	41,447,996,070	5.4%	94.6%				
8	1/1/2006	828,990,063	39,587,707,105	40,416,697,168	2.1%	97.9%				
9	1/1/2007	648,355,773	40,858,680,659	41,507,036,431	1.6%	98.4%		378,207,534	23,834,230,384	24,212,437,918
10	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
11	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
12	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
13	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
14	1/1/2012	26,249,927,504	14,081,888,264	40,331,815,767	65.1%	34.9%		8.8%	**91.2%**	
15	1/1/2013	27,606,595,915	13,105,583,049	40,712,178,964	67.8%	32.2%				
16	1/1/2014	27,982,223,924	12,428,028,611	40,410,252,535	69.2%	30.8%				
17	1/1/2015	28,198,011,260	12,711,369,252	40,909,380,511	68.9%	31.1%				
18	1/1/2016	28,489,999,682	12,397,313,914	40,887,313,595	69.7%	30.3%				
19	1/1/2017	28,082,858,392	11,927,276,247	40,010,134,639	70.2%	29.8%				
20	1/1/2018	11,258,228,414	5,057,736,610	16,315,965,024	69.0%	31.0%				

Exhibit KRP-4

Exhibit KRP – 5

	A	BM	BN	BO	BP	BQ	CI	CQ	CR	CS	DJ
1	Attachment OCA-I-2-a-iii										
2						PJM Transmission Enhancement Zonal Cost Allocation Percentages June 2007 - January 2015					PJM
3									% Load Ratio Share =	100%	
4		Subtotals		Calendar Year Totals		Load Ratio Share Allocations (%)			Load Ratio Share Allocations ($)		
5							PECO			AE	PECO
6											
7	June - December 2007	$ 3,387,825		$ 3,387,825		June - December 2007	6.14%		June - December 2007	$70,128	$208,012
8	January - May 2008	$ 8,707,928				January - May 2008	6.05%		January - May 2008	$179,383	$526,830
9	June - September 2008	$ 13,515,112				June - September 2008	6.05%		June - September 2008	$278,411	$817,664
10	October - December 2008	$ 10,684,812		$ 32,907,851		October - December 2008	6.05%		October - December 2008	$220,107	$646,431
11	January - May 2009	$ 25,659,830				January - May 2009	6.32%		January - May 2009	$484,971	$1,621,701
12	June 2009	$ 6,782,274				June 2009	6.32%		June 2009	$128,185	$428,640
13	July - December 2009	$ 49,191,587		$ 81,633,692		July - December 2009	6.32%		July - December 2009	$929,721	$3,108,908
14	January - May 2010	$ 51,579,964				January - May 2010	5.88%		January - May 2010	$1,026,441	$3,032,902
15	June 2010	$ 18,122,296				June 2010	5.88%		June 2010	$360,634	$1,065,591
16	July - December 2010	$ 108,878,115		$ 178,580,375		July - December 2010	5.88%		July - December 2010	$2,166,674	$6,402,033
17	January - May 2011	$ 112,865,829				January - May 2011	6.30%		January - May 2011	$2,358,896	$7,110,547
18	June 2011	$ 23,695,935				June 2011	6.30%		June 2011	$495,245	$1,492,844
19	July - December 2011	$ 142,219,254		$ 278,781,018		July - December 2011	6.30%		July - December 2011	$2,972,382	$8,959,813
20	January - April 2012	$ 109,572,548				January - April 2012	5.57%		January - April 2012	$2,016,135	$6,103,191
21	May 2012	$ 27,393,137				May 2012	5.54%		May 2012	$501,294	$1,517,580
22	June 2012	$ 34,501,344				June - 2012	5.54%		June - 2012	$631,375	$1,911,374
23	July - December 2012	$ 207,143,195		$ 378,610,224		June - December 2012	5.54%		June - December 2012	$3,790,720	$11,475,733
24	January - May 2013	$ 193,626,152				January - May 2013	5.47%		January - May 2013	$3,486,593	$10,600,045
25	June 2013	$ 38,106,420				June 2013	5.29%		June 2013	$663,052	$2,015,830
26	July - December 2013	$ 230,448,741		$ 462,181,314		July - December 2013	5.29%		July - December 2013	$4,009,808	$12,190,738
27	January - May 2014	$ 221,129,981				January - May 2014	5.43%		January - May 2014	$3,825,549	$12,007,358
28	June 2014	$ 48,964,053				June 2014	5.43%		June 2014	$847,078	$2,658,748
29	July - December 2014	$ 295,870,756		$ 565,964,790		July - December 2014	5.43%		July - December 2014	$5,118,564	$16,065,782
30	January 2015	$ 53,495,978		$ 53,495,978		January 2015	5.18%		January 2015	$818,488	$2,771,092

Exhibit KRP-5

Exhibit KRP – 6

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 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 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

Exhibit KRP-6
Page 2

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,918,194,391	1,951,963,263
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,055,492,966	1,075,385,996
5	Large (or Ind.) (See Instr. 4)	1,411,765,065	1,390,410,448
6	(444) Public Street and Highway Lighting	30,325,951	31,081,649
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways	57,157,379	58,317,986
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,472,935,752	4,507,159,342
11	(447) Sales for Resale	39,488,223	30,244,836
12	TOTAL Sales of Electricity	4,512,423,975	4,537,404,178
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,512,423,975	4,537,404,178
15	Other Operating Revenues		
16	(450) Forfeited Discounts	20,200,057	26,952,800
17	(451) Miscellaneous Service Revenues	8,329,555	5,694,869
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	25,692,959	25,518,646
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-13,950,524	-24,527,510
22	(456.1) Revenues from Transmission of Electricity of Others	192,740,043	197,140,504
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	233,012,090	230,779,309
27	TOTAL Electric Operating Revenues	4,745,436,065	4,768,183,487

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/12/2010	Year/Period of Report End of 2009/Q4

Exhibit KRP-6
Page 3

ELECTRIC OPERATING REVENUES (Account 400)

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2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
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4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,858,586,744	1,918,194,391
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,036,416,060	1,055,492,966
5	Large (or Ind.) (See Instr. 4)	1,310,803,597	1,411,765,065
6	(444) Public Street and Highway Lighting	30,394,719	30,325,951
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways	59,409,377	57,157,379
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,295,610,497	4,472,935,752
11	(447) Sales for Resale	21,387,461	39,488,223
12	TOTAL Sales of Electricity	4,316,997,958	4,512,423,975
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,316,997,958	4,512,423,975
15	Other Operating Revenues		
16	(450) Forfeited Discounts	15,661,391	20,200,057
17	(451) Miscellaneous Service Revenues	8,893,558	8,329,555
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	26,775,686	25,692,959
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-8,912,002	-13,950,524
22	(456.1) Revenues from Transmission of Electricity of Others	193,610,760	192,740,043
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	236,029,393	233,012,090
27	TOTAL Electric Operating Revenues	4,553,027,351	4,745,436,065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Edison Company of Indiana, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

Exhibit KRP-6
Page 4

ELECTRIC OPERATING REVENUES (Account 400)

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3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales		
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)		
5	Large (or Ind.) (See Instr. 4)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers		
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity		
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds		
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property		
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,219,392	2,251,943
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	2,219,392	2,251,943
27	TOTAL Electric Operating Revenues	2,219,392	2,251,943

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment, PECO Energy Electric Tariff No. 5, Supplement No. 76 Effective December 1, 2018	: : : :	Docket No. M-2018-3005860

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct 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).

Signature: Karl R. Pavlovic
Karl R. Pavlovic

Consultant Address: PCMG and Associates, LLC.
22 Brookes Avenue
Gaithersburg, MD 20877

DATED: August 5, 2019
*277032

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Office of Consumer Advocate	)	
	)	
v.	)	**Docket Nos. M-2018-3005860**
	)	**C-2018-3006242**
PECO Energy Company	)	

SURREBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF THE

PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

October 24, 2019

EXHIBIT
OCA Statement
No. 1-SR
PENGAD 800-631-6989

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING ON AUGUST 5, 2019?

A. Yes. Exhibit KRP-1 to my direct testimony summarizes my qualifications and experience.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my direct testimony and responses to PECO information requests I explained that for the period June 2007 to December 2010: (1) PECO's FERC transmission stated rate contained a cost component for RTEP charges that PECO recorded to FERC Transmission Operating Expense Account No. 561.8,[1] (2) PECO recovered the costs of transmission service for its default PLR service customers through its PAPUC unbundled retail tariff transmission charges to default PLR service

[1] Pavlovic Direct, page 6, lines 2-6.

customers,[2] (3) PECO provided no data and/or information demonstrating that its transmission revenues were insufficient to recover its RTEP charges,[3] and (4) PECO's transmission revenues were more than sufficient to recover RTEP charges.[4] On that basis, I concluded that PECO should retain no RTEP credits for the period June 2007 to December 2010. I also explained that PECO's calculation of the RTEP credit refund for the period 2007 – 2010 is not based on RTEP charges actually incurred for the period June 2007 to December 2010 and is therefore a highly speculative number.[5]

The purpose of this surrebuttal testimony is to respond to PECO witness Bisti's rebuttal testimony that addresses: (1) my analysis and conclusion that PECO should not retain the RTEP credits for the period June 2007 to December 2010,[6] (2) the reasonableness of PECO's calculation of the 2007 – 2010 RTEP credit refund it proposes to retain,[7] and (3) whether PECO should refund to ratepayers the $5.5 million RTEP credits that PECO seeks to retain.[8]

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, I find that:

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[2] PECO-OCA-II-7; PECO-OCA-II-4 (Exhibit KRP-1SR).
[3] Pavlovic Direct, page 6, line 18 to page 7, line 3.
[4] Pavlovic Direct, page 8, lines 1-8; see also response to OCA-V-2 (Exhibit KRP-2SR).
[5] Pavlovic Direct, page 9, line 5 – page 12, line 8.
[6] Bisti Rebuttal, page 1, line 18 to page 2, line 10 and page 3, line 5 to page 13, line 17.
[7] Bisti Rebuttal, page 2, line 11 to page 3, line 6 and page 14, line 1 to page 16, line 10.
[8] Bisti Rebuttal, page 2, lines 6-10.

- RTEP charges were included in PECO's retail base rates during the 2007-2010 period;
- RTEP charges were included in PECO's FERC Network Integration Transmission Service (NITS) and Point-to-Point Service rates during the 2007-2010 period;
- The costs PECO incurred providing transmission service to other entities and load serving entities (LSEs) and to its default PLR service customers were one and the same;
- My analysis did not commingle revenues from different transmission services;
- PECO's calculation of the $5.5 million RTEP credits it seeks to retain is not supported by its actual PJM billed RTEP charges for the period June 2008 to December 2010.; and
- The $5.5 million of RTEP credits PECO seeks to retain should be refunded to ratepayers through the NBT.

Q. HAVE YOU PREPARED A LIST OF EXHIBITS TO YOUR TESTIMONY?

A. Yes. The following exhibits are referenced in and attached to this testimony.

KRP-1SR – OCA Responses to PECO-OCA-II-7 and PECO-OCA-II-4

KRP-2SR – PECO Response to OCA-V-2

KRP-3SR – Tariff Time Line

KRP-4SR – PaPUC Dkt. R-2010-2161575, Statement No. 9, Direct Testimony of Alan B. Cohn

KRP-5SR – PaPUC Dkt. P-2014-2409362, 12/4/14 Opinion and Order

KRP-6SR – FERC Dkt. ER97-3189-005, 3/16/98 Settlement Agreement

KRP-7SR – PECO 1998 and 1999 FERC Form 1 Reports, p. 321

KRP-8SR – FERC Dkt. RM04-12-000, 12/16/05 Order No. 668

KRP-9SR – PaPUC Dkts. R-00973953/P-00971265, 4/29/98 Joint Petition for Settlement

KRP-10SR– PaPUC Dkts. R-00973953/P-00971265, 4/29/98 Joint Petition for Settlement, Appendix A

KRP-11SR – PECO Exhibit No. JAB-6

KRP-12SR – PECO Exhibit No. JAB-5

B. MY ANALYSIS AND CONCLUSION THAT PECO SHOULD NOT RETAIN RTEP CREDITS FOR THE PERIOD JUNE 2007 TO DECEMBER 2010

Q. WHAT DOES WITNESS BISTI'S TESTIMONY ALLEGE REGARDING YOUR ANALYSIS AND CONCLUSION?

A. Witness Bisti maintains that my analysis does not provide a valid basis for requiring PECO to refund pre-2011 RTEP credits to retail customers because: (1) the analysis errs in ignoring the important fact that during the period 2011 through 2015 PECO recovered RTEP charges through the Transmission Service Charge (TSC) and Non-Bypassable Transmission Charge (NBT) reconcilable adjustment clauses,[9] (2) the analysis errs in assuming that how PECO records costs for accounting purposes determines how they are recovered for ratemaking purposes,[10] (3) the analysis errs in ignoring important differences in the kinds of transmission costs PECO incurs,[11] and (4) the analysis errs in commingling revenues from two different kinds of transmission service.[12] I address and rebut each of these alleged errors below.

[9] Bisti Rebuttal, page 3, line 4 to page 7, line 6.
[10] Bisti Rebuttal, page 8, lines 10-12 and page 9, line 4 to page 10, line 5.
[11] Bisti Rebuttal, page 8, lines 12-16 and page 10, line 6 to page 11, line 8.
[12] Bisti Rebuttal, page 8, lines 16-18 and page 11, line 9 to page 13, line 17.

Q. DO YOU HAVE ANY INITIAL CHRONOLOGICAL OR TERMINOLOGICAL OBSERVATIONS TO MAKE REGARDING THE ISSUES ADDRESSED BY WITNESS BISTI?

A. Yes. With regard to chronology, there are four sets of tariff rates involved in PECO's RTEP Credit refund proposal. (1) PECO's FERC 1998 transmission stated rates,[13] that were first effective January 1, 1999. (2) PECO's PaPUC restructuring unbundled retail tariff rates,[14] that also were first effective January 1, 1999. (3) PECO's 2010 PaPUC Transmission Service Charge (TSC) tariff rates,[15] that were first effective January 1, 2011. (4) PECO's 2015 PaPUC Non-Bypassable Transmission Service Charge (NBT) tariff rates,[16] that were first effective June 1, 2015. During the period at issue here, June 2007 through December 2010, one and two above were in effect, while three and four above were not (Exhibit KRP-3SR).

With regard to terminology, Witness Bisti refers frequently to Provider of Last Resort (POLR) service and to transmission and generation components costs and rates associated with POLR service.[17] The PaPUC tariff covering the period 1999 through 2010 refers, not to POLR service, but rather to "default PLR service" and I use the later locution in the testimony below.

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[13] PJM Open Access Transmission Tariff (OATT).
[14] PaPUC Electric Tariff No. 3.
[15] PaPUC Electric Tariff No. 4.
[16] PaPUC Electric Tariff No. 5.
[17] Bisti Rebuttal, pages 4-5, 10, and 12-13.

1. MY ANALYSIS DOES NOT IGNORE THE FACT THAT, DURING THE PERIOD OF 2011 THROUGH 2015, PECO RECOVERED RTEP CHARGES THROUGH THE TSC AND NBT RECONCILIABLE ADJUSTMENT CLAUSES.

Q. WHAT DOES WITNESS BISTI'S TESTIMONY STATE REGARDING THE TSC AND NBT?

A. Witness Bisti correctly explains that from 2011 to 2015, PECO recovered transmission costs through first the TSC and later the NBT[18] and that prior to 2011 PECO recovered its transmission costs through the unbundled transmission component of its retail base rates.[19] From this he concludes that

> "... the unbundled transmission component of PECO's retail rates did not include the PJM charges at issue in this proceeding [RTEP charges]. Indeed, during the period 2007-2010, the at-issue PJM charges [RTEP charges] were not included for recovery in *any* rate charged to *any* person or entity."[20]

Q. IS WITNESS BISTI ACCURATE IN STATING THAT PRIOR TO THE TSC, RTEP CHARGES WERE NOT RECOVERED IN ANY PECO RATE?

A. No. In its 2010 rate case proceeding that established the TSC, PECO Witness Cohn explained that PECO removed transmission costs from base rates and placed them in the TSC rider.[21]

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[18] Bisti Rebuttal, page 3, line 16 to page 4, line 2.
[19] Bisti Rebuttal, page 4, line 5 to page 5, line 5.
[20] Bisti Rebuttal, page 5, lines 6-9.
[21] PaPUC Docket No. R-2010-216575, Statement No. 9, page 24-25 and Exhibit ABC-6 (Exhibit KRP-4SR).

The transmission cost components removed from base rates are comprised of: (1) Network Service Costs, (2) RTEP Charges, (3) PJM Expansion Recovery Charge, (4) Transmission Cash Working Capital Cost, and (5) Gross Receipts Tax.[22] The TSC was effective January 1, 2011. Subsequently, in its 2014 Default Service Program (DSP-III) proceeding, PECO removed the RTEP Charges and PJM Expansion Recovery Charge from the TSC and placed them in the Non-Bypassable Transmission Charge (NBT) rider.[23]

Q. DOES YOUR ANALYSIS IGNORE THE FACT THAT THE TSC AND NBT ARE RECONCILIABLE ADJUSTMENT CLAUSES IN ITS ANALYSIS OF RECOVERY OF RTEP CHARGES DURING THE PERIOD JUNE 2007 THROUGH DECEMBER 2010?

A. No. While Witness Bisti presents that fact as a demonstration that RTEP charges were not recovered in PECO's rates prior to 2011, my analysis properly takes that fact as irrelevant to the question of RTEP charge recovery. The salient fact of the TSC and NBT is that they recover RTEP charges that were removed from base rates and placed first in the TSC and later in the NBT, thus demonstrating that RTEP charges were recovered through PECO's base tariff rates during the period June 2007 through December 2010.

2. MY ANALYSIS CORRECTLY ASSUMES THAT COST ACCOUNTING DETERMINES RECOVERY THROUGH RATES

[22] PaPUC Docket No. R-2010-216575, Statement No. 9, page 25-27 and Exhibits ABC-7 and ABC-8 (Exhibit KRP-4SR).
[23] PaPUC Docket No. R-2014-2409362, 12/4/14 Opinion and Order, pages 40-46 (Exhibit KRP-5SR).

Q. WHAT IS WITNESS BISTI'S TESTIMONY REGARDING COST ACCOUNTING AND RATE RECOVERY?

A. Witness Bisti states: (a) that my analysis errs in assuming that how PECO records costs for accounting purposes determines how they are recovered for ratemaking purposes, and (b) that the settlement underlying PECO's 1998 NITS rate specifically excluded all costs recorded in Account 561.[24]

Q. DOES YOUR ANALYSIS ERR IN ASSUMING THAT HOW COSTS ARE RECORDED FOR ACCOUNTING PURPOSES DETERMINES HOW THEY ARE RECOVERED FOR RATEMAKING PURPOSES?

A. No. My analysis correctly assumes that the costs recorded in PECO's regulatory accounts are the component building blocks of the revenue requirements that are the bases of PECO's rates. This is particularly the case with transmission rates, which are calculated purely on a cost basis by dividing the revenue requirement by peak demand without consideration of non-cost ratemaking policies and principals. For example, as discussed above, because regulatory cost accounts are the components of rates, PECO was able in 2010 to identify the RTEP charge component of its base rates and transfer that component to the TSC for recovery.

Q. DID PECO'S TRANSMISSION SETTLEMENT IN 1998 EXCLUDE ALL COSTS RECORDED IN ACCOUNT 561 FROM PECO'S NITS AND POINT-TO-POINT RATES?

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[24] Bisti Rebuttal, page 8, lines 10-12 and page 9, line 4 to page 10, line 5.

A. No. The 1998 transmission settlement removed only $2,766,000 of Account 561 Scheduling, System Control and Dispatching costs from the NITS and Point-to-Point revenue requirements.[25] The $2,766,000 of Scheduling, System Control and Dispatching costs were not, however, all the costs recorded in Account 561. For the years 1997, 1998 and 1999, PECO recorded $4,608,393, $5,681,472 and $5,857,840, respectively, in Account 561.[26]

Q. WHAT IS THE RELATIONSHIP OF ACCOUNT 561.8 TO THE ACCOUNT 561 REFERENCED IN THE 1998 TRANSMISSION SETTLEMENT?

A. Account 561.8 is a subaccount of the Account 561 referenced in the 1998 transmission settlement. In 2005, the FERC issued Order 668 which made a number of revisions to the FERC Uniform System of Accounts (USoA). One of those sets of revisions disaggregated the costs or expenses recorded in Account 561 into eight subaccounts:[27]

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 dispatching services;
561.5 Reliability, planning and standard development;
561.6 Transmission service studies;

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[25] 1998 Settlement Agreement (SA) Secs. 7, 8 and 9 and Attachments B-1, B-2, C-1, C-2, D-1 and D-2; The SA set all of PECO's FERC transmission rates under the PJM Open Access Transmission Tariff (OATT). (a) Reactive Supply and Voltage Control from Generation Sources Service – SA Sec. II.6. PJM OATT Schedule 2. (b) Network Integration Transmission Service – SA Sec. II.7.a. PJM OATT Attachment H-7. (c) Scheduling, System Control and Dispatch Service (Ancillary Services) – SA Sec. II. 7. b. PJM OATT Schedule 1A. (d) Long-Term and Short-Term Firm Point-to-Point Transmission Service – SA Sec. II.8. PJM OATT Schedule 7. (e) Non-Firm Point-to-Point Transmission Service – SA Sec. II.9. PJM OATT Schedule 8 (Exhibit KRP-6SR).
[26] PECO 1998 and 1999 FERC Form 1 Report, page 321, line 84 (Exhibit KRP-7SR).
[27] Order 668 at paragraphs 47-48 (pages 23-24) accounts 561.1-561-3, paragraphs 55-57 (pages 26-27), paragraphs 61-62 (pages 29-30) accounts 561.6-561.7, paragraphs 63 and 67-68 (pages 30-33) accounts 561.4 and 561.8, and pages 71-75 (Exhibit KRP-8SR).

561.7 Generation Interconnection studies;

561.8 Reliability, planning and standard development services.

As can be seen, the Scheduling, System Control and Dispatching costs excluded from the NITS and Point-to-Point rates were disaggregated into Account 561.4. Thus costs recorded in Account 561.8 would not be excluded from the NITS and Point-to-Point revenue requirements and rates.

Q. WHAT DO YOU CONCLUDE FROM THIS?

A. I conclude that the PECO Scheduling, System Control and Dispatching costs excluded from the revenue requirement by the 1998 settlement were recorded in Account 561.4, while RTEP charges that PECO incurred for the period June 2007 through December 2010 were properly recorded in Account 561.8, which costs were not excluded from the revenue requirement.

3. THE TRANSMISSION COSTS THAT PECO INCURS IN OBTAINING TRANSMISSION SERVICE FOR DEFAULT PLR SERVICE CUSTOMERS AND PROVIDING TRANSMISSION SERVICE TO OTHER ENTITIES AND LOAD SERVING ENTITIES (LSES) ARE ONE AND THE SAME

Q. WHAT DOES WITNESS BISTI'S TESTIMONY STATE REGARDING TRANSMISSION SERVICE COSTS INCURRED BY PECO?

A. Witness Bisti states that my analysis ignores important differences between the kinds of transmission service costs that PECO incurs: (a) in providing NITS transmission service to other entities, including other LSEs, and (b) as an LSE in obtaining transmission service for its retail customers.[28] Specifically, Witness Bisti argues that during the 2007-2010 period: (1) PECO as an LSE incurred costs "for transmission service from transmission owners to move generation to the PECO zone,"[29] by which he means RTEP charges,[30] (2) these RTEP charges "had to be recovered in the transmission component of its unbundled retail rates,"[31] and (3) "these RTEP charges were not, and could not be part of PECO's network service rate."[32]

Q. WHAT IS AN LSE?

A. LSE is an acronym for "load serving entity," which in this context is any electric supplier providing electricity to retail customers in the PECO zone. As the default PLR service provider in the PECO zone, PECO did and does operate as an LSE. During the 2007-2010 period, PECO provided transmission service to retail default PLR service customers under its unbundled base rates described above.

Q. IS WITNESS BISTI CORRECT IN THIS TESTIMONY?

A. It is true that during the 2007-2010 period PECO incurred RTEP charges. It is also true that during the 2007-2010 period these RTEP charges were in PECO's unbundled retail base rates, as PECO explained in its 2010 rate case. It is decidedly false that during the

[28] Bisti Rebuttal, page 8, lines 12-16 and page 10, line 6 to page 11, line 8.
[29] Bisti Rebuttal, page 10, lines 17-19.
[30] Bisti Rebuttal, page 11, lines 1-4.
[31] Bisti Rebuttal, page 10, line 19 to page 11, line 1.
[32] Bisti Rebuttal, page 11, lines 5-6.

2007-2010 period RTEP charges were not part of PECO's network service rate, as explained immediately above.

Q. WHAT WAS THE RETAIL BASE RATE TARIFF PROVISION UNDER WHICH PECO RECOVERED TRANSMISSION SERVICE COSTS DURING THE 2007-2010 PERIOD?

A. PECO's retail base rates were unbundled in its 1998 restructuring proceeding pursuant to a 4/29/98 Joint Petition for Settlement (JPS) subsequently approved by the Commission in its 5/14/98 Final Order.[33] The JPS unbundled the base rates into five cost components: Transmission, Distribution, Competitive Transition Charge/Intangible Transition Charge, Shopping Credit and Generation.[34] The transmission and distribution components were subject to a combined cap until 12/31/2006 and the generation rate was capped until January 1, 2011.[35] While the transmission and distribution components were subject to a combined cap, the transmission component was allowed to increase, in which case the increase would be offset by a corresponding decrease in the distribution component.[36] Regarding the transmission cost component,[37] the settlement stated explicitly that it was calculated and used only for the purposes of unbundling rates, because the "Pennsylvania Public Utility Commission does not regulate the rates for transmission service."[38] The Commission did not have the authority to set a retail transmission rate. In recognition of

[33] Pa. PUC Dockets R-00973953 and P-00971265.
[34] 1998 Joint Petition for Settlement (JPS), Sec. B.20, pages 11-12 and Schedule 1 (Exhibit KRP-9SR).
[35] Bisti Rebuttal, footnotes 8 and 9.
[36] JPS, Sec. B.21, page 15 (Exhibit KRP-9SR).
[37] JPS, Sec. B.21, page 12, Schedule 1, column 1 (Exhibit KRP-9SR).
[38] JPS, Sec. B.21, page 12, Schedule 1, column 1, note (b) (Exhibit KRP-9SR).

this fact, rather than stating a transmission rate, the compliance base rate tariff contained the following statement.

> "TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service."[39]

Stated more succinctly, the costs of transmission service under PJM's OATT were passed through to PECO's default PLR service customers that did not obtain transmission service on their own.

Q. WHAT DO YOU CONCLUDE FROM THIS?

A. I conclude that my analysis does not ignore Witness Bisti's purported differences between PECO zone transmission service costs and the costs of transmission service for PECO's default PLR service customers because there were no differences.

4. MY ANALYSIS DOES NOT IMPROPERLY COMMINGLE REVENUES FROM DIFFERENT KINDS OF TRANSMISSION SERVICE

Q. WHAT IS WITNESS BISTI'S TESTIMONY REGARDING THE COMMINGLING OF TRANSMISSION SERVICE REVENUES?

A. Witness Bisti states that my analysis improperly commingles: (a) revenues from PECO's transmission service to other entities and other LSEs with (b) revenues from the retail

[39] JPS, Appendix A, Tariff Electric PA. P.U.C. No. 3 effective January 1, 1999, pages 35, 38, 39, 42, 43, 45, 46, 47, 48, 50, 52, 54, 57, 59, 61, 63 and 65 (Exhibit KRP-10SR).

component included in PECO's retail base rates to default PLR service customers.[40] This testimony is in response to my analysis that during the 2007-2010 period: (1) PECO's NITS revenues were more than sufficient to cover PECO's RTEP charges,[41] and (2) if those revenues were insufficient, PECO could have applied to the FERC for an increase to its NITS rates.[42] Specifically, Witness Bisti argues that PECO's NITS revenues during the 2007-2010 period are not relevant to the issue of recovery of the costs of transmission service PECO provided to default PLR service customers,[43] because PECO's retail base rates to default PLR service customers did not include cost recovery of RTEP charges.[44]

Q. IS WITNESS BISTI CORRECT IN THIS TESTIMONY?

A. No, for three reasons. First, PECO's NITS revenues are relevant because, as demonstrated above, PECO's NITS rates included a component for RTEP charges (Section III.B.2, above). Second, as also demonstrated above, PECO's retail base rates to default PLR service customers included cost recovery of RTEP charges (Section III.B.1, above). Third, the RTEP charges in PECO's retail base rates to default PLR service customers were a pass through of the RTEP charges in PECO's NITS rates (Section III.B.3, above).

C. PECO'S CALCULATION OF RTEP CREDITS BASED ON PECO'S PJM BILLED RTEP CHARGES DOES NOT SUPPORT THE REASONABLENESS OF THE $5.5 MILLION RTEP CREDITS IT PROPOSES TO RETAIN.

[40] Bisti Rebuttal, page 8, lines 16-18 and page 11, line 9 to page 13, line 17.
[41] Bisti Rebuttal page 11, line 13 to page 12, line 6.
[42] Bisti Rebuttal page 13, lines 3-7.
[43] Bisti Rebuttal, page 12, lines 13-19 and page 13, lines 10-11.
[44] Bisti Rebuttal, page 12, line 19 to page 13, line 2 and page 12, lines 12-13.

Q. WHAT DOES WITNESS BISTI'S TESTIMONY STATE REGARDING THE CALCULATION OF RTEP CREDITS IT PROPOSES TO RETAIN FOR THE PERIOD JUNE 2007 TO DECEMBER 2010?

A. Witness Bisti states that: (1) PECO's calculation of the RTEP credits it proposes to retain is based on the reasonable estimated RTEP charges that PJM used to calculate the settlement RTEP credits,[45] and (2) that PECO's actual RTEP charges for the period June 2008 to December 2010 support the reasonableness of the estimated $5.5 million RTEP credits it proposes to retain.[46]

Q. ARE THE PJM ESTIMATES OF PECO ZONE RTEP CHARGES REASONABLE?

A. The FERC found the PJM estimates to be a reasonable basis for the settlement calculation of PECO zone RTEP credits. That, however, does not make PECO's calculation of the RTEP credits to retain reasonable

Q. DO PECO'S PJM BILLED RTEP CHARGES AND CALCULATION OF RTEP CREDITS SUPPORT THE REASONABLENESS OF PECO'S PROPOSAL TO RETAIN $5.5 MILLION RTEP CREDITS?

A. No. Whatever the reasonableness of PJM's calculation of RTEP credits, that reasonableness is lost when PECO uses RTEP charges that were not the basis of the calculated RTEP credits to calculate the RTEP credits it seeks to retain. PECO's PJM billed RTEP charges for the June 2007 to December 2010 period are simply irrelevant to the issue of calculating the settlement RTEP credits associated with that period.

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[45] Bisti Rebuttal, page 14, line 9 to page 15, line 7.
[46] Bisti Rebuttal, page 15, line 13 to page line 12 and Exhibit JAB-4R.

D. THE $5.5 MILLION RTEP CREDITS THAT PECO SEEKS TO RETAIN SHOULD BE REFUNDED TO RATEPAYERS THROUGH THE NBT

Q. WHAT IS WITNESS BISTI'S TESTIMONY REGARDING REFUNDING THE RTEP CREDITS FOR THE 2007-2010 PERIOD THROUGH THE NBT?

A. Witness Bisti maintains that the $5.5 million in RTEP credits for the 2007-2010 period that it proposes to retain should not be refunded through the NBT because "PECO's pre-2011 base rates did not reflect any RTEP charges."[47]

Q. DID PECO'S PRE-2011 BASE RATES REFLECT RTEP CHARGES?

A. Yes. As I explained above, PECO's pre-2011 tariff base rates passed the charges for transmission service through to its default PLR service customers.

Q. IS THE $5.5 MILLION IN RTEP CREDITS ALL OF THE RTEP CREDITS ATTRIBUTABLE TO 2007-2010 PERIOD?

A. No. PECO calculates that a total of $6,095,642 in FERC settlement RTEP credits are attributable to the 2007-2010 period,[48] but proposes to retain only 91.2%,[49] $5.560,416,[50] of that total that PECO calculates to be attributable to its default PLR service customers during that period. 8.8% or $535,226 ($6,095,642 minus $5,560,416) in 2007-2010 period RTEP credits PECO attributes to Electric Generation Supplier (EGS) customers.

[47] Bisti Rebuttal, page 13, lines 10-17 and footnote 28.
[48] PECO Exhibit JAB-6, "2007-2010 PJM Transmission Enhancement Zonal Cost Allocation using Prior Method" (Exhibit KRP-11SR).
[49] PECO Exhibit JAB-6, "PECO Default Service Usage%" (Exhibit KRP-11SR) and PECO Exhibit JAB-5 PECO EGS Shopping Statistics (Exhibit KRP-12).
[50] PECO Exhibit JAB-6, "RTEP Credit to be retained by PECO."

Q. HOW DOES PECO PROPOSE TO REFUND RTEP CREDITS FOR THE 2011-2015 PERIOD?

A. For the period 2011-2015 PECO proposes to refund the RTEP credits to customers through the NBT.

Q. WHY IS PECO REFUNDING THE 2011-2015 RTEP CREDITS THROUGH THE NBT.

A. The FERC settlement RTEP credits were calculated based on PJM's estimates of the RTEP charges billed to all the LSEs serving retail customers in the PECO zone during the 2011-2015 period, both PECO and EGS. The NBT is a non-bypassable rate adjustment clause mechanism that applies to all retail customers in the PECO zone. By refunding the 2011-2015 RTEP credits through the NBT, PECO effects a refund to all retail customers in the PECO zone.

Q. HOW WERE THE RTEP CREDITS FOR THE 2007-2015 PERIOD CALCULATED?

A. The FERC settlement RTEP credits for the 2007-2010 period were calculated based on PJM's estimates of the RTEP charges billed to all the LSEs serving retail customers in the PECO zone during the 2007-2010 period, both PECO and EGS.

Q. HOW SHOULD THE RTEP CREDITS FOR THE 2007-2010 PERIOD BE REFUNDED TO CUSTOMERS?

A. Because the FERC settlement RTEP credits for the 2007-2010 period were calculated based on the estimated RTEP charges billed to PECO and EGSs, all of those RTEP credits,

$5,560,416 and $535,226 respectively, should be refunded to PECO's default PLR service customers and EGS customers through the NBT.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by PECO.

Exhibit KRP – 1SR

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-7: Reference Dr. Pavlovic's Direct Testimony at page 6, lines 1-6. Please describe in detail how "cost-based ratemaking principles" demonstrate that PECO's base retail transmission rates effective from June 2007 through December 31, 2010, reflected RTEP charges.

RESPONSE: Under the rate of return/revenue requirement/peak demand ratemaking model used before the FERC and specifically in the case of PECO's 1998 transmission rate model, rates consist of a component for operating expenses and taxes and a component for return on rate base. PECO's June 2007 to December 31, 2010 RTEP charges as a load serving entity were recorded to FERC Operating Expense Account No. 561.8, did not constitute Scheduling, System Control and Dispatch Service costs which were excluded from PECO's 1998 FERC transmission revenue requirement, and thus were included in the operating expense component of PECO's 1998 FERC transmission rates. During the period June 2007 through December 31, 2010 PECO's retail Distribution and Transmission tariff charges included charges for transmission service for customers receiving Default PLR Service. Therefore, PECO's base retail transmission rates effective from June 2007 through December 31, 2010 reflected RTEP charges.

Response prepared by: Dr. Karl Pavlovic

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

18 CFR Ch. I Pt.101

(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

Exhibit KRP – 2SR

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held December 4, 2014

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
James H. Cawley
Pamela A. Witmer
Gladys M. Brown, Statement

Petition of PECO Energy Company for Approval of its Default Service Program for the period from June 1, 2015 through May 31, 2017	P-2014-2409362

OPINION AND ORDER

BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition are the Exceptions of PECO Energy Company (PECO or the Company), the Retail Energy Supply Association (RESA), the Office of Small Business Advocate (OSBA), and the Philadelphia Area Industrial Energy Users Group (PAIEUG) filed on October 10, 2014, to the Recommended Decision (R.D.) of Administrative Law Judge (ALJ) Cynthia Williams Fordham, issued on September 30,

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

Docket No. M-2018-3005860

Response of PECO Energy Company
To Interrogatories of the Office of Consumer Advocate

Response Date: 9/27/2019

OCA-V-2

Please refer to page 10, lines 5-12 of the Direct Testimony of Joseph A. Bisti and PECO Energy Company FERC Form 1 Reports for the years 2006-2011. For the period 2006-2011, please provide PECO's FERC Form 1 Report Account 456.1 "Revenues from Transmission of Electricity of Others" balance (page 300, line 22, column (b)) disaggregated by PJM OATT revenues under (a) Attachment H-7, (b) Schedule 2, (c) Schedule 7, (d) Schedule 8 and (e) Schedule 1A that are not recorded in Account 457.1 "Regional Transmission Service Revenues."

RESPONSE:

Revenues are not a balance sheet account and therefore it is not appropriate to refer to FERC Form 1 values as "balances." With that understanding, PECO's FERC Form 1 Report Account 456.1 "Revenues from Transmission of Electricity of Others" values (page 300, line 22, column (b) for the years 2006-2011 are shown below. Please also refer to supporting Attachment OCA-V-2.

Year	FERC Form 1 Account 456.1 "Revenues from Transmission of Electricity of Others"
2006	$ 160,624,236
2007	$ 197,140,504
2008	$ 192,740,043
2009	$ 193,610,760
2010	$ 176,563,746
2011	$ 193,348,873

PECO does not have data available to support disaggregation of these values into the above-specified components.

Exhibit KRP – 3SR

PECO TRANSMISSION TARIFF TIMELINE

Date	Description	PECO FERC Transmission Stated Rates ER97-3189-005	PECO PaPUC Unbundled Base Rates R-00973953 P-00971265	PECO PaPUC Transmission Service Charge (TSC) rates R-2010-2161575	PECO PaPUC Non-Bypassable Transmission Service Charge (NBT) rates P-2014-2409362	FERC Regional Transmission Enhancement Project (RTEP) Credits Historical Period EL05-121-009	PECO Proposed RTEP Credit Retention Period
		(A)	(B)	(C)	(D)	(E)	(F)
January 1, 1999	PECO PJM OATT Transmission tariffs effective: Network Intergrated Transmission Service (Attachment H-7), Auxilliary Services (Schedule 1A), Reactive Supply and Voltage Control from Generation Sources Service (Schedule 2), Point-to-Point Transmission Service (Shcedules 7 and 8)						
	Peco PaPUC Unbundled tariffs effective: Distribution, Transmission, CTC/ITC, Shopping Credit and Generation						
June 1, 2007	PJM began billing the RTEP Charges to the PECO zone						
	Start of EL05-121-009 RTEP Credit historical refund period						
December 31, 2010	PECO PaPUC Unbundled tariffs expired						
January 1, 2011	PECO PaPUC Transmission Service Charge (TSC) tariff effective						
June 1, 2015	PECO PaPUC Non-Bypassable Transmission Service Charge (NBT) tariff effective; RTEP charges moved from TSC to NBT						
December 31, 2015	End of EL05-121-009 RTEP Credit historical refund period						

Exhibit KRP – 4SR

PECO ENERGY COMPANY
STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2010-2161575

DIRECT TESTIMONY

WITNESS: ALAN B. COHN

SUBJECTS: REVENUE ALLOCATION AND RATE DESIGN

DATED: MARCH 31, 2010

IV. TRANSMISSION SERVICE CHARGE RIDER

46. Q. How have transmission costs charged to PECO by the PJM Interconnection LLC ("PJM") been reflected in developing the Company's proposed base rates and base rate revenue requirement?

A. All of the costs charged to PECO by PJM have been included in base rate revenue requirements in developing the proposed base rates. However, the Company is proposing an alternative cost recovery method that would recover such costs under a Transmission Service Charge ("TSC"). The proposed TSC is a Section 1307 adjustment clause in the form set forth in PECO's proposed TSC Rider. The tariff pages that comprise the TSC Rider are provided as PECO Exhibit ABC-6. 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 the base rates established at the conclusion of this case. I would note that initially all of the major electric utilities in Pennsylvania have a transmission of cost recovery clause like the TSC or have asked to implement one.

47. Q. What categories of costs would be recovered under the TSC Rider?

A. As I explained, the TSC Rider would recover all transmission charges imposed by PJM, as set forth on PJM's bills to PECO, which would include, principally, network service charges and regional transmission enhancement plan charges, and any other load-serving entity ("LSE") transmission-related charges not paid by energy suppliers, as set forth in the Company's Supply Master Agreements approved in the Company's default-service proceeding.

48. Q. Have you prepared an exhibit that shows the transmission costs that will be removed from base rates and recovered through the TSC?

A. Yes, Exhibit ABC- 7 shows, by category, the PJM-imposed costs that PECO will remove from base rates and recover through a TSC.

49. Q. Will the TSC be by-passable?

A. Yes, if the TSC proposed by PECO is approved as filed, it will be by-passable. The proposed TSC will apply only to customers that purchase default service from the Company because the transmission costs being recovered are incurred by PECO for default service. EGS are LSEs, as defined by PJM, and, as such, are charged the same categories of costs for transmission service that PECO would recover under the TSC for the default service it provides. Thus, recovering transmission costs under the TSC assures competitive neutrality between default service and service offered by an EGC since the TSC, as a by-passable charge, would be included in PECO's price-to-compare.

50. Q. How would the costs recovered under the TSC be allocated to customer classes and recovered from customers?

A. The costs to be recovered under the TSC would be allocated to customer classes and recovered from default service customers on the same basis those costs would be allocated to customer classes and recovered from customers if they were included in base rates. Mr. Howard Gorman discusses the allocation of transmission costs in PECO Statement No. 8. To assure that the costs allocated to each rate schedule will be recovered from customers in the same manner as those costs would be recovered in base rates, PECO proposes to allocate the total transmission charges it pays based upon the network service peak load of its default service customers. The TSC will replace the current transmission charges that retain the declining-block rate structure. As noted above, the change in rate design along with recovery under a reconcilable mechanism will assure a level playing field with competitive suppliers.

51. Q. What are the principal elements of the TSC?

A. The TSC, as proposed by the Company, consists of the following principal elements:

(1) The TSC will be calculated separately for each customer class. For residential customers, the TSC will be a kWh charge. For commercial and industrial customers, the TSC will be a kW charge.

(2) The TSC will become effective on a service-rendered basis at the same time as the base rates established in this case.

(3) Subsequent proposed TSC rates and accompanying information will be filed by December 1 of each year to become effective on January 1 of the next year and remain in effect for 12 months. Accordingly, the TSC Computation Year will be the 12 months beginning on January 1 and ending on December 31 of the same year. The TSC Reconciliation Year will be the 12 months ending on October 31 immediately preceding the Computation Year.

(4) The costs included in the calculation of the TSC for each Computation Year will be based on the projected transmission costs for that period, and the charge will be calculated on the basis of projected default service sales. A working-capital component will also be included in the charge, which is discussed separately in Section V.

(5) The TSC will be fully reconcilable. The reconciliation will compare revenue billed under the TSC to PECO's actual transmission costs recoverable under the TSC for the Reconciliation Year. Interest on over and under-collections will accrue at the legal rate set forth in 41 P.S. § 202 (currently 6.0%).

52. Q. Have you prepared an exhibit showing the calculation of the TSC?

A. Yes. Exhibit ABC-8 shows the mechanics of the calculation of the TSC based on the transmission costs claimed in this case and test year sales.

V. GENERATION SUPPLY AND TRANSMISSION WORKING CAPITAL RIDER

53. Q. What are the components PECO proposes to include in its Generation Supply Adjustment ("GSA") and its TSC to reflect the cost of working capital requirements associated with providing generation and transmission service for default service customers?

A. PECO proposes to include a Generation Supply Working Capital ("GSWC") charge in its GSA and a Transmission Cost Working Capital ("TCWC") charge in its TSC. The GSWC and TCWC charges are being added in order to "unbundle" the working capital revenue requirement associated with a portion of PECO's default generation supply and transmission service costs by recovering that revenue requirement in the GSA and TSC, which apply only to default service customers, rather than in base rates, which are charged to all (shopping and non-shopping) customers. The GSWC and TSWC components of the GSA and TSC will recover the portion of the generation and transmission service working capital revenue requirement that would be avoided if a customer were served by an EGS in lieu of taking default service.

54. Q. What portion of PECO's default generation service and transmission service working capital requirement would not be incurred if a customer received service from an EGS?

A. The working capital requirement that PECO avoids when a customer shops corresponds to the working capital requirement an EGS incurs when it serves a PECO

TRANSMISSION SERVICE CHARGE

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;

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.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $356 per mW

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

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 a rate of 6% and shall be calculated form the month of over or under collection 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 (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 freconciliation 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 = $0.00 per location

(C) Indicates Change

PECO Energy Company
PJM Transmission Costs
($1000)

Network Service Cost for the PECO Zone			
2010 Peak Load		8338	MW
Network Service Charge	$	20,942	per MW-yr
Total Network Service Charges	$	174,604	
Regional Transmisson Expansion Plan charges			
Estimated 2010 payments	$	13,872	
PJM expansion Recovery Charge	$	259	
Cash Working Capital for transmission Cost	$	2,969	Exhibit ABC-9
Gross Receipts Tax	$	12,020	
Total Cost to be Recovered in Surcharge	$	203,723	

PECO Energy Company
Calculation of the Transmission Service Charge

Network Service Cost for the PECO Zone			
2009 Peak Load		8338	MW
Network Service Charge	$	20,942	per MW-yr
Total Network Service Charges	$	174,604	
Regional Transmisson Expansion Plan charges			
Estimated 2010 payments	$	13,872	
PJM Expansion recovery Charge		259	
Cash Working Capital for transmission Cost	$	2,969	Exhibit ABC-9
Gross Receipts Tax	$	12,020	
Total Cost to be Recovered in Surcharge	$	203,723	

Rate Class	NSPL(1)		Revenue Requirement	Recovery Units kW or kWh		Rate	
Residential	0.3647	$	74,283	10130440	$	0.0073	per kWh
RH	0.0509	$	10,367	2636620	$	0.0039	per kWh
OP	0.005	$	1,018	290626	$	0.0034	per kWh
Small C&I	0.2525	$	51,430	28329115	$	1.82	per kW-month
C&I	0.3271	$	66,625	33204342	$	2.01	per kW-month
Lighting	0	$	-	220000	$	-	per location per month
Total	1.000	$	203,723				

(1) per Exhibit HSG-5

Exhibit KRP – 5SR

related to Hourly Pricing Transition and recovery of PJM charges.

(3) Recovery of Certain PJM Charges

48. The issue of whether certain PJM charges should be recovered by PECO through a non-bypassable transmission service charge is reserved for litigation.[7] The electric service tariff pages and supplier tariff provisions referenced in the Joint Petition do not change the current assignment of responsibility for PJM charges to load-serving entities (except for meter error correction charges which will now be allocated to all load-serving entities as permitted by the PJM tariff instead of requiring default service suppliers to cover all such costs). PECO will address any Commission determinations regarding collection of PJM charges through a non-bypassable transmission charge in a subsequent compliance filing. Nothing in this Joint Petition shall prejudice the parties with respect to their litigation position in opposition to or support of a non-bypassable transmission service charge, provided, however, that PECO shall support a non-bypassable transmission service charge in accordance with the following paragraphs.

a) The non-bypassable transmission service charge shall recover the following PJM charges from all distribution customers on a class basis: (1) Transmission Enhancement charges (a/k/a Regional Transmission expansion Plan ("RTEP") (PJM bill line 1108); (2) Expansion Cost Recovery charges (PJM bill line 1730); and (3) Generation Deactivation/ Reliability Must Run ("RMR") charges (PJM bill line 1930) for which charges are set after the approval of PECO's Revised DSP III by the Commission.

(b) Generation Deactivation/RMR charges will continue to be the responsibility of DSP II wholesale default service suppliers until the terms of the applicable DSP II supply master agreements expire.

(c) Costs to implement this non-bypassable transmission service charge will be included in the non-bypassable transmission service charge and allocated to classes consistent with the methodology used in PECO's current transmission service charge.

(d) PECO will amend its Electric Generation Supplier Coordination Tariff to include an appendix listing those PJM billing items that are the responsibility of EGSs.

49. Should the Commission approve a non-bypassable transmission service charge for PECO distribution customers, Joint Petitioners agree to PECO's implementation of the non-bypassable transmission charge as described in Paragraph 48.

50. Joint Petitioners further agree that the charges listed in Paragraph 48 are the only charges that shall be included in a non-bypassable transmission service charge if such charge is approved by the Commission for PECO's service territory. Unaccounted for Energy, meter error correction charges and any other PJM charges shall not be included in any PECO non-bypassable transmission service charge or litigated in this proceeding (provided, however, that all issues with respect to Network Integration Transmission Service ("NITS") may be litigated in this proceeding).

F. Standard Offer Program

(1) Program Administration

51. PECO's currently-effective EGS Standard Offer Program ("Standard Offer Program" or "SOP"), including the cost recovery mechanisms approved by the Commission in the DSP II Orders, will continue until the earlier of: (1) six months following a Commission Order modifying the SOP as a result of a settlement reached through the stakeholder process outlined in Paragraphs 57-61 below; (2) a Commission Order modifying the SOP as a result of a statewide investigation of standard offer customer referral programs; or (3) May 31, 2017.

52. PECO will post the discounted SOP prices to its "SUCCESS" EGS website at the time each quarterly PTC is published.

In regard to the Exceptions of PAIEUG, we are in agreement with PECO that PAIEUG misconstrues the Partial Settlement and PECO's proposed procurement schedule and that the basis for the potential higher risk premiums alleged by PAIEUG in the wholesale bids for hourly-priced service should not be a concern. The timing of the proposed Hourly Pricing Transition within the Partial Settlement is such that wholesale default suppliers would not need to factor in the risk premiums as alleged by PAIEUG. Accordingly, for all of the reasons above, we shall adopt the recommendation of the ALJ that PECO be allowed to implement hourly-priced default service for Medium Commercial customers who are properly outfitted with interval meters as outlined in the Joint Petition. Therefore, we shall deny the Exceptions filed by the OSBA and PAIEUG on this issue.

B. Recovery of Certain PJM Charges

1. Use of a Non-Bypassable Rider

a. Positions of the Parties

PECO initially proposed that load serving entities (LSEs), including EGSs, continue to be responsible for transmission costs that comprise various PJM charges, including Generation Deactivation/RMR charges, NITS charges and RTEP charges. However, in light of the FirstEnergy EDCs' proposal in their DSP III proceedings to collect certain PJM bill charges through a non-bypassable charge, PECO indicated from the beginning of this proceeding that it would monitor the FirstEnergy EDCs' proceedings and take into consideration any Commission direction to the FirstEnergy EDCs as it might apply to PECO's proposals for DSP III. PECO St. No. 2 at 18, n.3; PECO St. No. 2-R at 17; PECO R.B. at 8.

Thereafter, in response to the recent *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of their Default Service Programs,* Docket Nos. P-2013-2391368, P-2013-2391372, P-2013-2391375 and P-2013-2391378 (Order entered July 24, 2014) (*FirstEnergy DSP III Order)*, PECO proposed a non-bypassable transmission service charge for all distribution customers, which includes RTEP charges, Expansion Cost Recovery charges (ECRCs) and generation deactivation charges attributable to PJM designations qualifying for such payments after Commission approval of DSP III, but excludes NITS as directed by the Commission. Tr. at 39-40. PECO also proposed to exclude PJM charges for both unaccounted for energy (UFE) and meter error correction charges from a non-bypassable transmission service charge. *Id.*

RESA recommended that PECO assume the cost responsibility for all PJM charges, including NITS, for all load, including default service and shopping load, and recover the costs of that responsibility from all customers through a non-bypassable charge. RESA M.B. at 28-39. RESA R.B. at 7-13.

PAIEUG objected to PECO's reliance on the *FirstEnergy DSP III Order* as justification for its recommendation concerning PJM charges. PAIEUG R.B. at 8. PAIEUG contended that since there was a settlement in the FirstEnergy proceeding, the Order only applies to the FirstEnergy territory. PAIEUG asserted that settlement agreements that are approved by the Commission do not have precedential effect. PAIEUG R.B. at 13-14.

b. ALJ's Recommendation

The ALJ recommended that PECO's proposal be adopted. The ALJ stated that PECO's proposal for a non-bypassable transmission service charge for all distribution customers includes RTEP; TEC/ECRC; and RMR charges and excludes

NITS, UFE and meter error correction charges from a non-bypassable transmission service charge. R.D. at 50-51.

c. Exceptions and Replies

In its Exception No. 1, PAIEUG states that the ALJ misapplied the evidence presented in this proceeding from both PECO and RESA and, in actuality, a non-bypassable rider on PECO's system for any customer class is unreasonable and unnecessary. PAIEUG explains that currently, PECO recovers generation, transmission, transmission-related and distribution costs from its default service customers, but recovers only distribution costs from its shopping customers, as the remaining costs are collected by these customers' EGSs. PAIEUG notes that in this proceeding, both PECO and RESA propose to implement a non-bypassable rider to transfer the collection of transmission-related costs from EGSs to PECO for all customers, shopping and non-shopping. PAIEUG claims that neither PECO nor RESA presented any evidence that would warrant this change in *status quo*. PAIEUG Exc. at 3-4.

PAIEUG states that PECO relies entirely on inapplicable findings from a recent Commission Order disposing of the FirstEnergy Companies' DSP III as evidence in support of the proposed non-bypassable rider. PAIEUG avers that PECO's reliance on this Order conflicts with language in the Order establishing the scope of the settlement achieved among the parties to the FirstEnergy proceeding as well as the Commission's longstanding policies establishing that negotiated settlement agreements are not precedential. PAIEUG asserts that granting PECO's proposed non-bypassable rider based upon the findings in the *FirstEnergy DSP III Order* conflicts with the non-precedential nature of settlement agreements approved by the Commission and would discourage parties from entering into future settlement agreements by creating a risk of prejudicial treatment in subsequent litigation. PAIEUG Exc. at 5-6.

Additionally, PAIEUG avers that RESA has only offered two irrelevant claims purporting to establish a change in circumstances from PECO's DSP II Order, where the Commission rejected a similar proposal to recover transmission-related costs on a non-bypassable basis. PAIEUG explains that RESA can only set forth unsubstantiated claims of rate volatility while alternatively attempting to demonstrate a change in circumstances based upon the Commission's unrelated *Guidelines for Use of Fixed Price Labels for Products With a Pass Through Clause,* Docket No. M-2013-2362961 (Order entered November 14, 2013) (*Fixed Price Order*). However, PAIEUG claims that RESA has been unable to provide any evidence of actual volatility in transmission-related costs with the sole basis for RESA's argument rely on nothing more than testimony claiming such costs are "unpredictable." PAIEUG asserts that RESA's claims are speculative and not supported by any data or objective facts and, therefore, fail to satisfy any burden of proof. Additionally, PAIEUG claims that RESA's efforts to portray the Commission's *Fixed Price Order* as a "change in circumstances" also fails to justify the proposed non-bypassable rider. PAIEUG notes that RESA raised the same argument in the FirstEnergy DSP III proceeding, where the Commission found that nothing in the *Fixed Price Order* constitutes a "changed circumstance" justifying non-bypassable recovery of transmission-related costs. PAIEUG opines that the ALJ's recommendation to implement a non-bypassable rider on PECO's system must be rejected. PAIEUG Exc. at 6-7.

PAIEUG also avers that the ALJ erred in allowing PECO's oral rejoinder testimony into the record. According to PAIEUG, PECO chose the oral rejoinder stage of this proceeding to propose adoption of a non-bypassable rider for all customers even though the Company had adequate opportunity to raise such a proposal as part of its case-in-chief or even in rebuttal testimony. PAIEUG states that although the ALJ finds that PECO's claim of providing notice to the parties via one line in the Company's Direct Testimony regarding PECO's monitoring of *FirstEnergy's DSP III* proceeding was adequate notice, review of the procedural circumstances surrounding PECO's oral rejoinder confirm that the ALJ's findings are inconsistent with the Commission's regulations regarding the presentation of evidence. PAIEUG opines that PECO's oral rejoinder should be stricken from the record in this proceeding. PAIEUG Exc. at 9. PAIEUG submits that notice of an EDC monitoring another, unrelated EDC's DSP proceeding, combined with another party's proposal for a non-bypassable rider, does not provide adequate due process for any party to respond much less litigate a proposal raised only during oral rejoinder. *Id.* at 10-12.

In its Replies to Exceptions, PECO first responds to PAIEUG's Exception that a non-bypassable charge is unreasonable, stating that it is inconsistent with the Commission's conclusion on pages 22-23 of the *FirstEnergy DSP III Order* that the recovery of PJM Transmission Charges on a non-bypassable basis would be beneficial to customers. While PECO agrees with PAIEUG that settlements are not generally precedential, PECO avers that PAIEUG never explains why the Commission's conclusion in approving the FirstEnergy Settlement that FirstEnergy customers will receive a benefit from the non-bypassable recovery of transmission charges does not apply to customers in PECO's service territory. PECO opines that its proposed exclusion of NITS costs, as well as additional charges originally proposed by RESA which are not transmission-related, appropriately mitigates any PAIEUG concerns that a non-bypassable TSC creates insurmountable problems for Large C&I customers in the negotiation of contracts with EGSs. As a result, PECO maintains that the ALJ correctly found the record supports its proposal and provides no basis for PAIEUG's objections. PECO R. Exc. at 7-8.

Next, in reply to PAIEUG's assertions with regard to PECO's oral rejoinder testimony, PECO submits that the Commission previously found that testimony submitted in response to arguments made by opposing party witnesses, as is the case here, in no way violates the Commission's regulations regarding the presentation of evidence (52 Pa. Code ¶ 5.243). *See, Pa.PUC v. Western Utils., Inc., Docket No.*

R-00963856, 1998 WL 201481, at 8-9 (Pa.P.U.C. Jan. 28, 1998). According to PECO, the Company explained PECO's proposed non-bypassable TSC at the evidentiary hearing in response to RESA's surrebuttal testimony that PECO's response to the developments in the FirstEnergy EDCs' proceedings in the Company's rebuttal testimony was "insufficient." Moreover, PECO asserts that the issue of recovery of PJM Charges has been extensively developed on the record in this proceeding. PECO maintains that, as the ALJ correctly determined, PAIEUG had the opportunity to present evidence opposing a non-bypassable TSC prior to PECO's rejoinder testimony. PECO R. Exc. at 8.

RESA also filed Replies to the Exception of PAIEUG with regard to the recovery of PJM Charges. RESA avers that PAIEUG is patently wrong on all of its points and, therefore, the Commission should enter an order that would require PECO to assume the cost responsibility for all PJM Charges, including NITS, and recover the costs from all customers through a non-bypassable charge. According to RESA, when costs are allocated based on regulatory action or control, those costs are not market-based costs, are subject to change, and are volatile. RESA maintains that the non-market-based nature of all the PJM Charges makes them non-hedgeable wholesale cost obligations that are unpredictable. As such, RESA asserts there is no market-based, transparent way to reasonably calculate future rate increases to the PJM Charges and then accurately factor them into retail pricing. This results in customers paying something other than the actual costs of the PJM Charges unless the EDC assumes the cost responsibility for the PJM Charges for all load and leverages its right to full and current cost recovery, claims RESA. RESA opines that this outcome, which would result from adopting the Partial Settlement, as modified by its Exceptions, would treat all customers fairly and equally. RESA R. Exc. at 12-14.

RESA further argues that Commission's *Fixed Price Order* places practical constraints on the ability of EGSs to recover the costs of future rate increases in non-market-based charges because under the present process, there is only one way for an

EGS to guarantee its ability to recover from customers the future, unpredictable rate changes in PJM Charges and that is to offer a variable-priced product. RESA avers that the practical impact of the *Fixed Price Order* for the competitive market is that EGSs assessing how to deal with unpredictable future rate changes in PJM Charges need to determine whether to rely exclusively on variable contracts to recover these costs or take the risk of offering fixed-price contracts knowing that the contracts will likely be cancelled if the EGS attempts to recover the costs from the customer. According to RESA, neither result is good for customers because each limits the variety of potential competitive products and competitive pricing that could be offered. RESA opines that requiring PECO to assume the cost responsibility for all load would lead to significant positive impacts for customers given the practical effect of the *Fixed Price Order*. RESA R. Exc. at 14-16.

d. Disposition

Based upon the evidence of record, we are in agreement with the ALJ's recommendation that the transmission cost recovery proposed in the Partial Settlement by the Joint Petitioners is reasonable and should be approved. We are in agreement with PAIEUG that settlements are not precedential. We find, however, that our determination in this proceeding is consistent with our recent determination in the FirstEnergy DSP III proceeding that the non-bypassable recovery of certain PJM transmission charges is beneficial to customers. We also conclude that PAIEUG has failed to demonstrate in this proceeding that these costs are better recovered in some manner other than the procedure the Parties agreed to within the FirstEnergy DSP III case. We further conclude that PAIEUG's assertions with regard to PECO's oral rejoinder testimony in this proceeding was properly rejected by the ALJ as PECO clearly indicated early in the process that it was monitoring the FirstEnergy proceeding and would reconsider its original proposal herein concerning transmission cost recovery. Accordingly, we shall deny the Exceptions of PAIEUG on this issue and adopt the ALJ's recommendation.

Exhibit KRP – 6SR

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March 16, 1998

FILED
OFFICE OF THE SECRETARY
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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	PJM LLC
By: [signature]	By: Barry Spector / rpc
Title: ATTORNEY	Title: ATTORNEY
ALLEGHENY	PJMICC
By: Robert Weinberg / rpc	By: David Kleppinger / rpc
Title: ATTORNEY	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
<u>for Network Integration Transmission Service</u>

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
<u>for Network Integration Transmission Service</u>

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

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

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 /GB

Vilna Waldron Gaston
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202-467-7000

Attorneys for PECO Energy Company

Dated: March 16, 1998

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have on this 16th day of March, 1998, caused the foregoing document to be sent by first class mail to all parties on the Restricted Service List adopted by the Presiding Administrative Law Judge in Docket No. ER97-3189-005.

Glen S. Bernstein
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(202) 467-7000

Attorney for PECO Energy Company

Exhibit KRP – 7SR

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	12/31/1998	Dec. 31, 1998

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	138,845	63,967
54	(542) Maintenance of Structures	7,315	2,084
55	(543) Maintenance of Reservoirs, Dams, and Waterways	173,933	29,228
56	(544) Maintenance of Electric Plant	978,411	818,765
57	(545) Maintenance of Miscellaneous Hydraulic Plant	882,256	892,193
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,180,760	1,806,237
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	4,977,387	4,480,457
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,880,785	1,822,966
63	(547) Fuel	7,526,135	8,121,500
64	(548) Generation Expenses	228,165	374,868
65	(549) Miscellaneous Other Power Generation Expenses	382,176	537,861
66	(550) Rents		129,268
67	TOTAL Operation (Enter Total of lines 62 thru 66)	10,017,261	10,986,463
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	837,315	790,538
70	(552) Maintenance of Structures	105,398	110,482
71	(553) Maintenance of Generating and Electric Plant	3,185,942	3,187,362
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	195,259	247,365
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	4,323,914	4,335,747
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	14,341,175	15,322,210
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,246,504,301	768,103,925
77	(556) System Control and Load Dispatching	7,265,633	8,858,047
78	(557) Other Expenses	8,000	492,793
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,253,777,934	777,454,765
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,062,865,433	1,632,472,997
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,427,832	3,453,042
84	(561) Load Dispatching	5,681,472	4,608,393
85	(562) Station Expenses	57,921	195,389
86	(563) Overhead Lines Expenses	101,745	1,137,380
87	(564) Underground Lines Expenses	2,926	285,125
88	(565) Transmission of Electricity by Others		
89	(566) Miscellaneous Transmission Expenses	3,918,685	14,630,917
90	(567) Rents	6,684,145	4,789,649
91	TOTAL Operation (Enter Total of lines 83 thru 90)	19,874,726	29,099,895
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	2,702,418	
94	(569) Maintenance of Structures	296,313	533,876
95	(570) Maintenance of Station Equipment	5,424,156	8,357,174
96	(571) Maintenance of Overhead Lines	256,368	4,148,855
97	(572) Maintenance of Underground Lines	280,999	275,273
98	(573) Maintenance of Miscellaneous Transmission Plant	5,396,974	8,064,592
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	14,357,228	21,379,770
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	34,231,954	50,479,665
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	4,509,988	7,168,213

Contains Privileged Information - Do Not Release

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	/ /	Dec. 31, 1999

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	289,943	138,845
54	(542) Maintenance of Structures	7,811	7,315
55	(543) Maintenance of Reservoirs, Dams, and Waterways	232,987	173,933
56	(544) Maintenance of Electric Plant	677,139	978,411
57	(545) Maintenance of Miscellaneous Hydraulic Plant	626,351	882,256
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,834,231	2,180,760
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	5,411,963	4,877,387
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,961,381	1,880,785
63	(547) Fuel	4,874,566	7,526,135
64	(548) Generation Expenses	171,810	228,165
65	(549) Miscellaneous Other Power Generation Expenses	162,424	382,176
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,170,181	10,017,261
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	599,505	837,315
70	(552) Maintenance of Structures	120,276	105,398
71	(553) Maintenance of Generating and Electric Plant	2,939,474	3,185,942
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	308,323	195,259
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,967,578	4,323,914
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	11,137,759	14,341,175
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,105,272,900	1,246,504,301
77	(556) System Control and Load Dispatching	149,473	7,265,633
78	(557) Other Expenses		8,000
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,105,422,373	1,253,777,934
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,988,096,635	2,062,865,433
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,655,772	3,427,832
84	(561) Load Dispatching	5,857,840	5,681,472
85	(562) Station Expenses	90,237	57,921
86	(563) Overhead Lines Expenses	3,397	101,745
87	(564) Underground Lines Expenses	931	2,926
88	(565) Transmission of Electricity by Others		
89	(566) Miscellaneous Transmission Expenses	3,167,893	3,918,685
90	(567) Rents	6,045,089	6,684,145
91	TOTAL Operation (Enter Total of lines 83 thru 90)	16,821,159	19,874,726
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	2,780,953	2,702,418
94	(569) Maintenance of Structures	236,329	296,313
95	(570) Maintenance of Station Equipment	5,950,348	5,424,156
96	(571) Maintenance of Overhead Lines	459,178	256,368
97	(572) Maintenance of Underground Lines	386,739	280,999
98	(573) Maintenance of Miscellaneous Transmission Plant	1,358,129	5,396,974
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	11,151,676	14,357,228
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	27,972,835	34,231,954
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	1,083,324	4,509,988

Exhibit KRP – 8SR

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 101

(Docket No. RM04-12-000; Order No. 668)

Accounting and Financial Reporting for Public Utilities Including RTOs

(Issued December 16, 2005)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations to update the accounting requirements for public utilities and licensees, including independent system operators and regional transmission organizations (collectively referred to as RTOs). The Commission is also amending its financial reporting requirements for the quarterly and annual financial reporting forms for these entities. These updates to the Commission's Uniform System of Accounts and the financial reporting requirements will allow for better comparability between public utilities and will result in improved transparency of financial information and will facilitate better understanding of RTO costs.

EFFECTIVE DATE: The amended regulations will become effective **[insert date 30 days after publication in the FEDERAL REGISTER]**, with the accounting and financial reporting changes and updates to become effective January 1, 2006.

45. One commenter supports the specific account structure the Commission proposes, as well as its applicability to both RTOs and non-RTO public utilities. However, that commenter suggests the Commission realign the grouping of the new accounts under two new functions (system control and transmission services) that it proposes should be created.[41]

46. Finally, a commenter notes that, in the text of the NOPR's discussion of Accounts 561.1, 561.2 and 561.3, the NOPR states that these proposed accounts are for use by both non-RTO public utilities and RTOs.[42] However, in the proposed text of the USofA for Accounts 561.1, 561.2 and 561.3, the proposed language specifically states that the accounts are to include expenses incurred by the regional transmission service provider, with no mention in the proposed text of non-RTO public utilities. The commenter suggests that the Commission revise the proposed text of the USofA for proposed Accounts 561.1, 561.2 and 561.3 to specifically state that the accounts may be used by RTOs, other public utilities and licensees, consistent with the NOPR's language.

iii. Commission Conclusion

47. The proposed accounts for recording load dispatch, scheduling and system control expenses provide greater transparency concerning the types of costs incurred by both RTOs and non-RTO public utilities in providing transmission services. Therefore, we

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[41] APPA at 19.

[42] See SCE at 3.

will adopt the proposed accounting for load dispatch, scheduling and system control expenses. However, based upon the comments received, we will adopt the proposed accounting with certain clarifications and modifications as discussed below.

48. The instructions to Accounts 561.1, 561.2 and 561.3 are revised to make clear that the accounts are to be used by both RTOs and non-RTO public utilities. Additionally, the items list of Account 561.2 has been revised to include certain items included in replaced Account 561, Load Dispatching, which were inadvertently not included on the list. These modifications add clarity as to which entities are to use the accounts and what types of costs are to be recorded in the load dispatch, scheduling and system control expense accounts.

49. We will not adopt one commenter's suggestion to realign the newly created accounts under its suggested new functions: system control and transmission service. The expanded expense accounts contained in the transmission function provide the requisite transparency concerning the activities and related costs incurred by public utilities, including RTOs, in providing transmission service for ratemaking and other Commission purposes. Moreover, the account structure appropriately herein adequately separates market service and transmission service activities.

50. Finally, we clarify that, to the extent that RTOs and non-RTO public utilities perform the same activities for load dispatch, scheduling and system control, then the costs of those activities should be accounted for in the same manner and recorded in the same accounts. For example, if an RTO incurs costs to manage the region-wide

allow consolidated reporting of *de minimus* amounts or alternatively guidance on the specific expenses to be recorded in the account.[46]

53. Other commenters support the proposed changes but believe the Commission should require additional accounts to offer more transparency and comparability. Specifically one commenter believes that Account 561.5 should be augmented by additional accounts for the portion of system planning, development and maintenance expenses that relate to market design initiatives and activities of RTOs, as opposed to control area operation.[47]

54. Finally, one commenter believes that the structure of this new account allows for inclusion of generation-related costs such as resource planning.

iii. Commission Conclusion

55. As the Commission explained in the NOPR, the existing USofA does not provide a specific expense account to record expenses for system planning and development activities. The Commission will adopt Account 561.5 as proposed as modified and discussed below. Commenters raise questions about the scope of planning costs that are to be recorded in Account 561.5 and how to record costs incurred relative to the different transmission planning time-scales, such as short-term, intermediate-term, and long-term. We will modify the instructions to Account 561.5 to allow inclusion of all transmission

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[46] See Indicated NYTO at 9-10.

[47] See City of Santa Clara, California at 21-22.

system planning time-scale planning costs, not just long-term planning. We will therefore modify the title of the account to Account 561.5, Reliability, Planning and Standards Development, to reflect the fact that planning costs other than long-term are to be recorded in Account 561.5.

56. RTOs are directed to report costs of system planning, development, and maintenance expenses in Account 561.5. We clarify to the extent that public utilities and licensees that are not RTOs perform similar activities; they should also include the costs that they incur for system planning and standards development in Account 561.5. We also clarify that all system planning and standards development costs recorded in this account are to be transmission related.

57. The Commission declines at this time to augment Account 561.5 with additional accounts for the portion of system planning, development and maintenance expenses that relate to market design initiatives and activities of RTOs, as opposed to control area operation. We have created a new regional market expense function and all market planning and development costs shall be recorded in the appropriate market expense account based on the nature of the planning and development costs incurred.

3. Proposed Accounts for Study Costs

i. Accounting NOPR

58. The USofA does not specially provide accounts for recording costs incurred to perform generation interconnect and transmission service studies. Therefore, the Commission proposed to create Account 561.6, Transmission Service Studies, to record

only be expensed in rare circumstances.[50] One commenter requests that the Commission clarify that the new expense accounts for study costs are not intended to cover all study costs, but only those costs that are neither reimbursed by customers nor capitalized. Alternatively, this commenter requests clarification that utilities may still charge out or capitalize such study costs as they have in the past.[51] Another commenter requests that the Commission exempt RTO member utilities from the proposed USofA changes for study costs because it provides little additional information. Alternatively, this commenter requests a waiver to eliminate reporting study costs in Account 561.6 and Account 561.7 because the costs are largely reimbursed by the RTO and will appear in the RTO financial reports. Additionally, this commenter requests that the cost of transmission service and generator interconnect studies be treated as capital expenditures.[52]

iii. Commission Conclusion

61. The Commission will adopt the proposed accounts for recording generation interconnection and transmission service study costs as clarified below. We clarify that Accounts 561.6 and 561.7 are only to be used to record the costs incurred by public utilities, including RTOs, to conduct studies for transmission service requests and

[50] National Grid at 10-12, Indicated NYTOs at 6 -10.

[51] National Grid at 10-12.

[52] Indicated NYTOs at 6 -10

generator service requests, respectively, when the costs are not directly reimbursable by a specific customer and the costs are otherwise charged to expense under the USofA..

62. Additionally, we clarify that the Commission did not propose any change and does not do so now related to the recording of the costs of conducting transmission and generation interconnect studies in Account 186, Miscellaneous Debits, by public utilities, including RTOs, pending reimbursement by the entity requiring the service. We further clarify that the Commission did not intend to change any capitalization requirements related to study costs. Public utilities are to continue to follow the Commission's existing rules and regulations for cost capitalization.

4. Accounts for RTO Billings

i. Accounting NOPR

63. In the NOPR, the Commission proposed to create three new sub-accounts in order to provide greater transparency for the payments made by public utilities and licensees to RTOs. The three new proposed sub-accounts are Account 561.4, Scheduling, System Control and Dispatching Services; Account 561.8, Reliability Planning and Standards Development Services; Account 575.7, Market Facilitation, Monitoring and Compliance Services.[53] The proposed new sub-accounts will be used by public utilities and licensees to record their share of costs billed to them by an RTO. Additionally, the Commission

[53] NOPR at P 65-68.

66. Finally, one commenter requests that the Commission not adopt an absolute rule that information on the three new cost sub-accounts be part of the settlement statements.[56] This commenter believes it will be expensive to include such cost breakdowns in monthly customer settlement statements. This commenter states that RTOs have sophisticated billing software that is not easy to modify and that a number of RTOs would have to make expensive and time-consuming changes to their billing systems in order to incorporate the required cost information directly into monthly settlement statements. This commenter suggests that a more flexible approach would recognize the reality that different RTOs have different software capabilities and allow each entity to comply with the Commission's requirement in their own efficient way.

iii. Commission Conclusion

67. The Commission will adopt the new accounts for RTO billings proposed in the NOPR with the modification discussed below. As the Commission explained in the NOPR, these new accounts will allow each RTO member to record its share of the RTO's total monthly operating costs in these new sub-accounts. The Commission will also require each RTO provide a breakdown of the allocation of that RTO's operational costs within each of the three sub-accounts. However, the Commission will not require RTOs to include this information in its monthly settlement statements because of software costs to implement changes to the RTO billing systems. Instead, the Commission will permit

[56] See ISO/RTO Council at 3-4.

RTOs to use another format to provide the information to its members. However, RTOs are nevertheless directed to provide a breakdown of the cost allocation to the three new sub-accounts on the date the billings are issued.

68. The Commission also clarifies that Account 575.7 is to be used only for costs billed to utilities by RTOs for market administration, monitoring and compliance services.

5. Account for Revenue From Transmission of Electricity

i. Accounting NOPR

69. In the NOPR, the Commission proposed to add a new sub-account to Account 456, Other Electric Revenues, in order to provide greater transparency by transmission owners for the revenues received for use of their transmission facilities.[57]

ii. Commenters

70. Commenters were generally supportive, but request that the Commission provide additional clarification.[58] One commenter requests that the Commission provide even more transparency regarding the particular sources of those revenues and how they relate to common ratemaking categories. This commenter suggests the Commission implement accounting for transmission revenues that would enable customers and the Commission to monitor whether previously accepted rates generate more than an appropriate level of

[57] NOPR at P 73-74.

[58] TAPS at 6-8, International Transmission at 7.

16. In part 101, Operation and Maintenance Expense Accounts, Account 561, Load Dispatching (Major only) is removed.

17. In part 101, Operation and Maintenance Expense Accounts, new expense accounts 561.1, 561.2, 561.3, 561.4, 561.5, 561.6, 561.7, 561.8, 569.1, 569.2, 569.3, 575.1,575.2, 575.3, 575.4 575.5, 575.6, 575.7, 575.8, 576.1, 576.2, 576.3, 576.4 and 576.5 are added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

561.1 Load dispatch-Reliability.

This account shall include the cost of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to manage the reliability coordination function as specified by the North American Electric Reliability Council (NERC) and individual reliability organizations. These activities shall include performing current and next day reliability analysis. This account shall include the costs incurred to calculate load forecasts, and performing contingency analysis.

561.2 Load dispatch-Monitor and operate transmission system.

This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This account shall also include the expense incurred to manage transmission facilities to maintain system reliability and to monitor the real-time flows and direct actions according to regional plans and tariffs as necessary.

ITEMS

1. Receive and analyze outage requests
2. Reschedule outage plans
3. Monitor solution quality field data values, providing model updates to NERC and coordinating network model changes across all systems
4. Conduct operating training related to NERC certification
5. Monitor generation resources and communicate expected dispatch actions
6. Ensure ancillary service requirements are met
7. Directing switching
8. Controlling system voltages
9. Obtaining reports on the weather and special events
10. Preparing operating reports and data for billing and budget purposes

561.3 Load dispatch-Transmission service and scheduling.

This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to process hourly, daily, weekly and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System (OASIS). It shall also include the expenses incurred to operate the automated transmission service request system and to monitor the status of all scheduled energy transactions.

561.4 Scheduling, system control and dispatching services.

This account shall include the costs billed to the transmission owner, load serving entity or generator for scheduling, system control and dispatching service. Include in this account service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities.

561.5 Reliability, planning and standards development.

This account shall include the cost of labor, materials used and expenses incurred for the system planning of the interconnected bulk electric transmission systems within a planning authority area.

ITEMS

1. Developing and maintaining transmission system models to evaluate transmission system performance.

2. Maintaining and applying methodologies and tools for the analysis and simulation of the transmission systems for the assessment and development of transmission expansion plans.

3. Assessing, developing and documenting transmission expansion plans.

4. Maintaining transmission system models (steady-state, dynamics, and short circuit).

5. Collecting transmission information and transmission facility characteristics and ratings.

6. Notifying participants of any planned transmission changes that may impact their facilities.

7. Developing and reporting on transmission expansion plans for assessment and compliance with reliability standards.

8. Developing reliability standards for the planning and operation of the interconnected bulk electric transmission systems that serve the United States, Canada, and Mexico.

9. Developing criteria and certification procedures for reliability authorities, transmission operators and others.

10. Outside services employed

Note: The cost of supervision, customer records and collection expenses, administrative and general salaries, office supplies and expenses, property insurance, injuries and damages, employee pension and benefits, regulatory commission expenses, general advertising, and rents shall be charged to the customer accounts, service, and administrative and general expense accounts contained in the Uniform System of Accounts.

561.6 Transmission service studies.

This account shall include the cost of labor, materials used and expenses incurred to conduct transmission services studies for proposed interconnections with the transmission system. Detailed records shall be maintained for each study undertaken and all reimbursements received for conducting such a study.

561.7 Generation interconnection studies.

This account shall include the cost of labor, materials used and expenses incurred to conduct generation interconnection studies for proposed interconnections with the transmission system. Detailed records shall be maintained for each study undertaken and all reimbursements received for conducting such a study.

561.8 Reliability planning and standards development services.

This account shall include the costs billed to the transmission owner, load serving entity, or generator for system planning of the interconnected bulk electric transmission system. Include also the costs billed by the regional transmission service provider for system reliability and resource planning to develop long-term strategies to meet customer demand and energy requirements. This account shall also include fees and expenses for outside services incurred by the regional transmission service provider and billed to the load serving entity, transmission owner or generator.

* * * * *

Exhibit KRP – 9SR

PECO ENERGY

PECO Settlement

Legal Department

File

JL 16 Attys

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Settlement Attachment L. Smith 3 Consults Settlement Only

APR 30 1998
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Assistant General Counsel

April 29, 1998

Hand Delivery

James McNulty, Secretary
Pennsylvania Public Utility Commission
Room B-20, North Office Building
Harrisburg, PA 17105-3265

Re: PECO Energy Company's Application For Approval Of Its Restructuring Plan et. al., Docket Nos. R-00973953 and P-00971265 - Joint Petition for Settlement

Dear Secretary McNulty:

On behalf of the signatory parties, enclosed for filing are three copies of a Joint Petition For Settlement of PECO Energy Company's Restructuring Plan and Related Appeals And Application For A Qualified Rate Order And Application For Transfer Of Generation Assets.

Sincerely,

Paul Bonney

Paul Bonney

PRB/mbo

Enclosures

cc: w/enclosures
The Honorable John M. Quain, Chairman
The Honorable Nora Mead Brownell, Commissioner
The Honorable John R. Hanger, Commissioner
The Honorable David W. Rolka, Commissioner
The Honorable Robert K. Bloom, Commissioner
Service List (Active & Inactive Parties)

113018

17a. On April 14, 1998, ALJ Chestnut issued a recommended decision concerning the issues in the Supplier Tariff docket. On April 20, 1998, parties filed exceptions to ALJ Chestnut's decision and the matter is presently pending before the Commission for decision.

18. On and after March 5, 1998, the Joint Petitioners signed a "Pre-Settlement Agreement" designed to set forth the procedural ground rules for participation in settlement negotiations aimed at resolving the matter in lieu of further litigation in state and federal courts. This Joint Petition is the product of these negotiations.

III. TERMS AND CONDITIONS

The Joint Petitioners, intending to be legally bound and for due consideration given, agree as follows:

A. Rate Reductions and Rate Unbundling

19. On January 1, 1999, PECO will reduce its retail electric rates by 8% from the levels that existed as of December 31, 1996. That 8% rate decrease will continue in effect until January 1, 2000, when the rate reduction will become 6%. The 6% rate reduction will continue in effect until December 31, 2000. The January 1, 1999, and January 1, 2000, rate decreases will apply to all retail rate classifications and all customers within those rate classifications as set forth on a system-average basis in Schedule 1 (excluding the components of LILR, EER and

Rule 4.6 contract charges that do not contain discounts off of Rate Schedules HT, EP, GS, and PD tariffed component charges).

20. ~~On~~ January 1, 1999, PECO will unbundle its retail electric rates and special contracts into the following components: (1) distribution charges, (2) transmission charges, (3) a Competitive Transition Charge ("CTC") and, if applicable, an Intangible Transition Charge ("ITC") and (4) a shopping credit. The system-wide average values for these components for the years indicated are set forth in the following Schedule 1. Attached as Appendix A and incorporated as part of this settlement are tariff sheets setting forth for each rate class the rates, subject to reconciliation as set forth in Part E, that will be effective from January 1, 1999 to December 31, 2010. The tariffs set forth in Appendix A are the tariffs that implement this settlement except as specifically set forth herein.

Schedule 1

SCHEDULE OF SYSTEM-WIDE AVERAGE RATES (a)

Effective Date	Transmission (b) (1)	Distribution (2)	T&D Rate Cap (3) = (1) + (2)	CTC or ITC (4)	Shopping Credit (5)	Generation Rate Cap (6)= (4) + (5)
	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh
January 1, 1999	0.45¢	2.53¢	2.98¢	1.72¢	4.46¢	6.18¢
January 1, 2000	0.45¢	2.53¢	2.98¢	1.92¢	4.46¢	6.38¢
January 1, 2001	0.45¢	2.53¢	2.98¢	2.51¢	4.47¢	6.98¢
January 1, 2002	0.45¢	2.53¢	2.98¢	2.51¢	4.47¢	6.98¢
January 1, 2003	0.45¢	2.53¢	2.98¢	2.47¢	4.51¢	6.98¢
January 1, 2004	0.45¢	2.53¢	2.98¢	2.43¢	4.55¢	6.98¢
January 1, 2005	0.45¢(d)	2.53¢(d)	2.98¢(d)	2.40¢	4.58¢	6.98¢
January 1, 2006	(c)	(c)	N/A	2.66¢	4.85¢	7.51¢
January 1, 2007	(c)	(c)	N/A	2.66¢	5.35¢	8.01¢
January 1, 2008	(c)	(c)	N/A	2.66¢	5.35¢	8.01¢
January 1, 2009	(c)	(c)	N/A	2.66¢	5.35¢	8.01¢
January 1, 2010	(c)	(c)	N/A	2.66¢	5.35¢	8.01¢

(a) All prices reflect average retail billing for all classes of service (including gross receipts tax). Detail of actual individual rates for each class of service is provided in Appendix A. The average prices as presented in this Schedule 1 reflect the profile of service contained in PECO's proof of revenue set forth in Appendix A.

(b) The Transmission prices listed are for unbundling only. The Pennsylvania Public Utility Commission does not regulate the rates for transmission service.

(c) The cap on PECO's transmission and distribution rates under Section 2804(4) of the Electric Competition Act will be extended until June 30, 2005

(d) Effective until June 30, 2005.

Schedule 1, Column 3 sets forth the cap on system-wide average transmission and distribution charges that will be in effect from January 1, 1999 through June 30, 2005, provided, however, PECO may if necessary request recovery of additional nuclear decommissioning expense after January 1, 2004, and such expense recovery will not be subject to any rate cap. The tariffed rates in Appendix A underlying the system-wide average figures for CTC/ITC from 1999 through 2010 set forth in Schedule 1, Column 4, and the shopping credits set forth in Schedule 1, Column 5 are fixed for each year, except as provided for in paragraph 24 pertaining to periodic reconciliation of the CTC/ITC. The generation rate caps shown on a system-wide average basis for each year are set forth in Schedule 1, column 6 above from 1999 through 2010.

B. Rate Caps and Transmission and Distribution Charges

21. The Joint Petitioners agree that the rate cap exceptions set forth in Section 2804(4) of the Electric Competition Act shall apply to the rates set forth in this settlement, except as otherwise specifically set forth herein. If at any time during the CTC Recovery Period, PECO requests and is granted a rate increase pursuant to Section 2804(4) of the Act (Rate Cap Exceptions) such increase shall not reduce the shopping credits listed in Schedule 1 and such increases shall be allocated to the appropriate unbundled rate category in accordance with determinations of the Commission. As set forth in Schedule 1, the generation rate cap is extended from 2005 to 2010, five years beyond the statutory rate cap period provided in the Electric Competition Act. Customer savings may be greater if, for example, customers obtain lower prices from a competitive

supplier or if PECO's provider of last resort residential generation rates, as provided in Part L, result in a lower rate.

The cap on PECO's transmission and distribution charges, which otherwise would expire on June 30, 2001 under Section 2804(4) of the Electric Competition Act (66 Pa. C.S. §2804(4)), will be extended until June 30, 2005, provided, however, that PECO may, if necessary, request recovery of additional nuclear decommissioning expense after January 1, 2004 and such expense recovery will not be subject to any rate cap and will be treated as an exception to the rate cap under Section 2804(4) and such increases shall not reduce the shopping credits listed in Schedule 1 and such increases shall be allocated to the appropriate unbundled rate category in accordance with determinations of the Commission. The Joint Petitioners shall not file a complaint with the Commission or otherwise challenge PECO's current transmission or distribution rate structure, or the current level of PECO's transmission rates or the current level of PECO's distribution rates as set forth in Appendix A hereto until the expiration of the transmission and distribution cap on June 30, 2005, provided, however, that any Joint Petitioner may participate as a complainant or otherwise in any future transmission rate proceeding in which an increase in PECO's current transmission rates or change in rate structure is proposed and, further, may file a complaint or otherwise participate in any proceeding before the Commission to adjust PECO's distribution rates as a result of any increase in PECO's transmission rates or change in rate structure in effect as of April 29, 1998. The transmission and distribution rate cap of 2.98 cents per KWH includes 2.97 cents for all existing costs and services and .01 cents for the sustainable development fund during the transmission and distribution rate cap period. No new fees shall be proposed or charged during the transmission and distribution rate cap period for a cost or service that is included in the bundled transmission and distribution rate.

Pursuant to this Settlement, PECO agrees to cap the sum of its transmission and distribution charges, as described above. If, during the period that this rate cap is in effect PECO's transmission charges or rates (including but not limited to ancillary charges) are increased, then PECO's distribution rates will be reduced in a non-discriminatory manner sufficiently to avoid exceeding the transmission and distribution rate cap.

C. Competitive Metering and Billing

22. On January 1, 1999, PECO will unbundle its retail electric rates for its metering, meter reading, and billing and collection services to provide credits for those customers that elect to have their alternative suppliers perform these services. The credits for metering, meter reading and billing for each customer class are set forth in Appendix B.

Effective January 1, 1999, subject to the ability of an Electric Generation Supplier ("EGS") to comply with the terms and conditions of "Competitive Billing and Collection Service" as set forth in Appendix C to this Joint Petition, a Commission-licensed EGS may (in addition to any other rights to act as agent for the customer set forth in PECO's

Exhibit KRP – 10SR

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

Docket No. M-2018-3005860

Response of PECO Energy Company
To Interrogatories of the Office of Consumer Advocate

Response Date: 10/18/2019

OCA-VI-3-b

Please refer to page 4, lines 5-7 of the Rebuttal Testimony of Joseph A. Bisti and PECO-OCA-II-4 Attachment C 4/29/19 Joint Petition For Full Settlement in Dockets R-00973953 and P-00971265, Sec. III.A., paragraph 20 and Schedule 1.

Please provide the Appendix A tariff sheets referenced in paragraph 20.

RESPONSE:

Please refer to Attachment OCA-VI-3-b.

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued: April 29, 1998

Except as expressly provided herein, this Tariff shall be effective: January 1, 1999

**ISSUED BY: C. A. MC NEILL, JR. - Chairman, President and Chief Executive Officer
2301 MARKET STREET
PHILADELPHIA, PA 19101**

NOTICE.

R-973953

APPENDIX A

1999

NOTE: In order to meet the filing deadline, the PECO Energy Company was unable to provide a working copy of the proof of revenue. A working copy will be available by the end of day, May 1.

TABLE OF CONTENTS

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; 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; 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. $5.10

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:

SUMMER MONTHS. (June through September)
4.57¢ per kWh for the first 500 kWh per dwelling unit
5.31¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
4.57¢ per kWh

COMPETITIVE TRANSITION CHARGE:

SUMMER MONTHS. (June through September)
2.04¢ per kWh for the first 500 kWh per dwelling unit
2.37¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
2.04¢ per kWh

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges, which are not applicable to the customer if it obtains Competitive Energy Supply, will apply to the customer if the customer receives Default PLR Service until the first billing month of the year 2001.

SUMMER MONTHS. (June through September)
4.77¢ per kWh for the first 500 kWh per dwelling unit
5.33¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
4.77¢ per kWh

Starting with the first billing month of the year 2001, the Company will charge customers that receive Default PLR Service a price determined in accordance with Section L, paragraph 38(e) of the Joint Petition for Full Settlement.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

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

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

RATE RT RESIDENCE TIME-OF-USE SERVICE

AVAILABILITY.

Single-phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family for the domestic requirements of its members when such service is provided through one meter. Service is also available for related farm purposes when such service is provided through one meter in conjunction with the farmhouse domestic requirements.

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; 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 if 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; 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.

DEFINITION OF PEAK-HOURS. On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $10.19

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS (June through September)
1.87¢ per off-peak kWh
7.61¢ per on-peak kWh
WINTER MONTHS (October through May)
1.87¢ per off-peak kWh
6.98¢ per on-peak kWh

COMPETITIVE TRANSITION CHARGE:
SUMMER MONTHS. (June through September)
1.11¢ per off-peak kWh
4.52¢ per on-peak kWh.
WINTER MONTHS. (October through May)
1.11¢ per off-peak kWh
4.15¢ per on-peak kWh.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges, which are not applicable to the customer if it obtains Competitive Energy Supply, will apply to the customer if the customer receives Default PLR Service until the first billing month of the year 2001.

SUMMER MONTHS. (June through September)
3.16¢ per off-peak kWh
8.46¢ per on-peak kWh
WINTER MONTHS. (October through May)
3.16¢ per off-peak kWh
7.87¢ per on-peak kWh

Starting with the first billing month of the year 2001, the Company will charge customers that receive Default PLR Service a price determined in accordance with Section L, paragraph 38(e) of the Joint Petition for Full Settlement.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

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

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE APPLY TO THIS RATE.

CONTRACT TERM. Not less than twelve months.

PAYMENT TERMS. Standard.

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 all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where all of the supplementary heating required is supplied by non-electric energy sources and/or by electric energy sources served on Rate O-P Off-Peak Service. 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: $5.10

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
4.35¢ per kWh for the first 500 kWh per dwelling unit
5.06¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
4.35¢ for the first 600 kWh per dwelling unit
1.81¢ per kWh for additional kWh.

COMPETITIVE TRANSITION CHARGE:
SUMMER MONTHS. (June through September)
2.06¢ per kWh for the first 500 kWh per dwelling unit
2.39¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
2.06¢ per kWh for the first 600 kWh per dwelling unit
0.86¢ per kWh for additional kWh.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges, which are not applicable to the customer if it obtains Competitive Energy Supply, will apply to the customer if the customer receives Default PLR Service until the first billing month of the year 2001.

SUMMER MONTHS. (June through September)
5.01¢ per kWh for the first 500 kWh per dwelling unit
5.59¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
5.01¢ per kWh for the first 600 kWh per dwelling unit
2.94¢ per kWh for additional kWh.

Starting with the first billing month of the year 2001, the Company will charge customers that receive Default PLR Service a price determined in accordance with Section L, paragraph 38(e) of the Joint Petition for Full Settlement.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

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

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE 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.

CAP RATE

AVAILABILITY.

To payment-troubled customers who are currently served under or otherwise qualify for Rate R or Rate RH (does not include multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for this rate and must demonstrate annual household gross income below 150% of the Federal Poverty guidelines.

Customers with annual household gross incomes below 100% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate I which provides a 51.9% discount on the pricing of the first 500 kWh of usage.

Customers with annual household gross incomes between 100% and 150% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate II which provides a 26% discount on the pricing of the first 500 kWh of usage.

Certification by various State agencies that a customer is receiving certain government assistance payments may be used where possible to expedite the eligibility process. These payments include (but are not limited to) AFDC, SSI, Food Stamps, PACE and Medicaid. Information available from the Pa. Department of Revenue may also be used where appropriate to expedite the process.

A process will be established to provide verification of eligibility for customers who do not fit the above processes. Asset testing will also be used where necessary and appropriate.

Customers being considered for the CAP Rates will be required to:

* Waive certain privacy rights to enable PECO Energy to effectively conduct the above certification process.
* Apply for and assign to PECO Energy at least one energy assistance grant from the Commonwealth.
* Participate in various energy education and conservation programs facilitated by PECO Energy.

MONTHLY RATE TABLE.

	RATE R		RATE RH			
	CAP I	CAP II	CAP I		CAP II	
			Summer	Winter	Summer	Winter
Fixed Distribution Service Charge	$5.10	$5.10	$5.10	$5.10	$5.10	$5.10
Variable Distribution Service Charge						
for the first 500 kWh	2.21 ¢/Kwh	3.39 ¢/kWh	2.10 ¢/kWh	2.10 ¢/kWh	3.22 ¢/kWh	3.22 ¢/kWh
for additional kWh	4.57 ¢/kWh	4.57 ¢/kWh	4.35 ¢/kWh	2.10 ¢/kWh	4.35 ¢/kWh	2.10 ¢/kWh
Competitive Transition Charge						
for the first 500 kWh	0.99 ¢/kWh	1.51 ¢/kWh	0.99 ¢/kWh	0.99 ¢/kWh	1.52 ¢/kWh	1.52 ¢/kWh
for additional kWh	2.04 ¢/kWh	2.04 ¢/kWh	2.06 ¢/kWh	0.99 ¢/kWh	2.06 ¢/kWh	0.99 ¢/kWh
Energy and Capacity Charge						
for the first 500 kWh	2.30 ¢/kWh	3.54 ¢/kWh	2.41 ¢/kWh	2.41 ¢/kWh	3.70 ¢/kWh	3.70 ¢/kWh
for additional kWh	4.77 ¢/kWh	4.77 ¢/kWh	5.01 ¢/kWh	2.41 ¢/kWh	5.01 ¢/kWh	2.41 ¢/kWh

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for Rate R or RH as applicable in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for Rate R or RH as applicable in Appendix B to the Joint Petition for Full Settlement.

ENERGY AND CAPACITY CHARGE: The preceding Energy and Capacity Charges, which are not applicable to the customer if it obtains Competitive Energy Supply, will apply to the customer if the customer receives Default PLR Service until the first billing month of the year 2001. Starting with the first billing month of the year 2001, the Company will charge customers that receive Default PLR Service a price determined in accordance with Section L, paragraph 38(e) of the Joint Petition for Full Settlement.

If the customer obtains Competitive Energy Supply, the customer will receive a credit, on the first 500 kWh of usage on their PECO Energy bill, as follows:

Customer Credit when obtaining Competitive Energy Supply:

RATE R		RATE RH	
CAP I	CAP II	CAP I	CAP II

		Summer	Winter	Summer	Winter
2.65¢/kWh	1.32 ¢/kWh	2.76 ¢/kWh	2.76 ¢/kWh	1.38 ¢/kWh	1.38 ¢/kWh

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

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE. Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE APPLY TO THIS RATE.

ARREARAGE.

Customers who qualify and are placed on the CAP Rate will have their pre-program arrearage forgiven if they remain current on their CAP bill for six to twelve months. *The development of any new* arrearage during this period will delay forgiveness. Customers that develop any new arrearage will be offered a payment agreement.

RATE OP OFF-PEAK SERVICE

AVAILABILITY.

In conjunction with Rates R, RT, R-H and with residence service under Rate GS, for any customer receiving service at 120/240 volts, 3 wires, or 120/208 volts, 3 wires, for the operation of 240-volt or 208-volt domestic equipment of a type approved by the Company. Any load connected for service under Rate OP may not be connected for service under any other rate during the period that service under Rate OP is interrupted. Service will be interrupted during on-peak periods as established by the Company. This rate is not available when the source of supply is service purchased from a neighboring company under a borderline-purchase agreement.

SPECIAL RULES AND REGULATIONS.

The normal control device furnished by the Company has a limited capacity. The customer shall notify the Company before connecting any load in addition to an existing water heater. If necessary, the Company will install a control device with a rating of 100 amperes to accommodate the additional 240-volt controlled load. For controlled loads larger than 100 amperes the control device shall be furnished, installed and maintained by the customer.

Service may be interrupted for a total of not more than 6-1/2 hours per day during scheduled periods which may vary from customer to customer.

The Company has a program to replace seven-day clock control devices as they fail with five-day radio-control devices which provide uninterrupted service on Saturdays, Sundays and holidays.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $4.58 per month

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE: 3.65¢ per kWh

COMPETITIVE TRANSITION CHARGE: 0.10¢ per kWh

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges, which are not applicable to the customer if it obtains Competitive Energy Supply, will apply to the customer if the customer receives Default PLR Service until the first billing month of the year 2001.

1.13¢ per kWh

Starting with the first billing month of the year 2001, the Company will charge customers that receive Default PLR Service a price determined in accordance with Section L, paragraph 38(e) of the Joint Petition for Full Settlement.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

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

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE APPLY TO THIS RATE.

PAYMENT TERMS.

Standard.

RATE R-S RENEWABLE ENERGY SERVICE

AVAILABILITY.

Single-phase electric service in the entire territory of the Company for a customer served under Rate R, Rate R-H, Rate R-T or Rate GS, that has installed a device or devices that are, in PECO Energy's sole judgment, a bona fide technology for use in generating electricity from qualifying renewable energy installations not exceeding 10 kW, and that will be operated in parallel with the Company's system. Qualifying renewable energy installations include solar panels, wind, hydro, biomass, methane field, and fuel cell generation. The customer's equipment must conform to the installation requirements contained in Appendix II of the Company's published "Requirements For Parallel Operation Of Non-Utility Generation." The Company will modify its distribution and transmission facilities as necessary to interconnect with the customer at a single point. A customer will be charged for all modifications, additions or retirements made to provide the interconnection, in accordance with Appendix II of the "Requirements for Parallel Operation of Non-Utility Generation."

(Not available when the source of supply is service purchased from
a neighboring Company under Rate BLI Borderline Interchange Service.)

METERING/BILLING PROVISIONS.

A customer may select one of the following billing and metering options in conjunction with the Applicable Rate R, Rate R-H, Rate R-T or Rate GS charges.

(a) A *non-ratcheted, bi-directional meter*, such as the existing meter at the facility, may be used to record net energy sales to the customer. If the renewable energy installation generates more electricity than the customer uses in any billing month, then the customer will not be charged for any energy usage, but the customer will not be paid by the Company for the excess energy delivered to PECO Energy. No dual metering charge shall apply.

(b) Two meters may be installed. One will measure the energy delivered by the Company that the customer uses, and the other will measure the energy delivered to the Company from the customer that is generated by the customer's qualified renewable energy installation.

(c) PECO Energy shall provide such other Qualified Meters on such terms as shall be approved by the Commission.

If, in any billing month, the amount of energy delivered by the Company under Option (b) or (c) that the customer uses is greater than the amount of energy the customer delivered to the Company, then the Company will bill the customer for the difference. If, in any billing month, the amount of energy delivered by the Company under Option (b) or (c) that the customer uses is less than the amount of energy the customer delivered to the Company, the Company will pay the customer for the excess using the monthly average PJM billing rate, market clearing price, or its successor. For customers with Rate R-T, and the appropriate metering equipment (Option(c)), the billing will reflect the on-peak and off-peak generation and use and a metering charge under Option (C) will apply. A monthly meter charge shall apply if Option (b) or (c) is selected. A customer may sell any excess energy to an EGS other than PECO Energy. However, the customer must pay the appropriate Variable Distribution Service Charges on this excess energy.

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

METERING CHARGE: Option (b) - $ 4.46
Option (c) - meter cost shall be based upon the net incremental cost of purchasing and installing the new metering equipment as approved by the Commission.

MONTHLY RATE TABLE FOR NET ENERGY USED BY CUSTOMER. (See Applicable Rate R, Rate R-H, Rate RT or Rate GS for charges.).

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge for the applicable Rate R, Rate R-H, Rate R-T or Rate GS Service and the metering charge if the customer has selected Option(b) or Option(c).

STATE TAX ADJUSTMENT CLAUSE APPLIES TO THIS RATE.

CONTRACT TERM.

Not less than twelve months.

PAYMENT TERMS.

Standard

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.

CURRENT CHARACTERISTICS.

Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:

$ 6.63 for single-phase service without demand measurement, or
$ 8.67 for single-phase service with demand measurement, or
$23.45 for polyphase service.

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:

3.58¢ per kWh for the first 80 hours' use of billing demand
* 1.68¢ per kWh for the next 80 hours' use of the billing demand
1.06¢ per kWh for additional use; except
0.47¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh

COMPETITIVE TRANSITION CHARGE:

4.90¢ per kWh for the first 80 hours' use of billing demand
* 2.30¢ per kWh for the next 80 hours' use of billing demand
1.45¢ per kWh for additional use; except
0.64¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

10.54¢ per kWh for the first 80 hours' use of billing demand
* 5.72¢ per kWh for the next 80 hours' use of billing demand
4.14¢ per kWh for additional use; except
2.63¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh.

* During October through May this block is eliminated.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF DEMAND.

The billing demand will 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, during October through May the billing demand will not be less than 40% of the highest billing demand in the preceding months of June through September, nor less than the minimum value stated in the contract for service. 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 40% of the highest billing demand in the preceding months of June through September, nor 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 $6.17 per kW of billing demand.

HEATING MODIFICATION.

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.

METERING.

A. Single Meter.

Applicable where an area is heated solely by permanently connected electric space heating installations (1) acceptable to the Company, (2) sensitive to outdoor temperature and (3) not less than 5 kilowatts. Qualifying electric heating systems are (1) electric resistance coils, (2) electric resistance baseboards, (3) electric boilers and (4) heat pumps with electric back-up.

During October through May the monthly maximum measured demand shall be reduced by one-half of the difference between the peak winter measured demand and the base load demand over the two most recent winter seasons preceding the start of the current winter season (October 1st). The demand reduction will be subject to annual review and any revisions will be based on the two most recent winter seasons. The base load demand will be defined as the lowest measured demand during the period from October to May. For time-of-use metered customers, the demand reduction will be based upon the difference between the peak winter and base load demands regardless of whether they occur on or off peak. During this period, the billing demand shall never be less than 15 kilowatts; except for those customers in service as of February 18, 1971, the billing demand during October through May shall not be less than one-half of the monthly measured demand.

A customer whose demand reduction was calculated under the methods in effect on October 17, 1996, will continue to receive the same reduction until the date of full Direct Access unless the current method (described in the preceding paragraph) yields a smaller billed demand for the customer.

A customer who adds new electrical connected heating load will receive the same proportion of forgiven demand to total demand that they currently receive.

This demand modification will only be applicable within 30 days of the date that the customer requests billing under this provision. It shall be the responsibility of the customer to notify the Company of any subsequent changes to its heating equipment or requirements.

B. Separate Meters.

At the option of the customer, electricity supplying permanently connected space heating installations or heating equipment sensitive to outdoor temperature with a total capacity of not less than 5 kilowatts, which are acceptable to the Company, will be measured apart from the customer's other requirements for electric service at the premises. Air conditioning equipment of rated electrical capacity up to twice that of the heating equipment also may be supplied through this separate heating circuit.

During October through May the usage of this separate circuit shall be billed at the charges listed below in lieu of the pricing of the basic Monthly Rate Table.

VARIABLE DISTRIBUTION SERVICE CHARGE: 0.84¢ per kWh
COMPETITIVE TRANSITION CHARGE: 1.14¢ per kWh
ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply:
3.56¢ per kWh

During June through September the combined usage shall be billed under the price provisions of the basic Monthly Rate Table.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

OFF-PEAK THERMAL STORAGE PROVISION.

Off-peak energy may be provided exclusively for qualifying Thermal Storage applications only in conjunction with this rate schedule when the load supplied is separately metered. This service will be billed separately at the rate of $11.21 per month, plus the charges listed below.

OFF-PEAK USAGE DURING THE WINTER AND SUMMER MONTHS:

VARIABLE DISTRIBUTION SERVICE CHARGE: 1.41¢ per kWh
COMPETITIVE TRANSITION CHARGE: 0.60¢ per kWh
ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply:

1.65¢ per kWh

ON-PEAK USAGE DURING THE WINTER MONTHS:

VARIABLE DISTRIBUTION SERVICE CHARGE: 2.17¢ per kWh
COMPETITIVE TRANSITION CHARGE: 0.93¢ per kWh
ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

2.51¢ per kWh

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

During the summer months, any on-peak demand and energy will contribute to the pricing of the basic Monthly Rate Table. To qualify for this provision, the customer must submit an engineering study performed by a professional engineer registered in the Commonwealth of Pennsylvania to the Company for technical review and approval. On-peak hours are defined as the hours between 8:00 a.m. and 8:00 p.m., Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 p.m. on Fridays. Off-peak hours are defined as

the hours other than those specified as on-peak hours. For Cooling Thermal Storage applications, during the months of June through September, on-peak hours will commence at 10:00 a.m. instead of 8:00 a.m.

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company or a non-profit senior citizen center may, upon application, elect to have its electric service billed at the pricing of Rate R Residential Service, Rate RT Residential Time of Use, Rate R-H Residential Heating Service, or Rate OP Off-Peak Service as appropriate for the application. The execution of a contract for a minimum term of one year will be required.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY - a separately metered service location consisting of a building, sirens, a garage for housing vehicular fire fighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of fire fighting services.

NON-PROFIT SENIOR CITIZEN CENTER - a separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided.

The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) as non-profit and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

PAYMENT TERMS.

Standard.

TERM OF CONTRACT.

The initial contract term shall be for at least one year.

PAYMENT TERMS.

Standard.

RATE-PD PRIMARY-DISTRIBUTION POWER

AVAILABILITY.

Untransformed service from the primary supply lines of the Company's *distribution* system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.

Standard primary service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $275.28

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$1.79 per kW of billing demand
1.58¢ per kWh of the first 150 hours' use of billing demand
0.94¢ per kWh of the first next 150 hours' use of billing demand
0.30¢ per kWh for additional use.

COMPETITIVE TRANSITION CHARGE:
$2.16 per kW of billing demand
1.91¢ per kWh of the first 150 hours' use of billing demand
1.13¢ per kWh for the next 150 hours' use of billing demand
0.36¢ per kWh for additional use.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

$3.97 per kW of billing demand
4.97¢ per kWh of the first 150 hours' use of billing demand
3.54¢ per kWh for the next 150 hours' use of billing demand
2.13¢ per kWh for additional use.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, the CTC, and the Energy and Capacity Charge.

TERM OF CONTRACT.

The initial contract term shall be for at least three years.

PAYMENT TERMS.

Standard.

RATE-HT HIGH-TENSION POWER

AVAILABILITY.

Untransformed service from the Company's standard high-tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.

Standard high-tension service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $286.86

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$1.68 per kW of billing demand
0.88¢ per kWh of the first 150 hours' use of billing demand
0.52¢ per kWh of the first 150 hours' use of billing demand,
but not more than 7,500,000 kwh
0.16¢ per kWh for additional use.

COMPETITIVE TRANSITION CHARGE:
$3.31 per kW of billing demand
1.77¢ per kWh for the first 150 hours' use of billing demand
1.04¢ per kWh for the next 150 hours' use of billing demand.
but not more than 7,500,000 kwh
0.33¢ per kWh for additional use.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

$5.94 per kW of billing demand
4.53¢ per kWh for the first 150 hours' use of billing demand
3.23¢ per kWh for the next 150 hours' use of billing demand.
but not more than 7,500,000 kwh
1.94¢ per kWh for additional use.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

TIME-OF-USE ADJUSTMENT:

Customers with measured demand of 2,000 kW or greater will be given a credit for energy use during off-peak hours and will be subject to an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months (October through May)
Off-peak credit...........	0.21¢ per kWh	0.21¢ per kWh
On-peak charge..........	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:
For customers supplied at 33,000 volts: 7¢ per kW of measured demand.
For customers supplied at 69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For customers supplied over 69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

DELIVERY POINTS.
Where the load of a customer located on single or contiguous premises becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer, an additional separate delivery point may be established for such premises upon the written request of the customer with billing continued as if the service were being delivered and metered at a single point, provided such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, the CTC, and the Energy and Capacity Charge, less the high voltage discount where applicable.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.

Outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rate SL-P, SL-S and SL-E.

MONTHLY RATE TABLE.

PRICE PER LIGHTING UNIT

MERCURY-VAPOR LAMPS	CTC	ENERGY AND CAPACITY	DISTRIBUTION (Company Pole)	DISTRIBUTION (Customer Pole)
100 Watts (nominally 4,000 Lumens)	$0.14	$0.32	$11.18	$10.01
175 Watts (nominally 8,000 Lumens)	$0.20	$0.45	$15.15	$14.03
250 Watts (nominally 12,000 Lumens)	$0.25	$0.56	$18.67	$17.67
400 Watts (nominally 20,000 Lumens)	$0.32	$0.73	$24.10	$22.78
400 Watts Floodlight (nominally 22,000 Lumens)	$0.35	$0.78	$26.06	$24.74

SODIUM-VAPOR LAMPS	CTC	ENERGY AND CAPACITY	DISTRIBUTION (Company Pole)	DISTRIBUTION (Customer Pole)
70 Watts (nominally 5,800 Lumens)	$0.20	$0.45	$15.26	$14.12
250 Watts (nominally 25,000 Lumens)	$0.33	$0.73	$24.29	$22.97
400 Watts (nominally 50,000 Lumens)	$0.36	$0.80	$26.66	$25.34
400 Watts Floodlight (nominally 50,000 Lumens)	$0.39	$0.86	$28.61	$27.29

STANDARD METAL HALIDE LAMPS	CTC	ENERGY AND CAPACITY	DISTRIBUTION (Company Pole)	DISTRIBUTION (Customer Pole)
400 Watts (nominally 36,000 Lumens)	$0.38	$0.85	$28.17	$26.89
1000 Watts (nominally 110,000 Lumens)	$0.68	$1.53	$49.29	$48.01

STANDARD HIGH PRESSURE SODIUM LAMPS	CTC	ENERGY AND CAPACITY	DISTRIBUTION (Company Pole)	DISTRIBUTION (Customer Pole)
70 Watts (nominally 5,800 Lumens)	$0.23	$0.50	$17.16	$15.88
100 Watts (nominally 9,500 Lumens)	$0.24	$0.53	$18.14	$16.86
150 Watts (nominally 16,000 Lumens)	$0.26	$0.58	$19.82	$18.54
250 Watts (nominally 25,000 Lumens)	$0.31	$0.70	$23.27	$21.98
400 Watts (nominally 50,000 Lumens)	$0.38	$0.86	$28.22	$26.93

The Energy and Capacity Charges set forth above will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

GENERAL PROVISIONS.

1. Standard Lighting Unit. A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires and a luminaire, including lamp, reactor and control.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, and all standard service-supply lines and all Lighting Units.
The customer will install, own and maintain all poles on the customer's property and all service extensions on the customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge. Any additional investment will be assumed by the customer.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

For underground supply furnished at the request of the customer where aerial supply would be normal, the Company will assume the cost up to the amount it would normally have invested and the additional cost shall be assumed by the customer.

3. Non-Standard installations. The Company may offer non-standard lighting units and installations in addition to those listed above in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Monthly Rate Table.

4. Location and Authorization. Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck. Customer construction shall meet the Company's standards which are based upon the National Electrical Code.

The customer shall obtain and submit any permits or other authority requisite to the installation and operation of the Lighting Units served hereunder.

5. Service. Each lamp shall be individually controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and to de-energize it during other periods. The service shall include the supply of lamps and their renewal when burned out. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity therefor.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

7. Equipment Removal . If the customer requests that the Company remove or replace any existing street lighting installation, except incandescent lights, the Company will charge for removal or replacement of the street lighting installations and the associated poles and conductors used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

8. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer and the customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaries and other equipment necessary to operate the lamps at the approved locations. The customer shall protect the Company from damage to the lighting system to the extent of their ability. At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

TERM OF CONTRACT.

The initial contract term for each Lighting Unit shall be for at least three years.

PAYMENT TERMS.

Standard

RATE SL-P STREET LIGHTING IN CITY OF PHILADELPHIA

AVAILABILITY.

For the safety and convenience of the public, only to a governmental agency, municipal, state or federal, for outdoor lighting of streets, highways, bridges, parks or similar places located within the City of Philadelphia, including directional highway signs at locations where other outdoor lighting service is provided hereunder, and by incandescent filament, mercury-vapor, fluorescent or sodium-vapor lamps of standard sizes and types approved by the Company, only if the customer installs, owns and maintains all Utilization Facilities as hereinafter defined. Service will be provided under this rate for street Lighting Units supported in a conventional manner such as on poles, posts, brackets or hangers, and under conditions of installation and supply acceptable to the Company.

CHARACTERISTICS OF SUPPLY.

Service under this rate will be from series 6.6 ampere circuits or from standard single-phase secondary circuits, as specified by the Company, except that, where conditions require, or where existing standard secondary circuits are not available, the Company at its option may supply service from nonstandard secondary circuits, providing nominally 240 volts.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:

For Lighting Units in service as of the fifteenth day of the month.

$ 8.64 per Lighting Unit supplied from standard secondary (aerial or underground) circuits where the customer owns the individual control for such Lighting Unit.

$ 9.24 per Lighting Unit supplied from aerial (series or secondary) circuits where the Company provides group controls.

$12.89 per Lighting Unit supplied from underground (series or secondary) circuits where the Company provides group controls.

VARIABLE DISTRIBUTION SERVICE CHARGE:

0.15¢ per watt.
0.78¢ per kWh of energy billed.

COMPETITIVE TRANSITION CHARGE:

0.08¢ per watt.
0.42¢ per kWh of energy billed.

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply:

0.02¢ per watt.
1.49¢ per kWh.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

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

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

LIGHTING UNIT.

A Lighting Unit shall comprise each lighting installation which is separately connected to a delivery point on the Company's series or secondary circuit.

DETERMINATION OF BILLING DEMAND.

The wattage, expressed to the nearest tenth of a watt, of a Lighting Unit 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 Lighting Units in service as of the fifteenth day of a month shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Lighting Unit 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 approved by the authorized representatives of the customer and the Company. The aggregate of the kilowatt-hours thus computed for all Lighting Units in service as of the fifteenth day of a month shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Ownership and Type of Control Facilities.

a. Lighting Units Supplied from Standard Secondary Circuits: customer shall provide, own and maintain for each of such Lighting Units, the individual control of a type approved by the Company except that, at the option of the customer, the Company will continue to provide group control facilities presently in service.

b. Lighting Units Supplied from Series and from Nonstandard Secondary Circuits: Company will provide, own and maintain group control facilities.

2. Ownership of Utilization Facilities.

a. Lighting Units Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, individual controls (where used) and other components required for the operation of such Lighting Units, conductors, molding and supporting insulators between the map receptacles and line wires of the Company's distribution facilities.

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

b. Lighting Units 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 (where used) and other components required for the operation of such Lighting Units, 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.

Where vertical extensions are required on foreign-owned posts for the support of such underground supplied Lighting Units, the extension shall be provided and owned by the customer. Rentals incurred on such foreign-owned posts shall be the responsibility of the customer.

Except as provided in 5 hereof, 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 or the sidewalk level as specified in 2b, 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. Where a splicing chamber is provided in the post base, the customer shall provide space for any relays or similar devices required for the operation on the street lighting circuit.

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.

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be provided from distribution facilities and equipment, including group control facilities where required, installed at the cost and expense of the Company and owned and controlled by it, except that in locations (such as bridges, overpasses, underpasses and limited access highways) where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control, the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Lighting Units. For new Lighting Units, relocated Lighting Units and for any modernization or maintenance work involving connections to the Company's distribution circuits. In accordance with the provisions of 2, the customer shall provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit, or at the splicing chamber in the post base (where provided), or at the nearest available manhole, handhole or splice box (where such splicing chamber is not provided). In the latter case, the customer will bill the Company for the cost of the conductors from the sidewalk level to the manhole, handhole or splice box. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Location and Type of Installation. The prices of the rate apply to street lighting service under conditions named herein at locations designated by the properly authorized representatives of the customer.

8. Service. Lighting service will be operated on all-night, every-night lighting schedules, to be approved by the authorized representatives of the customer and the Company, under which lights normally are turned on after sunset and off before sunrise. Extended lighting service during all daylight hours will be provided for lamps specified by the customer.

9. Change in Size of Type of Lighting Units. Written notice of any planned change in size or type of any components of Lighting Units by locations shall be furnished by the customer to the Company or less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings of Lighting Units used.

10. Service Maintenance. Upon receipt of report of Lighting Unit or Units not burning, the Company will determine the cause of failure and will restore service on street lighting or distribution circuit and control equipment, disconnecting if necessary any faulty Lighting Units from the circuit. Customer will make necessary repairs between the lamp receptacle of the faulty Lighting Unit or Units and the point of connection to the Company's street lighting or distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replace facilities.

11. Authorization and Protection. The customer shall, to the extent of ability, furnish any requisite authority for the erection and maintenance of poles wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the light system.

12. Additional Lighting. Lighting service for additional lamps installed by the customer will be provided by the Company upon written notice from the customer specifying the locations of the installations unless the proposed additional lighting makes the investment or cost of providing distribution equipment excessive. In which case a portion of the investment or cost shall be borne by the customer subject to agreement between the customer and the Company.

13. Relocation of Lighting Units. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

14. Outage Allowance. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service and the customer will use reasonable diligence to protect the lighting system. In lieu of determination of the actual hours of Lighting Unit outages resulting from a failure of any light to burn for any reason, a deduction of 0.20% of the sum of the Company's monthly Fixed and Variable Distribution Service Charges, CTCs and Energy and Capacity Charges (unless the Customer is receiving Default PLR Service) will be made on the monthly bill. The Company shall not be liable for service interruptions as a result of the customer's failure to protect the lighting system, or as a result of riot, fire, storm, flood, interference by civil or military authorities or any other cause beyond its control.

TERM OF CONTRACT.

The initial contract term for each lighting unit shall be for at least one year.

PAYMENT TERMS.

Bills will be rendered monthly.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
Outdoor lighting of streets, highways, bridges, parks and similar places located in Suburban Counties.

ANNUAL RATE TABLE - MANUFACTURER'S RATING OF LAMP SIZES.

Incandescent Filament Lamps:

Size of Lamp	Billing Watts	Distribution	CTC	Energy & Capacity
320 Lumens	32	$74.27	$5.64	$ 9.84
600 Lumens	58	$103.49	$7.86	$13.71
1,000 Lumens	103	$145.16	$11.02	$19.24
2,500 Lumens	202	$199.76	$15.17	$26.45
6,000 Lumens	448	$227.91	$17.31	$30.18
10,000 Lumens	690	$272.85	$20.72	$36.14

Mercury Vapor Lamps

Size of Lamp	Billing Watts	Distribution	CTC	Energy & Capacity
4,000 Lumens	115	$170.82	$12.97	$22.64
8,000 Lumens	191	$180.41	$13.70	$23.89
12,000 Lumens	275	$192.36	$14.61	$25.48
20,000 Lumens	429	$225.97	$17.16	$29.93
42,000 Lumens	768	$321.89	$24.45	$42.64
59,000 Lumens	1,090	$362.83	$27.56	$48.06

Sodium-Vapor Lamps

Size of Lamp	Billing Watts	Distribution	CTC	Energy & Capacity
5,800 Lumens	94	$169.54	$12.88	$22.45
9,500 Lumens	131	$184.34	$14.00	$24.41
16,000 Lumens	192	$207.04	$15.72	$27.42
25,000 Lumens	294	$235.22	$17.86	$31.16
50,000 Lumens	450	$280.26	$21.28	$37.13

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

The Energy and Capacity Charges set forth above will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

GENERAL PROVISIONS.

1. Service. The lighting service will be operated on an all-night, every-night lighting schedule of approximately 4,100 hours annual burning time (average monthly burning hours = 341.11 hours), under which lights are turned on after sunset and off before sunrise. It includes the supply of lamps and their removal when burned out or broken.

2. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction to the Company's monthly Fixed and Variable Distribution Service Charges, CTCs and Energy and Capacity Charges (unless the Customer is receiving Default PLR Service) will be made on the monthly bill for the hours of failure if such failure continues for a period in excess of 12 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

3. Lighting Installations. The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for

lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

Standard lighting installations under standard conditions of supply will be made on the public highways at the expense of the Company to the extent warranted by the revenue in prospect, any additional investment to be assumed by the customer.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other electric distribution facilities are underground, supply may be underground.

For underground supply furnished at the request of the Company where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and the additional cost shall be assumed by the customer.

The installation cost of lighting on private property, or for contracts of less than standard term, shall be paid by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

4. Excess Costs. In cases where the remote location of the proposed new or additional lighting, or the number or spacing of the lamps, or the lack of necessary supply lines or any other reason makes the cost of installation excessive, such excess costs shall be assumed by the customer as mutually agreed.

5. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer and the customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaries and other equipment necessary to operate the lamps at the approved locations. The customer shall protect the Company from damage to the damage to the lighting system to the extent of one's ability. At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

6. Equipment Removal. If the customer requests that the Company remove or replace any existing street lighting installation, except incandescent lights, the Company will charge for removal or replacement of the street lighting installations and the associated poles and conducts used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining life value of the removed or replaced equipment less salvage.

PAYMENT TERMS.

Bills will be rendered monthly. Each month, for the purpose of prorating the price, shall be considered 1/12 of a year.

TERM OF CONTRACT.

The initial contract term for each lighting installation shall be for at least three years.

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 located outside of the City of Philadelphia, 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:	\$9.53 per Service Location (as defined below)
SERVICE LOCATION CTC CHARGE:	\$0.31 per Service Location (as defined below)

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

0.116 ¢ per Watt
0.734¢ per kWh

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, 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.

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.

3. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

4. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 10.

Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

5. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

6. 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. Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the customer to the Company not less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the lamp receptacle of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

10. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

11. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE TL TRAFFIC LIGHTING SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for electric traffic signal lights installed, owned and maintained by the municipality.

CURRENT CHARACTERISTICS.
Standard single-phase secondary service.

RATE TABLE.

VARIABLE DISTRIBUTION SERVICE CHARGE: 2.11¢ per kWh

COMPETITIVE TRANSITION CHARGE: 2.24¢ per kWh

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

5.57¢ per kWh

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, 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, 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.

MINIMUM CHARGE.
$3.56 per month per signal light.

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

PAYMENT TERMS.
Standard.

RATE BLI BORDERLINE INTERCHANGE SERVICE

AVAILABILITY.

Electric service supplied under reciprocal agreements, to neighboring electric utilities for resale in their adjacent territory at delivery points where the Company in its judgment can provide capacity in excess of the requirements of present and prospective customers in its own territory and for periods fixed by contract and terminable after the expiration of the initial term if capacity is no longer available.

CURRENT CHARACTERISTICS.

Standard primary or secondary service.

MONTHLY RATE TABLE.

INVESTMENT CHARGE:

An amount equal to 1% per month on the additional investment in facilities required to deliver and meter the service supplied.

BORDERLINE INTERCHANGE SERVICE CHARGE:

14.86¢ per kWh.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

MEASUREMENT.

The energy delivered may be metered or may be estimated from the purchaser's resales plus an agreed-upon correction to cover transformation and distribution losses.

TERM OF CONTRACT.

The initial contract term shall be for at least five years, and thereafter from year to year until terminated by 60 days' notice from either party.

PAYMENT TERMS.

Payment of amounts billed shall be made within 15 days from date of bill.

RATE EP ELECTRIC PROPULSION

AVAILABILITY.

This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high-tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances.

CURRENT CHARACTERISTICS.

Standard sixty hertz (60 Hz) high-tension service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $1,243.85 per delivery point

METERING AND BILLING CREDITS A customer receiving Advanced Meter Services from a MSP other than the Company will receive a credit on the Fixed Distribution Service Charge equal to the Total Metering Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement. A customer receiving Consolidated EGS Billing will receive a credit on the Fixed Distribution Service Charge equal to the Billing and Collection Credit set forth for this Base Rate in Appendix B to the Joint Petition for Full Settlement.

VARIABLE DISTRIBUTION SERVICE CHARGE:

$2.98 per kW of billing demand
0.23¢ per kWh

COMPETITIVE TRANSITION CHARGE:

$3.93 per kW of billing demand
0.30¢ per kWh

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

$7.19 per kW of billing demand
1.91¢ per kWh

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

TIME-OF-USE ADJUSTMENT:

There will be a credit for energy use during off-peak hours and an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months (October through May)
Off-peak credit	0.21¢ per kWh	0.21¢ per kWh
On-peak charge	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:

For delivery points supplied at 33,000 volts: 7¢ per kW
For delivery points supplied at 69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.

If the load of a customer located at a delivery point becomes greater than the capacity of the circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point.

RATE AL - ALLEY LIGHTING IN CITY OF PHILADELPHIA

APPLICABILITY. To multiple, unmetered lighting service supplied the City of Philadelphia to operate incandescent lamps and appurtenances installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities.

LIGHTING DISTRIBUTION SERVICE DEFINED. All-night outdoor lighting of alleys and courts by incandescent lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.

VARIABLE DISTRIBUTION SERVICE CHARGE: 11.12¢ per kWh

COMPETITIVE TRANSITION CHARGE: 0.16¢ per kWh

ENERGY AND CAPACITY CHARGE: The following Energy and Capacity Charges will apply to the customer if the customer receives Default PLR Service. These charges are not applicable to the customer if it obtains Competitive Energy Supply.

.34¢ per kWh

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT PLR SERVICE: Unless such a customer is able to obtain transmission service on its own, PECO Energy will provide transmission service, and will impose charges on such a customer for such transmission service.

STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE

PLAN OF MONTHLY BILLING. Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION. The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever.

TERM OF CONTRACT. The initial contract term for each lighting unit shall be for at least one year.

APPLICABILITY INDEX OF RIDERS

Introductory Statement

Customers under different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the Base Rate under which they are provided service. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the customer and the Company as the case may require, notwithstanding anything to the contrary contained in the Base Rate to which the rider is applied.

	Page No.	R	RT	RH & RS	OP	GS	PD	HT	POL	SL-P	SL-S	SL-E	EP	BLI	AL
Riders															
Auxiliary Service		X	X	X	X	X	X	X							
Capacity Reservation								X							
Casualty		X	X	X	X	X	X	X					X		
Construction							X	X					X		
Cooling Thermal Storage HT								X							
Curtailment HT								[5]							
Economic Efficiency						X		X							
Emergency Energy Conservation								X							
Employment & Economic Recovery						[3]	X	X							
Incremental Process						X		X							
IR - 1								X							
Investment Return Guarantee						X	X	X							
LILR								[4]							
Night Service GS						X									
Night Service HT								X							
Night Service PD							X								
Off-Peak							[2]	[2]							
Receivership		X	X	X	X	X	X	X							
Seasonal Capacity Charge								X							
Temporary Service		X	X	X	X	X	X	X							
Transformer Rental							[1]	[1]							

NOTES:

[1] Rider restricted to customers served prior to October 15, 1963.
[2] Rider restricted to customers served as of October 5, 1972.
[3] Effective June 3, 1985 this rider is available under Rate GS, but only when the qualifying or new service location is in an Enterprise Development Area as described in Title 16, Chapter 23 of the Pennsylvania Code.
[4] Rider restricted to customers under contract on December 1, 1995.
[5] Rider restricted to customers under contract on January 1, 1999.

Exhibit KRP – 11SR

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)

Exhibit KRP – 12SR

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%
1/1/2008	528,840,851	40,756,335,749	41,285,176,601	1.3%	98.7%
1/1/2009	414,295,060	39,560,600,153	39,974,895,213	1.0%	99.0%
1/1/2010	505,130,870	42,286,726,581	42,791,857,451	1.2%	98.8%
1/1/2011	22,940,362,490	18,661,761,485	41,602,123,975	55.1%	44.9%
1/1/2012	26,249,927,504	14,081,888,264	40,331,815,767	65.1%	34.9%
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%

378,207,534	23,834,230,384	24,212,437,918
471,567,956	40,158,467,951	40,630,035,907
459,712,965	40,923,663,367	41,383,376,332
11,722,746,680	30,474,244,033	42,196,990,713
13,032,235,135	135,390,605,735	148,422,840,870
8.8%	**91.2%**	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment, PECO Energy Electric Tariff No. 5, Supplement No. 76 Effective December 1, 2018	: : : :	Docket No. M-2018-3005860

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1-SR, are true and correct 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).

Signature: ______________________
Karl R. Pavlovic

Consultant Address: PCMG and Associates, LLC.
22 Brookes Avenue
Gaithersburg, MD 20877

DATED: October 24, 2019
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