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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

June 17, 2014

In the Matter of the Provision of Basic Generation Service
for Year Two of the Post-Transition Period
- and -
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2012
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2013
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2014

Docket Nos. EO03050394, EO11040250, ER12060485, ER13050378

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Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No. ________________

Kristi Izzo, Secretary
Board of Public Utilities
44 South Clinton Avenue, 9th Fl
Post Office Box 350
Trenton, NJ 08625-0350

Dear Secretary Izzo:

Enclosed for filing on behalf of Jersey Central Power & Light Company (“JCP&L”), Public Service Electric and Gas Company (“PSE&G”) and Rockland Electric Company (“RECO”) (collectively, the “EDCs”) please find an original and 10 copies of tariff sheets and supporting exhibits proposed by each of the EDCs and revised to reflect changes to the PJM Open Access Transmission Tariff (“OATT”) made in response to: (i) the annual formula rate update filings made by PPL Electric Utilities Corporation (“PPL”) in Federal Energy Regulatory Commission (“FERC”) Docket No. ER09-1148, by American Electric Power Service Corporation (“AEP”) in

FERC Docket No. ER08-1329 and ER10-335, and by Trans-Allegheny Interstate Line Company ("TrAILCo") in FERC Docket No. ER07-562, and (ii) the formula rate update filings made by the public utility affiliates of Pepco Holdings Inc. ("PHI") in FERC Docket No. ER08-1423 and the respective utility affiliate compliance filings for formula rate updates made by Atlantic City Electric Company ("ACE") in Docket No ER09-1156, Delmarva Power and Light ("Delmarva") in Docket No. ER09-1158, and Potomac Electric Power Company ("PEPCO") in Docket No. ER09-1159 (the filings referred to in (i) and (ii) above are collectively referred to as the "Filings").

Background

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), the Board of Public Utilities (Board) authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreements ("SMAs"). Furthermore, by subsequent Orders, the BPU has approved Section 15.9 of the Supplier Master Agreements ("SMA") filed by the EDCs, which authorize the EDCs to increase or decrease the rates paid to suppliers for FERC-approved rates and changes to Firm Transmission Service once approved by the Board.

The Transmission Enhancement Charges ("TECs") detailed in Schedule 12 of the PJM OATT were implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (again, as defined in the PJM OATT) that are requested by PJM for reliability or economic purposes. TECs are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects.

In turn, the EDCs file with the Board to recover costs associated with TECs from BGS customer and to pay BGS suppliers for TEC charges assigned to them by PJM for the load they serve in the respective EDC service territories.[1]

Request for Board Approval

The EDCs request Board approval to implement revised BGS-FP and BGS-CIEP tariff rates effective September 1, 2014. In support of this request, the EDCs have included pro-forma tariff sheets shown in Attachment 1. The proposed BGS tariff rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved

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[1] The EDCs pay suppliers subject to the conditions of the Board-approved Supplier Master Agreements

BGS tariff sheets. The attached pro-forma tariff sheets propose an effective date of September 1, 2014 and will remain in effect until changed. The BGS-FP and BGS-CIEP rates included in the amended tariff sheets for each EDC are revised to reflect costs effective on June 1, 2014 for TECs resulting from all of the FERC-approved Filings, except the AEP-East filing which is effective on July 1, 2014.

Attachment 2 shows the cost impact for the 2014/2015 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the projects covered by the Filings, as posted on the PJM website. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs assuming implementation on September 1, 2014 is included as Attachment 3. Copies of the Filings and all formula rate updates are included as Attachment 4, and can also be found on the PJM website at http://www.pjm.com/markets-and-operations/transmission-service/formula-rates.aspx.

The EDCs also request that the BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the updates from formula rates effective June 1 and July 1, 2014. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-FP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges. This treatment is consistent with the previously-approved mechanisms.

This filing satisfies the requirements of ¶¶ 15.9 (a)(i) and (ii) of the BGS-FP and BGS- CIEP SMAs, which mandate that BGS-FP and BGS-CIEP Suppliers be notified of rate increases for firm transmission service, and that the EDCs file for and obtain Board approval of an increase in retail rates commensurate with the FERC-implemented rate increase.

We thank the Board for all courtesies extended.

Respectfully submitted,

Alexander C. Stern

Attachments

cc: Jerry May, NJBPU
Alice Bator, NJBPU
Frank Perrotti, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (Electronic)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, EO11040250, ER12060485, ER13050378

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, EO11040250, ER12060485, ER13050378

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, EO11040250, ER12060485, ER13050378

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Attachment 1A

Public Service Electric and Gas Company Tariff Sheets

Attachment 1B

Jersey Central Power and Light Tariff Sheets

Attachment 1C

Rockland Electric Company Tariff Sheets

Attachment 1A

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 75**

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.110210	$0.117925	$0.110391	$0.118118
RS – in excess of 600 kWh	0.110210	0.117925	0.118927	0.127252
RHS – first 600 kWh	0.088601	0.094803	0.087042	0.093135
RHS – in excess of 600 kWh	0.088601	0.094803	0.098455	0.105347
RLM On-Peak	0.163655	0.175111	0.173101	0.185218
RLM Off-Peak	0.057443	0.061464	0.054512	0.058328
WH	0.055954	0.059871	0.057587	0.061618
WHS	0.055954	0.059871	0.057498	0.061523
HS	0.091512	0.097918	0.097044	0.103837
BPL	0.054301	0.058102	0.051748	0.055370
BPL-POF	0.054301	0.058102	0.051748	0.055370
PSAL	0.054301	0.058102	0.051748	0.055370

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: Effective:

Issued by DANIEL J. CREGG, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$ 5.2076
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.5721
Charge applicable in the months of October through May	$ 5.2076
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.5721

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 55,352.82 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 102.29 per MW per month
Virginia Electric and Power Company	$ 66.20 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 20.61 per MW per month
PPL Electric Utilities Corporation	$ 47.01 per MW per month
American Electric Power Service Corporation	$ 5.18 per MW per month
Atlantic City Electric Company.	$ 4.58 per MW per month
Delmarva Power and Light Company	$ 8.00 per MW per month
Potomac Electric Power Company.	$ 12.17 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 4.8788
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.2203

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Attachment 1A

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 55,352.82 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 102.29 per MW per month
Virginia Electric and Power Company	$ 66.20 per MW per month
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PPL Electric Utilities Corporation	$ 47.01 per MW per month
American Electric Power Service Corporation	$ 5.18 per MW per month
Atlantic City Electric Company.	$ 4.58 per MW per month
Delmarva Power and Light Company	$ 8.00 per MW per month
Potomac Electric Power Company.	$ 12.17 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 4.8788
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.2203

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: Effective:

Issued by DANIEL J. CREGG, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Rider BGS-FP
Basic Generation Service – Fixed Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL. Effective January 1, 2013, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective September 1, 2014, a TRAILCO4-TEC surcharge of **$0.000471** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000054** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000072** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000034** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000022** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000202** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective March 3, 2014, a PATH3-TEC surcharge of **$0.000089** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000287** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001165** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: (**$0.001207)** (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Issued: **Effective: September 1, 2014**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective September 1, 2014, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	TRAILCO4-TEC	PEPCO2-TEC	ACE2-TEC
GT – High Tension Service	**$0.000054**	**$0.000006**	**$0.000009**
GT	**$0.000230**	**$0.000027**	**$0.000035**
GP	**$0.000278**	**$0.000032**	**$0.000043**
GS and GST	**$0.000471**	**$0.000054**	**$0.000072**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000004**	**$0.000002**	**$0.000022**
GT	**$0.000017**	**$0.000011**	**$0.000098**
GP	**$0.000020**	**$0.000013**	**$0.000120**
GS and GST	**$0.000034**	**$0.000022**	**$0.000202**

Effective March 3, 2014, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	PATH3-TEC	VEPCO3-TEC	PSEG2-TEC
GT – High Tension Service	**$0.000010**	**$0.000032**	**$0.000131**
GT	**$0.000044**	**$0.000140**	**$0.000570**
GP	**$0.000054**	**$0.000171**	**$0.000696**
GS and GST	**$0.000089**	**$0.000287**	**$0.001165**

4) BGS Reconciliation Charge per KWH: ($0.000220) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
First 250 kWh ...... @	1.209 ¢ per kWh	1.209 ¢ per kWh
Over 250 kWh ..... @	1.209 ¢ per kWh	1.209 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh	0.707 ¢ per kWh	0.707 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

(6) Securitization Charges

In accordance with General Information Section 35, the Securitization Charges shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.441 ¢ per kWh	0.441 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.412 ¢ per kWh	0.412 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

(6) Securitization Charges

In accordance with General Information Section 35, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(7) Smart Grid Surcharge

In accordance with General Information Section 36, a Smart Grid Surcharge shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY HEATING SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ......@	0.811 ¢ per kWh	0.811 ¢ per kWh
Off-Peak All other kWh ......@	0.811 ¢ per kWh	0.811 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh .....@	0.420 ¢ per kWh	0.420 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE (Continued)

RATE - MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
First 250 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh
Next 450 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh
Over 700 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh ... @	0.439 ¢ per kWh	0.439 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

(6) Securitization Charges

In accordance with General Information Section 35, the Securitization Charges shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

Attachment 1C

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$1.92 per kW	$1.92 per kW
Period II	All kW @	0.50 per kW	0.50 per kW
Period III	All kW @	1.74 per kW	1.74 per kW
Period IV	All kW @	0.50 per kW	0.50 per kW
Usage Charge			
Period I	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period II	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period III	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period IV	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.273 ¢ per kWh	0.273 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(Continued)

ISSUED: EFFECTIVE:

ISSUED BY: Timothy Cawley, President
Mahwah, New Jersey 07430

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 2.458 ¢ per kWh during the billing months of October through May and 3.973 ¢ per kWh during the summer billing months and a Transmission Charge of 0.552 ¢ per kWh and a Transmission Surcharge of 0.273¢ per kWh during all billing months.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.96 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (4), (5), (6), (7), (8) and (9) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

(B) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(Continued)

Attachment 2A
Cost Allocation of 2014/2015 TrailCo Schedule 12 Charges
Attachment 2B
Cost Allocation of 2014/2015 Delmarva Schedule 12 Charges
Attachment 2C
Cost Allocation of 2014/2015 ACE Schedule 12 Charges
Attachment 2D
Cost Allocation of 2014/2015 PEPCo Schedule 12 Charges
Attachment 2E
Cost Allocation of 2014/2015 PPL Schedule 12 Charges
Attachment 2F
Cost Allocation of 2014/2015 AEP-East Schedule 12 Charges

Please note that PJM has implemented section based formatting for the PJM Open Access Transmission Tariff which is reflected in Attachment 2 herein. PJM no longer provides individual page original sheet numbers and update information.

Attachment 2A

PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement	**PJM Upgrade ID**	**June 2014- May 2015 Annual Revenue Requirement**	**ACE Zone Share**[1]	**JCP&L Zone Share**[1]	**PSE&G Zone Share**[1]	**RE Zone Share**[1]	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 163,862,883	1.70%	3.96%	6.46%	0.27%	$2,785,669	$6,488,970	$10,585,542	$442,430	$20,302,611
Wylie Ridge [2]	b0218	$ 2,980,500	11.62%	15.28%	0.00%	0.00%	$346,334	$455,420	$0	$0	$801,755
Black Oak	b0216	$ 6,591,961	1.70%	3.96%	6.46%	0.27%	$112,063	$261,042	$425,841	$17,798	$816,744
Meadowbrook 200 MVAR capacitor	b0559	$ 1,569,641	1.70%	3.96%	6.46%	0.27%	$26,684	$62,158	$101,399	$4,238	$194,478
Replace Kammer 765/500 kV TXfmr	b0495	$ 5,639,113	1.70%	3.96%	6.46%	0.27%	$95,865	$223,309	$364,287	$15,226	$698,686
Doubs TXfmr 2	b0343	$ 753,095	1.85%	0.00%	0.00%	0.00%	$13,932	$0	$0	$0	$13,932
Doubs TXfmr 3	b0344	$ 692,062	1.86%	0.00%	0.00%	0.00%	$12,872	$0	$0	$0	$12,872
Doubs TXfmr 4	b0345	$ 820,685	1.85%	0.00%	0.00%	0.00%	$15,183	$0	$0	$0	$15,183
New Osage 138KV Ckt	b0674-b1023.3	$ 1,949,884	0.00%	0.00%	0.25%	0.01%	$0	$0	$4,875	$195	$5,070
Cap at Grover 230	b0556	$ (12,627)	8.58%	18.16%	26.13%	0.97%	-$1,083	-$2,293	-$3,300	-$122	-$6,799
Upgrade transformer 500/230	b1153	$ 2,675,178	3.72%	12.52%	20.44%	0.71%	$99,517	$334,932	$546,806	$18,994	$1,000,249
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 812,203	1.70%	3.96%	6.46%	0.27%	$13,807	$32,163	$52,468	$2,193	$100,632
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 7,338,047	1.70%	3.96%	6.46%	0.27%	$124,747	$290,587	$474,038	$19,813	$909,184
Build 250 MVAR svc at Altoona 230kV	b1801	$ 2,835,308	6.45%	8.12%	8.16%	0.33%	$182,877	$230,227	$231,361	$9,357	$653,822
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 52,211	0.00%	5.48%	0.00%	0.00%	$0	$2,861	$0	$0	$2,861
							$3,828,467	**$8,379,376**	**$12,783,317**	**$530,120**	**$25,521,281**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 1,065,276.44	10,414.4	$ 102.29	$ 7,456,935	$ 5,326,382	$ 12,783,317
JCP&L	$ 698,281.34	6,378.9	$ 109.47	$ 4,887,969	$ 3,491,407	$ 8,379,376
ACE	$ 319,038.95	2,739.2	$ 116.47	$ 2,233,273	$ 1,595,195	$ 3,828,467
RE	$ 44,176.68	438.4	$ 100.77	$ 309,237	$ 220,883	$ 530,120
Total Impact on NJ Zones	**$ 2,126,773.41**			**$ 14,887,414**	**$ 10,633,867**	**$ 25,521,281**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2014 allocation share percentages are from PJM OATT issued 5/27/2014
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(14) Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0229	Install fourth Bedington 500/138 kV		APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0238	Reconductor Doubs – Dickerson and Doubs – Aqueduct 1200 MVA	As specified under the procedures detailed in Attachment H-18B, Section 1.b	BGE (16.66%) / Dominion (33.66%) / PEPCO (49.68%)
b0240	Open the Black Oak #3 500/138 kV transformer for the loss of Hatfield – Back Oak 500 kV line		APS (100%)
b0245	Replacement of the existing 954 ACSR conductor on the Bedington – Nipetown 138 kV line with high temperature/low sag conductor		APS (100%)
b0246	Rebuild of the Double Tollgate – Old Chapel 138 kV line with 954 ACSR conductor	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)
b0273	Open both North Shenandoah #3 transformer and Strasburg – Edinburgh 138 kV line for the loss of Mount Storm – Meadowbrook 572 500 kV		APS (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0322	Convert Lime Kiln substation to 230 kV operation		APS (100%)
b0323	Replace the North Shenandoah 138/115 kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.33	Replace Meadow Brook 138kV breaker 'MD-1'		APS (100%)
b0347.34	Replace Meadow Brook 138kV breaker 'MD-2'		APS (100%)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (100%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / Neptune* (0.42%) / PPL (4.60%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0406.1	Replace Mitchell 138 kV breaker "#4 bank"		APS (100%)
b0406.2	Replace Mitchell 138 kV breaker "#5 bank"		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker "#2 transf"		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker "#3 bank"		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker "Charlerio #2"		APS (100%)

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Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker “Union Jct”		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker “#1 transf”		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.2	Replace Marlowe 138 kV breaker "MBO"		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker "BMA"		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker "BMR"		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker "WC-1"		APS (100%)
b0407.6	Replace Marlowe 138 kV breaker "R11"		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker "W"		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker "138 kV bus tie"		APS (100%)
b0408.1	Replace Trissler 138 kV breaker "Belmont 604"		APS (100%)
b0408.2	Replace Trissler 138 kV breaker "Edgelawn 90"		APS (100%)
b0409.1	Replace Weirton 138 kV breaker "Wylie Ridge 210"		APS (100%)
b0409.2	Replace Weirton 138 kV breaker "Wylie Ridge 216"		APS (100%)
b0410	Replace Glen Falls 138 kV breaker "McAlpin 30"		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		APS (100%)

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Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

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Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV		APS (100%)
b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation		APS (100%)
b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR		APS (100%)
b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR		APS (100%)
b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls		APS (100%)
b0589	Replace five 138 kV breakers at Cecil		APS (100%)

*Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0590	Replace #1 and #2 breakers at Charleroi 138 kV		APS (100%)
b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV		APS (100%)
b0673	Rebuild Elko – Carbon Center Junction using 230 kV construction		APS (100%)
b0674	Construct new Osage – Whiteley 138 kV circuit		APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)
b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'		APS (100%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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**East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT's at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT's at Whiteley 138 kV		APS (100%)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)

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**East Coast Power, L.L.C

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)
b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)		APS(100%)
b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)		APS(100%)
b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)		APS(100%)
b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)		APS(100%)
b0941	Replace Opequon 138 kV breaker 'BUSTIE'		APS(100%)
b0942	Replace Butler 138 kV breaker '#1 BANK'		APS(100%)
b0943	Replace Butler 138 kV breaker '#2 BANK'		APS(100%)
b0944	Replace Yukon 138 kV breaker 'Y-8'		APS(100%)
b0945	Replace Yukon 138 kV breaker 'Y-3'		APS(100%)
b0946	Replace Yukon 138 kV breaker 'Y-1'		APS(100%)
b0947	Replace Yukon 138 kV breaker 'Y-5'		APS(100%)
b0948	Replace Yukon 138 kV breaker 'Y-2'		APS(100%)
b0949	Replace Yukon 138 kV breaker 'Y-19'		APS(100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0950	Replace Yukon 138 kV breaker 'Y-4'		APS(100%)
b0951	Replace Yukon 138 kV breaker 'Y-9'		APS(100%)
b0952	Replace Yukon 138 kV breaker 'Y-11'		APS(100%)
b0953	Replace Yukon 138 kV breaker 'Y-13'		APS(100%)
b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'		APS(100%)
b0955	Replace Yukon 138 kV breaker 'Y-7'		APS(100%)
b0956	Replace Pruntytown 138 kV breaker 'P-9'		APS(100%)
b0957	Replace Pruntytown 138 kV breaker 'P-12'		APS(100%)
b0958	Replace Pruntytown 138 kV breaker 'P-15'		APS(100%)
b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'		APS(100%)
b0960	Replace Pruntytown 138 kV breaker 'P-2'		APS(100%)
b0961	Replace Pruntytown 138 kV breaker 'P-5'		APS(100%)
b0962	Replace Yukon 138 kV breaker 'Y-18'		APS(100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0963	Replace Yukon 138 kV breaker 'Y-10'		APS(100%)
b0964	Replace Pruntytown 138 kV breaker 'P-11'		APS(100%)
b0965	Replace Springdale 138 kV breaker '138E'		APS(100%)
b0966	Replace Pruntytown 138 kV breaker 'P-8'		APS(100%)
b0967	Replace Pruntytown 138 kV breaker 'P-14'		APS(100%)
b0968	Replace Ringgold 138 kV breaker '#3 XFMR BANK'		APS(100%)
b0969	Replace Springdale 138 kV breaker '138C'		APS(100%)
b0970	Replace Rivesville 138 kV breaker '#8 XFMR BANK'		APS(100%)
b0971	Replace Springdale 138 kV breaker '138F'		APS(100%)
b0972	Replace Belmont 138 kV breaker 'B-16'		APS(100%)
b0973	Replace Springdale 138 kV breaker '138G'		APS(100%)
b0974	Replace Springdale 138 kV breaker '138V'		APS(100%)
b0975	Replace Armstrong 138 kV breaker 'BROOKVILLE'		APS(100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0976	Replace Springdale 138 kV breaker '138P'		APS(100%)
b0977	Replace Belmont 138 kV breaker 'B-17'		APS(100%)
b0978	Replace Springdale 138 kV breaker '138U'		APS(100%)
b0979	Replace Springdale 138 kV breaker '138D'		APS(100%)
b0980	Replace Springdale 138 kV breaker '138R'		APS(100%)
b0981	Replace Yukon 138 kV breaker 'Y-12'		APS(100%)
b0982	Replace Yukon 138 kV breaker 'Y-17'		APS(100%)
b0983	Replace Yukon 138 kV breaker 'Y-14'		APS(100%)
b0984	Replace Rivesville 138 kV breaker '#10 XFMR BANK'		APS(100%)
b0985	Replace Belmont 138 kV breaker 'B-14'		APS(100%)
b0986	Replace Armstrong 138 kV breaker 'RESERVE BUS'		APS(100%)
b0987	Replace Yukon 138 kV breaker 'Y-16'		APS(100%)
b0988	Replace Springdale 138 kV breaker '138T'		APS(100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'		APS(100%)
b0990	Change reclosing on Cabot 138 kV breaker 'C-9'		APS(100%)
b0991	Change reclosing on Belmont 138 kV breaker 'B-7'		APS(100%)
b0992	Change reclosing on Belmont 138 kV breaker 'B-12'		APS(100%)
b0993	Change reclosing on Belmont 138 kV breaker 'B-9'		APS(100%)
b0994	Change reclosing on Belmont 138 kV breaker 'B-19'		APS(100%)
b0995	Change reclosing on Belmont 138 kV breaker 'B-21'		APS(100%)
b0996	Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'		APS(100%)
b0997	Change reclosing on Cabot 138 kV breaker 'C-4'		APS(100%)
b0998	Change reclosing on Cabot 138 kV breaker 'C-1'		APS(100%)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)
b1022.4	Add static capacitors at North Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.5	Add static capacitors at South Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.6	Add static capacitors at Manifold 138 kV		APS (96.98%) / DL (3.02%)
b1022.7	Add static capacitors at Houston 138 kV		APS (96.98%) / DL (3.02%)
b1023.1	Install a 500/138 kV transformer at 502 Junction		APS (100%)
b1023.2	Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit		APS (100%)
b1023.3	Construct a new 502 Junction - Osage 138 kV line		APS (100%)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)
b1131	Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment		APS (100%)
b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal equipment		APS (100%)
b1133	Upgrade terminal equipment at Springdale		APS (100%)
b1135	Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor		APS (100%)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (78.59%) / PENELEC (14.08%) / ECP ** (0.23%) / PSEG (6.83%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1145	Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1146	Replace Layton - Smithton #61 138 kV line structures to increase line rating		APS (100%)
b1147	Replace Smith – Yukon 138 kV line structures to increase line rating		APS (100%)
b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR		APS (100%)
b1149	Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR		APS (100%)
b1150	Upgrade terminal equipment at Social Hall		APS (100%)
b1151	Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR		APS (100%)
b1152	Reconductor Grand Point – South Chambersburg		APS (100%)
b1159	Replace Peters 138 kV breaker 'Bethel P OCB'		APS (100%)
b1160	Replace Peters 138 kV breaker 'Cecil OCB'		APS (100%)
b1161	Replace Peters 138 kV breaker 'Union JctOCB'		APS (100%)
b1162	Replace Double Toll Gate 138 kV breaker 'DRB-2'		APS (100%)
b1163	Replace Double Toll Gate 138 kV breaker 'DT 138 kV OCB'		APS (100%)
b1164	Replace Cecil 138 kV breaker 'Enlow OCB'		APS (100%)
b1165	Replace Cecil 138 kV breaker 'South Fayette'		APS (100%)
b1166	Replace Wylie Ridge 138 kV breaker 'W-9'		APS (100%)
b1167	Replace Reid 138 kV breaker 'RI-2'		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1171.1	Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work		BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)
b1171.3	Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1200	Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor		APS (100%)
b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bus		APS (100%)
b1221.2	Construct Bear Run 230 kV substation with 230/138 kV transformer		APS (100%)
b1221.3	Loop Carbon Center Junction – Williamette line into Bear Run		APS (100%)
b1221.4	Carbon Center – Carbon Center Junction & Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV		APS (100%)
b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV lines		APS (100%)
b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR		AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCPL (2.92%) / ME (6.10%) / Neptune (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)
b1233.1	Upgrade terminal equipment at Washington		APS (100%)
b1234	Replace structures between Ridgeway and Paper city		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1235	Reconductor the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW		APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)
b1237	Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line		APS (100%)
b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substation		APS (100%)
b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substation		APS (100%)
b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation		APS (100%)
b1241	Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal		APS (100%)
b1242	Replace structures between Collins Ferry and West Run		APS (100%)
b1243	Install a 138 kV capacitor at Potter Substation		APS (100%)
b1261	Replace Butler 138 kV breaker '1-2 BUS 138'		APS (100%)
b1383	Install 2nd 500/138 kV transformer at 502 Junction		APS (93.27%) / DL (5.39%) / PENELEC (1.34%)
b1384	Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR		APS (100%)
b1385	Reconductor Halfway – Paramount 138 kV with 1033 ACCR		APS (100%)
b1386	Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1387	Reconductor Double Tollgate – Meadow Brook 138 kV		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1388	Reconductor Feagans Mill – Millville 138 kV with 954 ACSR		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1389	Reconductor Bens Run – St. Mary’s 138 kV with 954 ACSR		AEP (12.40%) / APS (17.80%) / DL (69.80%)
b1390	Replace Bus Tie Breaker at Opequon		APS (100%)
b1391	Replace Line Trap at Gore		APS (100%)
b1392	Replace structure on Belmont – Trissler 138 kV line		APS (100%)
b1393	Replace structures Kingwood – Pruntytown 138 kV line		APS (100%)
b1395	Upgrade Terminal Equipment at Kittanning		APS (100%)
b1401	Change reclosing on Pruntytown 138 kV breaker ‘P-16’ to 1 shot at 15 seconds		APS (100%)
b1402	Change reclosing on Rivesville 138 kV breaker ‘Pruntytown #34’ to 1 shot at 15 seconds		APS (100%)
b1403	Change reclosing on Yukon 138 kV breaker ‘Y21 Shepler’ to 1 shot at 15 seconds		APS (100%)
b1404	Replace the Kiski Valley 138 kV breaker ‘Vandergrift’ with a 40 kA breaker		APS (100%)
b1405	Change reclosing on Armstrong 138 kV breaker ‘GARETTRJCT’ at 1 shot at 15 seconds		APS (100%)
b1406	Change reclosing on Armstrong 138 kV breaker ‘KITTANNING’ to 1 shot at 15 seconds		APS (100%)
b1407	Change reclosing on Armstrong 138 kV breaker ‘BURMA’ to 1 shot at 15 seconds		APS (100%)
b1408	Replace the Weirton 138 kV breaker ‘Tidd 224’ with a 40 kA breaker		APS (100%)
b1409	Replace the Cabot 138 kV breaker ‘C9 Kiski Valley’ with a 40 kA breaker		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1507.2	Terminal Equipment upgrade at Doubs substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)
b1816.2	Adjust the control settings of all existing capacitors at Mt Airy 34.5kV, Monocacy 138kV, Ringgold 138kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies		APS (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.3	Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit		APS (100%)
b1816.4	Isolate and bypass the 138 kV reactor at Germantown Substation		APS (100%)
b1816.6	Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent		APS (100%)
b1822	Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS		APS (100%)
b1823	Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation		APS (100%)
b1824	Reconductor Grant Point - Guilford 138kV line approximately 8 miles of 556 ACSR with 795 ACSR		APS (100%)
b1825	Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line		APS (100%)
b1826	Change the CT ratio at Double Toll Gate 138 kV SS on MDT line		APS (100%)
b1827	Change the CT ratio at Double Toll Gate 138 kV SS on MBG line		APS (100%)
b1828.1	Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1828.2	Reconductor the Stonewall – Stephenson 2.08 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)
b1829	Replace the existing 138 kV 556.5 ACSR substation conductor risers with 954 ACSR at the Redbud 138 kV substation, including but not limited to the line side disconnect leads		APS (100%)
b1830	Replace 1200 A wave trap and 1024 ACAR breaker risers at Halfway 138 kV substation, and replace 1024 ACAR breaker risers at Paramount 138 kV substation		APS (100%)
b1832	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 1 (207) 230 kV line terminal		APS (100%)
b1833	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 2 (231) 230 kV line terminal		APS (100%)
b1835	Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV		APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)
b1836	Replace 1200 A wave trap with 1600 A wave trap at Reid 138 kV SS		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1837	Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV		APS (100%)
b1838	Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches		APS (100%)
b1839	Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS		APS (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1840	Construct a 138 kV line between Buckhannon and Weston 138 kV substations		APS (100%)
b1902	Replace line trap at Stonewall on the Stephenson 138 kV line terminal		APS (100%)
b1941	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong		APS (67.86%) / PENELEC (32.14%)
b1942	Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings		APS (100%)
b1964	Convert Moshannon substation to a 4 breaker 230 kV ring bus		APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / Neptune* (0.53%) / PECO (15.53%) / PPL (20.02%)
b1965	Install a 44 MVAR 138 kV capacitor at Luxor substation		APS (100%)
b1986	Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal		APS (100%)
b1987	Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry		APS (100%)
b1988	Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line		APS (100%)
b1989	Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line		APS (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2095	Replace Weirt 138 kV breaker 'S-TORONTO226' with 63kA rated breaker		APS (100%)
b2096	Revise the reclosing of Weirt 138 kV breaker '2&5 XFMR'		APS (100%)
b2097	Replace Ridgeley 138 kV breaker '#2 XFMR OCB'		APS (100%)
b2098	Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40kA rated breaker		APS (100%)
b2099	Revise the reclosing of Ridgeley 138 kV breaker 'RC1'		APS (100%)
b2100	Replace Ridgeley 138 kV breaker 'WC4' with 40kA rated breaker		APS (100%)
b2101	Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40kA rated breaker		APS (100%)
b2102	Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40kA rated breaker		APS (100%)
b2103	Replace Armstrong 138 kV breaker 'BURMA' with 40kA rated breaker		APS (100%)
b2104	Replace Armstrong 138 kV breaker 'KITTANNING' with 40kA rated breaker		APS (100%)
b2105	Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40kA rated breaker		APS (100%)
b2106	Replace Wylie Ridge 345 kV breaker 'WK-1' with 63kA rated breaker		APS (100%)
b2107	Replace Wylie Ridge 345 kV breaker 'WK-2' with 63kA rated breaker		APS (100%)
b2108	Replace Wylie Ridge 345 kV breaker 'WK-3' with 63kA rated breaker		APS (100%)
b2109	Replace Wylie Ridge 345 kV breaker 'WK-4' with 63kA rated breaker		APS (100%)
b2110	Replace Wylie Ridge 345 kV breaker 'WK-6' with 63kA rated breaker		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2111	Replace Wylie Ridge 138 kV breaker 'WK-7' with 63kA rated breaker		APS (100%)
b2112	Replace Wylie Ridge 345 kV breaker 'WK-5'		APS (100%)
b2113	Replace Weirton 138 kV breaker 'NO 6 XFMR' with 63kA rated breaker		APS (100%)
b2114	Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)		APS (100%)
b2124.1	Add a new 138 kV line exit		APS (100%)
b2124.2	Construct a 138 kV ring bus and install a 138/69 kV autotransformer		APS (100%)
b2124.3	Add new 138 kV line exit and install a 138/25 kV transformer		APS (100%)
b2124.4	Construct approximately 5.5 miles of 138 kV line		APS (100%)
b2124.5	Convert approximately 7.5 miles of 69 kV to 138 kV		APS (100%)
b2156	Install a 75 MVAR 230 kV capacitor at Shingletown Substation		APS (100%)
b2165	Replace 800A wave trap at Stonewall with a 1200 A wave trap		APS (100%)
b2166	Reconductor the Millville – Sleepy Hollow 138kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800		APS (100%)
b2168	For Grassy Falls 138kV Capacitor bank adjust turn-on voltage to 1.0pu with a high limit of 1.04pu, For Crupperneck and Powell Mountain 138kV Capacitor Banks adjust turn-on voltage to 1.01pu with a high limit of 1.035pu		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2169	Replace/Raise structures on the Yukon-Smithton 138 kV line section to eliminate clearance de-rate		APS (100%)
b2170	Replace/Raise structures on the Smithton-Shepler Hill Jct 138 kV line section to eliminate clearance de-rate		APS (100%)
b2171	Replace/Raise structures on the Parsons-William 138 kV line section to eliminate clearance de-rate		APS (100%)
b2172	Replace/Raise structures on the Parsons - Loughs Lane 138 kV line section to eliminate clearance de-rate		APS (100%)

Note: Projects 1800 and 1801 being built by Met Ed
and owned by TrailCo

(5) Metropolitan Edison Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1002	Replace Hunterstown 115 kV breaker '96392'		ME (100%)
b1003	Replace Hunterstown 115 kV breaker '96292'		ME (100%)
b1004	Replace Hunterstown 115 kV breaker '99192'		ME (100%)
b1061	Replace existing Yorkana 230/115 kV transformer banks 1 and 4 with a single, larger transformer similar to transformer bank #3		ME (100%)
b1061.1	Replace the Yorkana 115 kV breaker ‘97282’		ME (100%)
b1061.2	Replace the Yorkana 115 kV breaker ‘B282’		ME (100%)
b1302	Replace the limiting bus conductor and wave trap at the Jackson 115 kV terminal of the Jackson – JE Baker Tap 115 kV line		ME (100%)
b1365	Reconductor the Middletown – Collins 115 kV (975) line 0.32 miles of 336 ACSR		ME (100%)
b1366	Reconductor the Collins – Cly – Newberry 115 kV (975) line 5 miles with 795 ACSR		ME (100%)
b1727	Reconductor 2.4 miles of existing 556 and 795 ACSR from Harley Davidson to Pleasureville 115 kV with 795 ACSS to raise the ratings		ME (100%)
b1800	Install a 500 MVAR SVC at the existing Hunterstown 500kV substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Note: Projects 1800 and 1801 being built by Met Ed
and owned by TrailCo

(5) Metropolitan Edison Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (6.45%) / AEP (2.57%) / APS (6.86%) / BGE (6.55%) / ConEd (0.29%) / DPL (12.35%) / Dominion (14.85%) / JCPL (8.12%) / ME (6.19%) / Neptune* (0.82%) / PECO (21.50%) / PPL (4.87%) / PSEG (8.16%) / RE (0.33%) / ECP** (0.09%)
b1816.5	Replace SCCIR (Sub-conductor) at Hunterstown Substation on the No. 1, 230/115 kV transformer		ME (100%)
b1999	Replace limiting wave trap, circuit breaker, substation conductor, relay and current transformer components at Northwood		ME (100%)
b2000	Replace limiting wave trap on the Glendon - Hosensack line		ME (100%)
b2001	Replace limiting circuit breaker and substation conductor transformer components at Portland 230kV		ME (100%)
b2002	Northwood 230/115 kV Transformer upgrade		ME (100%)
b2023	Construct a new North Temple - Riverview - Cartech 69 kV line (4.7 miles) with 795 ACSR		ME (100%)
b2024	Upgrade 4/0 substation conductors at Middletown 69 kV		ME (100%)
b2025	Upgrade 4/0 and 350 Cu substation conductors at the Middletown Junction terminal of the Middletown Junction - Wood Street Tap 69 kV line		ME (100%)
b2026	Upgrade an OC protection relay at the Baldy 69 kV substation		ME (100%)
b2148	Install a 115 kV 28.8 MVAR capacitor at Pleasureville substation		ME (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Attachment 2B

PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for Delmarva Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2014 - May 2015 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
New 500 kV MAPP TX line - Delmarva portion	b0512	$ 14,753,405	1.70%	3.96%	6.46%	0.27%	$250,808	$584,235	$953,070	$39,834	$1,827,947
Replace line trap- Keeney	b0272.1	$ 29,990	1.70%	3.96%	6.46%	0.27%	$510	$1,188	$1,937	$81	$3,716
Add two breakers- Keeney	b0751	$ 696,486	1.70%	3.96%	6.46%	0.27%	$11,840	$27,581	$44,993	$1,881	$86,295
Totals							**$263,158**	**$613,003**	**$1,000,000**	**$41,796**	**$1,917,957**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 83,333.36	10,414.4	$ 8.00	$ 583,334	$ 416,667	$ 1,000,000
JCP&L	$ 51,083.61	6,378.9	$ 8.01	$ 357,585	$ 255,418	$ 613,003
ACE	$ 21,929.83	2,739.2	$ 8.01	$ 153,509	$ 109,649	$ 263,158
RE	$ 3,482.97	438.4	$ 7.94	$ 24,381	$ 17,415	$ 41,796
Total Impact on NJ Zones	**$ 159,829.77**			**$ 1,118,808**	**$ 799,149**	**$ 1,917,957**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2014 allocation share percentages are from PJM OATT issued 5/27/2014
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(3) Delmarva Power & Light Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0144.1	Build new Red Lion – Milford – Indian River 230 kV circuit		DPL (100%)
b0144.2	Indian River Sub – 230 kV Terminal Position		DPL (100%)
b0144.3	Red Lion Sub – 230 kV Terminal Position		DPL (100%)
b0144.4	Milford Sub – (2) 230 kV Terminal Positions		DPL (100%)
b0144.5	Indian River – 138 kV Transmission Line to AT-20		DPL (100%)
b0144.6	Indian River – 138 & 69 kV Transmission Ckts. Undergrounding		DPL (100%)
b0144.7	Indian River – (2) 230 kV bus ties		DPL (100%)
b0148	Re-rate Glasgow – Mt. Pleasant 138 kV and North Seaford – South Harrington 138 kV		DPL (100%)
b0149	Complete structure work to increase rating of Cheswold – Jones REA 138 kV		DPL (100%)
b0221	Replace disconnect switch on Edgewood-N. Salisbury 69 kV		DPL (100%)
b0241.1	Keeny Sub – Replace overstressed breakers		DPL (100%)
b0241.2	Edgemoor Sub – Replace overstressed breakers		DPL (100%)
b0241.3	Red Lion Sub – Substation reconfigure to provide for second Red Lion 500/230 kV transformer		DPL (84.5%) / PECO (15.5%)
b0261	Replace 1200 Amp disconnect switch on the Red Lion – Reybold 138 kV circuit		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV		DPL (100%)
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River – Frankford 138 kV line		DPL (100%)
b0272.1	Replace line trap and disconnect switch at Keeney 500 kV substation – 5025 Line Terminal Upgrade		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)†
b0282	Install 46 MVAR capacitors on the DPL distribution system		DPL (100%)
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony – Edgemoor 230 kV circuit, increase the operating temperature of the conductor		DPL (100%)
b0295	Raise conductor temperature of North Seaford – Pine Street – Dupont Seaford		DPL (100%)
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade		DPL (100%)
b0320	Create a new 230 kV station that splits the 2nd Milford to Indian River 230 kV line, add a 230/69 kV transformer, and run a new 69 kV line down to Harbeson 69 kV		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0382	Cambridge Sub – Close through to Todd Substation		DPL (100%)
b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0384	Replace Indian River AT-20 (400 MVA)		DPL (100%)
b0385	Oak Hall to New Church (13765) Upgrade		DPL (100%)
b0386	Cheswold/Kent (6768) Rebuild		DPL (100%)
b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer		DPL (100%)
b0388	Hallwood/Parksley (6790-2) Upgrade		DPL (100%)
b0389	Indian River AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade		DPL (100%)
b0391	Kent/New Meredith (6704-2) Upgrade		DPL (100%)
b0392	East New Market Sub – Establish a 69 kV Bus Arrangement		DPL (100%)
b0415	Increase the temperature ratings of the Edgemoor – Christiana – New Castle 138 kV by replacing six transmission poles		DPL (100%)
b0437	Spare Keeney 500/230 kV transformer		DPL (100%)
b0441	Additional spare Keeney 500/230 kV transformer		DPL (100%)
b0480	Rebuild Lank – Five Points 69 kV		DPL (100%)
b0481	Replace wave trap at Indian River 138 kV on the Omar – Indian River 138 kV circuit		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0482	Rebuild Millsboro – Zoar REA 69 kV		DPL (100%)
b0483	Replace Church 138/69 kV transformer and add two breakers		DPL (100%)
b0483.1	Build Oak Hall – Wattsville 138 kV line		DPL (100%)
b0483.2	Add 138/69 kV transformer at Wattsville		DPL (100%)
b0483.3	Establish 138 kV bus position at Oak Hall		DPL (100%)
b0484	Re-tension Worcester – Berlin 69 kV for 125ºC		DPL (100%)
b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC		DPL (100%)
b0494.1	Install a 2nd Red Lion 230/138 kV		DPL (100%)
b0494.2	Hares Corner – Relay Improvement		DPL (100%)
b0494.3	Reybold – Relay Improvement		DPL (100%)
b0494.4	New Castle – Relay Improvement		DPL (100%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0513	Rebuild the Ocean Bay – Maridel 69 kV line		DPL (100%)
b0527	Replace existing 12 MVAR capacitor at Bethany with a 30 MVAR capacitor		DPL (100%)
b0528	Replace existing 69/12 kV transformer at Bethany with a 138/12 kV transformer		DPL (100%)
b0529	Install an additional 8.4 MVAR capacitor at Grasonville 69 Kv		DPL (100%)
b0530	Replace existing 12 MVAR capacitor at Wye Mills with a 30 MVAR capacitor		DPL (100%)
b0531	Create a four breaker 138 kV ring bus at Wye Mills and add a second 138/69 kV transformer		DPL (100%)
b0566	Rebuild the Trappe Tap – Todd 69 kV line		DPL (100%)
b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line		DPL (100%)
b0568	Install a third Indian River 230/138 kV transformer		DPL (100%)
b0725	Add a third Steele 230/138 kV transformer		DPL (100%)
b0732	Rebuild Vaugh – Wells 69 kV		DPL (100%)
b0733	Add a second 230/138 kV transformer at Harmony		DPL (97.06%) / PECO (2.94%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0734	Rebuild Church – Steele 138 kV		DPL (100%)
b0735	Rebuild Indian River – Omar – Bethany 138 kV		DPL (100%)
b0736	Rebuild Dupont Edgemoor – Edgemoor – Silverside 69 kV		DPL (69.46%) / PECO (17.25%) / ECP** (0.27%) / PSEG (12.53%) / RE (0.49%)
b0737	Build a new Indian River – Bishop 138 kV line		DPL (100%)
b0750	Convert 138 kV network path from Vienna – Loretto – Piney - Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV		DPL (100%)
b0751	Add two additional breakers at Keeney 500 kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0752	Replace two circuit breakers to bring the emergency rating up to 348 MVA		DPL (100%)
b0753	Add a second Loretto 230/138 kV transformer		DPL (100%)
b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line to bring the normal rating to 298 MVA and the emergency rating to 333 MVA		DPL (100%)
b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, and operate the 34.5 kV bus normally open		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line		DPL (100%)
b0874	Reconfigure Brandywine substation		DPL (100%)
b0876	Install 50 MVAR SVC at 138th St 138 kV		DPL (100%)
b0877	Build a 2nd Vienna-Steele 230 kV line		DPL (100%)
b0879.1	Apply a special protection scheme (load drop at Stevensville and Grasonville)		DPL (100%)
b1246	Re-build the Townsend – Church 138 kV circuit		DPL (100%)
b1247	Re-build the Glasgow – Cecil 138 kV circuit		DPL (72.06%) / PECO (27.94%)
b1248	Install two 15 MVAR capacitor at Loretto 69 kV		DPL (100%)
b1249	Reconfigure the existing Sussex 69 kV capacitor		DPL (100%)
b1603	Upgrade 19 miles conductor of the Wattsville - Signepost - Stockton - Kenney 69 kV circuit		DPL (100%)
b1604	Replace CT at Reybold 138 kV substation		DPL (100%)
b1723	Replace strand bus and disconnect switch at Glasgow 138 kV substation		DPL (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-3.

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1899.1	Install new variable reactors at Indian River and Nelson 138 kV		DPL (100%)
b1899.2	Install new variable reactors at Cedar Creek 230 kV		DPL (100%)
b1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV		DPL (100%)

Attachment 2C

PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for ACE Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2014 - May 2015 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Upgrade AE portion of Delco Tap	b0265	$ 661,364	88.94%	9.38%	0.00%	0.00%	$588,217	$62,036	$0	$0	$650,253
Replace Monroe 230/69 kV TXfmrs	b0276	$ 1,010,512	91.28%	0.00%	8.29%	0.23%	$922,395	$0	$83,771	$2,324	$1,008,491
Reconductor Union - Corson 138 kV	b0211	$ 1,725,340	64.81%	25.70%	6.31%	0.00%	$1,118,193	$443,412	$108,869	$0	$1,670,474
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 3,461,269	1.70%	3.96%	6.46%	0.27%	$58,842	$137,066	$223,598	$9,345	$428,851
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 2,468,012	64.81%	25.70%	6.31%	0.00%	$1,599,519	$634,279	$155,732	$0	$2,389,529
Totals							**$4,287,165**	**$1,276,794**	**$571,970**	**$11,670**	**$6,147,599**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 47,664.16	10,414.4	$ 4.58	$ 333,649	$ 238,321	$ 571,970
JCP&L	$ 106,399.47	6,378.9	$ 16.68	$ 744,796	$ 531,997	$ 1,276,794
ACE	$ 357,263.79	2,739.2	$ 130.43	$ 2,500,847	$ 1,786,319	$ 4,287,165
RE	$ 972.47	438.4	$ 2.22	$ 6,807	$ 4,862	$ 11,670
Total Impact on NJ Zones	**$ 512,299.89**			**$ 3,586,099**	**$ 2,561,499**	**$ 6,147,599**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:

1) 2014 allocation share percentages are from PJM OATT issued 5/27/2014
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(1) Atlantic City Electric Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0135	Build new Cumberland – Dennis 230 kV circuit which replaces existing Cumberland – Corson 138 kV		AEC (100%)
b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVAR SVC and 50 MVAR capacitor		AEC (100%)
b0137	Build new Dennis – Corson 138 kV circuit		AEC (100%)
b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR capacitor at Cardiff		AEC (100%)
b0139	Build new Cardiff – Lewis 138 kV circuit		AEC (100%)
b0140	Reconductor Laurel – Woodstown 69 kV		AEC (100%)
b0141	Reconductor Monroe – North Central 69 kV		AEC (100%)
b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV circuit		AEC (88.94%) / ConEd (1.04%) / JCPL (9.38%) / Neptune* (0.64%)
b0276	Replace both Monroe 230/69 kV transformers		AEC (91.28%) / PSEG (8.29%) / RE (0.23%) / ECP** (0.20%)
b0276.1	Upgrade a strand bus at Monroe to increase the rating of transformer #2		AEC (100%)
b0277	Install a second Cumberland 230/138 kV transformer		AEC (100%)
b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation		AEC (100%)
b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substation		AEC (100%)
b0281.3	Install 8 MVAR capacitors on the AE distribution system		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0142	Reconductor Landis – Minotola 138 kV		AEC (100%)
b0143	Reconductor Beckett – Paulsboro 69 kV		AEC (100%)
b0210	Install a new 500/230kV substation in AEC area. The high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)†
b0210	Install a new 500/230kV substation in AEC area, the high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)††
b0211	Reconductor Union - Corson 138kV circuit		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)
b0212	Substation upgrades at Union and Corson 138kV		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0214	Install 50 MVAR capacitor at Cardiff 230kV substation		AEC (100%)
b0431	Monroe Upgrade New Freedom strand bus		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)
b0871	Install 35 MVAR capacitor at Motts Farm 69 kV		AEC (100%)
b1072	Modify the existing EMS load shedding scheme at Cedar to additionally sense the loss of both Cedar 230/69 kV transformers and shed load accordingly		AEC (100%)
b1127	Build a new Lincoln-Minitola 138 kV line		AEC (100%)
b1195.1	Upgrade the Corson sub T2 terminal		AEC (100%)
b1195.2	Upgrade the Corson sub T1 terminal		AEC (100%)
b1244	Install 10 MVAR capacitor at Peermont 69 kV substation		AEC (100%)
b1245	Rebuild the Newport-South Millville 69 kV line		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1250	Reconductor the Monroe – Glassboro 69 kV		AEC (100%)
b1250.1	Upgrade substation equipment at Glassboro		AEC (100%)
b1280	Sherman: Upgrade 138/69 kV transformers		AEC (100%)
b1396	Replace Lewis 138 kV breaker 'L'		AEC (100%)
b1398.5	Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1598	Reconductor Sherman Av – Carl's Corner 69kV circuit		AEC (100%)
b1599	Replace terminal equipments at Central North 69 kV substation		AEC (100%)
b1600	Upgrade the Mill T2 138/69 kV transformer		AEC (88.83%) / JCPL (4.74%) / HTP (0.20%) / ECP** (0.22%) / PSEG (5.78%) / RE (0.23%)
b2157	Re-build 5.3 miles of the Corson - Tuckahoe 69 kV circuit		AEC (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

Attachment 2D

PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for PEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement	**PJM Upgrade ID**	**June 2014- May 2015 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
New 500 kV MAPP TX line - PEPCO portion	b0512	$ 16,591,450	1.70%	3.96%	6.46%	0.27%	$282,055	$657,021	$1,071,808	$44,797	$2,055,681
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 3,671,353	1.78%	2.67%	3.81%	0.00%	$65,350	$98,025	$139,879	$0	$303,254
Replace 230 1A breaker	b0512.7	$ 348,274	1.70%	3.96%	6.46%	0.27%	$5,921	$13,792	$22,499	$940	$43,151
Replace 230 1B breaker	b0512.8	$ 348,274	1.70%	3.96%	6.46%	0.27%	$5,921	$13,792	$22,499	$940	$43,151
Replace 230 2A breaker	b0512.9	$ 348,274	1.70%	3.96%	6.46%	0.27%	$5,921	$13,792	$22,499	$940	$43,151
Replace 230 3A breaker	b0512.12	$ 351,338	1.70%	3.96%	6.46%	0.27%	$5,973	$13,913	$22,696	$949	$43,531
Ritchie-Benning 230 lines	b0526	$ 10,425,543	0.77%	1.39%	2.10%	0.08%	$80,277	$144,915	$218,936	$8,340	$452,469
Totals							**$451,416**	**$955,250**	**$1,520,815**	**$56,907**	**$2,984,387**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 126,734.55	10,414.4	$ 12.17	$ 887,142	$ 633,673	$ 1,520,815
JCP&L	$ 79,604.13	6,378.9	$ 12.48	$ 557,229	$ 398,021	$ 955,250
ACE	$ 37,618.01	2,739.2	$ 13.73	$ 263,326	$ 188,090	$ 451,416
RE	$ 4,742.25	438.4	$ 10.82	$ 33,196	$ 23,711	$ 56,907
Total Impact on NJ Zones	**$ 248,698.93**			**$ 1,740,893**	**$ 1,243,495**	**$ 2,984,387**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:

1) 2014 allocation share percentages are from PJM OATT issued 5/27/2014
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(10) Potomac Electric Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0146	Installation of (2) new 230 kV circuit breakers at Quince Orchard substation on circuits 23028 and 23029		PEPCO (100%)
b0219	Install two new 230 kV circuits between Palmers Corner and Blue Plains		PEPCO (100%)
b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit		PEPCO (100%)
b0238.1	Modify Dickerson Station H 230 kV		PEPCO (100%)
b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV transformer, 2 500 kV circuit breakers and miscellaneous bus work		BGE (19.33%) / Dominion (17%) / PEPCO (63.67%)
b0319	Add a second 1000 MVA Bruches Hill 500/230 kV transformer		PEPCO (100%)
b0366	Install a 4th Ritchie 230/69 kV transformer		PEPCO (100%)
b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0367.2	Reconductor circuit "23033" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)
b0375	Install 0.5% reactor at Dickerson on the Pleasant View – Dickerson 230 kV circuit		AEC (1.02%) / BGE (25.42%) / DPL (2.97%) / ME (1.72%) / PECO (3.47%) / PEPCO (65.40%)
b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.66%) / BGE (22.09%) / ConEd (0.18%) / DPL (3.69%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.53%) / PEPCO (41.78%) / PPL (2.07%)
b0478	Reconductor the four circuits from Burches Hill to Palmers Corner		APS (1.68%) / BGE (1.83%) / PEPCO (96.49%)
b0496	Replace existing 500/230 kV transformer at Brighton		APS (5.67%) / BGE (29.68%) / Dominion (10.91%) / PEPCO (53.74%)
b0499	Install third Burches Hill 500/230 kV transformer		APS (3.54%) / BGE (7.31%) / PEPCO (89.15%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.7	Advance n0772 (Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.18	Advance n0783 (Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.22	Advance n0787 (Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.26	Advance n0791 (Replace Chalk Point 230 Kv breaker (4C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0526	Build two Ritchie – Benning Station A 230 kV lines		AEC (0.77%) / BGE (16.76%) / DPL (1.22%) / JCPL (1.39%) / ME (0.59%) / Neptune* (0.13%) / PECO (2.10%) / PEPCO (74.86%) / PSEG (2.10%) / RE (0.08%)
b0561	Install 300 MVAR capacitor at Dickerson Station "D" 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0637	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0638	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0639	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0640	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0641	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0642	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0643	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0644	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0645	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0646	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0647	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0648	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0649	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0701	Expand Benning 230 kV station, add a new 250 MVA 230/69 kV transformer at Benning Station 'A', new 115 kV Benning switching station		BGE (30.57%) / PEPCO (69.43%)
b0702	Add a second 50 MVAR 230 kV shunt reactor at the Benning 230 kV substation		PEPCO (100%)
b0720	Upgrade terminal equipment on both lines		PEPCO (100%)
b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line		PEPCO (100%)
b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line		PEPCO (100%)
b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line		PEPCO (100%)
b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0730	Add slow oil circulation to the four Bells Mill Road – Bethesda 138 kV lines, add slow oil circulation to the two Buzzard Point – Southwest 138 kV lines; increasing the thermal ratings of these six lines allows for greater adjustment of the O Street phase shifters		PEPCO (100%)
b0731	Implement an SPS to automatically shed load on the 34 kV Bells Mill Road bus for this N-2 condition. The SPS will be in effect for 2013 and 2014 until a third Bells Mill 230/34 kV is placed in-service in 2015		PEPCO (100%)
b0746	Upgrade circuit for 3,000 amps using the ACCR		AEC (0.73%) / BGE (31.05%) / DPL (1.45%) / PECO (2.46%) / PEPCO (62.88%) / PPL (1.43%)
b0747	Upgrade terminal equipment on both lines: Quince Orchard - Bells Mill 230 kV (030) and (028)		PEPCO (100%)
b0802	Advance n0259 (Replace Dickerson Station H Circuit Breaker 412A)		PEPCO (100%)
b0803	Advance n0260 (Replace Dickerson Station H Circuit Breaker 42A)		PEPCO (100%)
b0804	Advance n0261 (Replace Dickerson Station H Circuit Breaker 42C)		PEPCO (100%)
b0805	Advance n0262 (Replace Dickerson Station H Circuit Breaker 43A)		PEPCO (100%)
b0806	Advance n0264 (Replace Dickerson Station H Circuit Breaker 44A)		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0809	Advance n0267 (Replace Dickerson Station H Circuit Breaker 45B)		PEPCO (100%)
b0810	Advance n0270 (Replace Dickerson Station H Circuit Breaker 47A)		PEPCO (100%)
b0811	Advance n0726 (Replace Dickerson Station H Circuit Breaker SPARE)		PEPCO (100%)
b0845	Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker		PEPCO (100%)
b0846	Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker		PEPCO (100%)
b0847	Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker		PEPCO (100%)
b0848	Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker		PEPCO (100%)
b0849	Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker		PEPCO (100%)
b0850	Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker		PEPCO (100%)
b0851	Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker		PEPCO (100%)
b0852	Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker		PEPCO (100%)
b0853	Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker		PEPCO (100%)
b0854	Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker		PEPCO (100%)
b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker		PEPCO (100%)
b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker		PEPCO (100%)
b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		PEPCO (100%)
b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker		PEPCO (100%)
b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker		PEPCO (100%)
b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker		PEPCO (100%)
b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker		PEPCO (100%)
b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA breaker		PEPCO (100%)
b1104	Replace Burtonsville 230 kV breaker ‘1C’		PEPCO (100%)
b1105	Replace Burtonsville 230 kV breaker ‘2C’		PEPCO (100%)
b1106	Replace Burtonsville 230 kV breaker ‘3C’		PEPCO (100%)
b1107	Replace Burtonsville 230 kV breaker ‘4C’		PEPCO (100%)
b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851 to a 230 kV line and Remove 230/138 kV Transformer at Ritchie and install a spare 230/138 kV transformer at Buzzard Pt		APS (4.74%) / PEPCO (95.26%)
b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 059		APS (4.74%) / PEPCO (95.26%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1592	Reconductor the Oak Grove – Bowie 230 kV circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1593	Reconductor the Bowie - Burtonsville 230 kV circuit and upgrade terminal equipments at Bowie and Burtonsville 230 kV substations		AEC (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1594	Reconductor the Oak Grove – Bowie 230 kV '23042' circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1595	Reconductor the Bowie – Burtonsville 230 kV '23042' circuit and upgrade terminal equipments at Oak Grove and Burtonsville 230 kV substations		AEC (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1596	Reconductor the Dickerson station "H" – Quince Orchard 230 kV '23032' circuit and upgrade terminal equipments at Dickerson station "H" and Quince Orchard 230 kV substations		AEC (0.80%) / BGE (33.68%) / DPL (2.09%) / PECO (3.07%) / PEPCO (60.36%)
b1597	Reconductor the Oak Grove - Aquasco 230 kV '23062' circuit and upgrade terminal equipments at Oak Grove and Aquasco 230 kV substations		AEC (1.44%) / BGE (48.60%) / DPL (2.52%) / PECO (5.00%) / PEPCO (42.44%)
b2008	Reconductor feeder 23032 and 23034 to high temp. conductor (10 miles)		BGE (33.05%) / DPL (1.38%) / PECO (1.35%) / PEPCO (64.22%) /
b2136	Reconductor the Morgantown - V3-017 230 kV '23086' circuit and replace terminal equipments at Morgantown		PEPCO (100%)
b2137	Reconductor the Morgantown - Talbert 230 kV '23085' circuit and replace terminal equipment at Morgantown		PEPCO (100%)
b2138	Replace terminal equipments at Hawkins 230 kV substation		PEPCO (100%)

Attachment 2E

PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for PPL Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement	**PJM Upgrade ID**	**June 2014- May 2015 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
New 500 KV Susquehana-Roseland Line	b0487	$ 86,641,270.39	1.70%	3.96%	6.46%	0.27%	$1,472,902	$3,430,994	$5,597,026	$233,931	$10,734,853
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 12,399.01	1.70%	3.96%	6.46%	0.27%	$211	$491	$801	$33	$1,536
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 8,891.07	1.70%	3.96%	6.46%	0.27%	$151	$352	$574	$24	$1,102
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 17,972.61	1.70%	3.96%	6.46%	0.27%	$306	$712	$1,161	$49	$2,227
New S-R additions < 500kV[2]	b0487.1	$ 1,264,457.14	0.00%	0.00%	5.13%	0.19%	$0	$0	$64,867	$2,402	$67,269
New substation and transformers Middletown	b0468	$ 3,559,666.02	0.00%	4.55%	5.93%	0.22%	$0	$161,965	$211,088	$7,831	$380,884
Totals							**$1,473,569**	**$3,594,514**	**$5,875,517**	**$244,271**	**$11,187,871**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 489,626.44	10,414.4	$ 47.01	$ 3,427,385	$ 2,448,132	$ 5,875,517
JCP&L	$ 299,542.83	6,378.9	$ 46.96	$ 2,096,800	$ 1,497,714	$ 3,594,514
ACE	$ 122,797.42	2,739.2	$ 44.83	$ 859,582	$ 613,987	$ 1,473,569
RE	$ 20,355.93	438.4	$ 46.43	$ 142,492	$ 101,780	$ 244,271
Total Impact on NJ Zones	**$ 932,322.62**			**$ 6,526,258**	**$ 4,661,613**	**$ 11,187,871**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2014 allocation share percentages are from PJM OATT issued 5/27/2014
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(9) PPL Electric Utilities Corporation

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double circuit, looping Met Ed's S. Lebanon – S. Reading line into Berks; replacement of S. Reading 230 kV breaker 107252		PPL (100%)
b0171.2	Replace wavetrap at Hosensack 500kV substation to increase rating of Elroy - Hosensack 500 kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0284.4	Changes at Juniata 500 kV substation		PPL (100%)
b0293.1	Replace wavetrap at the Martins Creek 230 kV bus		PPL (100%)
b0293.2	Raise the operating temperature of the 2-1590 ACSR to 140C for the Martins Creek – Portland 230 kV circuit		PPL (100%)
b0440	Spare Juniata 500/230 kV transformer		PPL (100%)
b0468	Build a new substation with two 150 MVA transformers between Dauphin and Hummelstown 230/69 kV substations by sectionalizing the Middletown Junction – New Lebanon 230 kV line		JCPL (4.55%) / Neptune* (0.37%) / PECO (1.79%) / PENELEC (0.33%) / PPL (86.63%) / ECP** (0.18%) / PSEG (5.93%) / RE (0.22%)
b0469	Install 130 MVAR capacitor at West Shore 230 kV line		PPL (100%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (16.90%) / PPL (77.59%) / ECP** (0.19%) / PSEG (5.13%) / RE (0.19%)
b0500.1	Conastone – Otter Creek 230 kV – Reconductor approximately 17.2 miles of 795 kcmil ACSR with new 795 kcmil ACSS operated at 160 deg C		AEC (6.27%) / DPL (8.65%) / JCPL (14.54%) / ME (10.59%) / Neptune* (1.37%) / PECO (15.66%) / PPL (21.02%) / ECP** (0.57%) / PSEG (20.56%) / RE (0.77%)

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The Annual Revenue Requirements associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-8G.

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles		PPL (100%)
b0595	Rebuild Lackawanna – Edella 69 kV line to double circuit		PPL (100%)
b0596	Reconductor and rebuild Stanton – Providence 69 kV #1 and #2 lines with 69 kV design; approximately 8 miles total		PPL (100%)
b0597	Reconductor Suburban – Providence 69 kV #1 and resectionalize the Suburban 69 kV lines		PPL (100%)
b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line portions		PPL (100%)
b0600	Tripp Park Substation: 69 kV tap off Stanton – Providence 69 kV line #3 to new substation		PPL (100%)
b0601	Jessup Substation: New 138/69 kV tap off of Peckville – Jackson 138/69 kV line		PPL (100%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood substation		PPL (100%)
b0605	Reconductor Stanton – Old Forge 69 kV line and resectionalize the Jenkins – Scranton 69 kV #1 and #2 lines		PPL (100%)
b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to Bartonsville substation		PPL (100%)
b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to Stroudsburg substation		PPL (100%)
b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to transformer #2 at Gilbert substation		PPL (100%)
b0610	At South Farmersville substation, a new 69 kV tap off Nazareth – Quarry #2 to transformer #2		PPL (100%)
b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles) of Siegfried – Quarry 69 kV line		PPL (100%)
b0613	East Tannersville Substation: New 138 kV tap to new substation		PPL (100%)
b0614	Elroy substation expansion and new Elroy – Hatfield 138/69 kV double circuit lines (1.9 miles)		PPL (100%)
b0615	Reconductor and rebuild 12 miles of Seidersville – Quakerstown 138/69 kV and a new 75 MVA, 230/69 kV transformer #4		PPL (100%)
b0616	New Springfield 230/69 kV substation and transmission line connections		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0620	New 138 kV line and terminal at Monroe 230/138 substation		PPL (100%)
b0621	New 138 kV line and terminal at Siegfried 230/138 kV substation and add a second circuit to Siegfried – Jackson for 8.0 miles		PPL (100%)
b0622	138 kV yard upgrades and transmission line rearrangements at Jackson 138/69 kV substation		PPL (100%)
b0623	New West Shore – Whitehill Taps 138/69 kV double circuit line (1.3 miles)		PPL (100%)
b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.7 miles) of Cumberland – West Shore 69 kV line		PPL (100%)
b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6 miles) of West Shore – Cumberland #3 and #4 lines		PPL (100%)
b0627	Replace UG cable from Walnut substation to Center City Harrisburg substation for higher ampacity (0.25 miles)		PPL (100%)
b0629	Lincoln substation: 69 kV tap to convert to modified Twin A		PPL (100%)
b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild from Landisville Tap – Mt. Joy (2 miles)		PPL (100%)
b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild to double circuit from Mt. Joy – Donegal (2 miles)		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0632	Terminate new S. Manheim – Donegal 69 kV circuit into S. Manheim 69 kV #3		PPL (100%)
b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of S. Manheim – West Hempfield 69 kV #3 line into a 69 kV double circuit		PPL (100%)
b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) into a 69 kV double circuit		PPL (100%)
b0703	Berks substation modification on Berks – South Akron 230 kV line. Modification will isolate the line fault on the South Akron line and will allow Berks transformer #2 to be energized by the South Lebanon 230 kV circuit		PPL (100%)
b0705	New Derry – Millville 69 kV line		PPL (100%)
b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10.9 MVAR capacitor bank near Bohemia 69 kV substation		PPL (100%)
b0708	New 69 kV double circuit from Jackson – Lake Naomi Tap		PPL (100%)
b0709	Install new 69 kV double circuit from Carlisle – West Carlisle		PPL (100%)
b0710	Install a third 69 kV line from Reese's Tap to Hershey substation		PPL (100%)
b0711	New 69 kV that taps West Shore – Cumberland 69 kV #1 to Whitehill 69 kV substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0712	Construct a new 69 kV line between Strassburg Tap and the Millwood – Engleside 69 kV #1 line		PPL (100%)
b0713	Construct a new 138 kV double circuit line between Dillersville Tap and the West Hempfield – Prince 138 kV line		PPL (100%)
b0714	Prepare Roseville Tap for 138 kV conversion		PPL (100%)
b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from the S. Akron 69 kV Yard to the S. Akron 138 kV Yard; Install switches on S. Akron – S. Manheim 138 kV #1 and #2 lines		PPL (100%)
b0716	Add a second 69 kV line from Morgantown – Twin Valley		PPL (100%)
b0717	Rebuild existing Brunner Island – West Shore 230 kV line and add a second Brunner Island – West Shore 230 kV line		PPL (100%)
b0718	SPS scheme to drop 190 MVA of 69 kV radial load at West Shore and 56 MVA of 69 kV radial load at Cumberland		PPL (100%)
b0719	SPS scheme at Jenkins substation to open the Stanton #1 and Stanton #2 230 kV circuit breakers after the second contingency		PPL (100%)
b0791	Add a fourth 230/69 kV transformer at Stanton		PENELEC (9.55%) / PPL (90.45%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1074	Install motor operators on the Jenkins 230 kV ‘2W’ disconnect switch and build out Jenkins Bay 3 and have MOD ‘3W’ operated as normally open		PPL (100%)
b0881	Install motor operators on Susquehanna T21 - Susquehanna 230 kV line East CB at Susquehanna 230 kV switching station		PPL (100%)
b0908	Install motor operators at South Akron 230 kV		PPL (100%)
b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus		PPL (100%)
b0910	Install a second 230 kV line between Jenkins and Stanton		PPL (100%)
b0911	Install motor operators at Frackville 230 kV		PPL (100%)
b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV line		PPL (100%)
b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps		PPL (100%)
b0915	Replace Walnut-Center City 69 kV cable		PPL (100%)
b0916	Reconductor Sunbury-Dalmatia 69 kV line		PPL (100%)
b1021	Install a new (#4) 138/69 kV transformer at Wescosville		PPL (100%)
b1196	Remove the Siegfried bus tie breaker and install a new breaker on the Martins Creek 230 kV line west bay to maintain two ties between the 230 kV buses		PPL (100%)
b1201	Rebuild the Hercules Tap to Double Circuit 69 kV		PPL (100%)
b1202	Mack-Macungie Double Tap, Single Feed Arrangement		PPL (100%)
b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lake Naomi 138/69 kV Tap		PPL (100%)
b1204	New Breinigsville 230-69 kV Substation		PPL (100%)
b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi from Quarry Substation to Macada Taps		PPL (100%)
b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation		PPL (100%)
b1210	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 1 – operate on the 69 kV system)		PPL (100%)
b1211	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 2 – operate on the 138 kV system)		PPL (100%)
b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation		PPL (100%)
b1213	Convert East Petersburg Taps from 69 kV to 138 kV operation, install two 10.8 MVAR capacitor banks		PPL (100%)
b1214	Terminate South Manheim-Donegal #2 at South Manheim, Reduce South Manheim 69 kV Capacitor Bank, Resectionalize 69 kV		PPL (100%)
b1215	Reconductor and rebuild 16 miles of Peckville-Varden 69 kV line and 4 miles of Blooming Grove-Honesdale 69 kV line		PPL (100%)
b1216	Build approximately 2.5 miles of new 69 kV transmission line to provide a "double tap – single feed" connection to Kimbles 69/12 kV substation		PPL (100%)
b1217	Provide a "double tap – single feed" connection to Tafton 69/12 kV substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1524	Build a new Pocono 230/69 kV substation		PPL (100%)
b1524.1	Build approximately 14 miles new 230 kV South Pocono – North Pocono line		PPL (100%)
b1524.2	Install MOLSABs at Mt. Pocono substation		PPL (100%)
b1525	Build new West Pocono 230/69 kV Substation		PPL (100%)
b1525.1	Build approximately 14 miles new 230 kV Jenkins-West Pocono 230 kV Line		PPL (100%)
b1525.2	Install Jenkins 3E 230 kV circuit breaker		PPL (100%)
b1526	Install a new Honeybrook – Twin Valley 69/138 kV tie		PPL (100%)
b1527	Construct a new 230/69 kV North Lancaster substation. The sub will be supplied from the SAKR-BERK 230kV Line		PPL (100%)
b1527.1	Construct new 69/138 kV transmission from North Lancaster 230/69 kV sub to Brecknock and Honeybrook areas		PPL (100%)
b1528	Install Motor-Operated switches on the Wescosville-Trexlertown #1 & #2 69 kV lines at East Texas Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1529	Add a double breaker 230 kV bay 3 at Hosensack		PPL (100%)
b1530	Replace Lock Haven 69kV ring bus with standard breaker and half design		PPL (100%)
b1532	Install new 32.4 MVAR capacitor bank at Sunbury		PPL (100%)
b1533	Rebuild Lycoming-Lock Haven #1 and Lycoming-Lock Haven #2 69kV lines		PPL (100%)
b1534	Rebuild 1.4 miles of the Sunbury-Milton 69kV		PPL (100%)
b1601	Re-configure the Breinigsville 500 kV substation with addition two 500 kV circuit breakers		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)†
b1602	Re-configure the Elimsport 230 kV substation to breaker and half scheme and install 80 MVAR capacitor		PPL (100%)
b1740	Install a 90 MVAR cap bank on the Frackville 230 kV bus #207973		PPL (100%)
b1756	Install a 3rd West Shore 230/69 kV transformer		PPL (100%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1757	Install a 230 kV motor-operated air-break switch on the Clinton - Elimsport 230 kV line		PPL (100%)
b1758	Rebuild 1.65 miles of Columbia - Danville 69 kV line		PPL (100%)
b1759	Install a 69 kV 16.2 MVAR Cap at Milton substation		PPL (100%)
b1760	Install motor operated devices on the existing disconnect switches that are located on each side of all four 230 kV CBs at Stanton		PPL (100%)
b1761	Build a new Paupack - North 230 kV line (Approximately 21 miles)		PPL (100%)
b1762	Replace 3.7 miles of the existing 230 kV Blooming Grove - Peckville line by building 8.4 miles of new 230 kV circuit onto the Lackawanna - Hopatcong tower-line		PPL (100%)
b1763	Re-terminate the Peckville - Jackson and the Peckville - Varden 69 kV lines from Peckville into Lackawanna		PPL (100%)
b1764	Build a new 230-69 kV substations (Paupack)		PPL (100%)
b1765	Install a 16.2 MVAR capacitor bank at Bohemia 69-12 kV substation		PPL (100%)
b1766	Reconductor/rebuild 3.3 miles of the Siegfried - Quarry #1 and #2 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1767	Install 6 motor-operated disconnect switches at Quarry substation		PPL (100%)
b1788	Install a new 500 kV circuit breaker at Wescosville		PPL (100%)
b1890	Add a second 230/69 kV transformer at North Pocono (NE/Pocono Reliability Project)		PPL (100%)
b1891	Build a new 230/138 kV Yard at Lackawanna (138 kV conversion from Lackawanna to Jenkins)		PPL (100%)
b1892	Rebuild the Throop Taps for 138 kV operation (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1893	Swap the Staton - Old Forge and Stanton - Brookside 69 kV circuits at Stanton (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1894	Rebuild and re-conductor 2.5 miles of the Stanton - Avoca 69 kV line		PPL (100%)
b1895	Rebuild and re-conductor 4.9 miles of the Stanton - Providence #1 69 kV line		PPL (100%)
b1896	Install a second 230/138 kV transformer and expand the 138 kV yard at Monroe		PPL (100%)
b1897	Build a new 230/138 kV substation at Jenkins (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1898	Install a 69 kV Tie Line between Richfield and Dalmatia substations		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2004	Replace the CTs and switch in South Akron Bay 4 to increase the rating		PPL (100%)
b2005	Replace the CTs and switch in SAKR Bay 3 to increase the rating of the Millwood-South Akron 230 kV Line and of the rating in Bay 3		PPL (100%)
b2006	Install North Lancaster 500/230 kV substation (below 500 kV portion)		AEC (1.10%) / ECP** (0.37%) / HTP (0.37%) / JCPL (9.61%) / ME (19.42%) / Neptune* (0.75%) / PECO (6.01%) / PPL (50.57%) / PSEG (11.35%) / RE (0.45%)
b2006.1	Install North Lancaster 500/230 kV substation (500 kV portion)		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b2007	Install a 90 MVAR capacitor bank at the Frackville 230 kV Substation		PPL (100%)
b2158	Install 10.8 MVAR capacitor at West Carlisle 69/12 kV substation		PPL (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

Attachment 2F

PJM Schedule 12 - Transmission Enhancement Charges for July 2014 - June 2015
Calculation of costs and monthly PJM charges for AEP -East Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**July 2014 - June 2015 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 1,093,199	1.70%	3.96%	6.46%	0.27%	$18,584	$43,291	$70,621	$2,952	$135,447
Rockport Reactor Bank	b1465.2	$ 2,804,328	1.70%	3.96%	6.46%	0.27%	$47,674	$111,051	$181,160	$7,572	$347,456
Transpose Rockport-Sullivan 765KV line	b1465.3	$ 4,094,860	1.70%	3.96%	6.46%	0.27%	$69,613	$162,156	$264,528	$11,056	$507,353
Switching changes Sullivan 765KV station	b1465.4	$ 777,399	1.70%	3.96%	6.46%	0.27%	$13,216	$30,785	$50,220	$2,099	$96,320
765kV circuit breaker at Wyoming station	b1661	$ 541,349	1.70%	3.96%	6.46%	0.27%	$9,203	$21,437	$34,971	$1,462	$67,073
Reconductor West Bellaire	b1970	$ 1,601,823	0.00%	1.68%	2.87%	0.11%	$0	$26,911	$45,972	$1,762	$74,645
Totals							**$158,289**	**$395,632**	**$647,472**	**$26,902**	**$1,228,295**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 14/15**	**2014TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2014 Impact (7 months)**	**2015 Impact (5 months)**	**2014-2015 Impact (12 months)**
PSE&G	$ 53,955.97	10,414.4	$ 5.18	$ 377,692	$ 269,780	$ 647,472
JCP&L	$ 32,969.30	6,378.9	$ 5.17	$ 230,785	$ 164,846	$ 395,632
ACE	$ 13,190.77	2,739.2	$ 4.82	$ 92,335	$ 65,954	$ 158,289
RE	$ 2,241.84	438.4	$ 5.11	$ 15,693	$ 11,209	$ 26,902
Total Impact on NJ Zones	**$ 102,357.88**			**$ 716,505**	**$ 511,789**	**$ 1,228,295**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:

1) 2014 allocation share percentages are from PJM OATT isssued 5/27/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2015, however resultant customer rates will not be changed.

SCHEDULE 12 – APPENDIX

(17) AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker 'B'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0490.3	Replace Amos 138 kV breaker 'B1'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0490.4	Replace Amos 138 kV breaker 'C'		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0490.5	Replace Amos 138 kV breaker ‘C1’		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0504	Add two advanced technology circuit breakers at Hanging Rock 765 kV to improve operational performance		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b0570	Reconductor East Side Lima – Sterling 138 kV		AEP (41.99%) / ComEd (58.01%)
b0571	Reconductor West Millersport – Millersport 138 kV		AEP (73.83%) / ComEd (19.26%) / Dayton (6.91%)
b0748	Establish a new 69 kV circuit between the Canal Road and East Wooster stations, establish a new 69 kV circuit between the West Millersburg and Moreland Switch stations (via Shreve), add reactive support via cap banks		AEP (100%)
b0838	Hazard Area 138 kV and 69 kV Improvement Projects		AEP (100%)
b0839	Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer		AEP (99.73%) / Dayton (0.27%)
b0840	String a second 138 kV circuit on the open tower position between Twin Branch and East Elkhart		AEP (100%)

* Neptune Regional Transmission System, LLC

** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0840.1	Establish a new 138/69-34.5kV Station to interconnect the existing 34.5kV network		AEP (100%)
b0917	Replace Baileysville 138 kV breaker 'P'		AEP (100%)
b0918	Replace Riverview 138 kV breaker '634'		AEP (100%)
b0919	Replace Torrey 138 kV breaker 'W'		AEP (100%)
b1032.1	Construct a new 345/138kV station on the Marquis-Bixby 345kV line near the intersection with Ross - Highland 69kV		AEP (89.97%) / Dayton (10.03%)
b1032.2	Construct two 138kV outlets to Delano 138kV station and to Camp Sherman station		AEP (89.97%) / Dayton (10.03%)
b1032.3	Convert Ross - Circleville 69kV to 138kV		AEP (89.97%) / Dayton (10.03%)
b1032.4	Install 138/69kV transformer at new station and connect in the Ross - Highland 69kV line		AEP (89.97%) / Dayton (10.03%)
b1033	Add a third delivery point from AEP's East Danville Station to the City of Danville.		AEP (100%)
b1034.1	Establish new South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.2	Loop the existing South Canton - Wayview 138kV circuit in-and-out of West Canton		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1034.3	Install a 345/138kV 450 MVA transformer at Canton Central		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.4	Rebuild/reconductor the Sunnyside - Torrey 138kV line		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.5	Disconnect/eliminate the West Canton 138kV terminal at Torrey Station		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.6	Replace all 138kV circuit breakers at South Canton Station and operate the station in a breaker and a half configuration		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.7	Replace all obsolete 138kV circuit breakers at the Torrey and Wagenhals stations		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.8	Install additional 138kV circuit breakers at the West Canton, South Canton, Canton Central, and Wagenhals stations to accommodate the new circuits		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1035	Establish a third 345kV breaker string in the West Millersport Station. Construct a new West Millersport – Gahanna 138kV circuit. Miscellaneous improvements to 138kV transmission system.		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1036	Upgrade terminal equipment at Poston Station and update remote end relays		AEP (100%)
b1037	Sag check Bonsack–Cloverdale 138 kV, Cloverdale–Centerville 138kV, Centerville–Ivy Hill 138kV, Ivy Hill–Reusens 138kV, Bonsack–Reusens 138kV and Reusens–Monel–Gomingo–Joshua Falls 138 kV.		AEP (100%)
b1038	Check the Crooksville - Muskingum 138 kV sag and perform the required work to improve the emergency rating		AEP (100%)
b1039	Perform a sag study for the Madison – Cross Street 138 kV line and perform the required work to improve the emergency rating		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1040	Rebuild an 0.065 mile section of the New Carlisle – Olive 138 kV line and change the 138 kV line switches at New Carlisle		AEP (100%)
b1041	Perform a sag study for the Moseley - Roanoke 138 kV to increase the emergency rating		AEP (100%)
b1042	Perform sag studies to raise the emergency rating of Amos – Poca 138kV		AEP (100%)
b1043	Perform sag studies to raise the emergency rating of Turner - Ruth 138kV		AEP (100%)
b1044	Perform sag studies to raise the emergency rating of Kenova – South Point 138kV		AEP (100%)
b1045	Perform sag studies of Tri State - Darrah 138 kV		AEP (100%)
b1046	Perform sag study of Scottsville – Bremo 138kV to raise the emergency rating		AEP (100%)
b1047	Perform sag study of Otter Switch - Altavista 138kV to raise the emergency rating		AEP (100%)
b1048	Reconductor the Bixby - Three C - Groves and Bixby - Groves 138 kV tower line		AEP (100%)
b1049	Upgrade the risers at the Riverside station to increase the rating of Benton Harbor – Riverside 138kV		AEP (100%)
b1050	Rebuilding and reconductor the Bixby – Pickerington Road - West Lancaster 138 kV line		AEP (100%)
b1051	Perform a sag study for the Kenzie Creek – Pokagon 138 kV line and perform the required work to improve the emergency rating		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1052	Unsix-wire the existing Hyatt - Sawmill 138 kV line to form two Hyatt - Sawmill 138 kV circuits		AEP (100%)
b1053	Perform a sag study and remediation of 32 miles between Claytor and Matt Funk.		AEP (100%)
b1091	Add 28.8 MVAR 138 kV capacitor bank at Huffman and 43.2 MVAR 138 kV Bank at Jubal Early and 52.8 MVAR 138 kV Bank at Progress Park Stations		AEP (100%)
b1092	Add 28.8 MVAR 138 kV capacitor bank at Sullivan Gardens and 52.8 MVAR 138 kV Bank at Reedy Creek Stations		AEP (100%)
b1093	Add a 43.2 MVAR capacitor bank at the Morgan Fork 138 kV Station		AEP (100%)
b1094	Add a 64.8 MVAR capacitor bank at the West Huntington 138 kV Station		AEP (100%)
b1108	Replace Ohio Central 138 kV breaker ‘C2’		AEP (100%)
b1109	Replace Ohio Central 138 kV breaker ‘D1’		AEP (100%)
b1110	Replace Sporn A 138 kV breaker ‘J’		AEP (100%)
b1111	Replace Sporn A 138 kV breaker ‘J2’		AEP (100%)
b1112	Replace Sporn A 138 kV breaker ‘L’		AEP (100%)
b1113	Replace Sporn A 138 kV breaker ‘L1’		AEP (100%)
b1114	Replace Sporn A 138 kV breaker ‘L2’		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1115	Replace Sporn A 138 kV breaker 'N'		AEP (100%)
b1116	Replace Sporn A 138 kV breaker 'N2'		AEP (100%)
b1227	Perform a sag study on Altavista – Leesville 138 kV circuit		AEP (100%)
b1231	Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer		AEP (96.69%) / Dayton (3.31%)
b1375	Replace Roanoke 138 kV breaker 'T'		AEP (100%)
b1376	Replace Roanoke 138 kV breaker 'E'		AEP (100%)
b1377	Replace Roanoke 138 kV breaker 'F'		AEP (100%)
b1378	Replace Roanoke 138 kV breaker 'G'		AEP (100%)
b1379	Replace Roanoke 138 kV breaker 'B'		AEP (100%)
b1380	Replace Roanoke 138 kV breaker 'A'		AEP (100%)
b1381	Replace Olive 345 kV breaker 'E'		AEP (100%)
b1382	Replace Olive 345 kV breaker 'R2'		AEP (100%)
b1416	Perform a sag study on the Desoto – Deer Creek 138 kV line to increase the emergency rating		AEP (100%)
b1417	Perform a sag study on the Delaware – Madison 138 kV line to increase the emergency rating		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1418	Perform a sag study on the Rockhill – East Lima 138 kV line to increase the emergency rating		AEP (100%)
b1419	Perform a sag study on the Findlay Center – Fostoria Ctl 138 kV line to increase the emergency rating		AEP (100%)
b1420	A sag study will be required to increase the emergency rating for this line. Depending on the outcome of this study, more action may be required in order to increase the rating		AEP (100%)
b1421	Perform a sag study on the Sorenson – McKinley 138 kV line to increase the emergency rating		AEP (100%)
b1422	Perform a sag study on John Amos – St. Albans 138 kV line to allow for operation up to its conductor emergency rating		AEP (100%)
b1423	A sag study will be performed on the Chemical – Capitol Hill 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1424	Perform a sag study for Benton Harbor – West Street – Hartford 138 kV line to improve the emergency rating		AEP (100%)
b1425	Perform a sag study for the East Monument – East Danville 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)
b1426	Perform a sag study for the Reusens – Graves 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1427	Perform a sag study on Smith Mountain – Leesville – Altavista – Otter 138 kV and on Boones – Forest – New London – JohnsMT – Otter		AEP (100%)
b1428	Perform a sag study on Smith Mountain – Candlers Mountain 138 kV and Joshua Falls – Cloverdale 765 kV to allow for operation up to		AEP (100%)
b1429	Perform a sag study on Fremont – Clinch River 138 kV to allow for operation up to its conductor emergency ratings		AEP (100%)
b1430	Install a new 138 kV circuit breaker at Benton Harbor station and move the load from Watervliet 34.5 kV station to West street 138 kV		AEP (100%)
b1432	Perform a sag study on the Kenova – Tri State 138 kV line to allow for operation up to their conductor emergency rating		AEP (100%)
b1433	Replace risers in the West Huntington Station to increase the line ratings which would eliminate the overloads for the contingencies listed		AEP (100%)
b1434	Perform a sag study on the line from Desoto to Madison. Replace bus and risers at Daleville station and replace bus and risers at Madison		AEP (100%)
b1435	Replace the 2870 MCM ACSR riser at the Sporn station		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1436	Perform a sag study on the Sorenson – Illinois Road 138 kV line to increase the emergency MOT for this line. Replace bus and risers at Illinois Road		AEP (100%)
b1437	Perform sag study on Rock Cr. – Hummel Cr. 138 kV to increase the emergency MOT for the line, replace bus and risers at Huntington J., and replace relays for Hummel Cr. – Hunt – Soren. Line at Soren		AEP (100%)
b1438	Replacement of risers at McKinley and Industrial Park stations and performance of a sag study for the 4.53 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1439	By replacing the risers at Lincoln both the Summar Normal and Summer Emergency ratings will improve to 268 MVA		AEP (100%)
b1440	By replacing the breakers at Lincoln the Summer Emergency rating will improve to 251 MVA		AEP (100%)
b1441	Replacement of risers at South Side and performance of a sag study for the 1.91 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1442	Replacement of 954 ACSR conductor with 1033 ACSR and performance of a sag study for the 4.54 miles of 2-636 ACSR section is expected		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1443	Station work at Thelma and Busseyville Stations will be performed to replace bus and risers		AEP (100%)
b1444	Perform electrical clearance studies on Clinch River – Clinchfield 139 kV line (a.k.a. sag studies) to determine if the emergency ratings can be utilized		AEP (100%)
b1445	Perform a sag study on the Addison (Buckeye CO-OP) – Thinever and North Crown City – Thivener 138 kV sag study and switch		AEP (100%)
b1446	Perform a sag study on the Parkersburg (Allegheny Power) – Belpre (AEP) 138 kV		AEP (100%)
b1447	Dexter – Elliot tap 138 kV sag check		AEP (100%)
b1448	Dexter – Meigs 138 kV Electrical Clearance Study		AEP (100%)
b1449	Meigs tap – Rutland 138 kV sag check		AEP (100%)
b1450	Muskingum – North Muskingum 138 kV sag check		AEP (100%)
b1451	North Newark – Sharp Road 138 kV sag check		AEP (100%)
b1452	North Zanesville – Zanesville 138 kV sag check		AEP (100%)
b1453	North Zanesville – Powelson and Ohio Central – Powelson 138 kV sag check		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1454	Perform an electrical clearance study on the Ross – Delano – Scioto Trail 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1455	Perform a sag check on the Sunny – Canton Central – Wagenhals 138 kV line to determine if all circuits can be operated at their summer emergency rating		AEP (100%)
b1456	The Tidd – West Bellaire 345 kV circuit has been de-rated to its normal rating and would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1457	The Tiltonsville – Windsor 138 kV circuit has been derated to its normal rating and would need an electrical clearance study to determine if the emergency rating could be utilized		AEP (100%)
b1458	Install three new 345 kV breakers at Bixby to separate the Marquis 345 kV line and transformer #2. Operate Circleville – Harrison 138 kV and Harrison – Zuber 138 kV up to conductor emergency ratings		AEP (100%)
b1459	Several circuits have been de-rated to their normal conductor ratings and could benefit from electrical clearance studies to determine if the emergency rating could be utilized		AEP (100%)
b1460	Replace 2156 & 2874 risers		AEP (100%)
b1461	Replace meter, metering CTs and associated equipment at the Paden City feeder		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1462	Replace relays at both South Cadiz 138 kV and Tidd 138 kV		AEP (100%)
b1463	Reconductor the Bexley – Groves 138 kV circuit		AEP (100%)
b1464	Corner 138 kV upgrades		AEP (100%)
b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station		AEC (0.71%) / AEP (75.06%) / APS (1.25%) / BGE (1.81%) / ComEd (5.91%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (3.89%) / JCPL (1.58%) / NEPTUNE (0.15%) / HTP (0.07%) / PECO (2.08%) / PEPCO (1.66%) / ECP (0.07%)** / PSEG (2.62%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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** East Coast Power, LLC

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1466.1	Create an in and out loop at Adams Station by removing the hard tap that currently exists		AEP (100%)
b1466.2	Upgrade the Adams transformer to 90 MVA		AEP (100%)
b1466.3	At Seaman Station install a new 138 kV bus and two new 138 kV circuit breakers		AEP (100%)
b1466.4	Convert South Central Co-op's New Market 69 kV Station to 138 kV		AEP (100%)
b1466.5	The Seaman – Highland circuit is already built to 138 kV, but is currently operating at 69 kV, which would now increase to 138 kV		AEP (100%)
b1466.6	At Highland Station, install a new 138 kV bus, three new 138 kV circuit breakers and a new 138/69 kV 90 MVA transformer		AEP (100%)
b1466.7	Using one of the bays at Highland, build a 138 kV circuit from Hillsboro – Highland 138 kV, which is approximately 3 miles		AEP (100%)
b1467.1	Install a 14.4 MVAr Capacitor Bank at New Buffalo station		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1467.2	Reconfigure the 138 kV bus at LaPorte Junction station to eliminate a contingency resulting in loss of two 138 kV sources serving the LaPorte area		AEP (100%)
b1468.1	Expand Selma Parker Station and install a 138/69/34.5 kV transformer		AEP (100%)
b1468.2	Rebuild and convert 34.5 kV line to Winchester to 69 kV, including Farmland Station		AEP (100%)
b1468.3	Retire the 34.5 kV line from Haymond to Selma Wire		AEP (100%)
b1469.1	Conversion of the Newcomerstown – Cambridge 34.5 kV system to 69 kV operation		AEP (100%)
b1469.2	Expansion of the Derwent 69 kV Station (including reconfiguration of the 69 kV system)		AEP (100%)
b1469.3	Rebuild 11.8 miles of 69 kV line, and convert additional 34.5 kV stations to 69 kV operation		AEP (100%)
b1470.1	Build a new 138 kV double circuit off the Kanawha – Bailysville #2 138 kV circuit to Skin Fork Station		AEP (100%)
b1470.2	Install a new 138/46 kV transformer at Skin Fork		AEP (100%)
b1470.3	Replace 5 Moab's on the Kanawha – Baileysville line with breakers at the Sundial 138 kV station		AEP (100%)
b1471	Perform a sag study on the East Lima – For Lima – Rockhill 138 kV line to increase the emergency rating		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1472	Perform a sag study on the East Lima – Haviland 138 kV line to increase the emergency rating		AEP (100%)
b1473	Perform a sag study on the East New Concord – Muskingum River section of the Muskingum River – West Cambridge 138 kV circuit		AEP (100%)
b1474	Perform a sag study on the Ohio Central – Prep Plant tap 138 kV circuit		AEP (100%)
b1475	Perform a sag study on the S73 – North Delphos 138 kV line to increase the emergency rating		AEP (100%)
b1476	Perform a sag study on the S73 – T131 138 kV line to increase the emergency rating		AEP (100%)
b1477	The Natrium – North Martin 138 kV circuit would need an electrical clearance study among other equipment upgrades		AEP (100%)
b1478	Upgrade Strouds Run – Strounds Tap 138 kV relay and riser		AEP (100%)
b1479	West Hebron station upgrades		AEP (100%)
b1480	Perform upgrades and a sag study on the Corner – Layman 138 kV section of the Corner – Muskingum River 138 kV circuit		AEP (100%)
b1481	Perform a sag study on the West Lima – Eastown Road – Rockhill 138 kV line and replace the 138 kV risers at Rockhill station to increase the emergency rating		AEP (100%)
b1482	Perform a sag study for the Albion – Robison Park 138 kV line to increase its emergency rating		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1483	Sag study 1 mile of the Clinch River – Saltville 138 kV line and replace the risers and bus at Clinch River, Lebanon, and Elk Garden Stations		AEP (100%)
b1484	Perform a sag study on the Hacienda – Harper 138 kV line to increase the emergency rating		AEP (100%)
b1485	Perform a sag study on the Jackson Road – Concord 183 kV line to increase the emergency rating		AEP (100%)
b1486	The Matt Funk – Poages Mill – Starkey 138 kV line requires		AEP (100%)
b1487	Perform a sag study on the New Carlisle – Trail Creek 138 kV line to increase the emergency rating		AEP (100%)
b1488	Perform a sag study on the Olive – LaPorte Junction 138 kV line to increase the emergency rating		AEP (100%)
b1489	A sag study must be performed for the 5.40 mile Tristate – Chadwick 138 kV line to determine if a higher emergency rating can be used		AEP (100%)
b1490.1	Establish a new 138/69 kV Butler Center station		AEP (100%)
b1490.2	Build a new 14 mile 138 kV line from Auburn station to Woods Road station VIA Butler Center station		AEP (100%)
b1490.3	Replace the existing 40 MVA 138/69 kV transformer at Auburn station with a 90 MVA 138/96 kV transformer		AEP (100%)
b1490.4	Improve the switching arrangement at Kendallville station		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1491	Replace bus and risers at Thelma and Busseyville stations and perform a sag study for the Big Sandy – Busseyville 138 kV line		AEP (100%)
b1492	Reconductor 0.65 miles of the Glen Lyn – Wythe 138 kV line with 3 – 1590 ACSR		AEP (100%)
b1493	Perform a sag study for the Bellfonte – Grantston 138 kV line to increase its emergency rating		AEP (100%)
b1494	Perform a sag study for the North Proctorville – Solida – Bellefonte 138 kV line to increase its emergency rating		AEP (100%)
b1495	Add an additional 765/345 kV transformer at Baker Station		AEC (0.41%) / AEP (87.22%) / BGE (1.03%) / ComEd (3.38%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / HTP (0.04%) / PECO (1.18%) / PEPCO (0.94%) / ECP** (0.04%) / PSEG (1.48%) / RE (0.06%)
b1496	Replace 138 kV bus and risers at Johnson Mountain Station		AEP (100%)
b1497	Replace 138 kV bus and risers at Leesville Station		AEP (100%)
b1498	Replace 138 kV risers at Wurno Station		AEP (100%)
b1499	Perform a sag study on Sporn A – Gavin 138 kV to determine if the emergency rating can be improved		AEP (100%)
b1500	The North East Canton – Wagenhals 138 kV circuit would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)

** East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1501	The Moseley – Reusens 138 kV circuit requires a sag study to determine if the emergency rating can be utilized to address a thermal loading issue for a category C3		AEP (100%)
b1502	Reconductor the Conesville East – Conesville Prep Plant Tap 138 kV section of the Conesville – Ohio Central to fix Reliability N-1-1 thermal overloads		AEP (100%)
b1659	Establish Sorenson 345/138 kV station as a 765/345 kV station		AEP (93.61%) / ATSI (2.99%) / ComEd (2.07%) / HTP (0.03%) / PENELEC (0.31%) / ECP** (0.03%) / PSEG (0.92%) / RE (0.04%)
b1659.1	Replace Sorenson 138 kV breaker 'L1'		AEP (100%)
b1659.2	Replace Sorenson 138 kV breaker 'L2' breaker		AEP (100%)
b1659.3	Replace Sorenson 138 kV breaker 'M1'		AEP (100%)
b1659.4	Replace Sorenson 138 kV breaker 'M2'		AEP (100%)
b1659.5	Replace Sorenson 138 kV breaker 'N1'		AEP (100%)
b1659.6	Replace Sorenson 138 kV breaker 'N2'		AEP (100%)
b1659.7	Replace Sorenson 138 kV breaker 'O1'		AEP (100%)
b1659.8	Replace Sorenson 138 kV breaker 'O2'		AEP (100%)
b1659.9	Replace Sorenson 138 kV breaker 'M'		AEP (100%)
b1659.10	Replace Sorenson 138 kV breaker 'N'		AEP (100%)

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AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1660	Install a 765/500 kV transformer at Cloverdale		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)

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AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1661	Install a 765 kV circuit breaker at Wyoming station		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1662	Rebuild 4 miles of 46 kV line to 138 kV from Pemberton to Cherry Creek		AEP (100%)
b1662.1	Circuit Breakers are installed at Cherry Creek (facing Pemberton) and at Pemberton (facing Tams Mtn. and Cherry Creek)		AEP (100%)
b1662.2	Install three 138 kV breakers at Grandview Station (facing Cherry Creek, Hinton, and Bradley Stations)		AEP (100%)
b1662.3	Remove Sullivan Switching Station (46 kV)		AEP (100%)

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AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation		AEP (100%)
b1663.1	Establish a new 10 mile double circuit 138 kV line between Jackson Ferry and Wythe		AEP (100%)
b1663.2	Install 2 765 kV circuit breakers, breaker disconnect switches and associated bus work for the new 765 kV breakers, and new relays for the 765 kV breakers at Jackson's Ferry		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1664	Install switched capacitor banks at Kenwood 138 kV stations		AEP (100%)
b1665	Install a second 138/69 kV transformer at Thelma station		AEP (100%)
b1665.1	Construct a single circuit 69 kV line from West Paintsville to the new Paintsville station		AEP (100%)
b1665.2	Install new 7.2 MVAR, 46 kV bank at Kenwood Station		AEP (100%)
b1666	Build an 8 breaker 138 kV station tapping both circuits of the Fostoria - East Lima 138 kV line		AEP (90.65%) / Dayton (9.35%)
b1667	Establish Melmore as a switching station with both 138 kV circuits terminating at Melmore. Extend the double circuit 138 kV line from Melmore to Fremont Center		AEP (100%)
b1668	Revise the capacitor setting at Riverside 138 kV station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1669	Capacitor setting changes at Ross 138 kV stations		AEP (100%)
b1670	Capacitor setting changes at Wooster 138 kV station		AEP (100%)
b1671	Install four 138 kV breakers in Danville area		AEP (100%)
b1676	Replace Natrium 138 kV breaker 'G (rehab)'		AEP (100%)
b1677	Replace Huntley 138 kV breaker '106'		AEP (100%)
b1678	Replace Kammer 138 kV breaker 'G'		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1679	Replace Kammer 138 kV breaker 'H'		AEP (100%)
b1680	Replace Kammer 138 kV breaker 'J'		AEP (100%)
b1681	Replace Kammer 138 kV breaker 'K'		AEP (100%)
b1682	Replace Kammer 138 kV breaker 'M'		AEP (100%)
b1683	Replace Kammer 138 kV breaker 'N'		AEP (100%)
b1684	Replace Clinch River 138 kV breaker 'E1'		AEP (100%)
b1685	Replace Lincoln 138 kV breaker 'D'		AEP (100%)
b1687	Advance s0251.7 (Replace Corrid 138 kV breaker '104S')		AEP (100%)
b1688	Advance s0251.8 (Replace Corrid 138 kV breaker '104C')		AEP (100%)
b1712.1	Perform sag study on Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1712.2	Rebuild the Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1733	Perform a sag study of the Bluff Point - Jauy 138 kV line. Upgrade breaker, wavetrap, and risers at the terminal ends		AEP (100%)
b1734	Perform a sag study of Randoph - Hodgins 138 kV line. Upgrade terminal equipment		AEP (100%)
b1735	Perform a sag study of R03 - Magely 138 kV line. Upgrade terminal equipment		AEP (100%)
b1736	Perform a sag study of the Industrial Park - Summit 138 kV line		AEP (100%)
b1737	Sag study of Newcomerstown - Hillview 138 kV line. Upgrade - terminal equipment		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1738	Perform a sag study of the Wolf Creek - Layman 138 kV line. - Upgrade terminal equipment including a 138 kV breaker and wavetrap		AEP (100%)
b1739	Perform a sag study of the Ohio Central - West Trinway 138 kV line		AEP (100%)
b1741	Replace Beatty 138 kV breaker '2C(IPP)'		AEP (100%)
b1742	Replace Beatty 138 kV breaker '1E'		AEP (100%)
b1743	Replace Beatty 138 kV breaker '2E'		AEP (100%)
b1744	Replace Beatty 138 kV breaker '3C'		AEP (100%)
b1745	Replace Beatty 138 kV breaker '2W'		AEP (100%)
b1746	Replace St. Claire 138 kV breaker '8'		AEP (100%)
b1747	Replace Cloverdale 138 kV breaker 'C'		AEP (100%)
b1748	Replace Cloverdale 138 kV breaker 'D1'		AEP (100%)
b1780	Install two 138kV breakers and two 138kV circuit switchers at South Princeton Station and one 138kV breaker and one 138kV circuit switcher at Switchback Station		AEP (100%)
b1781	Install three 138 kV breakers and a 138kV circuit switcher at Trail Fork Station in Pineville, WV		AEP (100%)
b1782	Install a 46kV Moab at Montgomery Station facing Carbondale (on the London - Carbondale 46 kV circuit)		AEP (100%)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1783	Add two 138 kV Circuit Breakers and two 138 kV circuit switchers on the Lonesome Pine - South Bluefield 138 kV line		AEP (100%)
b1784	Install a 52.8 MVAR capacitor bank at the Clifford 138 kV station		AEP (100%)
b1811.1	Perform a sag study of 4 miles of the Waterford - Muskingum line		AEP (100%)
b1811.2	Rebuild 0.1 miles of Waterford - Muskingum 345 kV with 1590 ACSR		AEP (100%)
b1812	Reconductor the AEP portion of the South Canton - Harmon 345 kV with 954 ACSR and upgrade terminal equipment at South Canton. Expected rating is 1800 MVA S/N and 1800 MVA S/E		AEP (100%)
b1817	Install (3) 345 kV circuit breakers at East Elkhart station in ring bus designed as a breaker and half scheme		AEP (100%)
b1818	Expand the Allen station by installing a second 345/138 kV transformer and adding four 138 kV exits by cutting in the Lincoln - Sterling and Milan - Timber Switch 138 kV double circuit tower line		AEP (88.30%) / ATSI (8.86%) / Dayton (2.84%)
b1819	Rebuild the Robinson Park - Sorenson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV		AEP (87.18%) / ATSI (10.06%) / Dayton (2.76%)
b1859	Perform a sag study for Hancock - Cave Spring - Roanoke 138 kV circuit to reach new SE ratings of 272MVA (Cave Spring-Hancock), 205MVA (Cave Spring-Sunscape), 245MVA (ROANO2-Sunscape)		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1860	Perform a sag study on the Crooksville - Spencer Ridge section (14.3 miles) of the Crooksville-Poston-Strouds Run 138 kV circuit to see if any remedial action needed to reach the SE rating (175MVA)		AEP (100%)
b1861	Reconductor 0.83 miles of the Dale - West Canton 138 kV Tie-line and upgrade risers at West Canton 138 kV		AEP (100%)
b1862	Perform a sag study on the Grant - Greentown 138 kV circuit and replace the relay CT at Grant 138 kV station to see if any remedial action needed to reach the new ratings of 251/286MVA		AEP (100%)
b1863	Perform a sag study of the Kammer - Wayman SW 138 kV line to see if any remedial action needed to reach the new SE rating of 284MVA		AEP (100%)
b1864.1	Add two additional 345/138 kV transformers at Kammer		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.2	Add second West Bellaire - Brues 138 kV circuit		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.3	Replace Kammer 138 kV breaker 'E'		AEP (100%)
b1865	Perform a sag study on the Kanawha - Carbondale 138 kV line to see if any remedial action needed to reach the new ratings of 251/335MVA		AEP (100%)
b1866	Perform a sag study on the Clinch River-Lock Hart-Dorton 138kV line,increase the Relay Compliance Trip Limit at Clinch River on the C.R.-Dorton 138kV line to 310 and upgrade the risers with 1590ACSR		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1867	Perform a sag study on the Newcomerstown - South Coshocton 138 kV line to see if any remedial action is needed to reach the new SE rating of 179MVA		AEP (100%)
b1868	Perform sag study on the East Lima - new Liberty 138 kV line to see if any remedial action is needed to reach the new SE rating of 219MVA		AEP (100%)
b1869	Perform a sag study of the Ohio Central - South Coshocton 138 kV circuit to see if any remedial action needed to reach the new SE ratings of 250MVA		AEP (100%)
b1870	Replace the Ohio Central transformer #1 345/138/12 kV 450 MVA for a 345/138/34.5 kV 675 MVA transformer		AEP (68.16%) / ATSI (25.27%) / Dayton (3.88%) / PENELEC (1.59%) / DEOK (1.10%)
b1871	Perform a sag study on the Central - West Coshocton 138 kV line (improving the emergency rating of this line to 254 MVA)		AEP (100%)
b1872	Add a 57.6 MVAr capacitor bank at East Elkhart 138 kv station in Indiana		AEP (100%)
b1873	Install two 138 kV circuit breakers at Cedar Creek Station and primary side circuit switcher on the 138/69/46 kV transformer		AEP (100%)
b1874	Install two 138 kV circuit breakers and one 138 kV circuit switcher at Magely 138 kV station in Indiana		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1875	Build 25 miles of new 138 kV line from Bradley Station through Tower 117 Station and terminating at McClung 138 kV station. Existing 69 kV distribution transformers will be replaced with 138 kV transformers		AEP (100%)
b1876	Install a 14.4 MVAr capacitor bank at Capital Avenue (AKA Currant Road) 34.5 kV bus		AEP (100%)
b1877	Relocate 138 kV Breaker G to the West Kingsport - Industry Drive 138 kV line and Remove 138 kV MOAB		AEP (100%)
b1878	Perform a sag study on the Lincoln - Robinson Park 138 kV line (Improve the emergency rating to 244 MVA)		AEP (100%)
b1879	Perform a sag study on the Hansonville - Meadowview 138 kV line (Improve the emergency rating to 245 MVA)		AEP (100%)
b1880	Rebuild the 15 miles of the Moseley - Roanoke 138 kV line. This project would consist of rebuilding both circuits on the double circuit line		AEP (100%)
b1881	Replace existing 600 Amp switches, station risers and increase the CT ratios associated with breaker 'G' at Sterling 138 kV Station. It will increase the rating to 296 MVA S/N and 384 MVA S/E		AEP (100%)
b1882	Perform a sag study on the Bluff Point - Randolf 138 kV line to see if any remedial action needed to reach the new SE rating of 255 MVA		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1883	Switch the breaker position of transformer #1 and SW Lima at East Lima 345 kV bus		AEP (100%)
b1884	Perform a sag study on Strawton station - Fisher Body - Deer Creek 138 kV line to see if any remedial action needed to reach the new SE rating of 250 MVA		AEP (100%)
b1887	Establish a new 138/69 kV source at Carrollton and construct two new 69 kV lines from Carrollton to tie into the Dennison - Miller SW 69 kV line and to East Dover 69 kV station respectively		AEP (100%)
b1888	Install a 69 kV line breaker at Blue Pennant 69 kV Station facing Bim Station and 14.4 MVAr capacitor bank		AEP (100%)
b1889	Install a 43.2 MVAR capacitor bank at Hinton 138 kV station (APCO WV)		AEP (100%)
b1901	Rebuild the Ohio Central - West Trinway (4.84 miles) section of the Academia - Ohio Central 138 kV circuit. Upgrade the Ohio Central riser, Ohio Central switch and the West Trinway riser		AEP (100%)
b1904.1	Construct new 138/69 Michiana Station near Bridgman by tapping the new Carlisle - Main Street 138 kV and the Bridgman - Buchanan Hydro 69 kV line		AEP (100%)
b1904.2	Establish a new 138/12 kV New Galien station by tapping the Olive - Hickory Creek 138 kV line		AEP (100%)
b1904.3	Retire the existing Galien station and move its distribution load to New Galien station. Retire the Buchanan Hydro - New Carlisile 34.5 kV line		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1904.4	Implement an in and out scheme at Cook 69 kV by eliminating the Cook 69 kV tap point and by installing two new 69 kV circuit breakers		AEP (100%)
b1904.5	Rebuild the Bridgman - Cook 69 kV and the Derby - Cook 69 kV lines		AEP (100%)
b1946	Perform a sag study on the Brues – West Bellaire 138 kV line		AEP (100%)
b1947	A sag study of the Dequine - Meadowlake 345 kV line #1 line may improve the emergency rating to 1400 MVA		AEP (100%)
b1948	Establish a new 765/345 interconnection at Sporn. Install a 765/345 kV transformer at Mountaineer and build ¾ mile of 345 kV to Sporn		ATSI (61.08%) / DL (21.87%) / Dominion (13.97%) / PENELEC (3.08%)
b1949	Perform a sag study on the Grant Tap – Deer Creek 138 kV line and replace bus and risers at Deer Creek station		AEP (100%)
b1950	Perform a sag study on the Kammer – Ormet 138 kV line of the conductor section		AEP (100%)
b1951	Perform a sag study of the Maddox-Convoy 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1952	Perform a sag study of the Maddox – T130 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1953	Perform a sag study of the Meadowlake - Olive 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1954	Perform a sag study on the Milan - Harper 138 kV line and replace bus and switches at Milan Switch station		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1955	Perform a sag study of the R-049 - Tillman 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
b1956	Perform a sag study of the Tillman - Dawkins 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
b1957	Terminate Transformer #2 at SW Lima in a new bay position		AEP (69.41%) / ATSI (23.11%) / ECP** (0.17%) / HTP (0.19%) / PENELEC (2.42%) / PSEG (4.52%) / RE (0.18%)
b1958	Perform a sag study on the Brookside - Howard 138 kV line and replace bus and risers at AEP Howard station		AEP (100%)
b1960	Sag Study on 7.2 miles SE Canton-Canton Central 138kV ckt		AEP (100%)
b1961	Sag study on the Southeast Canton – Sunnyside 138kV line		AEP (100%)
b1962	Add four 765 kV breakers at Kammer		AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)
b1963	Build approximately 1 mile of circuit comprising of 2-954 ACSR to get the rating of Waterford-Muskinum 345 kV higher		AEP (100%)

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**East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1970	Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit		APS (33.51%) / ATSI (32.21%) / DL (18.64%) / Dominion (6.01%) / ECP** (0.10%) / HTP (0.11%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (4.58%) / PSEG (2.87%) / RE (0.11%)
b1971	Perform a sag study to improve the emergency rating on the Bridgville – Chandlersville 138 kV line		AEP (100%)
b1972	Replace disconnect switch on the South Canton 765/345 kV transformer		AEP (100%)
b1973	Perform a sag study to improve the emergency rating on the Carrollton – Sunnyside 138 kV line		AEP (100%)
b1974	Perform a sag study to improve the emergency rating on the Bethel Church – West Dover 138 kV line		AEP (100%)
b1975	Replace a switch at South Millersburg switch station		AEP (100%)
b2017	Reconductor or rebuild Sporn - Waterford - Muskingum River 345 kV line		ATSI (37.04%) / AEP (34.35%) / DL (10.41%) / Dominion (6.19%) / APS (3.94%) / PENELEC (3.09%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / HTP (0.09%) / ECP** (0.08%) / PSEG (2.00%) / RE (0.08%)
b2018	Loop Conesville - Bixby 345 kV circuit into Ohio Central		ATSI (58.58%) / AEP (14.16%) / APS (12.88%) / DL (7.93%) / PENELEC (5.73%) / Dayton (0.72%)
b2019	Establish Burger 345/138 kV station		AEP (93.74%) / APS (4.40%) / DL (1.11%) / ATSI (0.74%) / PENELEC (0.01%)

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**East Coast Power, L.L.C.

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2020	Rebuild Amos - Kanawah River 138 kV corridor		AEP (88.39%) / APS (7.12%) / ATSI (2.89%) / DEOK (1.58%) / PEPCO (0.02%)
b2021	Add 345/138 transformer at Sporn, Kanawah River & Muskingum River stations		AEP (91.92%) / DEOK (3.60%) / APS (2.19%) / ATSI (1.14%) / DL (1.08%) / PEPCO (0.04%) / BGE (0.03%)
b2021.1	Replace Kanawah 138 kV breaker 'L'		AEP (100%)
b2021.2	Replace Muskingum 138 kV breaker 'HG'		AEP (100%)
b2021.3	Replace Muskingum 138 kV breaker 'HJ'		AEP (100%)
b2021.4	Replace Muskingum 138 kV breaker 'HE'		AEP (100%)
b2021.5	Replace Muskingum 138 kV breaker 'HD'		AEP (100%)
b2021.6	Replace Muskingum 138 kV breaker 'HF'		AEP (100%)
b2021.7	Replace Muskingum 138 kV breaker 'HC'		AEP (100%)
b2021.8	Replace Sporn 138 kV breaker 'D1'		AEP (100%)
b2021.9	Replace Sporn 138 kV breaker 'D2'		AEP (100%)
b2021.10	Replace Sporn 138 kV breaker 'F1'		AEP (100%)
b2021.11	Replace Sporn 138 kV breaker 'F2'		AEP (100%)
b2021.12	Replace Sporn 138 kV breaker 'G'		AEP (100%)
b2021.13	Replace Sporn 138 kV breaker 'G2'		AEP (100%)
b2021.14	Replace Sporn 138 kV breaker 'N1'		AEP (100%)
b2021.15	Replace Kanawah 138 kV breaker 'M'		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2022	Terminate Tristate - Kyger Creek 345 kV line at Sporn		AEP (97.99%) / DEOK (2.01%)
b2027	Perform a sag study of the Tidd - Collier 345 kV line		AEP (100%)
b2028	Perform a sag study on East Lima - North Woodcock 138 kV line to improve the rating		AEP (100%)
b2029	Perform a sag study on Bluebell - Canton Central 138 kV line to improve the rating		AEP (100%)
b2030	Install 345 kV circuit breakers at West Bellaire		AEP (100%)
b2031	Sag study on Tilton - W. Bellaire section 1 (795 ACSR), about 12 miles		AEP (100%)
b2032	Rebuild 138 kV Elliot tap - Poston line		ATSI (73.02%) / Dayton (19.39%) / DL (7.59%)
b2033	Perform a sag study of the Brues - W. Bellaire 138 kV line		AEP (100%)
b2046	Adjust tap settings for Muskingum River transformers		AEP (100%)
b2047	Replace relay at Greenlawn		AEP (100%)
b2048	Replace both 345/138 kV transformers with one bigger transformer		AEP (92.49%) / Dayton (7.51%)
b2049	Replace relay		AEP (100%)
b2050	Perform sag study		AEP (100%)

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AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2051	Install 3 138 kV breakers and a circuit switcher at Dorton station		AEP (100%)
b2052	Replace transformer		AEP (67.17%) / ATSI (27.37%) / Dayton (3.73%) / PENELEC (1.73%)
b2054	Perform a sag study of Sporn - Rutland 138 kV line		AEP (100%)
b2069	Replace George Washington 138 kV breaker 'A' with 63kA rated breaker		AEP (100%)
b2070	Replace Harrison 138 kV breaker '6C' with 63kA rated breaker		AEP (100%)
b2071	Replace Lincoln 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2072	Replace Natrum 138 kV breaker 'I' with 63kA rated breaker		AEP (100%)
b2073	Replace Darrah 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)
b2074	Replace Wyoming 138 kV breaker 'G' with 80kA rated breaker		AEP (100%)
b2075	Replace Wyoming 138 kV breaker 'G1' with 80kA rated breaker		AEP (100%)
b2076	Replace Wyoming 138 kV breaker 'G2' with 80kA rated breaker		AEP (100%)
b2077	Replace Wyoming 138 kV breaker 'H' with 80kA rated breaker		AEP (100%)
b2078	Replace Wyoming 138 kV breaker 'H1' with 80kA rated breaker		AEP (100%)
b2079	Replace Wyoming 138 kV breaker 'H2' with 80kA rated breaker		AEP (100%)
b2080	Replace Wyoming 138 kV breaker 'J' with 80kA rated breaker		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2081	Replace Wyoming 138 kV breaker 'J1' with 80kA rated breaker		AEP (100%)
b2082	Replace Wyoming 138 kV breaker 'J2' with 80kA rated breaker		AEP (100%)
b2083	Replace Natrum 138 kV breaker 'K' with 63kA rated breaker		AEP (100%)
b2084	Replace Tanner Creek 345 kV breaker 'P' with 63kA rated breaker		AEP (100%)
b2085	Replace Tanner Creek 345 kV breaker 'P2' with 63kA rated breaker		AEP (100%)
b2086	Replace Tanner Creek 345 kV breaker 'Q1' with 63kA rated breaker		AEP (100%)
b2087	Replace South Bend 138 kV breaker 'T' with 63kA rated breaker		AEP (100%)
b2088	Replace Tidd 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2089	Replace Tidd 138 kV breaker 'M2' with 63kA rated breaker		AEP (100%)
b2090	Replace McKinley 138 kV breaker 'A' with 40kA rated breaker		AEP (100%)
b2091	Replace West Lima 138 kV breaker 'M' with 63kA rated breaker		AEP (100%)
b2092	Replace George Washington 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)
b2093	Replace Turner 138 kV breaker 'W' with 63kA rated breaker		AEP (100%)
b2135	Build a new 138 kV line from Falling Branch to Merrimac and add a 138/69 kV transformer at Merrimac Station		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2160	Add a fourth circuit breaker to the station being built for the U4-038 project (Conelley), rebuild U4-038 - Grant Tap line as double circuit tower line		AEP (100%)
b2161	Rebuild approximately 20 miles of the Allen - S073 double circuit 138 kV line (with one circuit from Allen - Tillman - Timber Switch - S073 and the other circuit from Allen - T-131 - S073) utilizing 1033 ACSR		AEP (100%)
b2162	Perform a sag study to improve the emergency rating of the Belpre - Degussa 138 kV line		AEP (100%)
b2163	Replace breaker and wavetrap at Jay 138 kV station		AEP (100%)

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**East Coast Power, L.L.C.

Attachment 3A
Translation of 2010/2011 Schedule 12 Charges into Rates – JCP&L
Attachment 3B
Translation of 2010/2011 Schedule 12 Charges into Rates – PSE&G
Attachment 3C
Translation of 2010/2011 Schedule 12 Charges into Rates - RECO

Attachment 3a

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL2-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2014 - May 2015

2014/2015 Average Monthly PPL2-TEC Costs Allocated to JCP&L Zone	$	299,542.83	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
PPL2-Transmission Enhancement Rate ($/MW-month)	$	46.96	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL2-TEC Surcharge ($/kWh)	PPL2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	3,220,969	17,081,462,895	$ 0.000189	$ 0.000202
Primary	359.9	202,804	1,814,916,713	$ 0.000112	$ 0.000120
Transmission @ 34.5 kV	290.1	163,472	1,772,254,996	$ 0.000092	$ 0.000098
Transmission @ 230 kV	12.9	7,269	342,194,514	$ 0.000021	$ 0.000022
Total	6378.9	3,594,514	21,010,829,118		

(1) Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months PPL Project costs from June 2014 through May 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

<u>Line No.</u>				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	PPL2-Transmission Enhancement Costs to FP Suppliers	$	3,011,347	= Line 3 x $46.96 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.18	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East2-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective July 2014 - June 2015

2014/2015 Average Monthly AEP-East2-TEC Costs Allocated to JCP&L Zone	$	32,969.30	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
AEP-East2-Transmission Enhancement Rate ($/MW-month)	$	5.17	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	AEP-East2-TEC Surcharge ($/kWh)	AEP-East2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	354,517	17,081,462,895	$ 0.000021	$ 0.000022
Primary	359.9	22,322	1,814,916,713	$ 0.000012	$ 0.000013
Transmission @ 34.5 kV	290.1	17,993	1,772,254,996	$ 0.000010	$ 0.000011
Transmission @ 230 kV	12.9	800	342,194,514	$ 0.000002	$ 0.000002
Total	6378.9	395,632	21,010,829,118		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months AEP-East Project costs from July 2014 through June 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	AEP-East2-Transmission Enhancement Costs to FP Suppliers	$	331,445	= Line 3 x $5.17 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.02	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed Delmarva Project Transmission Enhancement Charge (Delmarva2-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved Delmarva Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2014 - May 2015

2014/2015 Average Monthly Delmarva2-TEC Costs Allocated to JCP&L Zone	$	51,083.61	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
Delmarva2-Transmission Enhancement Rate ($/MW-month)	$	8.01	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Delmarva2-TEC Surcharge ($/kWh)	Delmarva2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	549,300	17,081,462,895	$ 0.000032	$ 0.000034
Primary	359.9	34,586	1,814,916,713	$ 0.000019	$ 0.000020
Transmission @ 34.5 kV	290.1	27,878	1,772,254,996	$ 0.000016	$ 0.000017
Transmission @ 230 kV	12.9	1,240	342,194,514	$ 0.000004	$ 0.000004
Total	6378.9	613,003	21,010,829,118		

(1) Cost Allocation of Delmarva Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months Delmarva Project costs from June 2014 through May 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	Delmarva2-Transmission Enhancement Costs to FP Suppliers	$	513,551	= Line 3 x $8.01 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE2-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2014 - May 2015

2014/2015 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	106,399.47	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
ACE2-Transmission Enhancement Rate ($/MW-month)	$	16.68	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	ACE2-TEC Surcharge ($/kWh)	ACE2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	1,144,108	17,081,462,895	$ 0.000067	$ 0.000072
Primary	359.9	72,037	1,814,916,713	$ 0.000040	$ 0.000043
Transmission @ 34.5 kV	290.1	58,066	1,772,254,996	$ 0.000033	$ 0.000035
Transmission @ 230 kV	12.9	2,582	342,194,514	$ 0.000008	$ 0.000009
Total	6378.9	1,276,794	21,010,829,118		

(1) Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months ACE Project costs from June 2014 through May 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	ACE2-Transmission Enhancement Costs to FP Suppliers	$	1,069,649	= Line 3 x $16.68 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.06	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO2-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2014 - May 2015

2014/2015 Average Monthly PEPCO2-TEC Costs Allocated to JCP&L Zone	$	79,604.13	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
PEPCO2-Transmission Enhancement Rate ($/MW-month)	$	12.48	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PEPCO2-TEC Surcharge ($/kWh)	PEPCO2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	855,979	17,081,462,895	$ 0.000050	$ 0.000054
Primary	359.9	53,896	1,814,916,713	$ 0.000030	$ 0.000032
Transmission @ 34.5 kV	290.1	43,443	1,772,254,996	$ 0.000025	$ 0.000027
Transmission @ 230 kV	12.9	1,932	342,194,514	$ 0.000006	$ 0.000006
Total	6378.9	955,250	21,010,829,118		

(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months PEPCO Project costs from June 2014 through May 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	PEPCO2-Transmission Enhancement Costs to FP Suppliers	$	800,272	= Line 3 x $12.48 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.05	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO4-TEC Surcharge) effective September 1, 2014
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2014 - May 2015

2014/2015 Average Monthly TRAILCO4-TEC Costs Allocated to JCP&L Zone	$	698,281.34	(1)
2014 JCP&L Zone Transmission Peak Load (MW)		6378.9	
TRAILCO4-Transmission Enhancement Rate ($/MW-month)	$	109.47	

				Effective September 1, 2014:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	TRAILCO4-TEC Surcharge ($/kWh)	TRAILCO4-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5716.0	7,508,585	17,081,462,895	$ 0.000440	$ 0.000471
Primary	359.9	472,768	1,814,916,713	$ 0.000260	$ 0.000278
Transmission @ 34.5 kV	290.1	381,078	1,772,254,996	$ 0.000215	$ 0.000230
Transmission @ 230 kV	12.9	16,946	342,194,514	$ 0.000050	$ 0.000054
Total	6378.9	8,379,376	21,010,829,118		

(1) Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2014/2015
(2) Based on 12 months TRAILCO Project costs from June 2014 through May 2015
(3) September 2014 through August 2015

<u>BGS-FP Supplier Payment Adjustment</u>

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,064,501	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		16,657,331	MWH
3	BGS-FP Eligible Transmission Obligation		5,344	MW
4	TRAILCO4-Transmission Enhancement Costs to FP Suppliers	$	7,019,923	= Line 3 x $109.47 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.42	= Line 4 / Line 2

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Project

TEC Charges for June 2014 - May 2015	$	12,783,317		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	102.29	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	1,227.48	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge								
in $/MWh	$ 0.417605	$ 0.237729	$ 0.378085	$ -	$ -	$ 0.261723	$ -	$ -
in $/kWh - rounded to 6 places	**0.000418**	**0.000238**	**0.000378**	**0**	**0**	**0.000262**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	10,386,199		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.3271	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.33	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	10,479,392		unrounded	= (6) * (3)
8	Difference due to rounding	$	93,193		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for Delmarva Projects

TEC Charges for June 2014 - May 2015	$	1,000,000		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	8.00	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	96.00	/MW/yr	

		RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW		4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh		13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge									
in $/MWh	$	0.032660	$ 0.018593	$ 0.029570	$ -	$ -	$ 0.020469	$ -	$ -
in $/kWh - rounded to 6 places		**0.000033**	**0.000019**	**0.000030**	**0**	**0**	**0.000020**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	812,294		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0256	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.03	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	952,672		unrounded	= (6) * (3)
8	Difference due to rounding	$	140,378		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2014 - May 2015	$	571,970		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	4.58	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	54.96	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge								
in $/MWh	$ 0.018698	$ 0.010644	$ 0.016929	$ -	$ -	$ 0.011719	$ -	$ -
in $/kWh - rounded to 6 places	**0.000019**	**0.000011**	**0.000017**	**0**	**0**	**0.000012**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	465,039		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0146	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.01	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	317,557		unrounded	= (6) * (3)
8	Difference due to rounding	$	(147,481)		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2014 - May 2015	$	1,520,815		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	12.17	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	146.04	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge								
in $/MWh	$ 0.049685	$ 0.028284	$ 0.044983	$ -	$ -	$ 0.031139	$ -	$ -
in $/kWh - rounded to 6 places	**0.000050**	**0.000028**	**0.000045**	**0**	**0**	**0.000031**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,235,703		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0389	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,270,229		unrounded	= (6) * (3)
8	Difference due to rounding	$	34,527		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2014 - May 2015
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2014 - May 2015	$	5,875,517		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	47.01	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	564.12	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge								
in $/MWh	$ 0.191921	$ 0.109254	$ 0.173759	$ -	$ -	$ 0.120281	$ -	$ -
in $/kWh - rounded to 6 places	**0.000192**	**0.000109**	**0.000174**	**0**	**0**	**0.000120**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	4,773,245		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.1503	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.15	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	4,763,360		unrounded	= (6) * (3)
8	Difference due to rounding	$	(9,885)		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for July 2014 - June 2015
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for June 2014 - May 2015	$	647,472		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,414.4		
Term (Months)		12		
OATT rate	$	5.18	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	62.16	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4430.4	34.5	78.4	0.0	0.0	4.9	0.0	0.0
Total Annual Energy - MWh	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567
Change in energy charge								
in $/MWh	$ 0.021148	$ 0.012039	$ 0.019146	$ -	$ -	$ 0.013254	$ -	$ -
in $/kWh - rounded to 6 places	**0.000021**	**0.000012**	**0.000019**	**0**	**0**	**0.000013**	**0**	**0**

Line #						
1	Total BGS-FP eligbile Trans Obl		8461.4	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		29,621,754	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		31,755,735	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	525,961		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0166	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.02	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	635,115		unrounded	= (6) * (3)
8	Difference due to rounding	$	109,154		unrounded	= (7) - (4)

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2014

To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly ACE-TEC Costs Allocated to RECO	$	972	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.05	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $972 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Sep 2014- Aug 2015 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7	55.93%	$ 6,527	719,675,000	$ 0.00001	$ 0.00001
SC2 Secondary	144.6	30.44%	$ 3,552	549,689,000	$ 0.00001	$ 0.00001
SC2 Primary	21.8	4.59%	$ 536	84,988,000	$ 0.00001	$ 0.00001
SC3	0.1	0.01%	$ 2	269,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,469,000	$ -	$ -
SC5	4.1	0.86%	$ 100	16,233,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,606,000	$ -	$ -
SC7	38.8	8.16%	$ 953	253,655,000	$ -	$ -
Total	475.1 (2)	100.00%	$ 11,670	1,636,584,000		

(1) Attachment 2 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	10,734.11	= Line 3 x $2.05 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective September 1, 2014

To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	2,242	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.72	

	Col. 1		Col. 2		Col.3=Col.2 x $2,242 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)		Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2014- Aug 2015 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7		55.93%	$	15,046	719,675,000	$	0.00002	$	0.00002
SC2 Secondary	144.6		30.44%	$	8,189	549,689,000	$	0.00001	$	0.00001
SC2 Primary	21.8		4.59%	$	1,236	84,988,000	$	0.00001	$	0.00001
SC3	0.1		0.01%	$	4	269,000	$	0.00001	$	0.00001
SC4	0.0		0.00%	$	-	6,469,000	$	-	$	-
SC5	4.1		0.86%	$	231	16,233,000	$	0.00001	$	0.00001
SC6	0.0		0.00%	$	-	5,606,000	$	-	$	-
SC7	38.8		8.16%	$	2,196	253,655,000	$	0.00001	$	0.00001
Total	475.1	(2)	100.00%	$	26,902	1,636,584,000				

(1) Attachment 2 - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	24,714.64	= Line 3 x $4.72 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Attachment 3C

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Delmarva) effective September 1, 2014

To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	3,483	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	7.33	

	Col. 1	Col. 2	Col.3=Col.2 x $3,483 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2014- Aug 2015 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7	55.93%	$ 23,376	719,675,000	$ 0.00003	$ 0.00003
SC2 Secondary	144.6	30.44%	$ 12,723	549,689,000	$ 0.00002	$ 0.00002
SC2 Primary	21.8	4.59%	$ 1,920	84,988,000	$ 0.00002	$ 0.00002
SC3	0.1	0.01%	$ 6	269,000	$ 0.00002	$ 0.00002
SC4	0.0	0.00%	$ -	6,469,000	$ -	$ -
SC5	4.1	0.86%	$ 359	16,233,000	$ 0.00002	$ 0.00002
SC6	0.0	0.00%	$ -	5,606,000	$ -	$ -
SC7	38.8	8.16%	$ 3,412	253,655,000	$ 0.00001	$ 0.00001
Total	475.1 (2)	100.00%	$ 41,796	1,636,584,000		

(1) Attachment 2 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	38,381.00	= Line 3 x $7.33 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.03	= Line 4/Line 2

Attachment 3C

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective September 1, 2014

To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	4,742	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	9.98	

	Col. 1	Col. 2	Col.3=Col.2 x $4,742 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2014- Aug 2015 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7	55.93%	$ 31,828	719,675,000	$ 0.00004	$ 0.00004
SC2 Secondary	144.6	30.44%	$ 17,322	549,689,000	$ 0.00003	$ 0.00003
SC2 Primary	21.8	4.59%	$ 2,614	84,988,000	$ 0.00003	$ 0.00003
SC3	0.1	0.01%	$ 8	269,000	$ 0.00003	$ 0.00003
SC4	0.0	0.00%	$ -	6,469,000	$ -	$ -
SC5	4.1	0.86%	$ 489	16,233,000	$ 0.00003	$ 0.00003
SC6	0.0	0.00%	$ -	5,606,000	$ -	$ -
SC7	38.8	8.16%	$ 4,646	253,655,000	$ 0.00002	$ 0.00002
Total	475.1 (2)	100.00%	$ 56,907	1,636,584,000		

(1) Attachment 2 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	52,256.81	= Line 3 x $9.98 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.04	= Line 4/Line 2

Attachment 3C

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PPL) effective September 1, 2014

To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly PPL-TEC Costs Allocated to RECO	$	20,356	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	42.84	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $20,356 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Sep 2014- Aug 2015 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7	55.93%	$ 136,620	719,675,000	$ 0.00019	$ 0.00020
SC2 Secondary	144.6	30.44%	$ 74,356	549,689,000	$ 0.00014	$ 0.00015
SC2 Primary	21.8	4.59%	$ 11,219	84,988,000	$ 0.00013	$ 0.00014
SC3	0.1	0.01%	$ 35	269,000	$ 0.00013	$ 0.00014
SC4	0.0	0.00%	$ -	6,469,000	$ -	$ -
SC5	4.1	0.86%	$ 2,101	16,233,000	$ 0.00013	$ 0.00014
SC6	0.0	0.00%	$ -	5,606,000	$ -	$ -
SC7	38.8	8.16%	$ 19,941	253,655,000	$ 0.00008	$ 0.00009
Total	475.1 (2)	100.00%	$ 244,272	1,636,584,000		

(1) Attachment 2 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	224,316.80	= Line 3 x $42.84 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.18	= Line 4/Line 2

Attachment 3C

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective September 1, 2014

To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2013/2014 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	44,177	(1)
2013 RECO Zone Transmission Peak Load (MW)		475.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	92.98	

	Col. 1	Col. 2	Col.3=Col.2 x $44,177 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2014- Aug 2015 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.7	55.93%	$ 296,494	719,675,000	$ 0.00041	$ 0.00044
SC2 Secondary	144.6	30.44%	$ 161,368	549,689,000	$ 0.00029	$ 0.00031
SC2 Primary	21.8	4.59%	$ 24,347	84,988,000	$ 0.00029	$ 0.00031
SC3	0.1	0.01%	$ 75	269,000	$ 0.00028	$ 0.00030
SC4	0.0	0.00%	$ -	6,469,000	$ -	$ -
SC5	4.1	0.86%	$ 4,559	16,233,000	$ 0.00028	$ 0.00030
SC6	0.0	0.00%	$ -	5,606,000	$ -	$ -
SC7	38.8	8.16%	$ 43,276	253,655,000	$ 0.00017	$ 0.00018
Total	475.1 (2)	100.00%	$ 530,119	1,636,584,000		

(1) Attachment 2 - Cost Allocation of TrAILCo Schedule 12 Charges to RECO Zone for June 2014 through May 2015

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,325,570	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,236,319	MWH
3	BGS-FP Eligible Transmission Obligation		436	MW
4	Transmission Enhancement Costs to FP Suppliers	$	486,857.52	= Line 3 x $92.98 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.39	= Line 4/Line 2

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective September 1, 2014
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2014
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates

(A) Transmission Surcharge rates by Transmission Project and Service Class (excluding SUT)

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
AEP-East - TEC	(3)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00009	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
PEPCO - TEC	(6)	0.00004	0.00003	0.00003	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00019	0.00014	0.00013	0.00013	0.00000	0.00013	0.00000	0.00008
PSE&G - TEC	(8)	0.00554	0.00341	0.00316	0.00323	0.00000	0.00341	0.00000	0.00212
TrAILCo - TEC	(9)	0.00041	0.00029	0.00029	0.00028	0.00000	0.00028	0.00000	0.00017
VEPCo - TEC	(10)	0.00028	0.00017	0.00016	0.00017	0.00000	0.00017	0.00000	0.00011
Total ($/kWh and excl SUT)		$0.00661	$0.00413	$0.00386	$0.00393	$0.00000	$0.00411	$0.00000	$0.00255
Total (¢/kWh and excl SUT)		0.661 ¢	0.413 ¢	0.386 ¢	0.393 ¢	0.000 ¢	0.411 ¢	0.000 ¢	0.255 ¢

(B) Transmission Surcharge rates by Transmission Project and Service Class (including SUT)

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
AEP-East - TEC	(3)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00010	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
PEPCO - TEC	(6)	0.00004	0.00003	0.00003	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00020	0.00015	0.00014	0.00014	0.00000	0.00014	0.00000	0.00009
PSE&G - TEC	(8)	0.00593	0.00365	0.00338	0.00346	0.00000	0.00365	0.00000	0.00227
TrAILCo - TEC	(9)	0.00044	0.00031	0.00031	0.00030	0.00000	0.00030	0.00000	0.00018
VEPCo - TEC	(10)	0.00030	0.00018	0.00017	0.00018	0.00000	0.00018	0.00000	0.00012
Total ($/kWh and incl SUT)		$0.00707	$0.00441	$0.00412	$0.00420	$0.00000	$0.00439	$0.00000	$0.00273
Total (¢/kWh and incl SUT)		0.707 ¢	0.441 ¢	0.412 ¢	0.420 ¢	0.000 ¢	0.439 ¢	0.000 ¢	0.273 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2014.
(2) ACE-TEC rates calculated in Attachment 5 of the joint filing.
(3) AEP-East-TEC rates calculated in Attachment 5 of the joint filing.
(4) Delmarva-TEC rates calculated in Attachment 5 of the joint filing.
(5) PATH-TEC rates pursuant to the Board's Order dated February 19, 2014 in Docket No. ER13121205.
(6) PEPCO-TEC rates calculated in Attachment 5 of the joint filing.
(7) PPL-TEC rates calculated in Attachment 5 of the joint filing.
(8) PSE&G-TEC rates pursuant to the Board's Order dated February 19, 2014 in Docket No. ER13121205.
(9) TrAILCo-TEC rates calculated in Attachment 5 of the joint filing.
(10) VEPCo-TEC rates pursuant to the Board's Order dated February 19, 2014 in Docket No. ER13121205.

Attachment 4A

TrAILCo Formula Rate Update Compliance Filing

Attachment 4B

Delmarva Formula Rate Update Compliance Filing

Attachment 4C

ACE Formula Rate Update Compliance Filing

Attachment 4D

PEPCo Formula Rate Update Compliance Filing

Attachment 4E

PPL Formula Rate Update Compliance Filing

Attachment 4F

AEP-East Formula Rate Update Compliance Filing

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	TrAILCo
	Shaded cells are input cells			**2014 Forecast**
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	0
2	Total Wages Expense		p354.28.b	0
3	Less A&G Wages Expense		p354.27.b	0
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	0
5	**Wages & Salary Allocator**		(Line 1 / Line 4), if line 2 = 0, then 100%	**100.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	1,326,179,788
7	Total Plant In Service		(Line 6)	1,326,179,788
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	81,132,821
9	Total Accumulated Depreciation		(Line 8)	81,132,821
10	Net Plant		(Line 7 - Line 9)	1,245,046,967
11	Transmission Gross Plant		(Line 15 + Line 21)	1,326,179,788
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	1,245,046,967
14	**Net Plant Allocator**		(Line 13 / Line 10, if line 10=0, enter 100%)	**100.0000%**
	Plant Calculations			
	Transmission Plant			
15	Transmission Plant In Service	(Note B)	Attachment 5	1,259,599,755
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	121,546,826
17	**Total Transmission Plant**		(Line 15 + Line 16)	**1,381,146,581**
18	General & Intangible		Attachment 5	66,580,033
19	Total General & Intangible		(Line 18)	66,580,033
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**66,580,033**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**1,447,726,614**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	72,434,228
24	Accumulated General Depreciation		Attachment 5	3,876,568
25	Accumulated Intangible Amortization		Attachment 5	4,822,025
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	8,698,593
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**8,698,593**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**81,132,821**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**1,366,593,793**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109	Enter Negative	Attachment 1	-171,670,276
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**-171,670,276**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**2,270,852**
34	**Transmission Related Land Held for Future Use**	(Note C)	Attachment 5	**0**
	Transmission Related Pre-Commercial Costs Capitalized			
35	Unamortized Capitalized Pre-Commercial Costs		Attachment 5	**0**
	Prepayments			
36	**Transmission Related Prepayments**	(Note A)	Attachment 5	**112,905**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	Attachment 5	0
38	Wage & Salary Allocator		(Line 5)	100.0000%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	0
40	Transmission Materials & Supplies		Attachment 5	0
41	**Transmission Related Materials & Supplies**		(Line 39 + Line 40)	**0**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 74)	1,522,598
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**190,325**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**-169,096,194**
46	**Rate Base**		(Line 30 + Line 45)	**1,197,497,599**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	8,669,961
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	937,961
49	Less Account 565		p321.96.b	0
50	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note M)	PJM Data	0
51	Plus Property Under Capital Leases		p200.4.c	0
52	**Transmission O&M**		(Lines 47 - 48 - 49 + 50 + 51)	**7,732,000**
	A&G Expenses			
53	Total A&G	(Note O)	p323.197.b	-7,147,363
54	Less Property Insurance Account 924		p323.185.b	43,049
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	0
56	Less General Advertising Exp Account 930.1		p323.191.b	0
57	Less PBOP Adjustment		Attachment 5	0
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	-7,190,412
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**-7,190,412**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note J)	Attachment 5	0
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924		p323.185.b	43,049
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	43,049
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**43,049**
	Account 566 Miscellaneous Transmission Expense			
70	Amortization Expense on Pre-Commercial Cost	Account 566	Attachment 5	0
71	Pre-Commercial Expense	Account 566	Attachment 5	0
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	937,961
73	Total Account 566		Sum (Lines 70 to 72)	**937,961**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**1,522,598**

Depreciation & Amortization Expense

	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	24,730,942
76	General Depreciation			Attachment 5	1,329,321
77	Intangible Amortization		(Note A)	Attachment 5	1,649,781
78	Total			(Line 76 + Line 77)	2,979,102
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**2,979,102**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**27,710,044**

Taxes Other than Income

82	**Transmission Related Taxes Other than Income**			Attachment 2	**9,504,363**
83	**Total Taxes Other than Income**			**(Line 82)**	**9,504,363**

Return / Capitalization Calculations

84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	657,124,621
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	0
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	657,124,621
	Capitalization				
90	Long Term Debt		(Note N)		450,000,000
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	2,219,377
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	-1,015,123
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	448,795,746
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	657,124,621
97	**Total Capitalization**			(Sum Lines 94 to 96)	1,105,920,367
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	40.5812%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0000%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	59.4188%
101	Debt Cost	Total Long Term Debt			0.0489
102	Preferred Cost	Preferred Stock		(Line 84 / Line 95)	0.0000
103	Common Cost	Common Stock	(Note I)	The most recent FERC approved ROE	0.1170
104	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 98 * Line 101)	0.0198
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0695
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.0893**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**106,995,672**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			6.92%
111	p	(percent of federal income tax deductible for state purp	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.50%
113	T/ (1-T)			65.28%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**54,348,037**
115	**Total Income Taxes**		**(Line 114)**	**54,348,037**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	1,366,593,793
117	Total Adjustment to Rate Base		(Line 45)	-169,096,194
118	**Rate Base**		(Line 46)	**1,197,497,599**
119	Total Transmission O&M		(Line 74)	1,522,598
120	Total Transmission Depreciation & Amortization		(Line 81)	27,710,044
121	Taxes Other than Income		(Line 83)	9,504,363
122	Investment Return		(Line 108)	106,995,672
123	Income Taxes		(Line 115)	54,348,037
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**200,080,714**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	1,447,726,614
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	1,447,726,614
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	200,080,714
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**200,080,714**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	3,057,090
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**197,023,624**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**197,023,624**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**1,310,983,205**
135	FCR		(Line 133 / Line 134)	**15.0287%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**13.1422%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**13.1422%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**0.8352%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**35,679,915**
140	Increased Return and Taxes		Attachment 4	**173,104,227**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**208,784,142**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**1,310,983,205**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**15.9258%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**14.0393%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**14.0393%**
146	**Net Revenue Requirement**		(Line 132)	**197,023,623.86**
147	Reconciliation amount		Attachment 6	**555,328.01**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**9,468,346.45**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0.00**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**207,047,298.32**
	Network Zonal Service Rate			
151	1 CP Peak	(Note K)	PJM Data	**N/A**
152	Rate ($/MW-Year)		(Line 150 / 151)	**N/A**
153	**Network Service Rate ($/MW/Year)**		**(Line 152)**	**N/A**

Notes

A Electric portion only

B For both the estimate and the reconciliation, Construction Work In Progress ("CWIP") and leases that are expensed as O&M (rather than amortized) are excluded.

For the Estimate Process:

Transmission plant in service will show the end of year balance and is linked to Attachment 5 which shows detail support by project.

The transmission plant will agree to or be reconciled to the FERC Form 1 balance for the transmission plant.

New Transmission Plant expected to be placed in service in the current calendar year will be based on the average of 13 monthly investment costs and shown separately detailed by project on Attachment 6.

Accumulated depreciation will show the end of year balance and is linked to Attachment 5 which shows detail support by project.

CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

For the Reconciliation Process:

Transmission plant in service will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes new transmission plant added to plant-in-service

Accumulated depreciation will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes accumulated depreciation associated with current year transmission plant.

CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Includes Transmission portion only and (i) only land that has an estimated in-service date within 10 years may be included and (ii) a plan for the land's use is required to be included in the filing whenever the cost of the land is proposed to be included in rates.

D Excludes all EPRI Annual Membership Dues

E Excludes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

H The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed.

I ROE will be established in the Commission order accepting the settlement in Docket No. ER07-562 and no change in ROE will be made absent a Section 205 or Section 206 filing at FERC.

J Education and outreach expenses relating to transmission, for example siting or billing

K As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations.

L Amount of transmission plant excluded from rates per Attachment 5.

M Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M on Line 47. If they are booked to Acct 565, they are included on Line 50. Copies of PJM invoices will be provided upon request.

N The capital structure will remain 50% equity and 50% debt until construction of all of the segments of the TrAIL Project is completed and the entire TrAIL Project is placed in service. The first year that these projects are in service the formula will be run based on the 50/50 capital structure and on the actual year end capital structure. The two results will be weighted based on: the number of days the last project was in service and 365 day minus the numbers of days the last project was in service divided by 365 days.

This can be illustrated using the following example:

Example:

Assume Last Project goes into service on day 260.
Hypothetical Capital Structure until the last project goes into service is 50/50.
Assume Year End actual capital structure is 60% equity and 40% debt.

Therefore: Weighted Equity = [50%*260+60%*(365-260)]/365

O Adjusted for additional interest associated with refund per FERC Docket No. PA12-18-000, an amount of $13,560

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

Trans-Allegheny Interstate Company

Line		B1	B2	B3	C	D	E	F	G	
		Beg of Year Total	***End of Year Total***	**End of Year for Est. Average for Final *Total***	**Retail Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**Total ADIT**	
1	**ADIT- 282 From Account Total Below**	394,680,133	419,149,254	406,914,694	[redacted]	419,149,254	-	-	419,149,254	
2	**ADIT-283 From Account Total Below**	41,190,814	39,093,942	40,142,378	[redacted]	39,093,942	-	-	39,093,942	
3	**ADIT-190 From Account Total Below**	(307,577,271)	(286,572,920)	(297,075,096)	[redacted]	(286,572,920)	-	-	(286,572,920)	Enter Negative
4	**Subtotal**					171,670,276	-	-	171,670,276	
5	**Wages & Salary Allocator**							100.0000%		
6	**Gross Plant Allocator**						100.0000%			
7	**ADIT**					171,670,276	-	-	171,670,276	

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 93.

Amount 1,015,123 < From Acct 283, below

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed,
Dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-190	**Beg of Year Balance p234.18.b**	**End of Year Balance p234.18.c**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Tax Interest Capitalized	-	-	-			-			Actual amount of tax interest capitalized
Depreciation	-	-	-			-			Book depreciation
Taxes Intercompany Charges AESC	0	-	-			-			Intercompany charges from the service company
Worker's Compensation	107,796	109,219	108,508			108,508			Actual amount of reserve for workers' compensation
Long Term Disability Accrual	-	24,415	12,208			12,208			Long term disability accrual
Excess Over/Under Prior Service	-	-	-			-			Excess over under prior service cost
Amortization Expense	-	-	-			-			Amortization of intangible plant
WV Rate Change Consolidated Benefit	-	-	-			-			Temporary difference due to change in state tax rate in West Virginia
CIAC - Taxable	-	-	-			-			Taxable CIAC
Taxes Accrued State Other	-	-	-			-			PA Sales Tax
Miscellaneous Other Property Tax	-	-	-			-			WV Property Tax
Merger Costs Capitalized	-	-	-			-			Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Reserve for EIB	-	-	-			-			Allocated portion of total liabilities relating to captive insurance
Power Tax Adjustment	79,377	81,454	80,416			80,416			System adjustment to reclass balances to correct FERC accounts
Operating Provision Enviro Accrual	-	-	-			-			Environmental clean-up expenses
State Income Taxes	1,684,577	0	842,289			842,289			Return/Accrual (catch up entry)
Merger Costs Licenses	98,248	107,065	102,657		102,657				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Merger Costs D&O Insurance	2,149	2,299	2,224		2,224				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Merger Costs - Indebtedness	82	0	41		41				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
NOL	0	-	-			-			Result of bonus depreciation
Federal NOL	257,698,000	258,092,677	257,895,339			257,895,339			Result of bonus depreciation
State NOL	47,183,053	27,477,990	37,330,522			37,330,522			Result of bonus depreciation - PA, WV and MD
FASB 109 Gross-Up	658,656	0	329,328			329,328			Reclass of the tax portion (gross-up) for property items included in account 282
Reevaluation Adjustment	723,989	413,120	568,555		568,555				Temporary difference resulting from purchase accounting transactions
Charitable Contribution Limit	-	3,761	1,881			1,881			Disallowance in current year for charitable deduction due to tax loss, tax attribute carries forward five years
Provision for Rate Refund	-	260,920	130,460			130,460			Set-up of a reserve on transmission companies for the amount of merger expenses that have been overcollected and are owed to customers - timing difference between book and tax
Subtotal	308,235,927	286,572,920	297,404,424	-	673,476	296,730,948	-	-	
Less FASB 109 included above	658,656	-	329,328	-	-	329,328	-	-	
Less FASB 106 included above									
Total	307,577,271	286,572,920	297,075,096	-	673,476	296,401,620	-	-	

Instructions for Account 190:

1. **ADIT items related only to Retail Related Operations are directly assigned to Column C.**
2. **ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.**
3. **ADIT items related only to Transmission are directly assigned to Column E.**
4. **ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.**
5. **ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.**
6. **Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.**

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT- 282	**Beg of Year Balance p274.9.b**	**End of Year Balance p275.9.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related Related**	**Only Transmission Related Related**	**Plant Related Related**	**Labor Related Related**	**JUSTIFICATION**
Property Related - ABFUDC	1,471,989	1,757,820	1,614,905			1,614,905			Allowance for borrowed funds used during construction (ABFUDC)
Property Related - Tax Depreciation	52,132,953	72,202,243	62,167,598			62,167,598			Tax depreciation
FASB 109 Fixed Asset Adjustment	2,875,185	2,950,414	2,912,800			2,912,800			Increase in AOFDC
FASB 109 Gross-Up	658,656	(6,574,963)	(2,958,154)			(2,958,154)			Reclass of the tax portion (gross-up) for property items included in account 282
Book Depreciation Expense	(23,043,665)	(34,270,107)	(28,656,886)			(28,656,886)			Book depreciation
Amortization Expense - Intangible Plant	(1,158,152)	(1,865,544)	(1,511,848)			(1,511,848)			Book depreciation / amortization
Bonus Depreciation	403,045,379	409,438,305	406,241,842			406,241,842			Tax depreciation
CIACS Taxable	(1,381,132)	(799,612)	(1,090,372)			(1,090,372)			Taxable CIAC
Tax Interest Capitalized	(31,447,541)	(33,033,740)	(32,240,641)			(32,240,641)			Actual amount of tax interest capitalized
Power Tax Adjustment	149,080	152,981	151,031			151,031			System adjustment to reclass balances to correct FERC accounts
A&G Expenses Capitalized	(279,682)	1,004,786	362,552			362,552			Accounting change relating to A&G expense
Estimated Property Regulatory Asset Adjustment	1,341,207	1,341,207	1,341,207			1,341,207			Property True-Up
Book Profit/Loss on Retirement	958	(61,299)	(30,171)			(30,171)			Result of gain or loss on asset retirements
Repair & Maintenance 481 a Adjustment	2,728,409	2,788,907	2,758,658			2,758,658			Portion of Repairs & Maintenance 481a Adjustment offset in Account 182
Repair & Maintenance Deduction	240,234	245,561	242,898			242,898			Portion of Repairs & Maintenance deduction offset in Account 182
Additional State Depreciation VA	(7,188,355)	287,806	(3,450,275)			(3,450,275)			Temporary difference for additional state depreciation allowed for VA tax return
Additional State Depreciation MD	(1,966,541)	(4,144,928)	(3,055,735)			(3,055,735)			Temporary difference for additional state depreciation allowed for MD tax return
Additional State Depreciation PA	-	(238,274)	(119,137)			(119,137)			Temporary difference for additional state depreciation allowed for PA tax return
AFUDC Equity Flow Through	238,513	242,761	240,637			240,637			Portion of AFUDC Equity that relates to property and booked to account 282
Cost of Removal	(312,253)	55,011	(128,621)			(128,621)			Temporary difference arising for removal of plant/property
MACRS/ACRS Property Retired Retail	107,599	1,524,917	816,258			816,258			Result of gain or loss on asset retirements
Pension Expense - Capital Portion	1,133	-	567			567			Temporary difference from Pension Expense that is Capitalized as property and booked to account 282 (instead of account 283)
Capitalized Vertical Tree Trimming	-	16,784	8,392			8,392			Temporary difference that is capitalized for book purposes but deductible for tax purposes
Life Insurance - Capital Portion	-	(481)	(241)			(241)			Temporary difference from Life Insurance that is capitalized as property and booked to account 282 (instead of account 283)
Ordinary Gain/Loss - Reverse Books	-	(305,359)	(152,680)			(152,680)			Reversal of book gains and losses
Vegetation Management - Transmission	-	(218)	(109)			(109)			Vegetation management transmission corridor capital cost and depreciation expenses required for the regulatory financial statement schedules
TBBS Property Adjustment	-	2,700,000	1,350,000			1,350,000			Adjustment to property in order to align Tax Basis Balance Sheet
T&D Repairs	-	109,727	54,864			54,864			Repair deduction on capitalized book asset deductible for tax purposes under Rev. Proc. 2011-43
Subtotal	398,213,974	415,524,705	406,869,340			406,869,340			
Less FASB 109 included above	3,533,841	(3,624,549)	(45,354)			(45,354)			
Less FASB 106 included above	-	-	-			-			
Total	394,680,133	419,149,254	406,914,694			406,914,694			

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-283	**Beg of Year Balance** **p276.19.b**	**End of Year Balance** **p277.19.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Deferred Tax Reclassification	-	-	-			-			ADIT balance sheet reclassification
Regulated Asset Prexy LT	-	-	-			-			Regulatory asset for Prexy reclassification Non-property related
WV Rate Change Consol Benefit	-	-	-			-			Temporary difference due to change in state tax rate in West Virginia
Reg Asset PJM Receivable -ST	34,434,127	32,724,308	33,579,218			33,579,218			Comparison of actual to forecast revenues - non-property related
Reg Asset PJM Receivable - LT	-	-	-			-			Comparison of actual to forecast revenues - non-property related
WV State Property Tax	1,062,586	1,318,026	1,190,306			1,190,306			West Virginia property tax payment
Intercompany Charge AESC	1,414,001	2,066,632	1,740,317			1,740,317			Intercompany charges from the service company
Deferred Charge EIB	-	-	-			-			Allocated portion of total liabilities relating to captive insurance
Unamortized Loss on Reacquired Debt	1,940,464	1,015,123	1,477,794			1,477,794			Unamortized debt expenses for existing debt that is refinanced and amortized over the life of the new debt
Power Tax Adjustment	43,628	44,205	43,917			43,917			System adjustment to reclass balances to correct FERC accounts
Pension Manual Company Allocation	-	-	-			-			Result of a change in pension methodology
Purchase Accounting Adj. Amortization	-	-	-		-				The merger has been accounted for under the purchase method of accounting and being eliminated for FERC accounting purposes.
State Income Taxes	-	-	-			-			Return/Accrual (catch up entry)
Energy Insurance Service Cell	2,478	2,291	2,385			2,385			Temporary difference resulting from deferred charges for Energy Insurance services
AFUDC Equity Flow Through	142,415	156,301	149,358			149,358			The tax portion (gross-up) of the AFUDC Equity booked in account 282
PA Apportionment Change Impact	254,152	-	127,076			127,076			Result of the impact of the PA Apportionment Change from a 90% sales factor to a 100% sales factor. This rate change will later be assigned on an M item basis
State Income Tax - Federal Deferred Only	1,896,963	1,711,721	1,804,342			1,804,342			Temporary difference resulting from the timing between when state income taxes are paid and when they are deductible on the federal tax return
Adjustment to Deferred Federal Tax	-	6,888	3,444			3,444			Adjustment to true-up deferred federal tax
FASB 109 Gross-up	-	6,574,963	3,287,482			3,287,482			Reclass of the tax portion (gross-up) for property items included in account 282
Merger Costs - Indebtedness	-	2,911	1,456			1,456			Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
Vegetation Management - Transmission	-	218	109			109			Vegetation Management Transmission Corridor capital cost and depreciation expenses required for the regulatory financial statement schedules
Reserve for EIB	-	45,318	22,659			22,659			Adjustment for reserve for EIB in Goodwill carried over to current year
Subtotal	41,190,814	45,668,905	43,429,860		-	43,429,860	-	-	
Less FASB 109 included above		6,574,963	3,287,482	-	-	3,287,482			
Less FASB 106 included above									
Total	41,190,814	39,093,942	40,142,378		-	40,142,378	-	-	

Instructions for Account 283:

1. **ADIT items related only to Retail Related Operations are directly assigned to Column C.**
2. **ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.**
3. **ADIT items related only to Transmission are directly assigned to Column E.**
4. **ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.**
5. **ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.**

6. **Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.**

Trans-Allegheny Interstate Line Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	FERC Form No.1 page, line & Col	Amount	Allocator	Allocated Amount	
	Plant Related			**Gross Plant Allocator**		
1.1	2012 State Property WV	p263.1.1(i)	2,391,738	100.0000%	$ 2,391,738	
1.2	2013 State Property WV	p263.1.2(i)	4,149,894	100.0000%	4,149,894	
1.3	2012 State Property PA (PURTA)	p263.25(i)	4,949	100.0000%	4,949	
1.4	2013 State Property PA (PURTA)	p263.26(i)	24,663	100.0000%	24,663	
1.5					-	
1.6	2012 Local Property WV	p263.1.9(i)	294,558	100.0000%	294,558	
1.7	2013 Local Property WV	p263.1.10(i)	13,693	100.0000%	13,693	
1.8	2013 Local Property VA	p263.1.13(i)	1,354,068	100.0000%	1,354,068	
1.9	2013 Local Property PA	p263.1.16(i)	3,068	100.0000%	3,068	
2.1	2012 Local Property MD	p263.1.19(i)	676,155	100.0000%	676,155	
2.2	2013 Local Property MD	p263.1.20(i)	611,569	100.0000%	611,569	
2.3	2013 Capital Stock Tax/Franchise MD	p263.9(i)	300	100.0000%	300	
2.4	2012 Capital Stock Tax/Franchise PA	p263.22(i)	-134,345	100.0000%	-134,345	
2.5	2013 Capital Stock Tax/Franchise PA	p263.23(i)	38,011	100.0000%	38,011	
2.6						
2.7	2012 WV Franchise Tax	p263.38(i)	12,276	100.0000%	12,276	
3.1	2013 WV Franchise Tax	p263.39(i)	53,401	100.0000%	53,401	
3.2	Capital Stock Tax/Franchise All States			100.0000%	0	
3.3	Gross Premium MD			100.0000%	0	
4.1	Gross Premium PA			100.0000%	0	
4.2				100.0000%	0	
4.3	State Sales/Use Tax PA	p263.19(i)	936	100.0000%	936	
6.1	State License WV			100.0000%	0	
6.5	Federal Excise Tax	p263.3(i)	1,078	100.0000%	1,078	
8	**Total Plant Related**		9,496,012	100.0000%	9,496,012	
	Labor Related			**Wages & Salary Allocator**		
9	Accrued Federal FICA		0			
10	Accrued Federal Unemployment		0			
11	State Unemployment		0			
12						
13						
14	**Total Labor Related**		0	100.0000%	-	
	Other Included			**Gross Plant Allocator**		
15	2012 MD GRT	p263.13(i)	0		0	
16	2013 MD GRT	p263.14(i)	8,351		8,351	
17					0	
18						
19	**Total Other Included**		8,351	100.0000%	8,351	
20	**Total Included (Lines 8 + 14 + 19)**		9,504,363		**9,504,363**	Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded					
21	Federal Income Tax	p263.2(i)	24,307,706			
22	Corporate Net Income Tax MD	p263.7(i)	752,301			
23	Corporate Net Income Tax PA	p263.18(i)	-1,752,183			
24	Corporate Net Income Tax VA	p263.30(i)	232,374			
25	Corporate Net Income Tax WV	p263.36(i)	9,776,945			
26						
27						
28						
29						
30						
31	**Subtotal, Excluded**		33,317,143			
32	**Total, Included and Excluded (Line 20 + Line 28)**		42,821,506			
33	**Total Other Taxes from p114.14.c**		9,504,364			
34	**Difference (Line 32 - Line 33)**		33,317,142			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they shall not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Trans-Allegheny Interstate Line Company

Attachment 3 - Revenue Credit Workpaper

			Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		-	Page 300 Line: 19 Column: b
2	Total Rent Revenues	(Line 1)	-	
	Account 456 - Other Electric Revenues (Note 1)			
3	Schedule 1A		-	
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-	
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		3,057,090	p328-330 Footnote Data Schedule Page: 328 Line: 1 Column: m
6	PJM Transitional Revenue Neutrality (Note 1)			
7	PJM Transitional Market Expansion (Note 1)			
8	Professional Services (Note 3)		-	
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)			
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-	
11	Gross Revenue Credits	(Sum Lines 2-10)	3,057,090	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	3,057,090	Input to Appendix A, Line 131
	<u>Revenue Adjustment to determine Revenue Credit</u>			
14a	Revenues associated with lines 14b-g are to be included in lines 2-10 and total of those revenues entered here		-	
14b	Costs associated with revenues in line 14a		-	
14c	Net Revenues (14a - 14b)		-	
14d	50% Share of Net Revenues (14c / 2)		-	
14e	Costs associated with revenues in line 14a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-	
14f	Net Revenue Credit (14d + 14e)		-	
14g	Line 14a less line 14f		-	
15	Amount offset in line 4 above		-	
16	Total Account 454 and 456		3,057,090	

17 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 178 of Appendix A.

18 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

19 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

20 Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 of the PJM OATT are not included in the total above to the extent they are credited under Schedule 12 of the PJM OATT.

Trans-Allegheny Interstate Line Company

Attachment 4 - Calculation with Incentive ROE

	Return and Taxes at High End of the range of Reasonableness			
A	Return and Taxes at High End of the range of Reasonableness	(Sum Lines 26 and 33 from below)	173,104,227	Input to Appendix A, Line 140
B	Difference between Base ROE and Incentive ROE		100	

Return Calculation

			Source Reference		
1	Rate Base		Appendix A, Line 46		1,197,497,599
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		657,124,621
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		0
5	Less Preferred Stock		Appendix A, Line 87		0
6	Less Account 216.1		Appendix A, Line 88		0
7	Common Stock		Appendix A, Line 89		657,124,621
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		450,000,000
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		2,219,377
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		-1,015,123
12	Total Long Term Debt		Appendix A, Line 94		448,795,746
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		657,124,621
15	Total Capitalization		Appendix A, Line 97		1,105,920,367
16	Debt %	Total Long Term Debt	Appendix A, Line 98		40.5812%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0.0000%
18	Common %	Common Stock	Appendix A, Line 100		59.4188%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0489
20	Preferred Cost	Preferred Stock	Appendix A, Line 102		0.0000
21	Common Cost	Common Stock		12.70%	0.1270
22	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 16 * 19)		0.0198
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0755
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.0953**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**114,111,059**

Composite Income Taxes

	Income Tax Rates			
27	FIT=Federal Income Tax Rate		Appendix A, Line 109	35.00%
28	SIT=State Income Tax Rate or Composite		Appendix A, Line 110	6.92%
29	p = percent of federal income tax deductible for state purposes		Appendix A, Line 111	0.00%
30	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Appendix A, Line 112	39.50%
31	T/ (1-T)		Appendix A, Line 113	65.28%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		58,993,169
33	**Total Income Taxes**		**(Line 32)**	**58,993,169**

	A	B	C	D	E	F	G
1						**Trans-Allegheny Interstate Line Company**	
2							
3						***Attachment 5 - Cost Support***	
4	**Plant in Service Worksheet**						
5			Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
6						**13 Month Balance for Reconciliation**	**EOY Balance for Estimate**
7			**Calculation of Transmission Plant In Service**	Source		**Total**	**Total**
8			December	p206.58.b	For 2012	1,209,952,076	
9			January	company records	For 2013	1,214,526,364	
10			February	company records	For 2013	1,214,526,364	
11			March	company records	For 2013	1,203,204,701	
12			April	company records	For 2013	1,203,204,702	
13			May	company records	For 2013	1,213,916,330	
14			June	company records	For 2013	1,210,223,391	
15			July	company records	For 2013	1,252,378,002	
16			August	company records	For 2013	1,252,086,670	
17			September	company records	For 2013	1,252,578,117	
18			October	company records	For 2013	1,253,022,612	
19			November	company records	For 2013	1,251,493,701	
20			December	p207.58.g	For 2013	1,259,599,755	1,259,599,755
21	15		**Transmission Plant In Service**			**1,230,054,830**	**1,259,599,755**
22						**Link to Appendix A, line 15**	**Link to Appendix A, line 15**
23			**Calculation of Distribution Plant In Service**	Source			
24			December	p206.75.b	For 2012	-	
25			January	company records	For 2013	-	
26			February	company records	For 2013	-	
27			March	company records	For 2013	-	
28			April	company records	For 2013	-	
29			May	company records	For 2013	-	
30			June	company records	For 2013	-	
31			July	company records	For 2013	-	
32			August	company records	For 2013	-	
33			September	company records	For 2013	-	
34			October	company records	For 2013	-	
35			November	company records	For 2013	-	
36			December	p207.75.g	For 2013	-	-
37			**Distribution Plant In Service**			-	-
38							
39			**Calculation of Intangible Plant In Service**	Source			
40			December	p204.5.b	For 2012	13,472,726	
41			December	p205.5.g	For 2013	10,393,869	10,393,869
42	18		**Intangible Plant In Service**			**11,933,298**	**10,393,869**
43						Link to Appendix A, line 18	**Link to Appendix A, line 18**
44			**Calculation of General Plant In Service**	Source			
45			December	p206.99.b	For 2012	53,131,377	-
46			December	p207.99.g	For 2013	56,186,164	**56,186,164**
47	18		**General Plant In Service**			**54,658,771**	**56,186,164**
48						**Link to Appendix A, line 18**	**Link to Appendix A, line 18**
49			**Calculation of Production Plant In Service**	Source			
50			December	p204.46b	For 2012	-	
51			January	company records	For 2013	-	
52			February	company records	For 2013	-	
53			March	company records	For 2013	-	
54			April	company records	For 2013	-	
55			May	company records	For 2013	-	
56			June	company records	For 2013	-	
57			July	company records	For 2013	-	
58			August	company records	For 2013	-	
59			September	company records	For 2013	-	
60			October	company records	For 2013	-	
61			November	company records	For 2013	-	
62			December	p205.46.g	For 2013	-	-
63			**Production Plant In Service**			-	-
64							
65							
66	6		**Total Plant In Service**	Sum of averages above		**1,296,646,898**	**1,326,179,788**
67						**Link to Appendix A, line 6**	**Link to Appendix A, line 6**

	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
5											Details											
6										**13 Month Plant Balance For reconciliation**												
7	**Black Oak**	**Wylie Ridge**	**502 Junction - Territorial Line**	**Potter SS**	**OsageWhiteley**	**Meadowbrook Transformer**	**North Shenandoah**	**Bedington Transformer**	**Meadowbrook Capacitor**	**Kammer**	**Doubs #2 Trans**	**Doubs #3 Trans**	**Doubs #4 Trans**	**Cabot SS**	**Armstrong**	**Farmers Valley Capacitor**	**Harvey Run Capacitor**	**Doubs SS**	**Meadowbrook SS**	**Grandview Capacitor**	**Total**	
8	46,608,153.24	22,852,072.54	1,053,948,475	-	-	8,202,933.96	1,923,901.73	7,723,538.61	6,496,239.32	39,532,735.30	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,209,952,076.09	
9	46,608,153.24	22,852,073.00	1,058,522,762	-	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,214,526,363.83	
10	46,608,153.24	22,852,073.00	1,058,522,762	-	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,214,526,363.83	
11	46,608,153.24	22,852,073.00	1,044,531,580	2,669,519	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,203,204,700.83	
12	46,608,153.24	22,852,073.00	1,044,531,581	2,669,519	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,203,204,701.83	
13	46,608,153.24	22,852,072.00	1,055,243,210	2,669,519	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,688,958.81	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,213,916,329.83	
14	46,608,153.24	17,452,834.00	1,056,948,041	2,672,772	-	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,210,223,391.02	
15	46,608,153.24	17,452,834.00	1,075,032,033	2,672,772	24,070,619	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,252,378,002.02	
16	46,608,153.24	17,452,834.00	1,075,303,614	2,016,512	24,163,966	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,252,086,670.02	
17	46,608,153.24	17,452,834.00	1,075,716,632	2,024,007	24,234,900	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,252,578,117.02	
18	46,608,153.24	17,452,834.00	1,075,902,153	2,024,007	24,493,874	8,202,934.00	1,923,902.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,253,022,612.02	
19	46,608,153.24	17,452,834.00	1,076,198,774	2,024,007	24,511,562	8,202,934.00	80,682.00	7,723,539.00	6,496,239.00	39,532,735.00	5,149,610.40	4,687,174.00	5,700,321.24	7,125,136.14	-	-	-	-	-	-	1,251,493,701.02	
20	46,608,150.00	17,447,442.00	1,076,419,995	2,024,007	24,832,065	8,202,934.00	80,682.00	7,723,538.00	6,496,239.00	39,534,385.00	5,149,270.54	4,686,053.01	5,700,307.34	7,123,323.00	1,350,836.00	934,823.00	831,938.00	3,306,399.00	484,588.00	662,780.00	1,259,599,754.89	
21	**46,608,153**	**19,944,376**	**1,063,601,662**	**1,805,126**	**11,254,384**	**8,202,934**	**1,640,330**	**7,723,539**	**6,496,239**	**39,532,862**	**5,149,584.26**	**4,687,911.53**	**5,700,320.17**	**7,124,996.67**	**103,910.46**	**71,909.46**	**63,995.23**	**254,338.38**	**37,276.00**	**50,983.08**	**1,230,054,829.56**	1,187,165,526.89

	A	B	C	D	E	F	G
1						Trans-Allegheny Interstate Line Company	
2							
3						*Attachment 5 - Cost Support*	
68							
69	**Accumulated Depreciation Worksheet**						
70	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						
71						**13 Month Balance for Reconciliation**	**EOY Balance for Estimate**
72			**Calculation of Transmission Accumulated Depreciation**	Source			
73			December	Prior year FERC Form 1 p219.25.b	For 2012	55,471,672	
74			January	company records	For 2013	57,485,813	
75			February	company records	For 2013	59,517,146	
76			March	company records	For 2013	61,553,150	
77			April	company records	For 2013	63,490,420	
78			May	company records	For 2013	65,481,280	
79			June	company records	For 2013	61,862,675	
80			July	company records	For 2013	63,939,653	
81			August	company records	For 2013	66,046,480	
82			September	company records	For 2013	68,165,957	
83			October	company records	For 2013	70,284,373	
84			November	company records	For 2013	70,558,306	
85			December	p219.25.b	For 2013	72,434,228	72,434,228
86	23		**Transmission Accumulated Depreciation**			**64,330,089**	**72,434,228**
87						**Link to Appendix A, line 23**	**Link to Appendix A, line 23**
88			**Calculation of Distribution Accumulated Depreciation**	Source			
89			December	Prior year FERC Form 1 p219.26.b	For 2012	-	
90			January	company records	For 2013	-	
91			February	company records	For 2013	-	
92			March	company records	For 2013	-	
93			April	company records	For 2013	-	
94			May	company records	For 2013	-	
95			June	company records	For 2013	-	
96			July	company records	For 2013	-	
97			August	company records	For 2013	-	
98			September	company records	For 2013	-	
99			October	company records	For 2013	-	
100			November	company records	For 2013	-	
101			December	p219.26.b	For 2013	-	-
102			**Distribution Accumulated Depreciation**			-	-
103							
104			**Calculation of Intangible Accumulated Depreciation**	Source			
105			December	Prior year FERC Form 1 p200.21.b	For 2012	3,161,074	
106			December	p200.21b	For 2013	4,822,025	4,822,025
107	25		**Accumulated Intangible Depreciation**			**3,991,550**	**4,822,025**
108						**Link to Appendix A, line 25**	**Link to Appendix A, line 25**
109			**Calculation of General Accumulated Depreciation**	Source			
110			December	Prior year FERC Form 1 p219.28b	For 2012	2,554,609	
111			December	p219.28.b	For 2013	3,876,568	3,876,568
112	24		**Accumulated General Depreciation**			**3,215,589**	**3,876,568**
113						**Link to Appendix A, line 24**	**Link to Appendix A, line 24**
114			**Calculation of Production Accumulated Depreciation**	Source			
115			December	Prior year FERC Form 1 p219.20.b-24.b	For 2012	-	
116			January	company records	For 2013	-	
117			February	company records	For 2013	-	
118			March	company records	For 2013	-	
119			April	company records	For 2013	-	
120			May	company records	For 2013	-	
121			June	company records	For 2013	-	
122			July	company records	For 2013	-	
123			August	company records	For 2013	-	
124			September	company records	For 2013	-	
125			October	company records	For 2013	-	
126			November	company records	For 2013	-	
127			December	p219.20.b thru 219.24.b	For 2013	-	-
128			**Production Accumulated Depreciation**			-	-
129							
130							
131	8		**Total Accumulated Depreciation**	Sum of averages above		**71,537,227**	**81,132,821**
132						**Link to Appendix A, line 8**	**Link to Appendix A, line 8**
133							

	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
70	Details																					
71	**13 Month Balance For Reconciliation**																					
72	**Black Oak**	**Wylie Ridge**	**502 Junction - Territorial Line**	**Potter SS**	**Osage Whiteley**	**Meadowbrook Transformer**	**North Shenandoah**	**Bedington Transformers**	**Meadowbrook Capacitor**	**Kammer**	**Doubs #2 Trans**	**Doubs #3 Trans**	**Doubs #4 Trans**	**Cabot SS**	**Armstrong**	**Farmers Valley Capacitor**	**Harvey Run Capacitor**	**Doubs SS**	**Meadowbrook SS**	**Grandview Capacitor**	**Total**	
73	6,791,773	1,631,098	41,579,077	-	-	771,808	177,844	591,942	439,909	2,673,778	221,899	144,388	311,230	136,928	-	-	-	-	-	-	55,471,672	
74	6,905,916	1,670,992	43,286,992	-	-	786,163	181,210	605,458	452,000	2,743,032	229,785	152,555	322,315	149,395	-	-	-	-	-	-	57,485,813	
75	7,020,059	1,710,983	45,012,018	-	-	800,518	184,577	618,974	464,090	2,812,215	237,685	160,762	333,401	161,864	-	-	-	-	-	-	59,517,146	
76	7,134,202	1,750,975	46,737,044	4,672	-	814,873	187,944	632,490	476,180	2,881,397	245,586	168,969	344,486	174,333	-	-	-	-	-	-	61,553,150	
77	7,175,579	1,790,966	48,436,991	8,453	-	829,228	191,311	646,006	488,270	2,950,579	253,486	177,176	355,572	186,802	-	-	-	-	-	-	63,490,420	
78	7,249,755	1,818,746	50,169,940	12,235	-	843,583	194,678	659,522	500,360	3,019,762	261,387	185,382	366,658	199,271	-	-	-	-	-	-	65,481,280	
79	7,363,972	(3,354,286)	51,453,166	17,048	-	857,938	198,045	673,039	512,451	3,088,944	269,288	193,586	377,744	211,740	-	-	-	-	-	-	61,862,675	
80	7,478,190	(3,331,900)	53,213,110	20,834	24,477	872,293	201,411	686,555	524,541	3,158,126	277,191	201,786	388,832	224,206	-	-	-	-	-	-	63,939,653	
81	7,592,408	(3,417,535)	55,086,856	24,620	73,024	886,649	204,778	700,071	536,631	3,227,308	285,094	209,984	399,921	236,669	-	-	-	-	-	-	66,046,480	
82	7,705,992	(3,395,094)	56,863,420	27,482	122,239	901,004	208,145	713,587	548,721	3,296,491	295,647	218,180	411,011	249,133	-	-	-	-	-	-	68,165,957	
83	7,820,273	(3,372,653)	58,640,526	30,350	171,794	915,359	211,512	727,103	560,811	3,365,673	303,552	226,375	422,101	261,596	-	-	-	-	-	-	70,284,373	
84	7,934,555	(3,350,212)	60,418,040	33,217	221,627	929,714	(1,630,288)	740,620	572,901	3,434,855	311,459	233,195	434,565	274,059	-	-	-	-	-	-	70,558,306	
85	8,048,836	(3,158,824)	61,782,823	36,085	271,800	944,069	(1,630,174)	754,136	584,992	3,504,039	319,366	239,958	447,084	286,459	-	-	-	-	-	3,579	72,434,228	
86	**7,401,655**	**(1,000,519)**	**51,744,616**	**16,538**	**68,074**	**857,938**	**(86,078)**	**673,039**	**512,451**	**3,088,938**	**270,110**	**193,254**	**378,071**	**211,727**	**-**	**-**	**-**	**-**	**-**	**275**	**64,330,089**	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Materials and Supplies			Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	
40	Transmission Materials & Supplies		p227.8	-	-	-	
37	Undistributed Stores Expense		p227.16	-	-	-	
	Allocated General Expenses						
51	Plus Property Under Capital Leases	0	p200.4.c	-	-	-	

Transmission / Non-transmission Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	Details
34	**Transmission Related Land Held for Future Use**	Total	-	-	-	Enter Details Here
		Non-transmission Related	-	-	-	
		Transmission Related	-	-	-	

CWIP & Expensed Lease Worksheet

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Beg of year	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	Attachment 5	1,276,556,179	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	1,209,952,076	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	55,471,672	-	-	

Pre-Commercial Costs Capitalized

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		EOY for Estimate and BOY for Final	Amortization Amount (Over 4 Years)	Calculated End of Year Balance	Average of Beginning and Ending Balances (for estimate and reconciliation)
35	**Unamortized Capitalized Pre-Commercial Costs**	$ -	$ -	$ -	$ -

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Beg of year	EPRI Dues	Details
	Allocated General & Common Expenses					
58	Less EPRI Dues	(Note D)	p352 & 353	0	0	Enter Details Here

Regulatory Expense Related to Transmission Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related		Details
	Directly Assigned A&G							
62	Regulatory Commission Exp Account 928	(Note G)	p323.189.b	-	-	-	Link to Appendix A, line 62	Enter Details Here

Safety Related Advertising Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Safety Related	Non-safety Related		Details
	Directly Assigned A&G							
66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	Link to Appendix A, line 66	Enter Details Here

MultiState Workpaper

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates		MD 8.25%	WV 7.0%	PA 9.99%	VA 6.0%		
			Composite	**Composite is calculated based on sales, payroll and property for each jurisdiction**				
110	SIT=State Income Tax Rate or Composite	(Note H)	6.9195%					

Education and Out Reach Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
63	General Advertising Exp Account 930.1	(Note J)	p323.191.b	-	-	-	Enter Details Here

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Excluded Plant Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
126	Excluded Transmission Facilities		(Note L)		**General Description of the Facilities**
	Step-Up Facilities			-	
	Instructions:			**Enter $**	
	1 Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process				
	2 If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,			**Or**	
	the following formula will be used:	**Example**		**Enter $**	
	A Total investment in substation	1,000,000			
	B Identifiable investment in Transmission (provide workpapers)	500,000			
	C Identifiable investment in Distribution (provide workpapers)	400,000			
	D Amount to be excluded (A x (C / (B + C)))	444,444			
					Add more lines if necessary

Prepayments

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	Average of Beginning and Ending Balances	Allocation	Transmission Related	Details
36	**Prepayments**				Enter $		Amount	
	Prepayments	Prepaid Insurance	77,275	148,535	112,905	100%	112,905	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		**77,275**	**148,535**	112,905		112,905	

Detail of Account 566 Miscellaneous Transmission Expenses

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Total	Details
70	Amortization Expense on Pre-Commercial Cost		$ -	
71	Pre-Commercial Expense		-	
72	Miscellaneous Transmission Expense		937,961	
	Total Account 566 Miscellaneous Transmission Expenses	p.321.97.b	$ 937,961	

Summary of Pre-Commercial Expenses

Cost Element Name	**Total**
Labor & Overhead (1)	-
Miscellaneous (2)	-
Outside Services Legal (3)	-
Outside Services Other (4)	-
Outside Services Rates (5)	-
Advertising (6)	-
Travel, Lodging and Meals (7)	-
Total	-

(1) Labor & overhead amount includes costs allocated to preparation of the preliminary survey and investigation.

(2) Miscellaneous amount includes rental of volunteer fire department facilities for open houses, Fed EX fees for various mailings from Legal, Procurement, Transmission & Finance, fees for various conference calls and PJM application fee.

(3) Outside legal services includes the cost for research and preparation of the filing to determine incentive rate availability.

(4) Other services other includes fees for website development, media relations services, campaign management, open houses and research services.

(5) Outside services rates includes the advice of a rate consultant regarding rate design.

(6) Advertising includes newspaper and other media announcements of public scoping meetings related to the proposed project.

(7) Travel, lodging and meals are the direct expenses for Allegheny staff to attend the scoping meetings.

	Net Revenue Requirement	
149	Facility Credits under Section 30.9 of the PJM OATT	-

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Depreciation Rates

							Annual Depreciation Expense															
TRANSMISSION PLANT		**Life**		**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Black Oak**	**Wylie Ridge**	**502 Junction - Territorial Line**	**Meadowbrook Transformer**	**North Shenandoah**	**Bedington Transformer**	**Meadowbrook Capacitor**	**Kammer Transformers**	**Doubs Replacement Transformer #2**	**Doubs Replacement Transformer #3**	**Doubs Replacement Transformer #4**	**Cabot SS**	**Grandview Capacitor**	**Potter**	**Osage Whitely**	**Total**
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43	-	-	2,540,256	-	-	-	-	-	-	-	-	-				2,540,256
352	Structures & Improvements	50	-	R3	(10)	2.20	4,888	-	1,433,430		-	-	-	-	-	78	-	146				1,438,542
	SVC	35	-			2.86	-	-	-	-	-	-	-	-	-	-	-	-				-
							-	-	-	-	-	-	-	-	-	-	-	-				-
353	Station Equipment						-	-	-	-	-	-	-	-	-	-	-	-				-
	Other	50	-	R2	(5)	2.10	10,666	349,317	487,744	172,262	35,203	162,194	440,803	830,261	107,499	98,280	120,387	210,359	3,579	35,061	57,050	3,120,666
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96	1,241,509	-	-	-	-	-	-	-				-				1,241,509
	SCADA	15	-	S3	0	6.67	-	-	-				12,639	-	-	-	-	-				12,639
							-	-	-	-	-	-	-	-	-	-	-	-				-
354	Towers & Fixtures	65	-	R4	(25)	1.92	-	-	7,288,351	-	-	-	-	-	-	-	-	-				7,288,351
355	Poles & Fixtures	55	-	R2.5	(20)	2.18	-	-	2,655,020	-	-	-	-	-	-	-	-	-				2,655,020
							-	-	-	-	-	-	-	-	-	-	-	-				-
356	Overhead Conductors & Devices						-	-	-	-	-	-	-	-	-	-	-	-				-
	Other	55	-	R2.5	(40)	2.80	-	-	6,219,209	-	-	-	-	-	-	-	-	-			214,751	6,433,959
	Clearing	70	-	R4	0	1.43	-	-	-	-	-	-	-	-	-	-	-	-				-
							-	-	-	-	-	-	-	-	-	-	-	-				-
357	Underground conduit	55	-	S3	(5)	1.91	-	-	-	-	-	-	-	-	-	-	-	-				-
358	Underground conductor and devices	45	-	R3	(5)	2.33	-	-	-	-	-	-	-	-	-	-	-	-				-
	SVC	35				2.86	-	-	-	-	-	-	-	-	-	-	-	-				-
Total Transmission Plant Depreciation							1,257,064	349,317	20,624,010	172,262	35,203	162,194	453,442	830,261	107,499	98,358	120,387	210,505	3,579	35,061	271,800	24,730,942

Total Transmission Depreciation Expense (must tie to p336.7.f) 24,730,942

Note 1: Depreciation rate is based on an 80 R2 survivor curve with a 35-year truncation.

GENERAL PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
390	Structures & Improvements	50	R1	0	2.00	903,456
391	Office Furniture & Equipment	20	SQ	0	5.00	81,909
	Information Systems	10	SQ	0	10.00	193,455
	Data Handling	10	SQ	0	10.00	-
392	Transportation Equipment					
	Other	15	SQ	20	5.33	-
	Autos	7	S3	20	11.43	-
	Light Trucks	11.5	L4	20	6.96	20,544
	Medium Truck	11.5	L4	20	6.96	-
	Trailers	18	L1	20	4.44	-
	ATV	15	SQ	20	5.33	-
393	Stores Equipment	20	SQ	0	5.00	-
394	Tools, Shop & Garage Equipment	20	SQ	0	5.00	-
396	Power Operated Equipment	18	L1	25	4.17	-
397	Communication Equipment	15	SQ	0	6.67	129,958
398	Miscellaneous Equipment	15	SQ	0	6.67	-
Total General Plant						1,329,321

Total General Plant Depreciation Expense (must tie to p336.10.b & c) 1,329,321

INTANGIBLE PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
303	Miscellaneous Intangible Plant	5	SQ	0	20.00	1,649,781
Total Intangible Plant						1,649,781

Total Intangible Plant Amoritization (must tie to p336.1 d & e) 1,649,781

These depreciation rates will not change absent the appropriate filing at FERC.

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

PBOP Expenses

	1	Total PBOP expenses	22,856,433
	2	Amount relating to retired personnel	8,786,372
	3	Amount allocated on FTEs	14,070,061
	4	Number of FTEs for Allegheny	4,408
	5	Cost per FTE	3,192
	6	TrAILCo FTEs (labor not capitalized) current year	0.000
	7	TrAILCo PBOP Expense for base year	-
	8	TrAILCo PBOP Expense in Account 926 for current year	0
57	9	PBOP Adjustment for Appendix A, Line 57	-

Lines 1-5 cannot change absent approval or acceptance by FERC in a separate proceeding.

Trans-Allegheny Interstate Line Company

Attachment 5a - Pre-Commercial Costs and CWIP

Step 1 Totals reported below are by project with the amounts to be expensed reported separately from those to be deferred and amortized (note, deferred costs related to 2006 include AFUDC).

For Forecasting purposes, Pre-Commercial expenses will be estimated. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

Step 2 For each project, where CWIP is to be recovered in rate base, CWIP will be estimated and the totals reported below by project. For the Reconciliation, for each project where CWIP is to be recovered in rate base the CWIP will be itemized by project below. Additionally, the amount of AFUDC that would have been capitalized for projects where CWIP is included in rate base will be reported in the FERC Form No. 1.

Step 3 For the Reconciliation, the total additions to plant in service for that year will be summarized by project to demonstrate no Pre-Commercial costs expensed were included in the additions to plant in service and AFUDC on projects where CWIP was recovered in rate base was included in the additions to plant in service. The Pre-commercial expenses are actual expenses incurred for the reconciliation year. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

	Column A		Column B	Column C Pre-Commercial Costs	Column D		Column E CWIP	Column F	Column G
Step 1	**For Estimate:**		Expensed (Estimated)	Deferred	Amount of Deferred Amortized in Year	**Estimate Step 2**	Average of 13 Monthly Balances		
	Prexy - 502 Junction 138 kV (CWIP)		-		-		-		
	Prexy - 502 Junction 500 kV (CWIP)		-		-		-		
	502 Junction - Territorial Line	(CWIP)	-		-		-		
	Total		-	-	-		-		
Step 3	**For Reconciliation:**			Pre-Commercial Costs		**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	AFUDC (If CWIP was not in Rate Base)
	Prexy - 502 Junction 138 kV (CWIP)		Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year				
	1		-	-	-		-	-	
	2		-	-	-		-	-	
	3		-	-	-		-	-	
	4		-	-	-		-	-	
	…								
	Total		-	-	-		-	-	
	Prexy - 502 Junction 500 kV (CWIP)								
	1		-	-	-		-	-	
	2		-	-	-		-	-	
	3		-	-	-		-	-	
	4		-	-	-		-	-	
	…								
	Total		-	-	-		-	-	
	502 Junction - Territorial Line	(CWIP)							
	1		-	-	-		9,522,794	-	136,129,170
	2		-	-	-		-	-	-
	3		-	-	-		-	-	-
	4		-	-	-		-	-	-
	…								
	Total		-	-	-		9,522,794	-	136,129,170
	Total Additions to Plant In Service (sum of the above for each project)				Refer to Attachment 5 - Cost Support Plant in Service Worksheet				136,129,170
	Total Additions to Plant in Service reported on pages 204-207 of the Form No. 1				Refer to Attachment 5 - Cost Support Plant in Service Worksheet				
	Difference (must be zero)								

Notes:

1 Small projects may be combined into larger projects where rate treatment is consistent. Pre-Commercial costs benefiting multiple projects will be allocated to projects based on the estimated plant in service of each project.

Allocation of Pre-Commercial Costs	Plant in Service (Estimated 2/12/2008)	Allocation
Prexy - 502 Junction 138 kV (CWIP)	94,140,000	0.10734
Prexy - 502 Junction 500 Kv (CWIP)	121,260,000	0.13827
502 Junction - Territorial Line (CWIP)	661,600,000	0.75439
Total	877,000,000	1.00000

2 Column D is the total CWIP balance including any AFUDC, Column E is the AFUDC if any in Column D, and Column F is the AFUDC that would have been in Column E if CWIP were not recovered in rate base.

Trans-Allegheny Interstate Line Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.
3	April	Year 2	TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect
6	April	Year 3	TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.
7	April	Year 3	Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).
8	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)
9	May	Year 3	Post results of Step 8 on PJM web site
10	June	Year 3	Results of Step 8 go into effect

Reconciliation Details

1 April Year 2 TO populates the formula with Year 1 data

Rev Req based on Year 1 data

Must run Appendix A to get this number (without any cap adds in Appendix A line 16 and without CWIP in Appendix A line 33)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Potter SS	Pleasureville Capacitor	Farmers Valley Capacitor	Harvey Run Capacitor	Osage Whitely SS WP	Osage Whitely SS MP	Buffalo Road Capacitor	502 Junction - Territorial Line (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	267,486
Jan 2013	Actual	2,665,904	-	-	-	-	-	-	(1,577,481)
Feb	Actual	3,614	-	-	-	-	-	-	1,197,338
Mar	Actual	2,036	-	-	-	-	-	-	485,502
Apr	Actual	300,912	-	-	-	-	-	-	367,955
May	Budget	-	-	959,961	-	-	-	-	568,482
Jun	Budget	-	1,319,617	-	499,205	13,191,570	6,487,910	-	1,072,808
Jul	Budget	-	-	-	-	-	-	-	197,279
Aug	Budget	-	-	-	-	-	-	-	301,835
Sep	Budget	-	-	-	-	-	-	-	91,790
Oct	Budget	-	-	-	-	-	-	922,010	601,374
Nov	Budget	-	-	-	-	-	-	-	1,374
Dec	Budget	-	-	-	-	-	-	-	1,154,713
Total		2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	4,730,456

Month End Balances								
Other Projects PIS (Monthly additions)	Potter SS	Pleasureville Capacitor	Farmers Valley Capacitor	Harvey Run Capacitor	Osage Whitely SS WP	Osage Whitely SS MP	Buffalo Road Capacitor	502 Junction - Territorial Line (monthly additions)
				(in service)	(in service)	(in service)	(in service)	CWIP
	-	-	-	-	-	-	-	267,486
	2,665,904	-	-	-	-	-	-	(1,309,995)
	2,669,519	-	-	-	-	-	-	(112,657)
	2,671,555	-	-	-	-	-	-	372,845
	2,972,467	-	-	-	-	-	-	740,801
	2,972,467	-	959,961	-	-	-	-	1,309,282
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,382,090
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,579,369
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,881,205
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,972,995
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	3,574,369
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	3,575,743
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	4,730,456
	34,759,177	**9,237,316**	**7,679,691**	**3,494,438**	**92,340,988**	**45,415,373**	**2,766,031**	**23,963,991**
	2,673,783	710,563	590,745	268,803	7,103,153	3,493,490	212,772	1,843,384
(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)			(Appendix A, Line 33)		

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation	
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)		(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	-
Jan 2013	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	-
Apr	Actual	-	-	-	-	-	-	-	-
May	Budget	-	-	-	-	-	-	-	-
Jun	Budget	-	-	-	-	-	-	3,025,907	-
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	1,048,348	672,714	1,338,361	837,559	-	-	-	-
Nov	Budget	-	-	-	-	-	6,571,112	-	-
Dec	Budget	-	-	-	-	1,219,340	-	-	-
Total		1,048,348	672,714	1,338,361	837,559	1,219,340	6,571,112	3,025,907	-

Month End Balances								
Other Projects PIS (Monthly additions)	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation	
				(in service)	(in service)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	-	-	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	-	6,571,112	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	1,219,340	6,571,112	3,025,907	-
	3,145,043	**2,018,142**	**4,015,083**	**2,512,676**	**1,219,340**	**13,142,225**	**21,181,347**	**-**
	241,926.42	155,241.71	308,852.51	193,282.80	93,795.35	1,010,940.37	1,629,334.40	

3 April Year 2 TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)

4 May Year 2 Post results of Step 3 on PJM web site

Total Revenue Requirement	Potter SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	Osage Whiteley	Armstrong	Farmers Valley	Harvey Run	Doubs SS
$ 190,601,269.13	348,087.87	1,046,691.89	821,968.57	689,859.11	749,016.02	5,628,691	924,868	1,090,625	1,139,687	267,713	6,927,031	3,222,388	165,659,996	1,379,530	-	76,907	34,994	-

Meadowbrook SS	Buffalo Road Capacitor	Pleasureville Capacitor	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation
-	27,699.78	92,504.99	31,495.32	20,210.23	40,208	25,163	12,211	131,610	212,116

5 June Year 2 Results of Step 3 go into effect

6 April Year 3 TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Hunterstown SVC	Waldo Run SS	Doubs SS	Meadowbrook SS	Conemaugh	Blairsville SS	Four Mile Jct	502 Junction - Territorial Line (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	1,154,713
Jan 2014	Actual	-	-	-	-	-	-	-	(197,847)
Feb	Actual	-	-	-	-	-	-	-	216,049
Mar	Actual	-	-	-	-	27,808,501	-	-	52,469
Apr	Actual	-	-	-	-	-	-	-	29,436
May	Budget	-	-	-	-	-	-	-	1,276,249
Jun	Budget	44,310,669	-	4,840,224	58,411,179	-	3,631,440	-	225,590
Jul	Budget	-	-	-	-	-	-	-	37,740
Aug	Budget	-	-	-	-	-	-	-	35,850
Sep	Budget	-	-	-	-	-	-	-	36,115
Oct	Budget	-	-	-	-	-	-	-	36,382
Nov	Budget	-	-	-	-	-	-	-	36,651
Dec	Budget	-	52,235,676	-	-	-	-	11,197,637	1,196,092
Total		44,310,669	52,235,676	4,840,224	58,411,179	27,808,501	3,631,440	11,197,637	4,135,490
New Transmission Plant Additions for Year 3 (13 month average balance)									

	Month End Balances								
	Other Projects PIS (Monthly additions)	Hunterstown SVC	Waldo Run SS	Doubs SS	Meadowbrook SS	Conemaugh	Blairsville SS	Four Mile Jct	502 Junction - Territorial Line (monthly additions)
					(in service)	(in service)	(in service)	(in service)	CWIP
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-	-	-	1,154,713
Jan 2014		-	-	-	-	-	-	-	956,866
Feb		-	-	-	-	-	-	-	1,172,915
Mar		-	-	-	-	27,808,501	-	-	1,225,384
Apr		-	-	-	-	27,808,501	-	-	1,254,820
May		-	-	-	-	27,808,501	-	-	2,531,069
Jun		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,756,659
Jul		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,794,400
Aug		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,830,250
Sep		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,866,365
Oct		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,902,747
Nov		44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,939,398
Dec		44,310,669	52,235,676	4,840,224	58,411,179	27,808,501	3,631,440	11,197,637	4,135,490
Total		**310,174,683**	**52,235,676**	**33,881,568**	**408,878,253**	**278,085,010**	**25,420,080**	**11,197,637**	**29,521,075**
New Transmission Plant Additions for Year 3 (13 month average balance)		23,859,591	4,018,129	2,606,274	31,452,173	21,391,155	1,955,391	861,357	2,270,852

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Johnstown SS (2nd xfmr)	Yeagertown		Altoona SVC			Luxor	Armstrong
		(in service)	(in service)		(in service)				(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	1,154,387	-
Jan 2014	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	-
Apr	Actual	-	-	-	-	-	-	-	-
May	Budget	-	-	-	35,057,738	-	-	-	-
Jun	Budget	4,278,432	-	-	-	-	-	-	11,068,995
Jul	Budget	-	461,543	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	-	-	-	-	-	-	-	-
Nov	Budget	-	-	-	-	-	-	-	-
Dec	Budget	-	-	-	-	-	-	-	-
Total		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
New Transmission Plant Additions for Year 3 (13 month average balance)									

	Month End Balances								
	Other Projects PIS (Monthly additions)	Johnstown SS (2nd xfmr)	Yeagertown		Altoona SVC			Luxor	Armstrong
					(in service)			(in service)	(in service)
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-	-	1,154,387	-
Jan 2014		-	-	-	-	-	-	1,154,387	-
Feb		-	-	-	-	-	-	1,154,387	-
Mar		-	-	-	-	-	-	1,154,387	-
Apr		-	-	-	-	-	-	1,154,387	-
May		-	-	-	35,057,738	-	-	1,154,387	-
Jun		4,278,432	-	-	35,057,738	-	-	1,154,387	11,068,995
Jul		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Aug		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Sep		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Oct		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Nov		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Dec		4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
Total		**29,949,024**	**2,769,258**	**-**	**280,461,904**	**-**	**-**	**15,007,031**	**77,482,965**
New Transmission Plant Additions for Year 3 (13 month average balance)		2,303,771.08	213,019.85	-	21,573,992.62	-	-	1,154,387.00	5,960,228.08

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Grand Point & Guilford SS	Moshannon	Carbon Center	Shawville	Northwood	Shuman Hill Sub	Buffalo Road	Pleasureville Capacitor
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)		(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	782,425
Jan 2014	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	
Apr	Actual	-	-	-	-	-	-	-	-
May	Budget	1,603,191	-	-	-	-	-	-	-
Jun	Budget	-	-	236,623	-	-	1,147,868	-	-
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	313,774	-
Oct	Budget	-	-	-	-	4,206,813	-	-	-
Nov	Budget	-	-	-	1,418,503	-	-	-	-
Dec	Budget	-	5,164,619	-	-	-	-	-	-
Total		1,603,191	5,164,619	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
New Transmission Plant Additions for Year 3 (13 month average balance)									

	Month End Balances								
	Other Projects PIS (Monthly additions)	Grand Point & Guilford SS	Moshannon	Carbon Center	Shawville	Northwood	Shuman Hill Sub	Buffalo Road	Pleasureville Capacitor
					(in service)	(in service)	(in service)	(in service)	(in service)
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-	-	-	782,425
Jan 2014		-	-	-	-	-	-	-	782,425
Feb		-	-	-	-	-	-	-	782,425
Mar		-	-	-	-	-	-	-	782,425
Apr		-	-	-	-	-	-	-	782,425
May		1,603,191	-	-	-	-	-	-	782,425
Jun		1,603,191	-	236,623	-	-	1,147,868	-	782,425
Jul		1,603,191	-	236,623	-	-	1,147,868	-	782,425
Aug		1,603,191	-	236,623	-	-	1,147,868	-	782,425
Sep		1,603,191	-	236,623	-	-	1,147,868	313,774	782,425
Oct		1,603,191	-	236,623	-	4,206,813	1,147,868	313,774	782,425
Nov		1,603,191	-	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
Dec		1,603,191	5,164,619	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
Total		**12,825,528**	**5,164,619**	**1,656,361**	**2,837,006**	**12,620,439**	**8,035,076**	**1,255,096**	**10,171,525**
New Transmission Plant Additions for Year 3 (13 month average balance)		986,579.08	397,278.38	127,412.38	218,231.23	970,803.00	618,082.77	96,545.85	782,425.00

Wylie Ridge (Monthly additions)	Black Oak (Monthly additions)	North Shenandoah (Monthly additions)	Meadowbrook Transformer (Monthly additions)	Bedington Transformer (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Kammer Transformers (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #4 (Monthly additions)	Cabot SS (Monthly Additions)	Pleasureville Capacitor	Farmers Valley	Harvey Run	Doubs SS	Potter SS (Monthly Additions)	Osage Whiteley (Monthly Additions)	Hunterstown SVC	502 Junction - Territorial Line (Monthly additions)
$ 3,057,444	6,670,531.27	260,047.48	1,126,239.68	1,078,130.57	1,230,313.09	5,565,459	742,257	682,675	810,779	1,109,023	102,828	122,857	109,335	777,058	296,319	3,499,572	3,135,687	163,391,038

Total Revenue Requirement	Waldo Run SS	Conemaugh	Meadowbrook SS	Blairsville	Four Mile Jct	Johnstown SS (2nd xfmr)	Yeagertown	Grandview Capacitor	Altoona SVC	Luxor	Armstrong	Grand Point & Guilford SS	Moshannon	Carbon Center	Shawville	Northwood	Shuman Hill Sub	Buffalo Road
$ 206,491,970.31	528,072.52	2,811,278.88	4,197,208.81	256,982.33	113,201.64	302,767	27,996	90,213	2,835,308	151,712	960,838	129,659	52,211	16,745	28,680	127,585	81,230	12,688

7 April Year 3 Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Potter SS	Cabot SS Transformer	Transformer	Doubs Transformer #3	Line (monthly additions)			
		(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-		7,971,225		
Jan 2013	Actual	-	-	-	-		(1,627,826)		
Feb	Actual	-	-	-	-		411,179		
Mar	Actual	-	-	-	-		168,379		
Apr	Actual	-	-	-	-		104,447		
May	Actual	-	-	-	-		963,048		
Jun	Actual	-	-	-	-		59,671		
Jul	Actual	-	-	-	-		67,103		
Aug	Actual	-	-	-	-		197,439		
Sep	Actual	-	-	-	-		28,035		
Oct	Actual	-	-	-	-		9,046		
Nov	Actual	-	-	-	-		16,044		
Dec	Actual	-	-	-	-		1,155,005		
Total		-	-	-	-	-	9,522,794	-	-

Month End Balances

(Monthly additions)	Potter SS	Cabot SS Transformer	Transformer	Doubs Transformer #3		(monthly additions)		
				(in service)	(in service)	CWIP		
	-	-	-	-	-	7,971,225	-	-
	-	-	-	-	-	6,343,399	-	-
	-	-	-	-	-	6,754,578	-	-
	-	-	-	-	-	6,922,957	-	-
	-	-	-	-	-	7,027,403	-	-
	-	-	-	-	-	7,990,451	-	-
	-	-	-	-	-	8,050,123	-	-
	-	-	-	-	-	8,117,226	-	-
	-	-	-	-	-	8,314,664	-	-
	-	-	-	-	-	8,342,699	-	-
	-	-	-	-	-	8,351,745	-	-
	-	-	-	-	-	8,367,789	-	-
	-	-	-	-	-	9,522,794	-	-
	-	**-**	**-**	**-**	**-**	**102,077,053**	**-**	**-**
	-	-	-	-	-	7,852,081	-	-

Result of Formula for Reconciliation

Total Revenue Requirement	Potter SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	Osage Whiteley	Armstrong	Farmers Valley	Harvey Run	Doubs SS
$ 191,138,273.23	274,053.06	1,134,259.28	831,548.34	698,936.19	759,496.57	5,699,914	1,252,999	1,104,285	1,153,703	265,886	6,851,053	3,147,983	166,116,271	1,766,520	13,885	9,609	8,551	33,985

Meadowbrook SS	Buffalo Road Capacitor	Pleasureville Capacitor	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation
4,981	-	-	10,355	-	-	-	-	-	-

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)

The Reconciliation in Step 8		The forecast in Prior Year		
191,138,273	-	190,601,269	=	537,004

<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr 0.2700%

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	44,750	0.2700%	11.5	1,389	46,140
Jul	Year 1	44,750	0.2700%	10.5	1,269	46,019
Aug	Year 1	44,750	0.2700%	9.5	1,148	45,898
Sep	Year 1	44,750	0.2700%	8.5	1,027	45,777
Oct	Year 1	44,750	0.2700%	7.5	906	45,657
Nov	Year 1	44,750	0.2700%	6.5	785	45,536
Dec	Year 1	44,750	0.2700%	5.5	665	45,415
Jan	Year 2	44,750	0.2700%	4.5	544	45,294
Feb	Year 2	44,750	0.2700%	3.5	423	45,173
Mar	Year 2	44,750	0.2700%	2.5	302	45,052
Apr	Year 2	44,750	0.2700%	1.5	181	44,932
May	Year 2	44,750	0.2700%	0.5	60	44,811
Total		537,004				545,704

		Balance	Interest	Amort	Balance
Jun	Year 2	545,704	0.2700%	46,277	500,900
Jul	Year 2	500,900	0.2700%	46,277	455,975
Aug	Year 2	455,975	0.2700%	46,277	410,929
Sep	Year 2	410,929	0.2700%	46,277	365,761
Oct	Year 2	365,761	0.2700%	46,277	320,471
Nov	Year 2	320,471	0.2700%	46,277	275,059
Dec	Year 2	275,059	0.2700%	46,277	229,524
Jan	Year 3	229,524	0.2700%	46,277	183,867
Feb	Year 3	183,867	0.2700%	46,277	138,086
Mar	Year 3	138,086	0.2700%	46,277	92,181
Apr	Year 3	92,181	0.2700%	46,277	46,153
May	Year 3	46,153	0.2700%	46,277	(0)
Total with interest				555,328	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest	555,328	**Input to Appendix A, Line 143**
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$ 206,491,970	
Revenue Requirement for Year 3	207,047,298	

Reconciliation Amount by Project

Total Revenue Requirement	Potter SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	Osage Whiteley	Armstrong	Farmers Valley	Harvey Run	Doubs SS
$ 555,328	(76,561)	90,555	9,907	9,387	10,838	73,654	339,328	14,126	14,495	(1,890)	(78,570)	(76,944)	471,845	400,195	14,358	(69,594)	(27,345)	35,144

Meadowbrook SS	Buffalo Road Capacitor	Pleasureville Capacitor	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation
5,151	(28,645)	(95,661)	(21,862)	(20,900)	(41,580)	(26,021)	(12,627)	(136,101)	(219,354)

9 May Year 3 Post results of Step 8 on PJM web site

$ 207,047,298

10 June Year 3 Results of Step 8 go into effect

$ 207,047,298

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

Line		Formula Line		
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3	A	137	FCR without Depreciation and Pre-Commercial Costs	13.1422%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	14.0393%
5	C		Line B less Line A	0.8971%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxes	0.8352%

8 **The FCR resulting from Formula in a given year is used for that year only.**
9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

Line				**PJM Upgrade ID: b0328.1 b0328.2; b0347.1; b0347.2; b0347.3; b0347.4**	**PJM Upgrade ID: b0218**	**PJM Upgrade ID: b0216**
10		Details		**502 Junction - Territorial Line (CWIP + Plant In Service)**	**Wylie Ridge Transformer (Plant In Service)**	**Black Oak (SVC) Dynamic Reactive Device (Plant In Service)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No
13	Input the allowed ROE	Allowed ROE		12.70%	11.70%	12.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	FCR without Incentive ROE		13.1422%	13.1422%	13.1422%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	FCR for This Project		14.0393%	13.1422%	14.0393%
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	Investment		1,016,908,024	20,606,266	38,559,314
17	Annual Depreciation Exp from Attachment 5			20,624,010	349,317	1,257,064

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	Wo Incentive ROE	2011	133,644,588.16	20,624,009.83	0.00	471,845.21	154,740,443.20	2,708,126.84	349,316.80	(76,943.60)	2,980,500.04	5,067,561.16	1,257,063.67	(78,570.05)	6,246,054.78
20	See Calculations for each item below	W Incentive ROE	2011	142,767,028.18	20,624,009.83	0.00	471,845.21	163,862,883.22	2,708,126.84	349,316.80	(76,943.60)	2,980,500.04	5,413,467.60	1,257,063.67	(78,570.05)	6,591,961.21

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For Plant in Service

"Pre-Commercial Exp" is equal to the amount of pre-commercial expense on Attachment 5a for each project expensed in year and amortized in year.
Revenue is equal to the "Return" ("Investment" times FCR) plus "Depreciation" plus "Pre-Commercial Exp" plus prior year "Reconciliation amount"
"Reconciliation Amount" is created in the reconciliation in Attachment 6 and included in the forecasted revenue requirement.

		PJM Upgrade ID: b0323				PJM Upgrade ID: b0230				PJM Upgrade ID: b0229			
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10		North Shenandoah Transformer (Plant In Service)				Meadowbrook Transformer (Plant In Service)				Bedington Transformer (Plant In Service)			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,710,856				7,258,865				6,969,402			
17	Annual Depreciation Exp from Attachment 5	35,203				172,262				162,194			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	224,844.97	35,202.51	(1,890.05)	258,157.43	953,978.12	172,261.56	14,494.65	1,140,734.33	915,936.21	162,194.36	14,126.25	1,092,256.82
20	See Calculations for each item below	224,844.97	35,202.51	(1,890.05)	258,157.43	953,978.12	172,261.56	14,494.65	1,140,734.33	915,936.21	162,194.36	14,126.25	1,092,256.82

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b0559				PJM Upgrade ID: b0495				PJM Upgrade ID: b0343				PJM Upgrade ID: b0344			
10		Meadowbrook Capacitor (Plant In Service)				Kammer Transformers (Plant In Service)				Doubs Replace Transformer #2				Doubs Replace Transformer #3			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	5,911,247				36,030,346				4,829,904				4,446,095			
17	Annual Depreciation Exp from Attachment 5	453,442				830,261				107,499				98,358			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	776,870.88	453,442.21	339,327.72	1,569,640.81	4,735,197.91	830,261.20	73,654.00	5,639,113.11	634,758.04	107,499.00	10,838.17	753,095.21	584,316.87	98,358.00	9,386.81	692,061.68
20	See Calculations for each item below	776,870.88	453,442.21	339,327.72	1,569,640.81	4,735,197.91	830,261.20	73,654.00	5,639,113.11	634,758.04	107,499.00	10,838.17	753,095.21	584,316.87	98,358.00	9,386.81	692,061.68

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b0345				PJM Upgrade ID: b0704				PJM Upgrade ID: b1941				PJM Upgrade ID: b0563			
10		Doubs Replace Transformer #4				Cabot SS - Install Autotransformer				Armstrong				Farmers Valley Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	5,253,224				6,836,864				7,311,064				934,823			
17	Annual Depreciation Exp from Attachment 5	120,387				210,505				0				0			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	690,391.74	120,387.00	9,906.66	820,685.40	898,517.77	210,505.16	90,555.41	1,199,578.34	960,838.27	0.00	14,358.34	975,196.61	122,856.77	0.00	(69,594.31)	53,262.46
20	See Calculations for each item below	690,391.74	120,387.00	9,906.66	820,685.40	898,517.77	210,505.16	90,555.41	1,199,578.34	960,838.27	0.00	14,358.34	975,196.61	122,856.77	0.00	(69,594.31)	53,262.46

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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Line		PJM Upgrade ID: b0564	PJM Upgrade ID: b1803	PJM Upgrade ID: b1243	PJM Upgrade ID: b0674, b1023, b1023.3
10		Harvey Run Capacitor	Doubs SS	Potter SS	Osage Whiteley
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No	No
13	Input the allowed ROE	11.70%	11.70%	11.70%	11.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%	13.1422%	13.1422%	13.1422%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%	13.1422%	13.1422%	13.1422%
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	831,938	5,912,673	1,987,922	24,560,265
17	Annual Depreciation Exp from Attachment 5	0	0	35,061	271,800

Line		b0564 Return	b0564 Depreciation	b0564 Reconciliation Amount	b0564 Revenue	b1803 Return	b1803 Depreciation	b1803 Reconciliation Amount	b1803 Revenue
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	109,335.37	0.00	(27,345.49)	81,989.88	777,058.29	0.00	35,144.45	812,202.74
20	See Calculations for each item below	109,335.37	0.00	(27,345.49)	81,989.88	777,058.29	0.00	35,144.45	812,202.74

Line		b1243 Return	b1243 Depreciation	b1243 Pre-Commercial Exp.	b1243 Reconciliation Amount	b1243 Revenue	b0674, b1023, b1023.3 Return	b0674, b1023, b1023.3 Depreciation	b0674, b1023, b1023.3 Pre-Commercial Exp.	b0674, b1023, b1023.3 Reconciliation amount	b0674, b1023, b1023.3 Revenue
18		Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue	Return	Depreciation	Pre-Commercial Exp.	Reconciliation amount	Revenue
19	See Calculations for each item below	261,258	35,061	0	(76,561)	219,757.80	3,227,771	271,800	0	400,195	3,899,766.99
20	See Calculations for each item below	261,258	35,061	0	(76,561)	219,757.80	3,227,771	271,800	0	400,195	3,899,766.99

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b1800				**PJM Upgrade ID: b1800**				**PJM Upgrade ID: b2433.1, b2433.2, b2433.3**				**PJM Upgrade ID: b1153**			
10		**Meadobrook SS**				**Hunterstown**				**Waldo Run SS**				**Conemaugh**			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	31,936,761				23,859,591				4,018,129				21,391,155			
17	Annual Depreciation Exp from Attachment 5	0				0				0				0			
18		**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**
19	See Calculations for each item below	4,197,209	0	5,151	4,202,359.60	3,135,687	0	0	3,135,686.94	528,073	0	0	528,072.52	2,811,279	0	(136,101)	2,675,178.21
20	See Calculations for each item below	4,197,209	0	5,151	4,202,359.60	3,135,687	0	0	3,135,686.94	528,073	0	0	528,072.52	2,811,279	0	(136,101)	2,675,178.21

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b1967				PJM Upgrade ID: b1609, b1769				PJM Upgrade ID: b1945				PJM Upgrade ID: b1610			
10		Blairsville SS				Four Mile Jct				Johnstown SS (2nd xfmr)				Yeagertown			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,955,391				861,357				2,303,771				213,020			
17	Annual Depreciation Exp from Attachment 5	0				0				0				0			
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	256,982	0	0	256,982.33	113,202	0	0	113,201.64	302,767	0	0	302,767.34	27,996	0	0	27,995.60
20	See Calculations for each item below	256,982	0	0	256,982.33	113,202	0	0	113,201.64	302,767	0	0	302,767.34	27,996	0	0	27,995.60

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b1990				PJM Upgrade ID: b1801				PJM Upgrade ID: b1965				PJM Upgrade ID: b1839			
10		Grandview Capacitor				Altoona SVC				Luxor				Grand Point & Guilford			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	659,201				21,573,993				1,154,387				986,579			
17	Annual Depreciation Exp from Attachment 5	3,579				0				0				0			
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	86,634	3,579	(21,862)	68,351.36	2,835,308	0	0	2,835,307.90	151,712	0	(20,900)	130,812.57	129,659	0	(41,580)	88,078.55
20	See Calculations for each item below	86,634	3,579	(21,862)	68,351.36	2,835,308	0	0	2,835,307.90	151,712	0	(20,900)	130,812.57	129,659	0	(41,580)	88,078.55

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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		PJM Upgrade ID: b1964				**PJM Upgrade ID: b1672**				**PJM Upgrade ID: b1998**				**PJM Upgrade ID: b1999, b2002**			
10		**Moshannon**				**Carbon Center**				**Shawville**				**Northwood**			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	397,278				127,412				218,231				970,803			
17	Annual Depreciation Exp from Attachment 5	0				0				0				0			
18		**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**
19	See Calculations for each item below	52,211	0	0	52,211.32	16,745	0	0	16,744.85	28,680	0	(26,021)	2,659.26	127,585	0	0	127,585.35
20	See Calculations for each item below	52,211	0	0	52,211.32	16,745	0	0	16,744.85	28,680	0	(26,021)	2,659.26	127,585	0	0	127,585.35

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

		PJM Upgrade ID: b2342				PJM Upgrade ID: b1770				PJM Upgrade ID: b2148			
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10		Shuman Hill Sub				Buffalo Road				Pleasureville Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%				13.1422%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%				13.1422%			
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	618,083				96,546				782,425			
17	Annual Depreciation Exp from Attachment 5	0				0				0			
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	81,230	0	0	81,229.98	12,688	0	(28,645)	(15,956.67)	102,828	0	(95,661)	7,166.75
20	See Calculations for each item below	81,230	0	0	81,229.98	12,688	0	(28,645)	(15,956.67)	102,828	0	(95,661)	7,166.75

For Plant in Service

"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

1																	
2																	
3																	
4																	
5																	
6																	
7																	
8																	
9																	
		PJM Upgrade ID: b0556				**PJM Upgrade ID: b1023.1**				**PJM Upgrade ID: bxxx**							
10		**Grover SS Capacitor**				**502 Junction Substation**											
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes											
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No											
13	Input the allowed ROE	11.70%				11.70%											
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.1422%				13.1422%											
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.1422%				13.1422%											
16	Forecast – End of prior year net plant plus current year forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	0				0											
17	Annual Depreciation Exp from Attachment 5	0				0											
18		**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation Amount**	**Revenue**	**Total**	**Incentive Charged**	**Revenue Credit**	$9,468,346.45
19	See Calculations for each item below	0	0	(12,627)	(12,627.46)	0	0	(219,354)	(219,353.70)	0.00	0.00	0.00	0.00	197,578,951.87		197,578,951.87	**Ax A Line 148**
20	See Calculations for each item below	0	0	(12,627)	(12,627.46)	0	0	(219,354)	(219,353.70)	0.00	0.00	0.00	0.00	207,047,298.32	207,047,298.32		

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

Attachment 8, page 1, Table 1 and 2

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT/Hypothetical Example

YEAR ENDED 12/31/2014

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	t=N	Issue Date	Maturity Date	ORIGINAL ISSUANCE	Net Proceeds At Issuance	Net Amount Outstanding at t=N	Months Outstanding at t=N	Average Net Outstanding in Year* z*	Weighted Outstanding Ratios	Effective Cost Rate (Tables 2 and 3)	Weighted Debt Cost at t = N (h) * (i)	
	Long Term Debt 12/31/2014											
	First Mortgage Bonds:											
(1)	7.09%, Debenture Description, Series, Name	1/1/2014	8/31/2030	$ 300,000,000	$ 294,600,000	$ 295,000,000	12	$ 295,156,250	66.23%	7.324%	4.8506%	
(2)	Coupon rate, Debenture Description, Series, N	1/1/2014	6/30/2025									
	Other Long Term Debt:											
(3)	6.6%, Medium Term Notes, Series, Name of I	04/01/2014	06/30/2024	$ 200,000,000	$ 198,000,000	$ 150,000,000	9	$ 150,200,000	33.70%	6.735%	2.2697%	
(4)	$1,000,000 variable rate LT Credit Line Dr Series, Name of Issuer	xx/xx/xxx	xx/xx/xxx	na	na	$ 359,000	12	$ 320,000	0.07%	6.590%	0.0047%	
	Total			$ 500,000,000		$ 445,359,000		$ 445,676,250	100.000%		7.13%	**

t = time

The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.

The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.

* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).

Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).

** This Total Weighted Average Debt Cost will be shown on Line 101 of formula rate Appendix A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2014

		(aa)	(bb)	(cc)	(dd)	14	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)	(ll)
	Long Term Debt Affiliate	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance		Issuance Expense	Loss/Gain on Reacquired Debt	Less Related ADIT (Attachment 1)	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Annual Interest	Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
	First Mortgage Bonds													
(1)	7.09%, Debenture Des No	1/1/2014	6/30/2025	$ 300,000,000	$ (2,400,000)		$ 3,000,000	-	xxx	$ 294,600,000	98.2000	0.07090	$ 21,270,000	7.324%
(2)	Coupon rate, Debenture Description, Series, N	xxx	xxx	xxx	xxx		xxx	xxx	xxx	xxx	xxxx	xxx	xxxx	xx.xxxx
	Other Long Term Debt:												-	
(3)	6.6%, Medium Term N No	4/1/2014	06/30/2024	200,000,000			2,000,000		xxx	$ 198,000,000	99.0000	0.06600	13,200,000	6.735%
	TOTALS			$ 500,000,000	(2,400,000)		$ 5,000,000	-	xxx	$ 492,600,000			$ 34,470,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation

Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Trans-Allegheny Interstate Line Company

Attachment 9 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

TrAILCo anticipates its financing will be a 7 year loan, where by TrAILCo pays Origination Fees of $5.2 million and a Commitments Fee of 0.3% on the undrawn principle.
Consistent with GAAP, TrAILCo will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, TrAILCo will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$**	**900,000,000**

Internal Rate of Return[1] **4.886348%**

Based on following Financial Formula[2]**:**

$$\text{NPV} = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Origination Fees	7,780,954
Addition Origination Fees	15,125
Total Issuance Expense	7,796,079

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

	2008	2008	2008	2008	2009	2010	2011	2012	2013	2014	2015
LIBOR Rate	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Spread	.	.	.	.	.	.	.	.	.	.	.
Interest Rate	6.13%	3.86%	4.05%	4.34%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
Bond $450M Interest Rate	$ 450,000,000					4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Revolver Interest Rate	$ 350,000,000	Draw 1	DONE			3.249%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 2, 3, 4	DONE			3.247%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 5	DONE			3.251%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 6	DONE - Roll over Draw 1 and 4			3.316%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 7	DONE			3.361%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 8	DONE - Roll over Draw 2, 3 and 5			3.422%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 9	DONE			3.417%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 10	DONE			3.348%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 11	DONE - Roll over Draw 6 and 9			3.498%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 12	DONE - Roll over Draw 10			3.418%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 13	DONE - Roll over Draw 7 and 8			3.398%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 14	DONE			3.275%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 15	DONE			3.275%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 16	DONE - Roll over Draw 11			3.289%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 17	DONE			3.248%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 17A	DONE - Roll over Draw 12, 14 and 15			3.286%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 18	DONE - Roll over Draw 13 and 17			3.286%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 19	DONE				3.283%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 20	DONE - Roll over Draw 16				3.304%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 21	DONE - Roll over Draw 17A and 19				3.312%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 22	DONE - Roll over Draw 18				3.312%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 23	DONE				3.222%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 24	DONE Roll over Draw 20				3.213%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 25	DONE Roll over Draw 21, 22 and 23				3.174%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 26	DONE Roll over Draw 25				3.169%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 27	DONE - Pay off Draw 26				3.196%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 28	DONE				1.936%	6.21%			

				GL '224100		GL '820204	GL '181100/654106	GL '820202			
(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)	(I)		
Year		**Capital Expenditures**	**Principle Drawn In Quarter ($000's)**	**Principle Drawn To Date**	**Outstanding Debt Balance**	**Interest Expense**	**Origination Fees**	**Commitment**	**Net Cash Flows (D-F-G-H)**	**Interest at effective rate**	**Amortization of origination fees and commitment fees**
2008											
12/24/2007	Q4	68,183,000	10,000,000	10,000,000	10,000,000		734,955.02		9,265,045	-	-
01/31/2008	Q1			10,000,000	9,265,045		31,013.00		(31,013)	46,132	46,132
02/4/2008	Q1			10,000,000	9,280,164		69,578.45		(69,578)	4,853	4,853
02/6/2008	Q1			10,000,000	9,215,438		137.50		(138)	2,409	2,409
02/29/2008	Q1			10,000,000	9,217,710		2,960.00		(2,960)	27,752	27,752
03/5/2008	Q1			10,000,000	9,242,502		125,384.16		(125,384)	6,042	6,042
3/24/2008	Q1	25,543,000		10,000,000	9,123,160	155,047.57			(155,048)	22,684	(132,363)
03/31/2008	Q1			10,000,000	8,990,797		17,011.00		(17,011)	8,230	8,230
04/30/2008	Q2			10,000,000	8,982,016		197,269.56		(197,270)	35,289	35,289
05/19/2008	Q2			10,000,000	8,820,035		109,824.88		(109,825)	21,931	21,931
6/23/2008	Q2	20,509,000		10,000,000	8,732,141	97,477.43			(97,477)	40,038	(57,439)
06/26/2008	Q2			10,000,000	8,674,702		43,098.82		(43,099)	3,402	3,402
06/30/2008	Q2			10,000,000	8,635,005		13,267.50		(13,268)	4,516	4,516
08/8/2008	Q3			10,000,000	8,626,253		1,577.79		(1,578)	44,084	44,084
08/13/2008	Q3			10,000,000	8,668,760		62,776.98		(62,777)	5,667	5,667
8/15/2008	Q3		55,000,000	65,000,000	8,611,650	59,689.48	7,780,953.85		47,159,357	2,251	(57,438)
8/20/2008	Q3			65,000,000	55,773,258		530.00		(530)	36,461	36,461
8/25/2008	Q3			65,000,000	55,809,189		15,125.00		(15,125)	36,485	36,485
9/3/2008	Q3			65,000,000	55,830,549		82,654.66		(82,655)	65,714	65,714
9/8/2008	Q3			65,000,000	55,813,609		1,957.50		(1,958)	36,487	36,487
9/11/2008	Q3			65,000,000	55,848,138		41,845.84		(41,846)	21,903	21,903
9/15/2008	Q3		(20,000,000)	45,000,000	55,828,196	243,199.31			(20,243,199)	29,196	(214,004)
9/25/2008	Q3			45,000,000	35,614,192		7,525.25		(7,525)	46,580	46,580
9/29/2008	Q3			45,000,000	35,653,247		98,058.08		(98,058)	18,645	18,645
9/30/2008	Q3	24,995,000		45,000,000	35,573,834		18,136.90	235,520.83	(253,658)	4,650	4,650
10/2/2008	Q4		20,000,000	65,000,000	35,324,826			78,506.96	19,921,493	9,235	9,235
10/17/2008	Q4			65,000,000	55,255,554		2,030.03		(2,030)	108,439	108,439

Trans-Allegheny Interstate Line Company

Attachment 9 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

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Each year, TrAILCo will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$**	**900,000,000**

Internal Rate of Return[1] **4.886348%**

Based on following Financial Formula[2]:

$$\text{NPV} = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Origination Fees	7,780,954
Addition Origination Fees	15,125
Total Issuance Expense	7,796,079

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

10/29/2008	Q4			65,000,000	55,361,963		266.90		(267)	86,901	86,901
11/19/2008	Q4			65,000,000	55,448,597		96,048.71		(96,049)	152,404	152,404
11/21/2008	Q4			65,000,000	55,504,952		730.00		(730)	14,511	14,511
12/15/2008	Q4		25,000,000	90,000,000	55,518,734	718,999.31			24,281,001	174,431	(544,569)
(1) 1/6/2009	Q1	42,068,000	-	90,000,000	79,974,165	-		618,333.53	(618,334)	230,297	230,297
2/17/2009	Q1		30,000,000	120,000,000	79,586,128	-		-	30,000,000	438,097	438,097
3/16/2009	Q1	75,475,000	40,000,000	160,000,000	110,024,225	933,987.50			39,066,013	388,964	(545,023)
3/25/2009	Q1		-	160,000,000	149,479,202			1,100,000.00	(1,100,000)	175,942	175,942
4/8/2009	Q2		-	160,000,000	148,555,144			549,166.67	(549,167)	272,085	272,085
5/15/2009	Q2		50,000,000	210,000,000	148,278,062				50,000,000	718,820	718,820
6/16/2009	Q2		40,000,000	250,000,000	198,996,882	1,405,039.11			38,594,961	834,057	(570,982)
6/30/2009	Q2		-	250,000,000	238,425,899				-	436,686	436,686
7/31/2009	Q3		-	250,000,000	238,862,586			453,194.44	(453,194)	969,797	969,797
8/3/2009	Q3		30,000,000	280,000,000	239,379,188				30,000,000	93,882	93,882
9/4/2009	Q3		50,000,000	330,000,000	269,473,071				50,000,000	1,129,444	1,129,444
9/16/2009	Q3		-	330,000,000	320,602,515	1,596,826.11			(1,596,826)	503,245	(1,093,581)
10/5/2009	Q4		45,000,000	375,000,000	319,508,934	207,916.06			44,792,084	794,450	586,534
10/16/2009	Q4			375,000,000	365,095,468			321,250.00	(321,250)	525,294	525,294
11/5/2009	Q4		30,000,000	405,000,000	365,299,512	-			30,000,000	956,176	956,176
12/4/2009	Q4		50,000,000	455,000,000	396,255,688				50,000,000	1,504,831	1,504,831
12/16/2009	Q4	73,715,000	-	455,000,000	447,760,519	1,374,479.16			(1,374,479)	702,843	(671,636)
1/4/2010	Q1			455,000,000	447,088,883			138,489.58	(138,490)	1,111,675	1,111,675
1/5/2010	Q1		30,000,000	485,000,000	448,062,068	892,331.11			29,107,669	58,568	(833,764)
1/15/2010	Q1		-	485,000,000	477,228,304	440,625.00			(440,625)	624,167	183,542
1/25/2010	Q1		(485,000,000)	-	477,411,847	423,000.00		18,489.58	(485,441,490)	624,407	201,407
1/25/2010	Q1		450,000,000	450,000,000	(7,405,236)		4,533,000.00		445,467,000	-	-
1/25/2010	Q1		45,000,000	495,000,000	438,061,764		5,852,578.67		39,147,421	-	-
1/27/2010	Q1			495,000,000	477,209,186		6,979.59		(6,980)	124,763	124,763
2/3/2010	Q1			495,000,000	477,326,969		58,000.00		(58,000)	436,922	436,922
2/3/2010	Q1			495,000,000	477,705,891		5,500.00		(5,500)	-	-
2/5/2010	Q1			495,000,000	477,700,391		82,116.73	2,934.74	(85,051)	124,892	124,892
2/12/2010	Q1		20,000,000	515,000,000	477,740,231				20,000,000	437,300	437,300
2/24/2010	Q1			515,000,000	498,177,531		23,770.00		(23,770)	781,982	781,982
3/10/2010	Q1		30,000,000	545,000,000	498,935,743		90,000.00		29,910,000	913,821	913,821
3/17/2010	Q1		-	545,000,000	529,759,564		195,720.20		(195,720)	484,916	484,916
3/26/2010	Q1		20,000,000	565,000,000	530,048,759		17,821.04		19,982,179	623,885	623,885
4/1/2010	Q2			565,000,000	550,654,823			255,416.67	(255,417)	432,008	432,008
4/5/2010	Q2			565,000,000	550,831,415		123,660.90		(123,661)	288,060	288,060
4/7/2010	Q2			565,000,000	550,995,814		201,250.00		(201,250)	144,054	144,054
4/8/2010	Q2			565,000,000	550,938,618		224,587.75		(224,588)	72,015	72,015
4/12/2010	Q1		30,000,000	595,000,000	550,786,045				30,000,000	288,036	288,036
4/14/2010	Q2			595,000,000	581,074,082		194,134.74		(194,135)	151,918	151,918
4/21/2010	Q2			595,000,000	581,031,865		18,977.41		(18,977)	531,848	531,848
4/26/2010	Q2		(65,000,000)	530,000,000	581,544,735	369,573.75			(65,369,574)	380,177	10,603
4/26/2010	Q2		65,000,000	595,000,000	516,555,339	55,920.56			64,944,079	-	(55,921)
4/28/2010	Q2			595,000,000	581,499,418	-	2,300.79		(2,301)	152,029	152,029
4/30/2010	Q2			595,000,000	581,649,147		2,156.70		(2,157)	152,068	152,068
5/7/2010	Q2		30,000,000	625,000,000	581,799,058				30,000,000	532,550	532,550
5/12/2010	Q2		(80,000,000)	545,000,000	612,331,608				(80,000,000)	400,304	400,304
5/12/2010	Q2		80,000,000	625,000,000	532,731,912	160,694.44			79,839,306	-	(160,694)
5/12/2010	Q2			625,000,000	612,571,218	81,275.00			(81,275)	-	(81,275)
5/12/2010	Q2			625,000,000	612,489,943	170,100.00			(170,100)	-	(170,100)
5/20/2010	Q2			625,000,000	612,319,843		182,500.00		(182,500)	640,599	640,599
5/26/2010	Q2		20,000,000	645,000,000	612,777,942				20,000,000	480,746	480,746
6/14/2010	Q2			645,000,000	633,258,687		150,071.58		(150,072)	1,574,581	1,574,581
7/1/2010	Q3			645,000,000	634,683,197			230,764	(230,764)	1,411,820	1,411,820
7/2/2010	Q3			645,000,000	635,864,253		1,168.50	-	(1,169)	83,116	83,116
7/7/2010	Q3		35,000,000	680,000,000	635,946,200				35,000,000	415,741	415,741
7/15/2010	Q3			680,000,000	671,361,942	8,500,000.00			(8,500,000)	702,368	(7,797,632)
7/26/2010	Q3		(65,000,000)	615,000,000	663,564,309				(65,000,000)	954,726	954,726
7/26/2010	Q3		(20,000,000)	595,000,000	599,519,036				(20,000,000)	-	-
7/26/2010	Q3		115,000,000	710,000,000	579,519,036				115,000,000	-	-
7/26/2010	Q3			710,000,000	694,519,036	115,798.33			(115,798)	-	(115,798)
7/26/2010	Q2			710,000,000	694,403,237	544,837.22		-	(544,837)	-	(544,837)
8/9/2010	Q3		(35,000,000)	675,000,000	693,858,400	107,415.00			(35,107,415)	1,270,829	1,163,414
8/9/2010	Q3		35,000,000	710,000,000	660,021,814	-			35,000,000	-	-
8/12/2010	Q3		(30,000,000)	680,000,000	695,021,814	271,680.83			(30,271,681)	272,581	900
8/12/2010	Q3		(80,000,000)	600,000,000	665,022,714	699,608.89			(80,699,609)	-	(699,609)
8/12/2010	Q3		110,000,000	710,000,000	584,323,106	-			110,000,000	-	-
8/30/2010	Q3			710,000,000	694,323,106	-	407,816.09		(407,816)	1,635,445	1,635,445
9/7/2010	Q3		30,000,000	740,000,000	695,550,735	-			30,000,000	727,674	727,674
9/26/2010	Q3		-	740,000,000	726,278,408	-			-	1,805,872	1,805,872
10/1/2010	Q4			740,000,000	728,084,280			**162,778**	(162,778)	475,975	475,975
10/8/2010	Q4		30,000,000	770,000,000	728,397,478	-			30,000,000	666,739	666,739
10/26/2010	Q4		(115,000,000)	655,000,000	759,064,217	1,028,023.33			(116,028,023)	1,787,940	759,916
10/26/2010	Q4		115,000,000	770,000,000	644,824,133	-			115,000,000	-	-
11/5/2010	Q4		30,000,000	800,000,000	759,824,133	-			30,000,000	993,774	993,774
11/9/2010	Q4		(35,000,000)	765,000,000	790,817,908	305,721.11			(35,305,721)	413,562	107,841
11/9/2010	Q4		(30,000,000)	735,000,000	755,925,749	171,937.50			(30,171,938)	-	(171,938)
11/9/2010	Q4		(30,000,000)	705,000,000	725,753,811	86,853.33			(30,086,853)	-	(86,853)
11/9/2010	Q4		95,000,000	800,000,000	695,666,958				95,000,000	-	-
11/12/2010	Q4		(110,000,000)	690,000,000	790,666,958	955,215.56			(110,955,216)	310,092	(645,123)
11/12/2010	Q4		(30,000,000)	660,000,000	680,021,835	18,946.67			(30,018,947)	-	(18,947)
11/12/2010	Q4		140,000,000	800,000,000	650,002,888	5.83			139,999,994	-	(6)
12/6/2010	Q4		20,000,000	820,000,000	790,002,882				20,000,000	2,482,059	2,482,059
12/23/2010	Q4			820,000,000	812,484,941		8,281.46		(8,281)	1,807,331	1,807,331

Trans-Allegheny Interstate Line Company

Attachment 9 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

TrAILCo anticipates its financing will be a 7 year loan, where by TrAILCo pays Origination Fees of $5.2 million and a Commitments Fee of 0.3% on the undrawn principle.
Consistent with GAAP, TrAILCo will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, TrAILCo will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$**	**900,000,000**

Internal Rate of Return[1]	**4.886348%**
Based on following Financial Formula[2]:	

$$NPV = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Origination Fees	7,780,954
Addition Origination Fees	15,125
Total Issuance Expense	**7,796,079**

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

1/3/2011	Q1			820,000,000	814,283,991			140,277.78	(140,278)	1,171,579	1,171,579
1/18/2011	Q1		-	820,000,000	815,315,292	9,000,000			(9,000,000)	1,600,050	(7,399,950)
1/26/2011	Q1		(115,000,000)	705,000,000	807,915,342	966,600.56			(115,966,601)	845,228	(121,373)
1/26/2011	Q1		115,000,000	820,000,000	692,793,969				115,000,000	-	-
2/9/2011	Q1		(20,000,000)	800,000,000	807,793,969	118,552.78			(20,118,553)	1,479,507	1,360,954
2/9/2011	Q1		(95,000,000)	705,000,000	789,154,923	797,767.78			(95,797,768)	-	(797,768)
2/9/2011	Q1		115,000,000	820,000,000	693,357,156				115,000,000	-	-
2/14/2011	Q1		(140,000,000)	680,000,000	808,357,156	1,201,215.56			(141,201,216)	528,453	(672,763)
2/14/2011	Q1		140,000,000	820,000,000	667,684,393				140,000,000	-	-
2/16/2011	Q1			820,000,000	807,684,393		3,098.63		(3,099)	211,164	211,164
4/1/2011	Q2		-	820,000,000	807,892,458			97,777.78	(97,778)	4,659,577	4,659,577
4/14/2011	Q2		10,000,000	830,000,000	812,454,257			-	10,000,000	1,381,663	1,381,663
4/26/2011	Q2		(115,000,000)	715,000,000	823,835,920	949,900.00			(115,949,900)	1,293,164	343,264
4/26/2011	Q2		115,000,000	830,000,000	709,179,184	-			115,000,000	-	-
5/9/2011	Q2		(115,000,000)	715,000,000	824,179,184	941,620.00			(115,941,620)	1,401,603	459,983
5/9/2011	Q2		(140,000,000)	575,000,000	709,639,166	1,081,920.00			(141,081,920)	-	(1,081,920)
5/9/2011	Q2		(10,000,000)	565,000,000	568,557,246	22,375.00			(10,022,375)	-	(22,375)
5/9/2011	Q2		235,000,000	800,000,000	558,534,871	-			235,000,000	-	-
5/16/2011	Q2		(235,000,000)	565,000,000	793,534,871	145,034.17			(235,145,034)	726,363	581,329
5/16/2011	Q2		235,000,000	800,000,000	559,116,200	-			235,000,000	-	-
5/23/2011	Q2		(235,000,000)	565,000,000	794,116,200	144,805.69			(235,144,806)	726,895	582,089
5/23/2011	Q2		50,000,000	615,000,000	559,698,289				50,000,000	-	-
5/26/2011	Q2		(115,000,000)	500,000,000	609,698,289	307,912.50	233,657		(115,541,569)	239,118	(68,795)
6/23/2011	Q2		(50,000,000)	450,000,000	494,395,838	88,994.45		-	(50,088,994)	1,812,670	1,723,675
6/23/2011	Q2		20,000,000	470,000,000	446,119,513	-		-	20,000,000	-	-
7/6/2011	Q3			470,000,000	466,119,513			171,736.11	(171,736)	792,685	792,685
7/15/2011	Q3			470,000,000	466,740,462	9,000,000			(9,000,000)	549,369	(8,450,631)
7/25/2011	Q3		(20,000,000)	450,000,000	458,289,831	34,417.78		-	(20,034,418)	599,398	564,980
10/18/2011	Q4			450,000,000	438,854,811			290,416.67	(290,417)	4,902,813	4,902,813
1/17/2012	Q1			450,000,000	443,467,207	9,000,000			(9,000,000)	5,306,145	(3,693,855)
3/2/2012	Q1			450,000,000	439,773,352		3,070.00		(3,070)	2,594,240	2,594,240
7/15/2012	Q3			450,000,000	442,364,522	9,000,000			(9,000,000)	7,874,847	(1,125,153)
1/15/2013	Q1			450,000,000	441,239,369	9,000,000			(9,000,000)	10,740,283	1,740,283
7/15/2013	Q3			450,000,000	442,979,652	9,000,000			(9,000,000)	10,604,752	1,604,752
1/15/2014	Q1			450,000,000	444,584,404	9,000,000			(9,000,000)	10,821,705	1,821,705
7/15/2014	Q3			450,000,000	446,406,108	9,000,000			(9,000,000)	10,686,780	1,686,780
1/15/2015	Q1		(450,000,000)	-	448,092,888	9,000,000			(459,000,000)	10,907,105	1,907,105
										-	-

Commitment fees for 4th quarter 2008

Attachment 4B-Delmarva Formula Rate Update

Attachment 4B

Pepco Holdings, Inc

701 Ninth Street, NW
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Washington, DC 20068

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alblauman@pepcoholdings.com

Amy L. Blauman
Associate General Counsel

May 15, 2014

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: Delmarva Power & Light Company ("Delmarva")
Informational Filing of 2014 Formula Rate Annual Update in
Docket No. ER09-1158 and Pursuant to Approved Settlement Agreement
in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Delmarva hereby submits electronically, for informational purposes, its 2014 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al.*, (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Delmarva [Delmarva Power & Light Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate year, and:
>
> (i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and
>
> (ii) file such Annual Update with FERC as an informational filing.[1]

The same information has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to

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[1] *See* Settlement Agreement, Exhibit B-1 containing PJM Tariff Attachment H3-E, Section 1.b.

aspects of the Annual Update. Consequently, and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Delmarva's 2014 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

Delmarva has made no Material Accounting Changes as defined in the Settlement.[3] Delmarva has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[4] Additionally, Delmarva has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[5]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Delmarva Power & Light Company

Enclosures

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[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1158 (February 17, 2010).

[3] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1.f.(iii). For the Commission's information, Delmarva no longer records PHI Service Company costs in Account 923 "Outside Services Employed," if those costs meet the definition of Account 928 "Regulatory Commission Expenses."

[4] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1.g.

[5] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1.h.

ATTACHMENT H-3D

Delmarva Power & Light Company

Formula Rate - Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	2013
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 2,042,668
2	Total Wages Expense		p354.28b	$ 32,790,866
3	Less A&G Wages Expense		p354.27b	$ 3,412,589
4	Total		(Line 2 - 3)	29,378,277
5	**Wages & Salary Allocator**		(Line 1 / 4)	**6.9530%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,922,321,370
7	Common Plant In Service - Electric		(Line 24)	81,900,614
8	Total Plant In Service		(Sum Lines 6 & 7)	3,004,221,984
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 891,161,896
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 23,320,980
11	Accumulated Common Amortization - Electric	(Note A)	p356	17,196,214
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	$ 48,343,205
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	980,022,295
14	Net Plant		(Line 8 - 13)	2,024,199,689
15	Transmission Gross Plant		(Line 29 - Line 28)	1,027,883,741
16	**Gross Plant Allocator**		(Line 15 / 8)	**34.2146%**
17	Transmission Net Plant		(Line 39 - Line 28)	711,658,482
18	**Net Plant Allocator**		(Line 17 / 14)	**35.1575%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 982,545,408
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	29,145,949
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**1,011,691,357**
23	General & Intangible		p205.5.g & p207.99.g	150,983,216
24	Common Plant (Electric Only)	(Notes A & B)	p356	81,900,614
25	Total General & Common		(Line 23 + 24)	232,883,830
26	Wage & Salary Allocation Factor		(Line 5)	6.95299%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**16,192,384**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**1,027,883,741**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 307,591,305
31	Accumulated General Depreciation		p219.28.c	$ 35,315,775
32	Accumulated Intangible Amortization		(Line 10)	23,320,980
33	Accumulated Common Amortization - Electric		(Line 11)	17,196,214
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	48,343,205
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	124,176,174
36	Wage & Salary Allocation Factor		(Line 5)	6.95299%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**8,633,954**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**316,225,259**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**711,658,482**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-187,530,001
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	-4,041,576
42	Net Plant Allocation Factor		(Line 18)	35.16%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-188,950,919**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**	(Note B)	p216.43.b as Shown on Attachment 6	-
43b	**Unamortized Abandoned Transmission Plant**		Attachment 5	-
	Transmission O&M Reserves			
44	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	-3,182,499
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	14,447,833
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**14,447,833**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 1,812,654
48	Wage & Salary Allocation Factor		(Line 5)	6.953%
49	Total Transmission Allocated		(Line 47 * 48)	126,034
50	Transmission Materials & Supplies		p227.8c	2,173,717
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**2,299,751**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	16,557,169
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**2,069,646**
	Network Credits			
55	Outstanding Network Credits	(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0
57	Net Outstanding Credits		(Line 55 - 56)	**0**
58	**TOTAL Adjustment to Rate Base**		(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	**-173,316,188**
59	**Rate Base**		(Line 39 + 58)	**538,342,294**

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b	$ 12,324,721
61	Less extraordinary property loss			Attachment 5	$ -
62	Plus amortized extraordinary property loss			Attachment 5	$ -
63	Less Account 565			p321.96.b	$ -
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565		(Note O)	PJM Data	$ -
65	Plus Transmission Lease Payments		(Note A)	p200.3.c	$ -
66	**Transmission O&M**			(Lines 60 - 63 + 64 + 65)	**12,324,721**
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	0
68	Total A&G			p323.197.b	$ 69,460,734
69	Less Property Insurance Account 924			p323.185b	443,951
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	5,310,577
71	Less General Advertising Exp Account 930.1			p323.191b	253,821
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	7,177,369
73	Less EPRI Dues		(Note D)	p352-353	0
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)	56,275,016
75	Wage & Salary Allocation Factor			(Line 5)	6.9530%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)	**3,912,795**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	163,571
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	**163,571**
80	Property Insurance Account 924			p323.185b	443,951
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	443,951
83	Net Plant Allocation Factor			(Line 18)	35.16%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)	**156,082**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**	**16,557,169**

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	22,429,989
86a	Amortization of Abandoned Transmission Plant			Attachment 5	0
87	General Depreciation			p336.10b&c	4,626,419
88	Intangible Amortization		(Note A)	p336.1d&e	28,053
89	Total			(Line 87 + 88)	4,654,472
90	Wage & Salary Allocation Factor			(Line 5)	6.9530%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)	**323,625**
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	3,479,929
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	3,479,929
95	Wage & Salary Allocation Factor			(Line 5)	6.9530%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)	**241,959**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**	**22,995,573**

Taxes Other than Income

98	**Taxes Other than Income**			Attachment 2	**6,383,930**
99	**Total Taxes Other than Income**			**(Line 98)**	**6,383,930**

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	$ 51,977,577
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	51,977,577
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	1,029,085,292
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	2,177,779
107	**Common Stock**			(Sum Lines 104 to 106)	1,031,263,071
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,073,230,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-13,035,330
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,771,785
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,061,966,455
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,031,263,071
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,093,229,526
117	Debt %	Total Long Term Debt		(Line 113 / 116)	50.73%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	49.27%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0489
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0248
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0557
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0805**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**43,337,925**

Composite Income Taxes

Income Tax Rates

128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite	(Note I)		8.39%
130	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.45%
132	T/ (1-T)			67.94%

ITC Adjustment

		(Note I)		
133	Amortized Investment Tax Credit	enter negative	Attachment 1	-88,888
134	T/(1-T)		(Line 132)	67.94%
135	Net Plant Allocation Factor		(Line 18)	35.1575%
136	**ITC Adjustment Allocated to Transmission**		(Line 133 * (1 + 134) * 135)	**-52,482**

137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 132 * 127 * (1-(123 / 126))]	**20,361,205**
138	**Total Income Taxes**		**(Line 136 + 137)**	**20,308,723**

REVENUE REQUIREMENT

Summary

139	Net Property, Plant & Equipment	(Line 39)	711,658,482
140	Adjustment to Rate Base	(Line 58)	-173,316,188
141	**Rate Base**	(Line 59)	**538,342,294**
142	O&M	(Line 85)	16,557,169
143	Depreciation & Amortization	(Line 97)	22,995,573
144	Taxes Other than Income	(Line 99)	6,383,930
145	Investment Return	(Line 127)	43,337,925
146	Income Taxes	(Line 138)	20,308,723
147	**Gross Revenue Requirement**	**(Sum Lines 142 to 146)**	**109,583,320**

Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities

148	Transmission Plant In Service		(Line 19)	982,545,408
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	982,545,408
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	109,583,320
153	**Adjusted Gross Revenue Requirement**		(Line 151 * 152)	**109,583,320**

Revenue Credits & Interest on Network Credits

154	**Revenue Credits**		Attachment 3	7,772,171
155	**Interest on Network Credits**	(Note N)	PJM Data	-
156	**Net Revenue Requirement**		**(Line 153 - 154 + 155)**	**101,811,148**

Net Plant Carrying Charge

157	Net Revenue Requirement	(Line 156)	**101,811,148**
158	Net Transmission Plant	(Line 19 - 30)	**674,954,103**
159	Net Plant Carrying Charge	(Line 157 / 158)	**15.0842%**
160	Net Plant Carrying Charge without Depreciation	(Line 157 - 86) / 158	**11.7610%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	(Line 157 - 86 - 127 - 138) / 158	**2.3312%**

Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE

162	Net Revenue Requirement Less Return and Taxes	(Line 156 - 145 - 146)	**38,164,501**
163	Increased Return and Taxes	Attachment 4	**68,100,754**
164	Net Revenue Requirement per 100 Basis Point increase in ROE	(Line 162 + 163)	**106,265,255**
165	Net Transmission Plant	(Line 19 - 30)	**674,954,103**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE	(Line 164 / 165)	**15.7441%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	(Line 163 - 86) / 165	**12.4209%**
168	**Net Revenue Requirement**	(Line 156)	**101,811,148**
169	True-up amount	Attachment 6	**4,013,158**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects	Attachment 7	**636,174**
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515	Attachment 5	**-**
171a	MAPP Abandonment recovery pursuant to ER13-607	Attachment 5	**14,666,395**
172	**Net Zonal Revenue Requirement**	(Line 168 + 169 +170+ 171+171a)	**121,126,876**

Network Zonal Service Rate

173	1 CP Peak	(Note L)	PJM Data	**4,019**
174	Rate ($/MW-Year)		(Line 172 / 173)	**30,141**
175	**Network Service Rate ($/MW/Year)**		**(Line 174)**	**30,141**

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5. For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Transmission Portion Only

D All EPRI Annual Membership Dues

E All Regulatory Commission Expenses

F Safety related advertising included in Account 930.1

G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.

J Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686 and ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.

K Education and outreach expenses relating to transmission, for example siting or billing

L As provided for in Section 34.1 of the PJM OATT and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.

M Amount of transmission plant excluded from rates per Attachment 5.

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 155.

O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included in on line 64

P Securitization bonds may be included in the capital structure per settlement in ER05-515.

Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.

R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months) effective on the date FERC approves the settlement in ER05-515.

Delmarva Power & Light Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet Tax Detail

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT-282	-	(580,608,998)	-	(580,608,998)
ADIT-283	(12,993,094)	(20,015,726)	(95,737,592)	(128,746,412)
ADIT-190	4,378,343	92,380,875	23,517,626	120,276,844
Subtotal	(8,614,751)	(508,243,850)	(72,219,966)	(589,078,566)
Wages & Salary Allocator			6.9530%	
Gross Plant Allocator		34.21464%		
ADIT	(8,614,751)	(173,893,804)	(5,021,445)	(187,530,001)
Total				

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 111

Amount (1,771,785)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Distribution Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Merrill Creek Excess Capacity	4,643,267	4,643,267				This represents deferred tax generated as a result of an extraordinary charge deducted for books relating to impaired assets due to the effects of deregulation. For tax purposes, the impairment did not give rise to a tax deduction. Deductions for tax are nondeductable.
Merrill Creek Excess Capacity Contra	(267,679)	(267,679)				This contra account represents an adjustment to the Merrill Creek Excess Capacity deferred tax generated relating to impaired assets due to the effects of deregulation.
Allowance for Doubtful Accounts	4,838,885	4,838,885				Under the Tax Reform Act of 1986, taxpayers were required to switch from the reserve method for bad debts to the specific write-off method. The amounts previously accumulated in a reserve were required to be included in taxable income over a four year period. The reserve method is used for book purposes. Related to all revenues.
Charitable Contributions	77,075	77,075				PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
Deferred ITC	1,958,760			1,958,760		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Environmental Expense	1,411,352	1,411,352				These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax no deduction is permitted until the "all events" test is met, typically when economic performance has occurred.
Reg Liability - FERC Formula Rate Adj	45,583		45,583			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Claims Reserve	891,665			891,665		These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for General and Auto liability claims. For tax no deduction is permitted until the "all events" test is met, typically when payment is made.
Merrill Creek - Rent	3,216,937	3,216,937				These deferred taxes are the result of rent being recorded ratably over the life of the lease for book purposes. For tax, rent is deductible when economic performance occurs. This asset is Generation related.
MERRILL CREEK RENT CONTRA	(442,050)	(442,050)				This contra account represents an adjustment to the Merrill Creek Rent deferred tax generated relating to rent deductible for tax purposes upon economic performance.
PJM Member Defaults	2,852			2,852		This relates to the reversal of the accrual that was book for GAAP. During December 2007 two members of PJM were declared in default on their obligations to PJM. These items are not deducatable for tax purposes until paid.
Miscellaneous	(232)			(232)		Immaterial timing differences.
Pension And Other Labor Related	6,918,795				6,918,795	Affects company personnel across all functions.
OPEB	10,761,719				10,761,719	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
Reg Asset - Storm Costs	3,778,124	3,778,124				A regulatory asset was established for the costs associated with Hurricane Irene in third quarter 2012. For book purposes the costs are expense immediately, while for book purposes the costs are amortized.
Federal and State NOL	132,699,989	22,240,567	4,332,760	89,527,830	16,598,832	PHI's consolidated return is in an NOL situation, therefore NOLs are carried forward until such time as PHI is in a taxable income position. DPL also has stand alone state taxable losses for 2008 forward. Also includes MD NOL of 6.6M that was created from an amended return.
SFAS 109- Regulatory Liability Electric	16,844,424			16,844,424		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related entirely to plant. These items are removed below.
SFAS 109- Regulatory Liability Gas	726,398	726,398				Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related entirely to plant. These items are removed below.
Other	(1,958,789)	(1,958,789)				Related to Gas, Production or Other.
Subtotal - p234	**186,147,074**	**38,264,087**	**4,378,343**	**109,225,298**	**34,279,345**	
Less FASB 109 Above if not separately removed	17,570,822	726,398		16,844,424		
Less FASB 106 Above if not separately removed	10,761,719				10,761,719	
Total	**157,814,534**	**37,537,689**	**4,378,343**	**92,380,875**	**23,517,626**	

Instructions for Account 190:

1. **ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
2. **ADIT items related only to Transmission are directly assigned to Column D**
3. **ADIT items related to Plant and not in Columns C & D are included in Column E**
4. **ADIT items related to labor and not in Columns C & D are included in Column F**

5. **Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded**
6. **Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c**

Delmarva Power & Light Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Distribution Related*	*Only Transmission*	*Plant*	*Labor*	**Justification**
FAS 109	(106,108,557)	(50,218,667)		(55,889,890)		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Plant Related	(580,608,998)			(580,608,998)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
Subtotal - p275	(686,717,555)	(50,218,667)	-	(636,498,888)	-	
Less FASB 109 Above if not separately removed	(106,108,557)	(50,218,667)		(55,889,890)		
Less FASB 106 Above if not separately removed						
Total	(580,608,998)	-	-	(580,608,998)	-	

Instructions for Account 282:

1. **ADIT items related only to Non-Electric**
2. **ADIT items related only to Transmission are directly assigned to Column D**
3. **ADIT items related to Plant and not in Columns C & D are included in Column E**
4. **ADIT items related to labor and not in Columns C & D are included in Column F**
5. **Deferred income taxes arise when items are**
6. **Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c**

Delmarva Power & Light Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

A *ADIT-283*	B *Total*	C *Gas, Prod Or Other Distribution Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G **Justification**
Merger Costs	(6,551,941)	(6,644,742)			92,801	Reflects deferred taxes generated on Delmarva Power & Light Company /Atlantic City Electric Company merger costs deducted for tax purposes. For books these costs were capitalized. Pension related and therefore labor related.
Materials Reserve	(754,550)	(754,550)				This represents deferred tax generated as a result of a deduction taken for amounts set aside in a reserve for book purposes. For tax no deduction is permitted until economic performance takes place. These reserves are related to deregulation of Energy.
Blueprint for the Future	(9,727,656)			(9,727,656)		When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Deferred Fuel	306,727	306,727				Difference between actual fuel expense as compared to the fuel expense computed in accordance with fuel adjustment clause formulas as deferred on books. In accordance with Section 162 Ordinary and Necessary Business Expenses and Section 461 Rules for Taxable year of Deduction, fuel costs are deductible in the year incurred for federal tax purposes. Rate surcharges are includible in the taxable year the underlying monthly bill is adjusted. Refunds are deductible in the taxable year that the liability is fixed and economic performance has occurred. These deferred taxes are the result of this book/tax difference. Generation Related.
Deferred Fuel Interest	(323,587)	(323,587)				This represents deferred tax generated as a result of interest income and/or expense accrued on the deferred fuel balance for book purposes. For tax purposes, interest income is recognized when received. Interest expense is deducted for tax when paid. Retail related.
Reacquired Debt	(1,771,785)	(1,771,785)				Reflects the deferred taxes generated as a result of the tax deductions taken for the cost to reacquire debt. For book purposes, these amounts were recorded as an asset in account 189 and are amortized over future periods.
Property Taxes	(4,428,604)	(4,428,604)				For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Unregulated related.
Reg Asset- COPCO Acquisition Adjustment	(9,101,261)			(9,101,261)		Amortization of COPCO acquisition adjustment. Beginning unamortized balance $40,456,550.00 represents recovery of the regulatory asset per Docket 9093, Order 81518, refers to MD Docket 8583, Order 71719; offset account 114000 Plant Acq Adj. Amortizing monthly. Fully amortized in 2010.
Reg Asset- Other Reg Assets	(47,546,045)	(47,546,045)				Represents various costs which we are, or will be through a future rate case, getting recovery through rate base.
Reg Asset - FERC Formula Rate Adj	(573,456)		(573,456)			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Reg Asset - Transmission MAPP	(12,419,638)		(12,419,638)			Represents deferred taxes on MAPP abandonment costs that are currently deductible for income tax purposes, versus amounts included in the MAPP Regulatory Asset that are amortized to book expense over a longer time period
Reg Asset - DSM DLC Program	(10,941,762)	(10,941,762)				For books, Demand Side Management Costs are deferred. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature.
Wilmington Coal Gas Site Cleanup	49	49				Timing differences related to Gas operations.
Interest on Contingent Taxes	(1,186,809)			(1,186,809)		Estimated book interest income on prior year taxes not included for tax purposes.
SFAS 109- Regulatory Asset Electric	(129,443,249)			(33,612,856)	(95,830,393)	Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
SFAS 109- Regulatory Asset Gas	(279,719)	(279,719)				Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Other	(469,107)	(469,107)				Related to Gas, Production or Other
Subtotal - p277 (Form 1-F filer: see note 6, below)	(235,212,393)	(72,853,125)	(12,993,094)	(53,628,582)	(95,737,592)	
Less FASB 109 Above if not separately removed	(33,892,575)	(279,719)		(33,612,856)		
Less FASB 106 Above if not separately removed	-					
Total	(201,319,818)	(72,573,405)	(12,993,094)	(20,015,726)	(95,737,592)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric
2. ADIT items related only to Transmission are directly assigned to Column B
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

	Item		Cumulative Balance	2013 Activity Amortization	
Rate Base Treatment					
Balance to line 41 of Appendix A	Total		4,041,576	476,426	Post 1980
Amortization					
Amortization to line 133 of Appendix A	Total		724,087	88,888	Pre 1981
Total			4,765,663	565,314	
Total Form No. 1 (p 266 & 267)			4,765,663	565,314	
Difference /1		check	-	-	

/1 Difference must be zero

Delmarva Power & Light Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	***Page 263 Col (i)***	***Allocator***	***Allocated Amount***
	Plant Related		***Gross Plant Allocator***	
1	Real property (State, Municipal or Local)	**18,074,198**		
2	Personal property	**-**		
3	Federal/State Excise	**27,298**		
4				
5				
6				
	Total Plant Related	18,101,496	34.2146%	6,193,362
	Labor Related		***Wages & Salary Allocator***	
7	Federal FICA & Unemployment	**2,637,574**		
8	Unemployment	**102,484**		
9				
10				
11				
	Total Labor Related	2,740,058	6.9530%	190,516
	Other Included		***Gross Plant Allocator***	
12	Miscellaneous	152		
13				
14				
	Total Other Included	152	34.2146%	52
	Total Included	20,841,706		6,383,930
	Excluded			
15	State Franchise Tax	**6,851,764**		
16	Gross Receipts	**214,058**		
17	Sales and Use	**522,073**		
18	Utility Tax for Delmarva	**6,517,279**		
19	City License			
20				
21	Total "Other" Taxes (included on p. 263)	34,946,880		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	34,946,880		
23	Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Delmarva Power & Light Company

Attachment 3 - Revenue Credit Workpaper

Account 454 - Rent from Electric Property

1	Rent from Electric Property - Transmission Related (Note 3)		1,871,791
2	Total Rent Revenues	(Sum Line 1)	1,871,791

Account 456 - Other Electric Revenues (Note 1)

3	Schedule 1A		$ 1,467,553
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		1,322,797
6	PJM Transitional Revenue Neutrality (Note 1)		
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		4,424,536
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	9,086,677
12	Less line 17g		(1,314,506)
13	Total Revenue Credits		7,772,171

Revenue Adjustment to determine Revenue Credit

14

Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 173 of Appendix A.

15 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

16 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	1,871,791
17b	Costs associated with revenues in line 17a	757,220
17c	Net Revenues (17a - 17b)	1,114,571
17d	50% Share of Net Revenues (17c / 2)	557,286
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	557,286
17g	Line 17f less line 17a	(1,314,506)
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.	7,955,148
19	Amount offset in line 4 above	98,495,789
20	Total Account 454, 456 and 456.1	115,537,613
21	Note 4: SECA revenues booked in Account 447.	

Delmarva Power & Light Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE				
A		100 Basis Point increase in ROE and Income Taxes		(Line 127 + Line 138)	68,100,754
B		100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	538,342,294
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	51,977,577
101	Less LTD Interest on Securitization Bonds			Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	51,977,577
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	1,029,085,292
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	2,177,779
107	**Common Stock**			(Sum Lines 104 to 106)	1,031,263,071
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,073,230,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-13,035,330
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,771,785
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,061,966,455
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,031,263,071
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,093,229,526
117	Debt %	Total Long Term Debt		(Line 113 / 116)	50.73%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	49.27%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0489
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J from Appendix A)	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost o	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0248
124	Weighted Cost o	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost o	Common Stock		(Line 119 * 122)	0.0606
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0854**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**45,990,154**

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite				8.39%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.45%
132	T/ (1-T)				67.94%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	Attachment 1	(88,888)
134	T/(1-T)			(Line 132)	68%
135	Net Plant Allocation Factor			(Line 18)	35.1575%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-52,482**
137	**Income Tax Component =**		CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		**22,163,082**
138	**Total Income Taxes**			**(Line 136 + 137)**	**22,110,600**

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	46,033,078	23,320,980	22,712,098	See Form 1
11	Accumulated Common Amortization - Electric	(Note A)	p356	20,471,683	17,196,214	3,275,469	See Form 1
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	57,648,216	48,343,205	9,305,011	See Form 1
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	100,306,937	81,900,614	18,406,323	See Form 1
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	4,765,665	4,323,645	442,020	See Form 1
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,866,329	1,812,654	53,676	97.124% Electric, 2.876% Non-Electric
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3.c				
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	28,053	28,053	0	See FERC Form 2, Page 337, Line 1, Column h for non-electric portion.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	3,479,929	3,479,929	0	See Form 1, electric only.
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	See Form 1, electric only.

Transmission / Non-transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	3,050,685	0	3,050,685	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	5,310,577	163,571	5,147,006	Enter Details
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	2,922,321,370	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	982,545,408	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	81,900,614	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	307,591,305	0	0	See Form 1

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	-	-	See Form 1

Delmarva Power & Light Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 5,310,577	163,571	5,147,006	FERC related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	5,310,577	163,571	5,147,006	FERC related

Safety Related Advertising Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	253,821	0	253,821	None

MultiState Workpaper

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				MD	PA	VA	DE	OH	Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.39%	8.25%	9.990%	6%	8.7%	5.10%	Apportioned: PA 0.0089%, VA 0.2928%, DE 6.7587%, MD 2.8168%, OH 0.0027%, NY 0.0016%

Education and Out Reach Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	253,821	0	253,821	None

Excluded Plant Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities					
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0	General Description of the Facilities
	Instructions:				Enter $	None
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process					
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,				Or	
	the following formula will be used:	Example			Enter $	
A	Total investment in substation	1,000,000				
B	Identifiable investment in Transmission (provide workpapers)	500,000				
C	Identifiable investment in Distribution (provide workpapers)	400,000				
D	Amount to be excluded (A x (C / (B + C)))	444,444				
						Add more lines if necessary

Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Delmarva Power & Light Company

Attachment 5 - Cost Support

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant related	36,914,258	6.953%	2,566,644	
	Plant Related	1,799,976	34.215%	615,855	
	Other		0.00%	-	
	Total Transmission Related Reserves	38,714,234		3,182,499	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Description of the Prepayments
45	Prepayments					
				Allocator	To Line 45	
	Pension Liabilities, if any, in Account 242		-	5.841%	-	
	Prepayments	$	19,335,109	5.841%	1,129,269	
	Prepaid Pensions if not included in Prepayments	$	228,037,705	5.841%	13,318,564	
			247,372,814	5.84%	14,447,833	
5	Wages & Salary Allocator		6.953%			
	Electric vs Gas		84%	Based on Modified Wisconsin Method		
	Modified Wages & Salaries Allocator		5.841%			Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Interest on Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement			
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515	Attachment 5	-	

PJM Load Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	4,018.7	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
DPL zone						
Total						

Delmarva Power & Light Company

Attachment 5 - Cost Support

Abandoned Tranmission Plant

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

A	Beginning Balance of Unamortized Transmission Plant	Per FERC Order	
B	Months Remaining in Amortization Period	Per FERC Order	
C	Monthly Ammortization	A/B	
D	Months in Year to be Amortized		
E	Amortization in Rate Year	C*D	Line 86a
F	Deductions		
G	End of Year Balance in Unamortized Transmission Plant	A-E-F	Line 43b

MAPP Abandonment recovery pursuant to ER13-607

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

			DPL		Pepco		Total
171a	2013-14 rate period	$	9,750,649	$	12,725,412	$	22,476,061
171a	2014-15 rate period	$	14,666,395		16,524,210	$	31,190,605
171a	2015-16 rate period	$	12,208,522		14,624,812	$	26,833,334
	Total	$	36,625,566	$	43,874,434	$	80,500,000

Delmarva Power & Light Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 11,562,337	$ 10,010,186	$ 20,420,219	$ 4,233,966	$ 46,226,708
Procurement & Administrative Services	5,632,450	4,165,574	9,450,856	317,756	19,566,636
Financial Services & Corporate Expenses	12,850,395	9,859,694	19,011,916	2,033,696	43,755,701
Insurance Coverage and Services	2,213,905	1,986,871	2,788,985	953,842	7,943,603
Human Resources	5,038,304	3,260,389	7,121,984	886,448	16,307,125
Legal Services	3,059,464	2,466,012	6,423,114	392,003	12,340,593
Audit Services	794,646	539,535	1,635,686	165,684	3,135,551
Customer Services	48,387,200	35,710,808	31,764,265	5,264	115,867,537
Utility Communication Services	97,515	-	150,770	-	248,285
Information Technology	15,258,104	10,897,942	33,943,020	299,235	60,398,301
External Affairs	2,912,889	2,316,651	4,804,603	379,617	10,413,760
Environmental Services	1,565,438	1,288,953	1,896,091	114,341	4,864,823
Safety Services	354,376	372,034	549,507	-	1,275,917
Regulated Electric & Gas T&D	30,083,042	23,758,286	42,089,790	15,969	95,947,087
Internal Consulting Services	566,310	347,896	876,072	-	1,790,278
Interns	179,453	83,801	207,544	210	471,008
Cost of Benefits	13,046,438	8,259,393	20,727,891	-	42,033,722
Building Services	8,916	103,717	5,007,690	2,288,416	7,408,739
Total	$ 153,611,182	$ 115,427,742	$ 208,870,003	$ 12,086,447	$ 489,995,374

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	Dec 31, 2013

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	60,366,527	148,288,038	215,438	208,870,003
2	Delmarva Power & Light Company	39,151,966	114,302,402	156,814	153,611,182
3	Atlantic City Electric Company	24,662,631	90,645,605	119,506	115,427,742
4	Pepco Energy Services, Inc.	2,777,499	6,713,524	11,618	9,502,641
5	Conectiv, LLC	11,767	55,656	563	67,986
6	Potomac Capital Investment Corporation	576,358	297,172	661	874,191
7	Thermal Energy Limited Partnership	15,648	601,358	572	617,578
8	ATS Operating Services, Inc.	114	291,725	285	292,124
9	Atlantic Southern Properties	14,398	171,009	248	185,655
10	Conectiv Energy Supply, Inc.	18,264	21,562	119	39,945
11	Pepco Holdings, Inc.	139,689	36,414	145	176,248
12	Conectiv Properties and Investments, Inc.	25,260	129,408	174	154,842
13	Conectiv Thermal Systems	2,917	100,349	102	103,368
14	Conectiv Communications, Inc.	69	8,798	11	8,878
15	Atlantic City Electric Transition Funding, LLC	30,739	2,906	16	33,661
16	Conectiv North East, LLC	257	4,446	5	4,708
17	Delaware Operating Services Company	228	13,936	8	14,172
18	ATE Investments, Inc.	1,848	969	4	2,821
19	Atlantic Generation, Inc.	109	928	2	1,039
20	Conectiv Services II, Inc.	344	6,113	3	6,460
21	Conectiv Solutions LLC	125	5		130
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	127,796,757	361,692,323	506,294	489,995,374

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2013
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	23,545,999	16,722,578	34,632,825	-	74,901,402	Not included
182.3	Other Regulatory Assets	10,488,915	114,841	11,696,727	-	22,300,483	Not included
184	Clearing Accounts - Other	(12,476)	(61,040)	78,748	(2,468)	2,764	Not included
408.1	Taxes other than inc taxes, utility operating inc	-	39,805	-	-	39,805	Not included
416-421	Other Income - Below the Line	374,987	626,685	587,151	12,088,915	13,677,738	Not included
426.1-426.5	Other Income Deductions - Below the Line	603,681	462,744	995,381	-	2,061,806	Not included
430	Interest-Debt to Associated Companies	229,913	175,178	315,777	-	720,868	Not included
431	Interest-Short Term Debt	(73,099)	(55,672)	(100,339)	-	(229,110)	Not included
556	System cont & load dispatch	1,602,698	1,401,597	1,249,833	-	4,254,128	Not included
557	Other expenses	1,311,562	1,194,307	1,669,382	-	4,175,251	Not included
560	Operation Supervision & Engineering	1,882,601	1,864,185	3,206,474	-	6,953,260	100% inclusion
561	Load dispatching	-	48	-	-	48	100% inclusion
561.1	Load Dispatching - Reliability	35,915	34,780	30,031	-	100,726	100% inclusion
561.2	Load Dispatch - Monitor & Operate Transmission Sys	53,681	17,527	992,559	-	1,063,767	100% inclusion
561.3	Load Dispatch - Transmission Service & Scheduling	47,778	54,385	28,496	-	130,659	100% inclusion
561.5	Reliability, Planning and Standards	129,486	121,848	3,951	-	255,285	100% inclusion
562	Station expenses	-	-	8,754	-	8,754	100% inclusion
564	Underground Line Expenses - Transmission	-	-	6,434	-	6,434	100% inclusion
566	Miscellaneous transmission expenses	457,843	240,714	463,170	-	1,161,727	100% inclusion
568	Maintenance Supervision & Engineering	280,592	252,490	262,052	-	795,134	100% inclusion
569.2	Maintenance of Computer Software	501,967	251,719	734,765	-	1,488,451	100% inclusion
569.4	Maintenance of Transmission Plant	-	-	265	-	265	100% inclusion
570	Maintenance of station equipment	150,049	86,648	405,920	-	642,617	100% inclusion
571	Maintenance of overhead lines	132,737	177,852	244,888	-	555,477	100% inclusion
572	Maintenance of underground lines	4,047	512	3,448	-	8,007	100% inclusion
573	Maintenance of miscellaneous transmission plant	27,446	21,698	111,154	-	160,298	100% inclusion
580	Operation Supervision & Engineering	658,487	331,800	755,181	-	1,745,468	Not included
581	Load dispatching	791,810	514,823	1,666,584	-	2,973,217	Not included
582	Station expenses	1,020,749	-	135,130	-	1,155,879	Not included
583	Overhead line expenses	73,167	132,571	27,597	-	233,335	Not included
584	Underground line expenses	26,046	-	112,600	-	138,646	Not included
585	Street lighting	2,232	-	91	-	2,323	Not included
586	Meter expenses	911,716	775,017	1,612,452	-	3,299,185	Not included
587	Customer installations expenses	48,804	73,395	494,290	-	616,489	Not included
588	Miscellaneous distribution expenses	3,840,313	4,228,331	6,315,909	-	14,384,553	Not included
589	Rents	27,645	21,112	-	-	48,757	Not included
590	Maintenance Supervision & Engineering	1,043,191	810,300	477,972	-	2,331,463	Not included
591	Maintain structures	-	-	3,880	-	3,880	Not included
592	Maintain equipment	481,027	422,133	1,051,748	-	1,954,908	Not included
593	Maintain overhead lines	880,924	696,824	1,702,388	-	3,280,136	Not included
594	Maintain underground line	76,399	58,003	671,570	-	805,972	Not included
595	Maintain line transformers	-	1,470	238,899	-	240,369	Not included
596	Maintain street lighting & signal systems	38,198	40,063	17,510	-	95,771	Not included
597	Maintain meters	17,551	34,757	64,712	-	117,020	Not included
598	Maintain distribution plant	30,723	17,358	885,881	-	933,962	Not included
800-894	Total Gas Accounts	2,213,518	-	-	-	2,213,518	Not included
902	Meter reading expenses	309,864	39,342	51,290	-	400,496	Not included
903	Customer records and collection expenses	36,340,896	35,227,261	31,444,855	-	103,013,012	Not included
907	Supervision - Customer Svc & Information	107,975	339,488	129,572	-	577,035	Not included
908	Customer assistance expenses	1,772,603	546,602	774,562	-	3,093,767	Not included
909	Informational & instructional advertising	111,858	28,138	157,175	-	297,171	Not included
913	Advertising expense	34,536	-	-	-	34,536	Not included
920	Administrative & General salaries	335,615	90,550	587,356	-	1,013,521	Wage & Salary Factor
921	Office supplies & expenses	49,363	39,388	77,162	-	165,913	Wage & Salary Factor
923	Outside services employed	48,324,843	39,986,311	81,108,695	-	169,419,849	Wage & Salary Factor
924	Property insurance	96,402	82,096	187,290	-	365,788	Net Plant Factor
925	Injuries & damages	1,937,057	1,600,813	3,065,515	-	6,603,385	Wage & Salary Factor
926	Employee pensions & benefits	7,077,618	3,685,817	11,260,050	-	22,023,485	Wage & Salary Factor
928	Regulatory commission expenses	1,376,532	485,623	2,624,783	-	4,486,938	Direct Transmission only
929	Duplicate charges-Credit	329,386	133,081	1,370,676	-	1,833,143	Wage & Salary Factor
930.1	General ad expenses	9,007	8,683	42,842	-	60,532	Direct Transmission only
930.2	Miscellaneous general expenses	1,130,320	998,849	2,006,066	-	4,135,235	Wage & Salary Factor
935	Maintenance of general plant	308,485	232,314	119,874	-	660,673	Wage & Salary Factor
	Total	**153,611,182**	**115,427,742**	**208,870,003**	**12,086,447**	**489,995,374**	

Delmarva Power & Light Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

91,572,540 Rev Req based on Year 1 data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			36,139,908		11.5	-	-	415,608,938	-	-	-	34,634,078	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar			(36,139,908)		9.5	-	-	(343,329,123)	-	-	-	(28,610,760)	-	
Apr	16,467,349				8.5	139,972,470	-	-	-	11,664,373	-	-	-	
May	8,824,256				7.5	66,181,920	-	-	-	5,515,160	-	-	-	
Jun	37,674,034				6.5	244,881,224	-	-	-	20,406,769	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov	318,141				1.5	477,212	-	-	-	39,768	-	-	-	
Dec	-				0.5	-	-	-	-	-	-	-	-	
Total	63,283,781	-	-	-		451,512,826	-	-	-	37,626,069	-	6,023,318	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										37,626,069	-	6,023,318	-	
								Input to Line 21 of Appendix A		37,626,069	-		-	37,626,069
								Input to Line 43a of Appendix A				6,023,318		6,023,318
								Month In Service or Month for CWIP		4.87	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 37,626,069 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

96,165,272 Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 96,165,272

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

111,649,911 Rev Req based on Prior Year data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 112,444,938 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	(483,638)		36,139,908		11.5	(5,561,842)	-	415,608,938	-	(463,487)	-	34,634,078	-	
Feb	3,797,943				10.5	39,878,404	-	-	-	3,323,200	-	-	-	
Mar	3,013,304		(36,139,908)		9.5	28,626,387	-	(343,329,123)	-	2,385,532	-	(28,610,760)	-	
Apr	19,641,459				8.5	166,952,398	-	-	-	13,912,700	-	-	-	
May	1,434,002				7.5	10,755,015	-	-	-	896,251	-	-	-	
Jun	14,569,686				6.5	94,702,962	-	-	-	7,891,913	-	-	-	
Jul	3,049,112				5.5	16,770,116	-	-	-	1,397,510	-	-	-	
Aug	(110,004)				4.5	(495,020)	-	-	-	(41,252)	-	-	-	
Sep	28,757,156				3.5	100,650,045	-	-	-	8,387,504	-	-	-	
Oct	14,064,989				2.5	35,162,472	-	-	-	2,930,206	-	-	-	
Nov	10,978,377				1.5	16,467,565	-	-	-	1,372,297	-	-	-	
Dec	13,732,554				0.5	6,866,277	-	-	-	572,190	-	-	-	
Total	112,444,938	-	-	-		510,774,780	-	-	-	42,564,565	-	6,023,318	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										42,564,565	-	6,023,318	-	
								Input to Line 21 of Appendix A		42,564,565	-		-	42,564,565
								Input to Line 43a of Appendix A				6,023,318		6,023,318
								Month In Service or Month for CWIP		7.46	#DIV/0!	#DIV/0!	#DIV/0!	

105,082,905 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			-		11.5	-	-	-	-	-	-	-	-	
Feb	14,832,964				10.5	155,746,123	-	-	-	12,978,844	-	-	-	
Mar	8,914,481		-		9.5	84,687,572	-	-	-	7,057,298	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May	14,575,693				7.5	109,317,694	-	-	-	9,109,808	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec	-				0.5	-	-	-	-	-	-	-	-	
Total	38,323,138	-	-	-		349,751,389	-	-	-	29,145,949	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		29,145,949	-	-	-	
117,113,718								Input to Line 21 of Appendix A		29,145,949	-		-	29,145,949
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		2.87	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
105,082,905	-	98,833,120	=	6,249,785

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	520,815	0.2800%	11.5	16,770	537,586
Jul	Year 1	520,815	0.2800%	10.5	15,312	536,127
Aug	Year 1	520,815	0.2800%	9.5	13,854	534,669
Sep	Year 1	520,815	0.2800%	8.5	12,395	533,211
Oct	Year 1	520,815	0.2800%	7.5	10,937	531,753
Nov	Year 1	520,815	0.2800%	6.5	9,479	530,294
Dec	Year 1	520,815	0.2800%	5.5	8,021	528,836
Jan	Year 2	520,815	0.2800%	4.5	6,562	527,378
Feb	Year 2	520,815	0.2800%	3.5	5,104	525,919
Mar	Year 2	520,815	0.2800%	2.5	3,646	524,461
Apr	Year 2	520,815	0.2800%	1.5	2,187	523,003
May	Year 2	520,815	0.2800%	0.5	729	521,545
Total		6,249,785				6,354,781

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	6,354,781	0.2800%	539,253	5,833,322
Jul	Year 2	5,833,322	0.2800%	539,253	5,310,403
Aug	Year 2	5,310,403	0.2800%	539,253	4,786,019
Sep	Year 2	4,786,019	0.2800%	539,253	4,260,168
Oct	Year 2	4,260,168	0.2800%	539,253	3,732,843
Nov	Year 2	3,732,843	0.2800%	539,253	3,204,043
Dec	Year 2	3,204,043	0.2800%	539,253	2,673,762
Jan	Year 3	2,673,762	0.2800%	539,253	2,141,995
Feb	Year 3	2,141,995	0.2800%	539,253	1,608,740
Mar	Year 3	1,608,740	0.2800%	539,253	1,073,992
Apr	Year 3	1,073,992	0.2800%	539,253	537,747
May	Year 3	537,747	0.2800%	539,253	-
Total with interest				6,471,031	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		4,013,158
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	117,113,718
Revenue Requirement for Year 3		121,126,876

10 May Year 3 Post results of Step 9 on PJM web site

$ 121,126,876 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 121,126,876

Delmarva Power & Light Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	11.761%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	12.421%
6	C		Line B less Line A	0.6599%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.3312%

9 **The FCR resulting from Formula in a given year is used for that year only.**

10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE f**

Line		Details		B0241.3 Red Lion sub reconfiguration	B0494.1-4 Red Lion-Keeney	B0241.1-.2 Red Lion-Keeney	B0567 Mt.Pleasant-Townsend
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	No	No	No
13	Useful life of project	Life		35	35	35	35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150	150	150	150
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		11.7610%	11.7610%	11.7610%	11.7610%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		12.7508%	12.7508%	12.7508%	12.7508%
18	Columns A, B or C from Attachment 6	Investment		14,689,101	3,099,104	2,418,717	6,414,723
19	Line 18 divided by line 13	Annual Depreciation Exp		419,689	88,546	69,106	183,278
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00	6.00	6.00	6

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
33	Base FCR	2014	12,800,502	419,689	12,380,814	1,875,793	2,700,648	88,546	2,612,102	395,754	2,107,739	69,106	2,038,633	308,869	5,773,251	183,278	5,589,973	840,713
34	W Increased ROE	2014	12,800,502	419,689	12,380,814	1,998,346	2,700,648	88,546	2,612,102	421,611	2,107,739	69,106	2,038,633	329,049	5,773,251	183,278	5,589,973	896,046
35	Base FCR	2015	12,380,814	419,689	11,961,125	1,826,433	2,612,102	88,546	2,523,556	385,341	2,038,633	69,106	1,969,527	300,742	5,589,973	183,278	5,406,695	819,158
36	W Increased ROE	2015	12,380,814	419,689	11,961,125	1,944,833	2,612,102	88,546	2,523,556	410,320	2,038,633	69,106	1,969,527	320,237	5,589,973	183,278	5,406,695	872,677
37	Base FCR	2016	11,961,125	419,689	11,541,437	1,777,074	2,523,556	88,546	2,435,010	374,927	1,969,527	69,106	1,900,421	292,614	5,406,695	183,278	5,223,417	797,602
38	W Increased ROE	2016	11,961,125	419,689	11,541,437	1,891,319	2,523,556	88,546	2,435,010	399,030	1,969,527	69,106	1,900,421	311,426	5,406,695	183,278	5,223,417	849,307
39	Base FCR	2017	11,541,437	419,689	11,121,748	1,727,714	2,435,010	88,546	2,346,464	364,513	1,900,421	69,106	1,831,314	284,487	5,223,417	183,278	5,040,140	776,047
40	W Increased ROE	2017	11,541,437	419,689	11,121,748	1,837,805	2,435,010	88,546	2,346,464	387,740	1,900,421	69,106	1,831,314	302,614	5,223,417	183,278	5,040,140	825,938
41	Base FCR	2018	11,121,748	419,689	10,702,059	1,678,355	2,346,464	88,546	2,257,919	354,099	1,831,314	69,106	1,762,208	276,359	5,040,140	183,278	4,856,862	754,492
42	W Increased ROE	2018	11,121,748	419,689	10,702,059	1,784,291	2,346,464	88,546	2,257,919	376,449	1,831,314	69,106	1,762,208	293,803	5,040,140	183,278	4,856,862	802,568
43	Base FCR	2019	10,702,059	419,689	10,282,371	1,628,995	2,257,919	88,546	2,169,373	343,685	1,762,208	69,106	1,693,102	268,231	4,856,862	183,278	4,673,584	732,937
44	W Increased ROE	2019	10,702,059	419,689	10,282,371	1,730,777	2,257,919	88,546	2,169,373	365,159	1,762,208	69,106	1,693,102	284,991	4,856,862	183,278	4,673,584	779,199
45	Base FCR	2020	10,282,371	419,689	9,862,682	1,579,636	2,169,373	88,546	2,080,827	333,271	1,693,102	69,106	1,623,996	260,104	4,673,584	183,278	4,490,306	711,381
46	W Increased ROE	2020	10,282,371	419,689	9,862,682	1,677,263	2,169,373	88,546	2,080,827	353,869	1,693,102	69,106	1,623,996	276,179	4,673,584	183,278	4,490,306	755,830
47	Base FCR	2021	9,862,682	419,689	9,442,994	1,530,276	2,080,827	88,546	1,992,281	322,857	1,623,996	69,106	1,554,890	251,976	4,490,306	183,278	4,307,028	689,826
48	W Increased ROE	2021	9,862,682	419,689	9,442,994	1,623,750	2,080,827	88,546	1,992,281	342,578	1,623,996	69,106	1,554,890	267,368	4,490,306	183,278	4,307,028	732,460
49	Base FCR	2022	9,442,994	419,689	9,023,305	1,480,917	1,992,281	88,546	1,903,735	312,444	1,554,890	69,106	1,485,783	243,849	4,307,028	183,278	4,123,751	668,271
50	W Increased ROE	2022	9,442,994	419,689	9,023,305	1,570,236	1,992,281	88,546	1,903,735	331,288	1,554,890	69,106	1,485,783	258,556	4,307,028	183,278	4,123,751	709,091
51	Base FCR	2023	9,023,305	419,689	8,603,616	1,431,557	1,903,735	88,546	1,815,189	302,030	1,485,783	69,106	1,416,677	235,721	4,123,751	183,278	3,940,473	646,716
52	W Increased ROE	2023	9,023,305	419,689	8,603,616	1,516,722	1,903,735	88,546	1,815,189	319,998	1,485,783	69,106	1,416,677	249,744	4,123,751	183,278	3,940,473	685,721
53	Base FCR	2024	8,603,616	419,689	8,183,928	1,382,198	1,815,189	88,546	1,726,644	291,616	1,416,677	69,106	1,347,571	227,594	3,940,473	183,278	3,757,195	625,160
54	W Increased ROE	2024	8,603,616	419,689	8,183,928	1,463,208	1,815,189	88,546	1,726,644	308,707	1,416,677	69,106	1,347,571	240,933	3,940,473	183,278	3,757,195	662,352
55	Base FCR	2025	8,183,928	419,689	7,764,239	1,332,839	1,726,644	88,546	1,638,098	281,202	1,347,571	69,106	1,278,465	219,466	3,757,195	183,278	3,573,917	603,605
56	W Increased ROE	2025	8,183,928	419,689	7,764,239	1,409,694	1,726,644	88,546	1,638,098	297,417	1,347,571	69,106	1,278,465	232,121	3,757,195	183,278	3,573,917	638,982
57	Base FCR	2026	7,764,239	419,689	7,344,551	1,283,479	1,638,098	88,546	1,549,552	270,788	1,278,465	69,106	1,209,359	211,339	3,573,917	183,278	3,390,639	582,050
58	W Increased ROE	2026	7,764,239	419,689	7,344,551	1,356,180	1,638,098	88,546	1,549,552	286,127	1,278,465	69,106	1,209,359	223,310	3,573,917	183,278	3,390,639	615,613
59	Base FCR	2027	7,344,551	419,689	6,924,862	1,234,120	1,549,552	88,546	1,461,006	260,374	1,209,359	69,106	1,140,252	203,211	3,390,639	183,278	3,207,362	560,495
60	W Increased ROE	2027	7,344,551	419,689	6,924,862	1,302,667	1,549,552	88,546	1,461,006	274,836	1,209,359	69,106	1,140,252	214,498	3,390,639	183,278	3,207,362	592,243
61		....	....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63																		

or specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by

B0483.1-.3 Oak Hall-Wattsville				B0320 Cool Springs				BO568 3rd Indian River			
No				No				No			
35				35				35			
No				No				No			
150				150				150			
11.7610%				11.7610%				11.7610%			
12.7508%				12.7508%				12.7508%			
8,379,558				14,504,530				6,681,345			
239,416				414,415				190,896			
12				9				8			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
7,661,310	239,416	7,421,894	1,112,303	13,157,681	414,415	12,743,266	1,913,147	6,235,922	190,896	6,045,026	901,849
7,661,310	239,416	7,421,894	1,185,770	13,157,681	414,415	12,743,266	2,039,289	6,235,922	190,896	6,045,026	961,687
7,421,894	239,416	7,182,478	1,084,145	12,743,266	414,415	12,328,851	1,864,408	6,045,026	190,896	5,854,131	879,398
7,421,894	239,416	7,182,478	1,155,242	12,743,266	414,415	12,328,851	1,986,447	6,045,026	190,896	5,854,131	937,346
7,182,478	239,416	6,943,062	1,055,988	12,328,851	414,415	11,914,435	1,815,668	5,854,131	190,896	5,663,235	856,947
7,182,478	239,416	6,943,062	1,124,715	12,328,851	414,415	11,914,435	1,933,606	5,854,131	190,896	5,663,235	913,006
6,943,062	239,416	6,703,646	1,027,830	11,914,435	414,415	11,500,020	1,766,929	5,663,235	190,896	5,472,340	834,496
6,943,062	239,416	6,703,646	1,094,187	11,914,435	414,415	11,500,020	1,880,764	5,663,235	190,896	5,472,340	888,665
6,703,646	239,416	6,464,230	999,672	11,500,020	414,415	11,085,605	1,718,190	5,472,340	190,896	5,281,444	812,045
6,703,646	239,416	6,464,230	1,063,660	11,500,020	414,415	11,085,605	1,827,923	5,472,340	190,896	5,281,444	864,324
6,464,230	239,416	6,224,815	971,515	11,085,605	414,415	10,671,190	1,669,451	5,281,444	190,896	5,090,549	789,594
6,464,230	239,416	6,224,815	1,033,132	11,085,605	414,415	10,671,190	1,775,082	5,281,444	190,896	5,090,549	839,983
6,224,815	239,416	5,985,399	943,357	10,671,190	414,415	10,256,775	1,620,711	5,090,549	190,896	4,899,653	767,142
6,224,815	239,416	5,985,399	1,002,605	10,671,190	414,415	10,256,775	1,722,240	5,090,549	190,896	4,899,653	815,642
5,985,399	239,416	5,745,983	915,199	10,256,775	414,415	9,842,360	1,571,972	4,899,653	190,896	4,708,757	744,691
5,985,399	239,416	5,745,983	972,077	10,256,775	414,415	9,842,360	1,669,399	4,899,653	190,896	4,708,757	791,302
5,745,983	239,416	5,506,567	887,042	9,842,360	414,415	9,427,944	1,523,233	4,708,757	190,896	4,517,862	722,240
5,745,983	239,416	5,506,567	941,549	9,842,360	414,415	9,427,944	1,616,557	4,708,757	190,896	4,517,862	766,961
5,506,567	239,416	5,267,151	858,884	9,427,944	414,415	9,013,529	1,474,494	4,517,862	190,896	4,326,966	699,789
5,506,567	239,416	5,267,151	911,022	9,427,944	414,415	9,013,529	1,563,716	4,517,862	190,896	4,326,966	742,620
5,267,151	239,416	5,027,735	830,726	9,013,529	414,415	8,599,114	1,425,755	4,326,966	190,896	4,136,071	677,338
5,267,151	239,416	5,027,735	880,494	9,013,529	414,415	8,599,114	1,510,874	4,326,966	190,896	4,136,071	718,279
5,027,735	239,416	4,788,319	802,569	8,599,114	414,415	8,184,699	1,377,015	4,136,071	190,896	3,945,175	654,886
5,027,735	239,416	4,788,319	849,967	8,599,114	414,415	8,184,699	1,458,033	4,136,071	190,896	3,945,175	693,939
4,788,319	239,416	4,548,903	774,411	8,184,699	414,415	7,770,284	1,328,276	3,945,175	190,896	3,754,280	632,435
4,788,319	239,416	4,548,903	819,439	8,184,699	414,415	7,770,284	1,405,192	3,945,175	190,896	3,754,280	669,598
4,548,903	239,416	4,309,487	746,253	7,770,284	414,415	7,355,869	1,279,537	3,754,280	190,896	3,563,384	609,984
4,548,903	239,416	4,309,487	788,912	7,770,284	414,415	7,355,869	1,352,350	3,754,280	190,896	3,563,384	645,257
....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

y FERC to become effective June 1, 2008 and November 1, 2008 respectiv

BO272.1 Keeney 500kV Sub	BO751 Keeney - Additional Breakers on 500kV Bus	BO566 Trappe Tap - Todd	BO733 Harmony Add 2nd 230/138 Auto Tr
Yes	Yes	No	No
35	35	35	35
No	No	No	No
0	0	150	0
11.7610%	11.7610%	11.7610%	11.7610%
11.7610%	11.7610%	12.7508%	11.7610%
217,662	5,055,041	16,372,433	10,567,349
6,219	144,430	467,784	301,924
6	6	12	4

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
208,334	6,219	202,115	29,990	4,838,396	144,430	4,693,967	696,486	15,904,649	467,784	15,436,865	2,283,309	10,366,066	301,924	10,064,142	1,485,565	$ 11,843,778		$ 11,843,778
208,334	6,219	202,115	29,990	4,838,396	144,430	4,693,967	696,486	15,904,649	467,784	15,436,865	2,436,114	10,366,066	301,924	10,064,142	1,485,565	$ 12,479,952	$ 12,479,952	
202,115	6,219	195,896	29,258	4,693,967	144,430	4,549,537	679,499	15,436,865	467,784	14,969,082	2,228,293	10,064,142	301,924	9,762,218	1,450,056	$ 11,546,731		$ 11,546,731
202,115	6,219	195,896	29,258	4,693,967	144,430	4,549,537	679,499	15,436,865	467,784	14,969,082	2,376,467	10,064,142	301,924	9,762,218	1,450,056	$ 12,162,384	$ 12,162,384	
195,896	6,219	189,677	28,527	4,549,537	144,430	4,405,107	662,513	14,969,082	467,784	14,501,298	2,173,277	9,762,218	301,924	9,460,293	1,414,547	$ 11,249,684		$ 11,249,684
195,896	6,219	189,677	28,527	4,549,537	144,430	4,405,107	662,513	14,969,082	467,784	14,501,298	2,316,821	9,762,218	301,924	9,460,293	1,414,547	$ 11,844,816	$ 11,844,816	
189,677	6,219	183,458	27,795	4,405,107	144,430	4,260,677	645,527	14,501,298	467,784	14,033,514	2,118,261	9,460,293	301,924	9,158,369	1,379,037	$ 10,952,637		$ 10,952,637
189,677	6,219	183,458	27,795	4,405,107	144,430	4,260,677	645,527	14,501,298	467,784	14,033,514	2,257,175	9,460,293	301,924	9,158,369	1,379,037	$ 11,527,247	$ 11,527,247	
183,458	6,219	177,239	27,064	4,260,677	144,430	4,116,248	628,540	14,033,514	467,784	13,565,730	2,063,245	9,158,369	301,924	8,856,445	1,343,528	$ 10,655,590		$ 10,655,590
183,458	6,219	177,239	27,064	4,260,677	144,430	4,116,248	628,540	14,033,514	467,784	13,565,730	2,197,528	9,158,369	301,924	8,856,445	1,343,528	$ 11,209,679	$ 11,209,679	
177,239	6,219	171,020	26,333	4,116,248	144,430	3,971,818	611,554	13,565,730	467,784	13,097,946	2,008,230	8,856,445	301,924	8,554,521	1,308,019	$ 10,358,543		$ 10,358,543
177,239	6,219	171,020	26,333	4,116,248	144,430	3,971,818	611,554	13,565,730	467,784	13,097,946	2,137,882	8,856,445	301,924	8,554,521	1,308,019	$ 10,892,111	$ 10,892,111	
171,020	6,219	164,801	25,601	3,971,818	144,430	3,827,388	594,568	13,097,946	467,784	12,630,163	1,953,214	8,554,521	301,924	8,252,596	1,272,510	$ 10,061,496		$ 10,061,496
171,020	6,219	164,801	25,601	3,971,818	144,430	3,827,388	594,568	13,097,946	467,784	12,630,163	2,078,236	8,554,521	301,924	8,252,596	1,272,510	$ 10,574,542	$ 10,574,542	
164,801	6,219	158,582	24,870	3,827,388	144,430	3,682,958	577,581	12,630,163	467,784	12,162,379	1,898,198	8,252,596	301,924	7,950,672	1,237,001	$ 9,764,448		$ 9,764,448
164,801	6,219	158,582	24,870	3,827,388	144,430	3,682,958	577,581	12,630,163	467,784	12,162,379	2,018,589	8,252,596	301,924	7,950,672	1,237,001	$ 10,256,974	$ 10,256,974	
158,582	6,219	152,363	24,138	3,682,958	144,430	3,538,529	560,595	12,162,379	467,784	11,694,595	1,843,182	7,950,672	301,924	7,648,748	1,201,491	$ 9,467,401		$ 9,467,401
158,582	6,219	152,363	24,138	3,682,958	144,430	3,538,529	560,595	12,162,379	467,784	11,694,595	1,958,943	7,950,672	301,924	7,648,748	1,201,491	$ 9,939,406	$ 9,939,406	
152,363	6,219	146,144	23,407	3,538,529	144,430	3,394,099	543,609	11,694,595	467,784	11,226,811	1,788,166	7,648,748	301,924	7,346,824	1,165,982	$ 9,170,354		$ 9,170,354
152,363	6,219	146,144	23,407	3,538,529	144,430	3,394,099	543,609	11,694,595	467,784	11,226,811	1,899,297	7,648,748	301,924	7,346,824	1,165,982	$ 9,621,838	$ 9,621,838	
146,144	6,219	139,926	22,676	3,394,099	144,430	3,249,669	526,622	11,226,811	467,784	10,759,027	1,733,150	7,346,824	301,924	7,044,899	1,130,473	$ 8,873,307		$ 8,873,307
146,144	6,219	139,926	22,676	3,394,099	144,430	3,249,669	526,622	11,226,811	467,784	10,759,027	1,839,650	7,346,824	301,924	7,044,899	1,130,473	$ 9,304,269	$ 9,304,269	
139,926	6,219	133,707	21,944	3,249,669	144,430	3,105,239	509,636	10,759,027	467,784	10,291,244	1,678,134	7,044,899	301,924	6,742,975	1,094,964	$ 8,576,260		$ 8,576,260
139,926	6,219	133,707	21,944	3,249,669	144,430	3,105,239	509,636	10,759,027	467,784	10,291,244	1,780,004	7,044,899	301,924	6,742,975	1,094,964	$ 8,986,701	$ 8,986,701	
133,707	6,219	127,488	21,213	3,105,239	144,430	2,960,810	492,650	10,291,244	467,784	9,823,460	1,623,118	6,742,975	301,924	6,441,051	1,059,454	$ 8,279,213		$ 8,279,213
133,707	6,219	127,488	21,213	3,105,239	144,430	2,960,810	492,650	10,291,244	467,784	9,823,460	1,720,357	6,742,975	301,924	6,441,051	1,059,454	$ 8,669,133	$ 8,669,133	
127,488	6,219	121,269	20,481	2,960,810	144,430	2,816,380	475,663	9,823,460	467,784	9,355,676	1,568,102	6,441,051	301,924	6,139,127	1,023,945	$ 7,982,166		$ 7,982,166
127,488	6,219	121,269	20,481	2,960,810	144,430	2,816,380	475,663	9,823,460	467,784	9,355,676	1,660,711	6,441,051	301,924	6,139,127	1,023,945	$ 8,351,564	$ 8,351,564	
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....		$ -	
																	$ 233,464,711	$ 223,984,684

Delmarva Power & Light Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4C - ACE formula Rate Update

Attachment 4C

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

202-872-2122
202-331-6767 Fax
alblauman@pepcoholdings.com

May 15, 2014

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426

Re: Atlantic City Electric Company ("Atlantic City")
Informational Filing of 2014 Formula Rate Annual Update in
Docket No. ER09-1156 and Pursuant to Approved Settlement Agreement
in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Atlantic City hereby submits electronically, for informational purposes, its 2014 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al*., (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Atlantic [Atlantic City Electric Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate Year, and:
>
> (i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and
>
> (ii) file such Annual Update with FERC as an informational filing.[1]

The same information contained in this informational filing has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to aspects of the Annual Update. Consequently,

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[1] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H1-B, Section 1.b.

and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Atlantic City's 2014 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

Atlantic City has made no Material Accounting Changes as defined in the Settlement.[3] Atlantic City has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[4] In addition, Atlantic City has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[5]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Atlantic City Electric Company

Enclosures

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[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1156 (February 17, 2010).

[3] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.f.(iii). For the Commission's information, Atlantic City no longer records PHI Service Company costs in Account 923 "Outside Services Employed," if those costs meet the definition of Account 928 "Regulatory Commission Expenses."

[4] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.g.

[5] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.h.

ATTACHMENT H-1A

Atlantic City Electric Company

Formula Rate - Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	2013
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 1,830,179
2	Total Wages Expense		p354.28b	$ 28,590,665
3	Less A&G Wages Expense		p354.27b	$ 1,045,224
4	Total		(Line 2 - 3)	27,545,441
5	Wages & Salary Allocator		(Line 1 / 4)	6.6442%
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,762,757,177
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	2,762,757,177
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 722,998,244
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 23,938,932
11	Accumulated Common Amortization - Electric	(Note A)	p356	$ -
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	$ -
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	746,937,176
14	Net Plant		(Line 8 - 13)	2,015,820,001
15	Transmission Gross Plant		(Line 29 - Line 28)	797,369,431
16	Gross Plant Allocator		(Line 15 / 8)	28.8614%
17	Transmission Net Plant		(Line 39 - Line 28)	571,627,600
18	Net Plant Allocator		(Line 17 / 14)	28.3571%
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 787,143,444
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	655,709
22	Total Transmission Plant In Service		(Line 19 - 20 + 21)	787,799,153
23	General & Intangible		p205.5.g & p207.99.g	$ 144,039,204
24	Common Plant (Electric Only)	(Notes A & B)	p356	$ -
25	Total General & Common		(Line 23 + 24)	144,039,204
26	Wage & Salary Allocation Factor		(Line 5)	6.64422%
27	General & Common Plant Allocated to Transmission		(Line 25 * 26)	9,570,278
28	Plant Held for Future Use (Including Land)	(Note C)	p214	782,029
29	TOTAL Plant In Service		(Line 22 + 27 + 28)	798,151,460
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 220,777,696
31	Accumulated General Depreciation		p219.28.c	$ 50,774,689
32	Accumulated Intangible Amortization		(Line 10)	23,938,932
33	Accumulated Common Amortization - Electric		(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	0
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	74,713,621
36	Wage & Salary Allocation Factor		(Line 5)	6.64422%
37	General & Common Allocated to Transmission		(Line 35 * 36)	4,964,135
38	TOTAL Accumulated Depreciation		(Line 30 + 37)	225,741,831
39	TOTAL Net Property, Plant & Equipment		(Line 29 - 38)	572,409,629
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-160,179,297
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	28.36%
43	Accumulated Deferred Income Taxes Allocated To Transmission		(Line 41 * 42) + Line 40	-160,179,297
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)	(Note B)	p216.43.b as Shown on Attachment 6	0
	Transmission O&M Reserves			
44	Total Balance Transmission Related Account 242 Reserves	Enter Negative	Attachment 5	-2,206,434
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	8,324,605
46	Total Prepayments Allocated to Transmission		(Line 45)	8,324,605
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,626,598
48	Wage & Salary Allocation Factor		(Line 5)	6.64%
49	Total Transmission Allocated		(Line 47 * 48)	108,075
50	Transmission Materials & Supplies		p227.8c	$ 1,617,885
51	Total Materials & Supplies Allocated to Transmission		(Line 49 + 50)	1,725,960
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	15,982,065
53	1/8th Rule		x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission		(Line 52 * 53)	1,997,758
	Network Credits			
55	Outstanding Network Credits	(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0
57	Net Outstanding Credits		(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base		(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	-150,337,408
59	Rate Base		(Line 39 + 58)	422,072,221

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b	$ 12,052,882
61	Less extraordinary property loss			Attachment 5	0
62	Plus amortized extraordinary property loss			Attachment 5	0
63	Less Account 565			p321.96.b	$ -
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565		(Note O)	PJM Data	$ -
65	Plus Transmission Lease Payments		(Note A)	p200.3c	$ -
66	Transmission O&M			(Lines 60 - 63 + 64 + 65)	12,052,882
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	$ -
68	Total A&G			p323.197.b	$ 62,286,747
69	Less Property Insurance Account 924			p323.185b	$ 382,417
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$ 4,144,900
71	Less General Advertising Exp Account 930.1			p323.191b	$ 254,678
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$ -
73	Less EPRI Dues		(Note D)	p352-353	$ -
74	General & Common Expenses			(Lines 67 + 68) - Sum (69 to 73)	57,504,752
75	Wage & Salary Allocation Factor			(Line 5)	6.6442%
76	General & Common Expenses Allocated to Transmission			(Line 74 * 75)	3,820,741
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	0
80	Property Insurance Account 924			p323.185b	$ 382,417
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	382,417
83	Net Plant Allocation Factor			(Line 18)	28.36%
84	A&G Directly Assigned to Transmission			(Line 82 * 83)	108,442
85	Total Transmission O&M			(Line 66 + 76 + 79 + 84)	15,982,065

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	18,602,770
87	General Depreciation			p336.10b&c	6,516,593
88	Intangible Amortization		(Note A)	p336.1d&e	51,891
89	Total			(Line 87 + 88)	6,568,484
90	Wage & Salary Allocation Factor			(Line 5)	6.6442%
91	General Depreciation Allocated to Transmission			(Line 89 * 90)	436,424
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	0
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	0
95	Wage & Salary Allocation Factor			(Line 5)	6.6442%
96	Common Depreciation - Electric Only Allocated to Transmission			(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization			(Line 86 + 91 + 96)	19,039,194

Taxes Other than Income

98	Taxes Other than Income			Attachment 2	867,622
99	Total Taxes Other than Income			(Line 98)	867,622

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	67,173,739
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	14,894,670
102	Long Term Interest			"(Line 100 - line 101)"	52,279,069
103	Preferred Dividends		enter positive	p118.29c	$ -
	Common Stock				
104	Proprietary Capital			p112.16c	$ 868,953,100
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	$ -
107	Common Stock			(Sum Lines 104 to 106)	868,953,100
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,071,319,580
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (8,625,030)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	-2,750,501
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-192,104,580
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	867,839,469
114	Preferred Stock			p112.3c	$ -
115	Common Stock			(Line 107)	868,953,100
116	Total Capitalization			(Sum Lines 113 to 115)	1,736,792,569
117	Debt %	Total Long Term Debt	(Note Q)	(Line 113 / 116)	50%
118	Preferred %	Preferred Stock	(Note Q)	(Line 114 / 116)	0%
119	Common %	Common Stock	(Note Q)	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0602
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0301
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0565
126	Total Return (R)			(Sum Lines 123 to 125)	0.0866
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	36,559,998

Composite Income Taxes

	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite	(Note I)		8.99%
130	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%
132	T/ (1-T)			69.05%
	ITC Adjustment	(Note I)		
133	Amortized Investment Tax Credit	enter negative	p266.8f	$ (848,130)
134	T/(1-T)		(Line 132)	69.05%
135	Net Plant Allocation Factor		(Line 18)	28.3571%
136	ITC Adjustment Allocated to Transmission		(Line 133 * (1 + 134) * 135)	-406,577
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 132 * 127 * (1-(123 / 126))]	16,466,764
138	Total Income Taxes		(Line 136 + 137)	16,060,187

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	572,409,629
140	Adjustment to Rate Base		(Line 58)	-150,337,408
141	Rate Base		(Line 59)	422,072,221
142	O&M		(Line 85)	15,982,065
143	Depreciation & Amortization		(Line 97)	19,039,194
144	Taxes Other than Income		(Line 99)	867,622
145	Investment Return		(Line 127)	36,559,998
146	Income Taxes		(Line 138)	16,060,187
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	88,509,067
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	787,143,444
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	787,143,444
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	88,509,067
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	88,509,067
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	2,913,639
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	85,595,428
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	85,595,428
158	Net Transmission Plant		(Line 19 - 30)	566,365,748
159	Net Plant Carrying Charge		(Line 157 / 158)	15.1131%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	11.8285%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	2.5377%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	32,975,243
163	Increased Return and Taxes		Attachment 4	56,187,782
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	89,163,025
165	Net Transmission Plant		(Line 19 - 30)	566,365,748
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	15.7430%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	12.4584%
168	Net Revenue Requirement		(Line 156)	85,595,428
169	True-up amount		Attachment 6	1,756,086
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	438,009
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)		Attachment 5	-
172	Net Zonal Revenue Requirement		(Line 168 - 169 + 171)	87,789,524
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	2,739
174	Rate ($/MW-Year)		(Line 172 / 173)	32,049
175	Network Service Rate ($/MW/Year)		(Line 174)	32,049

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5. For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Transmission Portion Only

D All EPRI Annual Membership Dues

E All Regulatory Commission Expenses

F Safety related advertising included in Account 930.1

G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.

J Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686 and ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.

K Education and outreach expenses relating to transmission, for example siting or billing

L As provided for in Section 34.1 of the PJM OATT and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.

M Amount of transmission plant excluded from rates per Attachment 5.

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 155.

O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included in on line 64

P Securitization bonds may be included in the capital structure per settlement in ER05-515.

Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.

R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months) effective on the date FERC approves the settlement in ER05-515.

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	-	(573,852,567)	-	
ADIT-283	(14)	(23,113,988)	(46,208,221)	
ADIT-190	74,977	51,160,461	5,162,435	
Subtotal	74,963	(545,806,094)	(41,045,786)	(586,776,917)
Wages & Salary Allocator			6.6442%	
Gross Plant Allocator		28.8614%		
ADIT	74,963	(157,527,089)	(2,727,171)	(160,179,297)

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 11

Amount 2,750,501

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed. Dissimilar iter
with amounts exceeding $100,000 will be listed separately

	A	B	C	D	E	F	G
		Total		Only			
			Gas, Prod or	Transmission			
ADIT-190			Other Related	Related	Plant	Labor	Justifications
190	BAD DEBT RESERVE	4,186,017	4,186,017				Under the Tax Reform Act of 1986, taxpayers were required to account for bad debts using the specific write-off method. The reserve method is used for book purposes. The amount represents the add-back of book reserve. Retail related.
190	ACCRUAL SEVERANCE	1,573,180				1,573,180	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual.
190	ENVIRONMENTAL EXPENSE	692,559	692,559				These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax no deduction is permitted until the "all events" test is met typically when economic performance has occurred. This book reserve is primarily related to Deepwater and BL England sites which should not be in transmission service. Generation Related.
190	MARK TO MARKET § 475 ADJUSTMENT	36,290			36,290		Pursuant to IRC Sec 475, the company is taking deduction to mark-to-market its accounts receivable. For book purposes, the receivables remained valued at their original amounts. Reflects unbilled revenues and customer accounts receivables. Applies to all functions.
190	OPEB	14,495,601				14,495,601	FAS No. 106 requires accrual basis instead of cash basis accounting for post retiremen health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	SECTION 461(H) - PREPAID INSURANCE	2,208,537			2,208,537		Book records a deduction for accrual liabilities of worker compensation and T&D property insurance. A tax deduction is only allowed for actual payments made. Related to both T & D plant
190	SERP	(149,116)				(149,116)	Affects company personnel across all functions
190	NOL	50,376,485			50,376,485		Related to both T & D plant
190	Stranded Costs	5,382,146	5,382,146				All Generation related
190	Accrued Liab - Auto	170,395				170,395	Affects company personnel across all functions
190	Accrued Liab - Misc.	2,483,650			2,483,650		Related to T&D plant
190	Deferred Comp	347,779				347,779	For book purposes, deferred compensation and deferred payments are expensed wher accrued. For tax purposes, they are not deducted until paid. Affects company personnel across all functions.
190	Accrued Liability - General	1,571,450			1,571,450		Related to T&D plant
190	Accrued Liability - Health Claim	275,152				275,152	Affects company personnel across all functions
190	Accrued Vacation	2,360,016				2,360,016	Affects company personnel across all functions
190	Charitable Contribution Limit	1,017,500	1,017,500				Related to gas, production or other
190	Income from Partnerships/Trusts	(151,927)	(151,927)				Related to gas, production or other
190	Accumulated Deferred Investment Tax Credi	1,979,863			1,979,863		Related to T&D plant
190	Reg Asset - FERC Formula Rate Adj. Trans. Svc	74,977		74,977			When a regulatory asset/liability is established, books credit/debit income, which for ta purposes needs to be reversed along with the associated amortization.
190	1999 AMT	(6,376,247)			(6,376,247)		Plant related
190	Accrued Liability - Directors' Fees	(45,057)			(45,057)		Related to T&D plant
190	BGS Deferred Related - Retail	15,632,782	15,632,782				Retail related
190	Accrued Sick Pay	585,028				585,028	Affects company personnel across all functions
190	Use Tax Reserve	905,354			905,354		Related to T&D plant
190	Other	629	629				Related to gas, production or other
190	Subtotal - p234	99,633,043	26,759,706	74,977	53,140,324	19,658,036	
	Less FASB 109 Above if not separately removed	1,979,863			1,979,863		
190	Less FASB 106 Above if not separately removed	14,495,601				14,495,601	FAS No. 106 requires accrual basis instead of cash basis accounting for post retiremen health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	Total	83,157,579	26,759,706	74,977	51,160,461	5,162,435	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excludec
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	A	B	C	D	E	F	G
ADIT-282		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
282	Plant Related	(573,852,567)			(573,852,567)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
	Subtotal - p275	(573,852,567)	-	-	(573,852,567)	-	
	Less FASB 109 Above if not separately removed	-					
	Less FASB 106 Above if not separately removed	-					
282	Total	(573,852,567)	-	-	(573,852,567)	-	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

	A	B	C	D	E	F	G
ADIT-283		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
283	LOSS ON REACQ DEBT	2,750,501	2,750,501				The cost of bond redemption is deductible currently for tax purposes and is amortized ove the life of the new bond issue for book purposes. Excluded here since included in Cost of Debt
283	ASBESTOS REMOVAL	(2)	(2)				Costs incurred and paid by the company for asbestos removal were tax deductible in full as paid . These costs were deferred and amortized for book purposes. Generation related.
283	Misc Deferred Debits - Retail	(44,319)	(44,319)				Retail related
283	DEFERRED EXPENSE CLEARING	(939,131)			(939,131)		Reflects the deferred taxes generated as a result of the tax deductions taken for actual store room expenses. For book purposes, these amounts were recorded as an asset in FERC account 163.
283	DSM COSTS	(117,333)	(117,333)				For books, Demand Side Management Costs are deferred. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature. Retail related.
283	Gross up on FAS 109 Deferred Taxes	(125,573,935)			(125,573,935)		FAS 109 Plant related
283	Stranded Costs	(52,369,659)	(52,369,659)				All Generation related
283	PENSION PAYMENT RESERVE	(43,361,260)				(43,361,260)	Affects company personnel across all functions
283	NUG BUYOUT	(16,218,049)	(16,218,049)				Generation related
283	AMORT of OPEB	(2)				(2)	OPEB, labor related and relates to all functions
283	Regulatory Asset - General	(460,163)				(460,163)	Regulatory liability for universal service func
283	Regulatory Asset - SREC Program	(3,520,409)	(3,520,409)				Generation related - Solar Renewable EnergyCertificate Program
283	Regulatory Asset - NJ RGGI	(677,248)	(677,248)				Related to gas, production or other
283	Reg Asset - FERC Formula Rate Adj. Trans. Svc	(14)		(14)			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
283	BGS Deferred Related - Retail	(47,647,942)	(47,647,942)				Retail related
283	Accrued Vacation	(2,386,794)				(2,386,794)	Affects company personnel across all functions
283	Decommissioning & Decontamination	(21,144)	(21,144)				Related to gas, production or other
283	Reg Asset-NJ Rec-Base	(12,621,823)			(12,621,823)		Related to both T & D plant
283	Interest on Contingent Taxes	(9,553,035)			(9,553,035)		Estimated book interest income on prior year taxes not included for tax purposes
283	Income from Partnerships/Trusts	(55,170)	(55,170)				Related to gas, production or other
283	Other	109,630,903	109,630,903				Related to gas, production or other
283	Subtotal - p277 (Form 1-F filer: see note 6, below)	(203,186,030)	(8,289,872)	(14)	(148,687,924)	(46,208,221)	
283	Less FASB 109 Above if not separately removed	(125,573,935)			(125,573,935)		
283	Less FASB 106 Above if not separately removed	-					
283	Total	(77,612,095)	(8,289,872)	(14)	(23,113,988)	(46,208,221)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

		Item	Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			
4	Amortization to line 133 of Appendix A	Total	5,307,291	848,130
5	Total		5,307,291	848,130
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.26	5,307,291	848,130
7	Difference /1		0	0

/1 Difference must be zero

Atlantic City Electric Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
1 Real property (State, Municipal or Local)	2,493,450		
2 Personal property	-		
3 City License	-		
4 State Excise	22,093		
Total Plant Related	2,515,543	28.8614%	726,020
Labor Related		***Wages & Salary Allocator***	
5 Federal FICA & Unemployment	1,739,343		
6 Unemployment	378,543		
Total Labor Related	2,117,886	6.6442%	140,717
Other Included		***Gross Plant Allocator***	
7 Miscellaneous	3,068		
Total Other Included	3,068	28.8614%	885
Total Included			867,622
Excluded			
8 State Franchise tax	-		
9 TEFA	9,618,651		
10 Use & Sales Tax	1,283,637		
11 Total "Other" Taxes (included on p. 263)	15,538,784		
12 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	15,538,784		
13 Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Atlantic City Electric Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		897,752
2	Total Rent Revenues	(Sum Line 1)	897,752
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 869,402
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		1,159,331
6	PJM Transitional Revenue Neutrality (Note 1)		-
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		619,380
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	3,545,865
12	Less line 17g		(632,226)
13	Total Revenue Credits		2,913,639

<u>Revenue Adjustment to determine Revenue Credit</u>

14 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 173 of Appendix A.

15 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

16 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	897,752
17b	Costs associated with revenues in line 17a	366,700
17c	Net Revenues (17a - 17b)	531,052
17d	50% Share of Net Revenues (17c / 2)	265,526
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	265,526
17g	Line 17f less line 17a	(632,226)
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.	12,100,865
19	Amount offset in line 4 above	82,465,252
20	Total Account 454, 456 and 456.1	98,111,982
21	Note 4: SECA revenues booked in Account 447.	

Atlantic City Electric Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE			
A	100 Basis Point increase in ROE and Income Taxes		(Line 127 + Line 138)	56,187,782
B	100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base		(Line 39 + 58)	422,072,221
	Long Term Interest			
100	Long Term Interest		p117.62c through 67c	67,173,739
101	Less LTD Interest on Securitization B	(Note P)	Attachment 8	14,894,670
102	**Long Term Interest**		"(Line 100 - line 101)"	52,279,069
103	**Preferred Dividends**	enter positive	p118.29c	0
	Common Stock			
104	Proprietary Capital		p112.16c	868,953,100
105	Less Preferred Stock	enter negative	(Line 114)	0
106	Less Account 216.1	enter negative	p112.12c	0
107	**Common Stock**		(Sum Lines 104 to 106)	868,953,100
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,071,319,580
109	Less Loss on Reacquired Debt	enter negative	p111.81.c	-8,625,030
110	Plus Gain on Reacquired Debt	enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	-2,750,501
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	-192,104,580
113	Total Long Term Debt		(Sum Lines Lines 108 to 112)	867,839,469
114	Preferred Stock		p112.3c	0
115	Common Stock		(Line 107)	868,953,100
116	**Total Capitalization**		(Sum Lines 113 to 115)	1,736,792,569
117	Debt %	(Note Q from Appendix A) Total Long Term Debt	(Line 113 / 116)	50%
118	Preferred %	(Note Q from Appendix A) Preferred Stock	(Line 114 / 116)	0%
119	Common %	(Note Q from Appendix A) Common Stock	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt	(Line 102 / 113)	0.0602
121	Preferred Cost	Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost	(Note J from Appendix A) Common Stock	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0301
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock	(Line 119 * 122)	0.0615
126	Total Return (R)		**(Sum Lines 123 to 125)**	**0.0916**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**38,670,359**

Composite Income Taxes (Note L)

	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite			8.99%
130	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%
132	T/ (1-T)			69.05%
	ITC Adjustment			
133	Amortized Investment Tax Credit	enter negative	p266.8f	-848,130
134	T/(1-T)		(Line 132)	69.05%
135	Net Plant Allocation Factor		(Line 18)	28.3571%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-406,577**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		17,924,000
138	**Total Income Taxes**			**17,517,423**

Atlantic City Electric Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 23,938,932	23,938,932	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	5,307,291	5,307,291	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,626,598	1,626,598	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3c	0			
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	51,891	51,891	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	12,898,257	782,029	12,116,228	Transmission Right of Way - Carll's Corner to Landis
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	4,144,900	0	4,144,900	

CWIP & Expensed Lease Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	2,762,757,177	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	787,143,444	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	220,777,696	0	0	See Form 1

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	0	0	See Form 1

Atlantic City Electric Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	4,144,900	0	4,144,900	Transmission related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,144,900	0	4,144,900	Transmission related.

Safety Related Advertising Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	254,678	-	254,678	None

MultiState Workpaper

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				NJ	PA				Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.9945%	9.00%	9.990%				Apportioned: NJ 8.8866%, PA 0.1079%

Education and Out Reach Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	254,678	-	254,678	None

Excluded Plant Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities					
149	Excluded Transmission Facilities		(Note M)	Attachment 5	-	General Description of the Facilities
	Instructions:				Enter $	None
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that					
	are not a result of the RTEP Process					
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,				Or	
	the following formula will be used:	Example			Enter $	
A	Total investment in substation	1,000,000				
B	Identifiable investment in Transmission (provide workpapers)	500,000				
C	Identifiable investment in Distribution (provide workpapers)	400,000				
D	Amount to be excluded (A x (C / (B + C)))	444,444				
						Add more lines if necessary

Atlantic City Electric Company

Attachment 5 - Cost Support

Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant relatec	6,795,874	6.64%	451,533	
	Plant Related	6,080,453	28.86%	1,754,902	
	Other		0.00%	-	
	Total Transmission Related Reserves	12,876,327		2,206,434	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			6.644%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	6.644%	-	
	Prepayments	$	19,134,338	6.644%	1,271,327	
	Prepaid Pensions if not included in Prepayments	$	106,156,644	6.644%	7,053,278	
			125,290,982		8,324,605	
						Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Atlantic City Electric Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)	-	Settelement agreement.

PJM Load Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	2,739.2	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
ACE zone						
Total						

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 11,562,337	$ 10,010,186	$ 20,420,219	$ 4,233,966	$ 46,226,708
Procurement & Administrative Services	5,632,450	4,165,574	9,450,856	317,756	19,566,636
Financial Services & Corporate Expenses	12,850,395	9,859,694	19,011,916	2,033,696	43,755,701
Insurance Coverage and Services	2,213,905	1,986,871	2,788,985	953,842	7,943,603
Human Resources	5,038,304	3,260,389	7,121,984	886,448	16,307,125
Legal Services	3,059,464	2,466,012	6,423,114	392,003	12,340,593
Audit Services	794,646	539,535	1,635,686	165,684	3,135,551
Customer Services	48,387,200	35,710,808	31,764,265	5,264	115,867,537
Utility Communication Services	97,515	-	150,770	-	248,285
Information Technology	15,258,104	10,897,942	33,943,020	299,235	60,398,301
External Affairs	2,912,889	2,316,651	4,804,603	379,617	10,413,760
Environmental Services	1,565,438	1,288,953	1,896,091	114,341	4,864,823
Safety Services	354,376	372,034	549,507	-	1,275,917
Regulated Electric & Gas T&D	30,083,042	23,758,286	42,089,790	15,969	95,947,087
Internal Consulting Services	566,310	347,896	876,072	-	1,790,278
Interns	179,453	83,801	207,544	210	471,008
Cost of Benefits	13,046,438	8,259,393	20,727,891	-	42,033,722
Building Services	8,916	103,717	5,007,690	2,288,416	7,408,739
Total	**$ 153,611,182**	**$ 115,427,742**	**$ 208,870,003**	**$ 12,086,447**	**$ 489,995,374**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	Dec 31, 2013

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	60,366,527	148,288,038	215,438	208,870,003
2	Delmarva Power & Light Company	39,151,966	114,302,402	156,814	153,611,182
3	Atlantic City Electric Company	24,662,631	90,645,605	119,506	115,427,742
4	Pepco Energy Services, Inc.	2,777,499	6,713,524	11,618	9,502,641
5	Conectiv, LLC	11,767	55,656	563	67,986
6	Potomac Capital Investment Corporation	576,358	297,172	661	874,191
7	Thermal Energy Limited Partnership	15,648	601,358	572	617,578
8	ATS Operating Services, Inc.	114	291,725	285	292,124
9	Atlantic Southern Properties	14,398	171,009	248	185,655
10	Conectiv Energy Supply, Inc.	18,264	21,562	119	39,945
11	Pepco Holdings, Inc.	139,689	36,414	145	176,248
12	Conectiv Properties and Investments, Inc.	25,260	129,408	174	154,842
13	Conectiv Thermal Systems	2,917	100,349	102	103,368
14	Conectiv Communications, Inc.	69	8,798	11	8,878
15	Atlantic City Electric Transition Funding, LLC	30,739	2,906	16	33,661
16	Conectiv North East, LLC	257	4,446	5	4,708
17	Delaware Operating Services Company	228	13,936	8	14,172
18	ATE Investments, Inc.	1,848	969	4	2,821
19	Atlantic Generation, Inc.	109	928	2	1,039
20	Conectiv Services II, Inc.	344	6,113	3	6,460
21	Conectiv Solutions LLC	125	5		130
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	127,796,757	361,692,323	506,294	489,995,374

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2013
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work in Progress	23,545,999	16,722,578	34,632,825	-	74,901,402	Not included
182.3	Other Regulatory Assets	10,488,915	114,841	11,696,727	-	22,300,483	Not included
184	Clearing Accounts - Other	(12,476)	(61,040)	78,748	(2,468)	2,764	Not included
408.1	Taxes other than inc taxes, utility operating inc	-	39,805	-	-	39,805	Not included
416-421	Other Income - Below the Line	374,987	626,685	587,151	12,088,915	13,677,738	Not included
426.1-426.5	Other Income Deductions - Below the Line	603,681	462,744	995,381	-	2,061,806	Not included
430	Interest-Debt to Associated Companies	229,913	175,178	315,777	-	720,868	Not included
431	Interest-Short Term Debt	(73,099)	(55,672)	(100,339)	-	(229,110)	Not included
556	System cont & load dispatch	1,602,698	1,401,597	1,249,833	-	4,254,128	Not included
557	Other expenses	1,311,562	1,194,307	1,669,382	-	4,175,251	Not included
560	Operation Supervision & Engineering	1,882,601	1,864,185	3,206,474	-	6,953,260	100% Inclusion
561	Load dispatching	-	48	-	-	48	100% Inclusion
561.1	Load Dispatching - Reliability	35,915	34,780	30,031	-	100,726	100% Inclusion
561.2	Load Dispatch - Monitor & Operate Transmission Sys	53,681	17,527	992,559	-	1,063,767	100% Inclusion
561.3	Load Dispatch - Transmission Service & Scheduling	47,778	54,385	28,496	-	130,659	100% Inclusion
561.5	Reliability, Planning and Standards	129,486	121,848	3,951	-	255,285	100% Inclusion
562	Station expenses	-	-	8,754	-	8,754	100% Inclusion
564	Underground Line Expenses - Transmission	-	-	6,434	-	6,434	100% Inclusion
566	Miscellaneous transmission expenses	457,843	240,714	463,170	-	1,161,727	100% Inclusion
568	Maintenance Supervision & Engineering	280,592	252,490	262,052	-	795,134	100% Inclusion
569.2	Maintenance of Computer Software	501,967	251,719	734,765	-	1,488,451	100% Inclusion
569.4	Maintenance of Transmission Plant	-	-	265	-	265	100% Inclusion
570	Maintenance of station equipment	150,049	86,648	405,920	-	642,617	100% Inclusion
571	Maintenance of overhead lines	132,737	177,852	244,888	-	555,477	100% Inclusion
572	Maintenance of underground lines	4,047	512	3,448	-	8,007	100% Inclusion
573	Maintenance of miscellaneous transmission plant	27,446	21,698	111,154	-	160,298	100% Inclusion
580	Operation Supervision & Engineering	658,487	331,800	755,181	-	1,745,468	Not included
581	Load dispatching	791,810	514,823	1,666,584	-	2,973,217	Not included
582	Station expenses	1,020,749	-	135,130	-	1,155,879	Not included
583	Overhead line expenses	73,167	132,571	27,597	-	233,335	Not included
584	Underground line expenses	26,046	-	112,600	-	138,646	Not included
585	Street lighting	2,232	-	91	-	2,323	Not included
586	Meter expenses	911,716	775,017	1,612,452	-	3,299,185	Not included
587	Customer installations expenses	48,804	73,395	494,290	-	616,489	Not included
588	Miscellaneous distribution expenses	3,840,313	4,228,331	6,315,909	-	14,384,553	Not included
589	Rents	27,645	21,112	-	-	48,757	Not included
590	Maintenance Supervision & Engineering	1,043,191	810,300	477,972	-	2,331,463	Not included
591	Maintain structures	-	-	3,880	-	3,880	Not included
592	Maintain equipment	481,027	422,133	1,051,748	-	1,954,908	Not included
593	Maintain overhead lines	880,924	696,824	1,702,388	-	3,280,136	Not included
594	Maintain underground line	76,399	58,003	671,570	-	805,972	Not included
595	Maintain line transformers	-	1,470	238,899	-	240,369	Not included
596	Maintain street lighting & signal systems	38,198	40,063	17,510	-	95,771	Not included
597	Maintain meters	17,551	34,757	64,712	-	117,020	Not included
598	Maintain distribution plant	30,723	17,358	885,881	-	933,962	Not included
800-894	Total Gas Accounts	2,213,518	-	-	-	2,213,518	Not included
902	Meter reading expenses	309,864	39,342	51,290	-	400,496	Not included
903	Customer records and collection expenses	36,340,896	35,227,261	31,444,855	-	103,013,012	Not included
907	Supervision - Customer Svc & Information	107,975	339,488	129,572	-	577,035	Not included
908	Customer assistance expenses	1,772,603	546,602	774,562	-	3,093,767	Not included
909	Informational & instructional advertising	111,858	28,138	157,175	-	297,171	Not included
913	Advertising expense	34,536	-	-	-	34,536	Not included
920	Administrative & General salaries	335,615	90,550	587,356	-	1,013,521	Wage & Salary Factor
921	Office supplies & expenses	49,363	39,388	77,162	-	165,913	Wage & Salary Factor
923	Outside services employed	48,324,843	39,986,311	81,108,695	-	169,419,849	Wage & Salary Factor
924	Property Insurance	96,402	82,096	187,290	-	365,788	Net Plant Factor
925	Injuries & damages	1,937,057	1,600,813	3,065,515	-	6,603,385	Wage & Salary Factor
926	Employee pensions & benefits	7,077,618	3,685,817	11,260,050	-	22,023,485	Wage & Salary Factor
928	Regulatory commission expenses	1,376,532	485,623	2,624,783	-	4,486,938	Direct Transmission only
929	Duplicate charges-Credit	329,386	133,081	1,370,676	-	1,833,143	Wage & Salary Factor
930.1	General ad expenses	9,007	8,683	42,842	-	60,532	Direct Transmission only
930.2	Miscellaneous general expenses	1,130,320	998,849	2,006,066	-	4,135,235	Wage & Salary Factor
935	Maintenance of general plant	308,485	232,314	119,874	-	660,673	Wage & Salary Factor
	Total	**153,611,182**	**115,427,742**	**208,870,003**	**12,086,447**	**489,995,374**	

Atlantic City Electric Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

79,847,077 Rev Req based on Year 1 data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	4,520,489				6.5	29,383,176	-	-	-	2,448,598	-	-	-	
Jul	637,095				5.5	3,504,024	-	-	-	292,002	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	5,157,584	-	-	-		32,887,200	-	-	-	2,740,600	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										2,740,600	-	-	-	
Input to Line 21 of Appendix A										2,740,600	-		-	2,740,600
Input to Line 43a of Appendix A												-		-
Month In Service or Month for CWIP										5.62	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 2,740,600 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

80,130,375 Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 80,130,375

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

85,984,003 Rev Req based on Prior Year data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2

For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 55,049,516 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	5,846,081				11.5	67,229,933	-	-	-	5,602,494	-	-	-	
Feb	6,198,950				10.5	65,088,975	-	-	-	5,424,081	-	-	-	
Mar	(606,687)				9.5	(5,763,524)	-	-	-	(480,294)	-	-	-	
Apr	7,293,039				8.5	61,990,835	-	-	-	5,165,903	-	-	-	
May	12,901,428				7.5	96,760,710	-	-	-	8,063,392	-	-	-	
Jun	7,822,009				6.5	50,843,057	-	-	-	4,236,921	-	-	-	
Jul	3,193,241				5.5	17,562,827	-	-	-	1,463,569	-	-	-	
Aug	(1,069,876)				4.5	(4,814,441)	-	-	-	(401,203)	-	-	-	
Sep	775,948				3.5	2,715,820	-	-	-	226,318	-	-	-	
Oct	2,934,441				2.5	7,336,103	-	-	-	611,342	-	-	-	
Nov	2,975,047				1.5	4,462,571	-	-	-	371,881	-	-	-	
Dec	6,785,893				0.5	3,392,946	-	-	-	282,746	-	-	-	
Total	55,049,516	-	-	-		366,805,811	-	-	-	30,567,151	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										30,567,151	-	-	-	
								Input to Line 21 of Appendix A		30,567,151	-		-	30,567,151
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.34	#DIV/0!	#DIV/0!	#DIV/0!	

83,512,979 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20

(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug	217,980				4.5	980,911	-	-	-	81,743	-	-	-	
Sep	1,967,886				3.5	6,887,601	-	-	-	573,967	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	2,185,866	-	-	-		7,868,512	-	-	-	655,709	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										655,709	-	-	-	
86,033,437								Input to Line 21 of Appendix A		655,709	-		-	655,709
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		8.40	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
83,512,979	-	81,816,934	=	1,696,045

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	141,337	0.2800%	11.5	4,551	145,888
Jul	Year 1	141,337	0.2800%	10.5	4,155	145,492
Aug	Year 1	141,337	0.2800%	9.5	3,760	145,097
Sep	Year 1	141,337	0.2800%	8.5	3,364	144,701
Oct	Year 1	141,337	0.2800%	7.5	2,968	144,305
Nov	Year 1	141,337	0.2800%	6.5	2,572	143,909
Dec	Year 1	141,337	0.2800%	5.5	2,177	143,514
Jan	Year 2	141,337	0.2800%	4.5	1,781	143,118
Feb	Year 2	141,337	0.2800%	3.5	1,385	142,722
Mar	Year 2	141,337	0.2800%	2.5	989	142,326
Apr	Year 2	141,337	0.2800%	1.5	594	141,931
May	Year 2	141,337	0.2800%	0.5	198	141,535
Total		1,696,045				1,724,539

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	1,724,539	0.2800%	146,341	1,583,027
Jul	Year 2	1,583,027	0.2800%	146,341	1,441,119
Aug	Year 2	1,441,119	0.2800%	146,341	1,298,813
Sep	Year 2	1,298,813	0.2800%	146,341	1,156,110
Oct	Year 2	1,156,110	0.2800%	146,341	1,013,006
Nov	Year 2	1,013,006	0.2800%	146,341	869,502
Dec	Year 2	869,502	0.2800%	146,341	725,596
Jan	Year 3	725,596	0.2800%	146,341	581,287
Feb	Year 3	581,287	0.2800%	146,341	436,574
Mar	Year 3	436,574	0.2800%	146,341	291,456
Apr	Year 3	291,456	0.2800%	146,341	145,932
May	Year 3	145,932	0.2800%	146,341	0
Total with interest				1,756,086	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	1,756,086
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 86,033,437
Revenue Requirement for Year 3	87,789,524

10 May Year 3 Post results of Step 9 on PJM web site

$ 87,789,524 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 87,789,524

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	11.8285%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	12.4584%
6	C		Line B less Line A	0.6299%

7 **FCR if a CIAC**

8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.5377%

9 **The FCR resulting from Formula in a given year is used for that year only.**

10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effecitve on December 1, 2007. Per FERC orde incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.**

		Details		B0265 Mickelton		B0276 Monroe	B0211 Union-Corson
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes		Yes	Yes
13	Useful life of project	Life		35		35	35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No		No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150		0	0
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		11.8285%		11.8285%	11.8285%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		12.7734%		11.8285%	11.8285%
18	Columns A, B or C from Attachment 6	Investment		4,854,660	may be weighted average of small projects	7,878,071	13,722,120
19	Line 18 divided by line 13	Annual Depreciation Exp		138,705		225,088	392,061
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00		6.00	9.00

		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
33	Base FCR	2014	4,230,489	138,705	4,091,785	622,702	6,865,176	225,088	6,640,088	1,010,512	11,663,802	392,061	11,271,741	1,725,340
34	W Increased ROE	2014	4,230,489	138,705	4,091,785	661,364	6,865,176	225,088	6,640,088	1,010,512	11,663,802	392,061	11,271,741	1,725,340
35	Base FCR	2015	4,091,785	138,705	3,953,080	606,295	6,640,088	225,088	6,415,001	983,887	11,271,741	392,061	10,879,681	1,678,965
36	W Increased ROE	2015	4,091,785	138,705	3,953,080	643,647	6,640,088	225,088	6,415,001	983,887	11,271,741	392,061	10,879,681	1,678,965
37	Base FCR	2016	3,953,080	138,705	3,814,376	589,889	6,415,001	225,088	6,189,913	957,263	10,879,681	392,061	10,487,620	1,632,590
38	W Increased ROE	2016	3,953,080	138,705	3,814,376	625,929	6,415,001	225,088	6,189,913	957,263	10,879,681	392,061	10,487,620	1,632,590
39	Base FCR	2017	3,814,376	138,705	3,675,671	573,482	6,189,913	225,088	5,964,825	930,638	10,487,620	392,061	10,095,560	1,586,215
40	W Increased ROE	2017	3,814,376	138,705	3,675,671	608,212	6,189,913	225,088	5,964,825	930,638	10,487,620	392,061	10,095,560	1,586,215
41	Base FCR	2018	3,675,671	138,705	3,536,967	557,075	5,964,825	225,088	5,739,737	904,013	10,095,560	392,061	9,703,499	1,539,840
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	590,495	5,964,825	225,088	5,739,737	904,013	10,095,560	392,061	9,703,499	1,539,840
43	Base FCR	2019	3,536,967	138,705	3,398,262	540,669	5,739,737	225,088	5,514,650	877,389	9,703,499	392,061	9,311,439	1,493,465
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	572,778	5,739,737	225,088	5,514,650	877,389	9,703,499	392,061	9,311,439	1,493,465
45	Base FCR	2020	3,398,262	138,705	3,259,557	524,262	5,514,650	225,088	5,289,562	850,764	9,311,439	392,061	8,919,378	1,447,091
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	555,060	5,514,650	225,088	5,289,562	850,764	9,311,439	392,061	8,919,378	1,447,091
47	Base FCR	2021	3,259,557	138,705	3,120,853	507,855	5,289,562	225,088	5,064,474	824,140	8,919,378	392,061	8,527,317	1,400,716
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	537,343	5,289,562	225,088	5,064,474	824,140	8,919,378	392,061	8,527,317	1,400,716
49	Base FCR	2022	3,120,853	138,705	2,982,148	491,448	5,064,474	225,088	4,839,386	797,515	8,527,317	392,061	8,135,257	1,354,341
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	519,626	5,064,474	225,088	4,839,386	797,515	8,527,317	392,061	8,135,257	1,354,341
51	Base FCR	2023	2,982,148	138,705	2,843,444	475,042	4,839,386	225,088	4,614,299	770,891	8,135,257	392,061	7,743,196	1,307,966
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	501,908	4,839,386	225,088	4,614,299	770,891	8,135,257	392,061	7,743,196	1,307,966
53	Base FCR	2024	2,843,444	138,705	2,704,739	458,635	4,614,299	225,088	4,389,211	744,266	7,743,196	392,061	7,351,136	1,261,591
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	484,191	4,614,299	225,088	4,389,211	744,266	7,743,196	392,061	7,351,136	1,261,591
55	Base FCR	2025	2,704,739	138,705	2,566,035	442,228	4,389,211	225,088	4,164,123	717,642	7,351,136	392,061	6,959,075	1,215,216
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	466,474	4,389,211	225,088	4,164,123	717,642	7,351,136	392,061	6,959,075	1,215,216
57	Base FCR	2026	2,566,035	138,705	2,427,330	425,822	4,164,123	225,088	3,939,035	691,017	6,959,075	392,061	6,567,015	1,168,841
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	448,757	4,164,123	225,088	3,939,035	691,017	6,959,075	392,061	6,567,015	1,168,841
59	Base FCR	2027	2,427,330	138,705	2,288,625	409,415	3,939,035	225,088	3,713,948	664,393	6,567,015	392,061	6,174,954	1,122,466
60	W Increased ROE	2027		138,705	(138,705)	120,987	3,939,035	225,088	3,713,948	664,393	6,567,015	392,061	6,174,954	1,122,466
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

ers in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmission

B0210 Orchard-500kV				B0210 Orchard-Below 500kV				B0277 Cumberland Sub:2nd Xfmr						
Yes				Yes				Yes						
35				35				35						
No				No				No						
150				150				150						
11.8285%				11.8285%				11.8285%						
12.7734%				12.7734%				12.7734%						
26,046,638				18,572,212				6,759,777						
744,190				530,635				193,136						
7.00				7				2						
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
22,015,611	744,190	21,271,421	3,260,283	15,697,941	530,635	15,167,306	2,324,702	6,019,420	193,136	5,826,284	882,299	$ 9,825,838		$ 9,825,838
22,015,611	744,190	21,271,421	3,461,269	15,697,941	530,635	15,167,306	2,468,012	6,019,420	193,136	5,826,284	937,350	$ 10,263,847	$ 10,263,847	
21,271,421	744,190	20,527,231	3,172,256	15,167,306	530,635	14,636,672	2,261,936	5,826,284	193,136	5,633,148	859,454	$ 9,562,794		$ 9,562,794
21,271,421	744,190	20,527,231	3,366,211	15,167,306	530,635	14,636,672	2,400,232	5,826,284	193,136	5,633,148	912,680	$ 9,985,622	$ 9,985,622	
20,527,231	744,190	19,783,042	3,084,230	14,636,672	530,635	14,106,037	2,199,169	5,633,148	193,136	5,440,011	836,609	$ 9,299,750		$ 9,299,750
20,527,231	744,190	19,783,042	3,271,153	14,636,672	530,635	14,106,037	2,332,452	5,633,148	193,136	5,440,011	888,010	$ 9,707,397	$ 9,707,397	
19,783,042	744,190	19,038,852	2,996,203	14,106,037	530,635	13,575,403	2,136,403	5,440,011	193,136	5,246,875	813,764	$ 9,036,705		$ 9,036,705
19,783,042	744,190	19,038,852	3,176,095	14,106,037	530,635	13,575,403	2,264,672	5,440,011	193,136	5,246,875	863,340	$ 9,429,172	$ 9,429,172	
19,038,852	744,190	18,294,662	2,908,177	13,575,403	530,635	13,044,768	2,073,637	5,246,875	193,136	5,053,738	790,919	$ 8,773,661		$ 8,773,661
19,038,852	744,190	18,294,662	3,081,037	13,575,403	530,635	13,044,768	2,196,893	5,246,875	193,136	5,053,738	838,670	$ 9,150,947	$ 9,150,947	
18,294,662	744,190	17,550,473	2,820,150	13,044,768	530,635	12,514,133	2,010,871	5,053,738	193,136	4,860,602	768,073	$ 8,510,617		$ 8,510,617
18,294,662	744,190	17,550,473	2,985,978	13,044,768	530,635	12,514,133	2,129,113	5,053,738	193,136	4,860,602	814,000	$ 8,872,722	$ 8,872,722	
17,550,473	744,190	16,806,283	2,732,123	12,514,133	530,635	11,983,499	1,948,105	4,860,602	193,136	4,667,465	745,228	$ 8,247,573		$ 8,247,573
17,550,473	744,190	16,806,283	2,890,920	12,514,133	530,635	11,983,499	2,061,333	4,860,602	193,136	4,667,465	789,330	$ 8,594,497	$ 8,594,497	
16,806,283	744,190	16,062,093	2,644,097	11,983,499	530,635	11,452,864	1,885,338	4,667,465	193,136	4,474,329	722,383	$ 7,984,529		$ 7,984,529
16,806,283	744,190	16,062,093	2,795,862	11,983,499	530,635	11,452,864	1,993,553	4,667,465	193,136	4,474,329	764,660	$ 8,316,273	$ 8,316,273	
16,062,093	744,190	15,317,904	2,556,070	11,452,864	530,635	10,922,229	1,822,572	4,474,329	193,136	4,281,192	699,538	$ 7,721,485		$ 7,721,485
16,062,093	744,190	15,317,904	2,700,804	11,452,864	530,635	10,922,229	1,925,773	4,474,329	193,136	4,281,192	739,989	$ 8,038,048	$ 8,038,048	
15,317,904	744,190	14,573,714	2,468,044	10,922,229	530,635	10,391,595	1,759,806	4,281,192	193,136	4,088,056	676,693	$ 7,458,441		$ 7,458,441
15,317,904	744,190	14,573,714	2,605,746	10,922,229	530,635	10,391,595	1,857,993	4,281,192	193,136	4,088,056	715,319	$ 7,759,823	$ 7,759,823	
14,573,714	744,190	13,829,524	2,380,017	10,391,595	530,635	9,860,960	1,697,040	4,088,056	193,136	3,894,919	653,848	$ 7,195,396		$ 7,195,396
14,573,714	744,190	13,829,524	2,510,687	10,391,595	530,635	9,860,960	1,790,213	4,088,056	193,136	3,894,919	690,649	$ 7,481,598	$ 7,481,598	
13,829,524	744,190	13,085,335	2,291,990	9,860,960	530,635	9,330,326	1,634,274	3,894,919	193,136	3,701,783	631,002	$ 6,932,352		$ 6,932,352
13,829,524	744,190	13,085,335	2,415,629	9,860,960	530,635	9,330,326	1,722,433	3,894,919	193,136	3,701,783	665,979	$ 7,203,373	$ 7,203,373	
13,085,335	744,190	12,341,145	2,203,964	9,330,326	530,635	8,799,691	1,571,507	3,701,783	193,136	3,508,646	608,157	$ 6,669,308		$ 6,669,308
13,085,335	744,190	12,341,145	2,320,571	9,330,326	530,635	8,799,691	1,654,653	3,701,783	193,136	3,508,646	641,309	$ 6,925,148	$ 6,925,148	
12,341,145	744,190	11,596,955	2,115,937	8,799,691	530,635	8,269,056	1,508,741	3,508,646	193,136	3,315,510	585,312	$ 6,406,264		$ 6,406,264
12,341,145	744,190	11,596,955	2,225,513	8,799,691	530,635	8,269,056	1,586,873	3,508,646	193,136	3,315,510	616,639	$ 6,336,871	$ 6,336,871	
....	....	.....	....	....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....		$ -	
													$ 176,293,711	$ 169,214,145

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	14,894,670
	Capitalization	
112	**Less LTD on Securitization Bonds**	192,104,580

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2013 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 25 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Attachment 4D - PEPCO Formula Rate Update

Attachment 4D

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

202-872-2122
202-331-6767 Fax
alblauman@pepcoholdings.com

May 15, 2014

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426

Re: Potomac Electric Power Company ("Pepco")
Informational Filing of 2014 Formula Rate Annual Update in
Docket No. ER09-1159 and Pursuant to Approved Settlement Agreement
in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Pepco hereby submits electronically, for informational purposes, its 2014 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al.*, (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Pepco [Potomac Electric Power Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate Year, and:
>
> (i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and
>
> (ii) file such Annual Update with FERC as an informational filing.[1]

The same information contained in this informational filing has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to aspects of the Annual Update. Consequently,

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[1] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H9-B, Section 1.b.

and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Pepco's 2014 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

Pepco has made no Material Accounting Changes as defined in the Settlement.[3] Pepco has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[4] Additionally, Pepco has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[5]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Potomac Electric Power Company

Enclosures

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[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1159 (February 17, 2010).
[3] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.f (iii). For the Commission's information, Pepco no longer records PHI Service Company costs in Account 923 "Outside Services Employed," if those costs meet the definition of Account 928 "Regulatory Commission Expenses."
[4] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.g.
[5] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.h.

ATTACHMENT H-9A

Potomac Electric Power Company

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	2013
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21b	$ 5,937,055
2	Total Wages Expense		p354.28b	$ 70,114,012
3	Less A&G Wages Expense		p354.27b	$ 6,087,532
4	Total		(Line 2 - 3)	64,026,480
5	Wages & Salary Allocator		(Line 1 / 4)	9.2728%
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 6,718,923,061
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	6,718,923,061
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 2,617,393,411
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 106,902,617
11	Accumulated Common Amortization - Electric	(Note A)	p356	0
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	2,724,296,028
14	Net Plant		(Line 8 - 13)	3,994,627,033
15	Transmission Gross Plant		(Line 29 - Line 28)	1,198,805,993
16	Gross Plant Allocator		(Line 15 / 8)	17.8422%
17	Transmission Net Plant		(Line 39 - Line 28)	773,773,409
18	Net Plant Allocator		(Line 17 / 14)	19.3704%
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 1,148,025,457
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	17,950,913
22	Total Transmission Plant In Service		(Line 19 - 20 + 21)	1,165,976,370
23	General & Intangible		p205.5.g & p207.99.g	354,041,723
24	Common Plant (Electric Only)	(Notes A & B)	p356	0
25	Total General & Common		(Line 23 + 24)	354,041,723
26	Wage & Salary Allocation Factor		(Line 5)	9.27281%
27	General & Common Plant Allocated to Transmission		(Line 25 * 26)	32,829,623
28	Plant Held for Future Use (Including Land)	(Note C)	p214	0
29	TOTAL Plant In Service		(Line 22 + 27 + 28)	1,198,805,993
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	402,859,372
31	Accumulated General Depreciation		p219.28.c	132,218,079
32	Accumulated Intangible Amortization		(Line 10)	106,902,617
33	Accumulated Common Amortization - Electric		(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	0
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	239,120,696
36	Wage & Salary Allocation Factor		(Line 5)	9.27281%
37	General & Common Allocated to Transmission		(Line 35 * 36)	22,173,212
38	TOTAL Accumulated Depreciation		(Line 30 + 37)	425,032,584
39	TOTAL Net Property, Plant & Equipment		(Line 29 - 38)	773,773,409
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-205,447,577
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	19.37%
43	Accumulated Deferred Income Taxes Allocated To Transmission		(Line 41 * 42) + Line 40	-205,447,577
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)	(Note B)	p216.43.b as Shown on Attachment 6	0
43b	Unamortized Abandoned Transmission Plant		Attachment 5	0
	Transmission O&M Reserves			
44	Total Balance Transmission Related Account 242 Reserves	Enter Negative	Attachment 5	-4,204,895
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	33,281,874
46	Total Prepayments Allocated to Transmission		(Line 45)	33,281,874
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	2,984,000
48	Wage & Salary Allocation Factor		(Line 5)	9.27%
49	Total Transmission Allocated		(Line 47 * 48)	276,701
50	Transmission Materials & Supplies		p227.8c	5,696,621
51	Total Materials & Supplies Allocated to Transmission		(Line 49 + 50)	5,973,322
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	40,519,740
53	1/8th Rule		x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission		(Line 52 * 53)	5,064,968
	Network Credits			
55	Outstanding Network Credits	(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0
57	Net Outstanding Credits		(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base		(Line 43 + 43a + 43b + 44 + 46 + 51 + 54 - 57)	-165,332,308
59	Rate Base		(Line 39 + 58)	608,441,100

O&M

	Transmission O&M			
60	Transmission O&M		p321.112.b	28,513,454
61	Less extraordinary property loss		Attachment 5	0
62	Plus amortized extraordinary property loss		Attachment 5	0
63	Less Account 565		p321.96.b	0
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data	0
65	Plus Transmission Lease Payments	(Note A)	p200.3.c	0
66	Transmission O&M		(Lines 60 - 63 + 64 + 65)	28,513,454
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	0
68	Total A&G		p323.197.b	139,966,697
69	Less Property Insurance Account 924		p323.185b	1,048,952
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	9,380,223
71	Less General Advertising Exp Account 930.1		p323.191b	2,250,343
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	0
73	Less EPRI Dues	(Note D)	p352-353	0
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)	127,287,179
75	Wage & Salary Allocation Factor		(Line 5)	9.2728%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)	11,803,101
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	0
80	Property Insurance Account 924		p323.185b	1,048,952
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
82	Total		(Line 80 + 81)	1,048,952
83	Net Plant Allocation Factor		(Line 18)	19.37%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)	203,186
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)	40,519,740

Depreciation & Amortization Expense

	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	25,266,582
86a	Amortization of Abandoned Transmission Plant		Attachment 5	0
87	General Depreciation		p336.10b&c	7,683,806
88	Intangible Amortization	(Note A)	p336.1d&e	2,178,935
89	Total		(Line 87 + 88)	9,862,741
90	Wage & Salary Allocation Factor		(Line 5)	9.2728%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)	914,553
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	0
95	Wage & Salary Allocation Factor		(Line 5)	9.2728%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization		(Line 86 + 86a + 91 + 96)	26,181,135

Taxes Other than Income

98	Taxes Other than Income	Attachment 2	8,709,500
99	Total Taxes Other than Income	(Line 98)	8,709,500

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	111,104,658
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	Long Term Interest			"(Line 100 - line 101)"	111,104,658
103	Preferred Dividends		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,922,346,859
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	-1,646,367
107	Common Stock			(Sum Lines 104 to 106)	1,920,700,492
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,909,500,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-24,630,347
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	8,564,525
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	1,893,434,178
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,920,700,492
116	Total Capitalization			(Sum Lines 113 to 115)	3,814,134,670
117	Debt %	Total Long Term Debt		(Line 113 / 116)	50%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0%
119	Common %	Common Stock		(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0587
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0291
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0569
126	Total Return (R)			(Sum Lines 123 to 125)	0.0860
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	52,346,391

Composite Income Taxes

	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite	(Note I)		8.97%
130	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.83%
132	T/ (1-T)			69.00%
	ITC Adjustment	(Note I)		
133	Amortized Investment Tax Credit	enter negative	p266.8f	-873,695
134	T/(1-T)		(Line 132)	69.00%
135	Net Plant Allocation Factor		(Line 18)	19.3704%
136	ITC Adjustment Allocated to Transmission		(Line 133 * (1 + 134) * 135)	-286,018
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 132 * 127 * (1-(123 / 126))]	23,890,908
138	Total Income Taxes		(Line 136 + 137)	23,604,889

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	773,773,409
140	Adjustment to Rate Base		(Line 58)	-165,332,308
141	Rate Base		(Line 59)	608,441,100
142	O&M		(Line 85)	40,519,740
143	Depreciation & Amortization		(Line 97)	26,181,135
144	Taxes Other than Income		(Line 99)	8,709,500
145	Investment Return		(Line 127)	52,346,391
146	Income Taxes		(Line 138)	23,604,889
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	151,361,655
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,148,025,457
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,148,025,457
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	151,361,655
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	151,361,655
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	6,206,755
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	145,154,900
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	145,154,900
158	Net Transmission Plant		(Line 19 - 30)	745,166,085
159	Net Plant Carrying Charge		(Line 157 / 158)	19.4795%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	16.0888%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	5.8963%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	69,203,620
163	Increased Return and Taxes		Attachment 4	81,129,473
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	150,333,093
165	Net Transmission Plant		(Line 19 - 30)	745,166,085
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	20.1744%
167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 163 - 86) / 165	16.7837%
168	Net Revenue Requirement		(Line 156)	145,154,900
169	True-up amount		Attachment 6	(133,608)
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	1,459,415
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515		Attachment 5	-
171a	MAPP Abandonment recovery pursuant to ER13-607		Attachment 5	16,524,210
172	Net Zonal Revenue Requirement		(Line 168 - 169 + 171)	163,004,917
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	6,533
174	Rate ($/MW-Year)		(Line 172 / 173)	24,949
175	Network Service Rate ($/MW/Year)		(Line 174)	24,949

Notes

A Electric portion only
B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant
that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected
to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5.
For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
C Transmission Portion Only
D All EPRI Annual Membership Dues
E All Regulatory Commission Expenses
F Safety related advertising included in Account 930.1
G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
"the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in
Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that
elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce
rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686 and
ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November
J 1, 2008 respectively. Per FERC order in Docket No. ER13-607 the ROE for the MAPP abandoned plant is 10.8% effective March 1, 2013.
K Education and outreach expenses relating to transmission, for example siting or billing
L As provided for in Section 34.1 of the PJM OATT and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.
M Amount of transmission plant excluded from rates per Attachment 5.
N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments
(net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A.
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 155.
O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M.
If they are booked to Acct 565, they are included in on line 64
P Securitization bonds may be included in the capital structure per settlement in ER05-515.
Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.
R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months)
effective on the date FERC approves the settlement in ER05-515.

END

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	***Plant Related***	***Labor Related***	***Total ADIT***
ADIT- 282	0	(1,130,747,761)	(13,223,172)	
ADIT-283	(11,269,171)	(108,949,085)	(105,446,889)	
ADIT-190	985,023	197,710,939	18,917,547	
Subtotal	(10,284,147)	(1,041,985,907)	(99,752,515)	
Wages & Salary Allocator			9.2728%	
Gross Plant Allocator		17.8422%		
ADIT	(10,284,147)	(185,913,567)	(9,249,863)	(205,447,577)

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 111

Amount	(8,564,525)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A ***ADIT-190***	**B** ***Total***	**C** ***Gas, Prod Or Other Related***	**D** ***Only Transmission Related***	**E** ***Plant Related***	**F** ***Labor Related***	**G** ***Justification***
Deferred Compensation(stk)	3,205,162				3,205,162	For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are deducted when paid. Affects company personnel across all functions.
Bad Debt Reserve Amort	6,735,997			6,735,997		Under the Tax Reform Act of 1986, taxpayers were required to switch from the reserve method for bad debts to the specific write-off method. The amounts previously accumulated in a reserve were required to be included in taxable income over a four year period. The reserve method is used for book purposes. Related to all revenues.
Excess Accrued Vacation Pay	1,961,442				1,961,442	For book purposes, accrued vacation pay is expensed during the current year. For tax purposes, only the portion of the vacation allowance actually taken or paid by March 15th of the following year can be deducted currently. Affects company personnel across all functions.
FAS 109 - Deferred Taxes on ITC	1,135,864			1,135,864		Pursuant to the requirements of FAS 109, Pepco's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant.
FAS 109 Regulatory Receivable/Liability	2,095,237			2,095,237		Pursuant to the requirements of FAS 109, Pepco's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant.
PG County Right of Way	451,318	451,318				For book purposes, these taxes were accrued when the proposed tax was enacted by the PG County Council. Since Maryland counties are prohibited from enacting any tax without the authority of the state legislature, for tax purposes they are not deductible until the tax is affirmed. Related to both T & D.
Mirant Settlement	4,104,266	4,104,266				Represents a payment from Mirant to Pepco to settle some of the Company's claims. For book purposes the payment was accounted for on the balance sheet as a contingent liablilty. For tax purposes, since the funds were received, a portion of the payment was treated as currently taxable.
Health Care Plans	1,061,343			1,061,343		Additions to the reserve for health insurance payments are deducted currently for book purposes but are deducted for tax purposes when they are paid. Affects company personnel across all functions
Severance Pay/Other Comp/Incentive Bonus	2,495,316				2,495,316	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual. Affects company personnel across all functions.
Accrued Retired Executive Compensation	1,213,275				1,213,275	This adjustment relates to the PNC Deferred Compensation Plans. For tax purposes, the book income/expense generated on the plans is reversed and then the tax income/expense is picked up
Accrued Liability - Environmental Site Exp	8,584,812	8,584,812				For book purposes, environmental expenses are expensed when accrued. For tax purposes, they are deducte when paid.
Prepaid Interest	2,037,674				2,037,674	For book purposes, prepaid expenses, which related to a future period but are paid in the current period, mus be capitalized and amortized to the balance sheet as an assset. For tax purposes, there is "12-month rule" which allows taxpayers that meet the 12-month rule to currently deduct the amount, as long as the benefits does not extend beyond 12 months. The prepaid interest relates to the Life Insurance plans, that is why this is labor related.
Contribution Carryforward	3,359,389			3,359,389		PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
Capital Loss Limitation	(6,179)	(6,179)				Capital losses are limited to the amount of capital gains.
FAS 106 OPEB Adjustment	32,707,421				32,707,421	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
Regulatory Assets- FERC True Up	985,023		985,023			For book purposes, a regulatory asset has been established for the FERC Formula Rate Filing true-up and book income has been increased. For tax purposes, this Regulatory Asset is not recognized and the book income must be reversed.
Federal/State NOL	192,729,450			184,724,772	8,004,677	PHI's consolidated return is in an NOL situation, therefore, they are carried forward until such time as PHI is in a taxable income position.
Interest on Contingent Taxes	602,399	602,399				Estimated book interest expense on prior year taxes not deductible for tax purpose
Miscellaneous	767,748	(1,061,689)		1,829,437		Relates to deferred taxes on regulatory assets and accrued liabilities. For regulatory assets books credits income and tax reverses the income and amortizes. For accrued liabilities books accrues expense and for tax the expense can only be deducted when paid
Subtotal - p234	266,226,957	12,674,926	985,023	200,942,040	51,624,967	
Less FASB 109 Above if not separately removed	3,231,101	-	-	3,231,101		
Less FASB 106 Above if not separately removed	32,707,421				32,707,421	
Total	230,288,435	12,674,926	985,023	197,710,939	18,917,547	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Accelerated Depreciation	(446,020,445)			(446,020,445)		This amount represents the difference between the tax depreciation on assets place in service after 1974 as computed pursuant to the Internal Revenue Code and the book depreciation associated with all assets
Repair Allowance	(380,567,183)			(380,567,183)		Deferred tax represents the difference between tax deductible repairs and book capitalization of repair costs. Affects company personnel across all functions.
Adj. Tax Gain - TDR's	871,366			871,366		This adjustment reflects the disposition or salvage relating to TDRs. For tax purposes salvage is required to be recognized currently as taxable income for certain depreciation vintages. For book purposes salvage is credited to the depreciation reserve. Relates to plant in all functions.
Adjust. Tax Gain (Operating)	176,452			176,452		This adjustment reflects the disposition or salvage relating to operating assets. For tax purposes salvage is required to be recognized currently as taxable income for certain depreciation vintages. For book purposes salvage is credited to the depreciation reserve. Related to all assets.
Control Center - Depreciation/Amort	(95,640,834)			(95,640,834)		For book purposes, the rental payments on the control center are expensed during the current year. For tax purposes, control center is treated as if Pepco continues to own it. The rent expense is added back to book income, the assets are depreciated and interest expense is imputed and deducted. Sale/lease back of center used for control of T & D.
Removal Cost Adjustment	(80,558,327)			(80,558,327)		Removal costs are deductible for tax purposes but are recorded as a reduction to the depreciation reserve for book purposes. Removal costs relating to post-1980 assets are required to be normalized under the Internal Revenue Code. Related to all assets.
Capitalized Interest	42,009,120			42,009,120		The Tax Reform Act of 1986 eliminated the current deduction for interest incurred during construction and required that it be capitalized and depreciated over the tax life of the asset. This deferred tax is due to the differences in the way AFUDC-debt is calculated versus the way interest must be calculated for tax purposes. Related to all plant.
AFUDC Debt	(7,351,764)			(7,351,764)		For book purposes, AFUDC is capitalized and depreciated. For tax purposes, AFUDC is not recognized. Related to all plant.
Capitalized Real Estate Taxes	(7,809)			(7,809)		For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Related to all plant.
Extraordinary Gain-Nova	(8,303,806)	(8,303,806)				This deferred tax balance relates to a prior Internal Revenue Service audit related to the sale of Pepco's northern Virginia sales territory and assets located therein. Retail related
Construction Per. Interest(Net)	264,333			264,333		For tax purposes some interest was required to be capitalized related to self constructed assets. For book purposes, AFUDC is used. Related to all plant.
FAS 109 - CCRF/AFUDC Equity	(45,586,631)			(45,586,631)		See the explanation for Account 190.
69 KV Line Amortization	218,609	218,609				This deferred tax balance relates to a prior Internal Revenue Service audit related to the depreciation period for 69kv line costs. Distribution related.
Simplified Service Method	(288,319,695)			(288,319,695)		For book purposes, certain overhead costs are capitalized and depreciated over the life of the related asset. For tax purposes, these overheads are currently deducted. Related to all plant
EUM Assets	6,253,612	6,253,612				This deferred tax balance relates to a prior Internal Revenue Service audit related to the depreciation of Energy Use Mgt. assets. Retail related
Casualty Losses	(21,007,670)			(21,007,670)		This deferred tax balance relates to the run out of the depreciation expense related to the 1998 casualty loss claim filed with the IRS. This item was previously included in depreciation above.
Control Center - Lease Payment	117,565,430			117,565,430		For book purposes, the rental payments on the control center are expensed during the current year. For tax purposes, control center is treated as if Pepco continues to own it. The rent expense is added back to book income, the assets are depreciated and interest expense is imputed and deducted. Sale/lease back of center used for control of T & D.
CIAC	81,102,929			81,102,929		Under the Tax Reform Act of 1986, post '86 CIAC must be included in income for tax purposes. Under IRS Notice 87-51, if CIAC are not grossed up, the deferred taxes must be included in rate base in order for the Company to be in compliance with the depreciation normalization provisions of the Internal Revenue Code. Related to both T & D plant.
Connection Fees	(3,257,050)	(3,257,050)				Connection fees are considered taxable income by the Internal Revenue Service and their costs are capitalized and depreciated for tax purposes. For book purposes, connection fees are excluded from income and from the depreciable cost of the assets as a contribution in aid of construction. Retail related.
Preliminary Survey Costs	46,915	46,915				For tax purposes, survey costs are to be capitalized under 263A and depreciated.
Conservation Costs (DSM)	(11,325,757)	(11,325,757)				DSM related. Retail related.
Pension Curtailment	3,496,754	3,496,754				For book purposes, these costs were expensed when the gain on the divestiture sale were recorded. For tax purposes, the costs are deducted when paid. Related to sale of generation assets.
SFAS 121 Impairment Loss	859,870	859,870				Write down of Benning/Buzzard point plant to fair market value based on the SFAS 121 impairment test for book purposes. For tax purposes, an asset can not be written down for the loss. Generation related
Capitalized A&G	1,342,018			1,342,018		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Capit'd Fringe Benefits	2,567,338			2,567,338		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Capit'd Payroll & Use Tax	1,274,152			1,274,152		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Leased Vehicles	(1,041,969)			(1,041,969)		For tax purposes leased vehicles are capitalized and depreciated. For book purposes, the vehicles are treated as leases, with a monthly lease amount being calculated. For tax purposes, a portion of the monthly lease amount needs to be added back.
Control Center - Interest Expense	(79,212,723)			(79,212,723)		For book purposes, the rental payments on the control center are expensed during the current year. For tax purposes, control center is treated as if Pepco continues to own it. The rent expense is added back to book income, the assets are depreciated and interest expense is imputed and deducted. Sale/lease back of center used for control of T & D.
FAS 109 - CCRF Equity	(15,743,143)	(15,743,143)				See the explanation for Account 190.
Capitalized Pension	21,807,520			21,807,520		For book purposes, a portion of pension is capitalized based on labor dollars charged to capital construction projects. For tax purposes, this capitalization must be revrsed and replaced with tax capitalization. Tax capitalization is based on the same capitalization percentage, but is applied to the current period funding rather the ant the book expesnes.
Capitalized OPEB	(13,223,172)				(13,223,172)	For book purposes, a portion of OPEB is capitalized based on labor dollars charged to capital construction projects. For tax purposes, this capitalization must be reversed and replaced with tax capitalization. Tax capitalization is based on the same capitalization percentage, but is applied to the current period funding rather than the book expenses.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(1,217,311,561)	(27,753,996)	0	(1,176,334,392)	(13,223,172)	
Less FASB 109 Above if not separately removed	(61,329,774)	(15,743,143)	0	(45,586,631)	0	
Less FASB 106 Above if not separately removed	0					
Total	(1,155,981,787)	(12,010,853)	0	(1,130,747,761)	(13,223,172)	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Amort Loss on Reacquisition	(8,564,525)	(8,564,525)				The cost of bond redemption is deductible currently for tax purposes and is amortized over the life of the new bond issue for book purposes. Related to all functions.
FAS 109 - Flowthrough Items	(45,042,563)			(45,042,563)		See the explanation for Account 190.
Pension Plan Contribution	(128,082,077)			(56,356,115)	(71,725,962)	The company is allowed to deduct for tax purposes all payments made to fund the General Retirement Plan per ERISA. For book purposes pension plan contributions are governed by FAS 106. This timing difference represents the excess tax payment over book. Affects company personnel across all functions.
Customer Sharing	(2,875,643)	(2,875,643)				For book purposes, the gain on the divestiture of the generating assets to be shared with customers was expensed when the gain on the sale was recorded. For tax purposes, gain to be shared is deducted when paid. Generation related
Blueprint for the Future	(2,849,679)			(2,849,679)		For book purposes, the cost of the Blueprint project is being currently deducted. For tax purposes, this amount can not be deducted current and must be capitalized.
Regulatory Assets- FERC True Up	(1,407,322)		(1,407,322)			For book purposes, a regulatory asset has been established for the FERC Formula Rate Filing true-up and book income has been increased. For tax purposes, this Regulatory Asset is not recognized and the book income must be reversed.
Regulatory Assets - MAPP - Transmission Only	(9,861,849)		(9,861,849)			Represents deferred taxes on MAPP abandonment costs that are currently deductible for income tax purposes, versus amounts included in the MAPP Regulatory Asset that are amortized to book expense over a longer time period.
Regulatory Assets	(132,284,166)	(48,819,949)		(49,743,291)	(33,720,927)	When a regulatory asset is established, books credits income, which for tax purposes needs to be reversed along with the associated amortization.
MD Property Taxes	(6,635,101)	(6,635,101)				For book purposes, the MD property taxes are accrued over the fiscal year. For tax purposes payments are deducted when paid based on the lien date.
Interest on Contingent Taxes	(6,368,219)	(6,368,219)				Estimated book interest income on prior year taxes not included for tax purposes
Miscellaneous	(2,051,971)	(2,051,971)				Relates to deferred taxes on regulatory assets and accrued liabilities. For regulatory assets books credits income and tax reverses the income and amortizes.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(346,023,115)	(75,315,408)	(11,269,171)	(153,991,647)	(105,446,889)	
Less FASB 109 Above if not separately removed	(45,042,563)			(45,042,563)		
Less FASB 106 Above if not separately removed	-				-	
Total	(300,980,552)	(75,315,408)	(11,269,171)	(108,949,085)	(105,446,889)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

		Item	Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			
4	Amortization to line 133 of Appendix A	Total	2,804,722	873,695
5	Total		2,804,722	873,695
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.2	2,804,722	873,695
7	Difference /1		-	-

/1 Difference must be zero

Potomac Electric Power Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	***Page 263 Col (i)***	***Allocator***	***Allocated Amount***
	Plant Related		***Gross Plant Allocator***	
1	Transmission Personal Property Tax (directly assigned to Transmission)	$ 8,236,143	100%	$ 8,236,143
1a	Other Personal Property Tax (excluded)	$ 25,844,466	0%	$ -
2	Capital Stock Tax		17.8422%	$ -
3	Gross Premium (insurance) Tax		17.8422%	$ -
4	PURTA		17.8422%	$ -
5	Corp License		17.8422%	$ -
			17.8422%	$ -
	Total Plant Related	34,080,609		8,236,143
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & state unemployment	5,073,414		
	Total Labor Related	5,073,414	9.2728%	470,448
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous	16,302		
	Total Other Included	16,302	17.8422%	2,909
	Total Included			8,709,500
	Currently Excluded			
8	Franchise	22,019,187		
9	kWhTax - State Gross Receipt (Excise Tax)	85,736,470		
10	Electric environmental surcharge	2,165,690		
11	Universal service fee	9,418,155		
12	Montgomery County Fuel	152,769,645		
13	PSC assessment	7,996,639		
14	Real property (State, Municipal or Local)	6,304,234		
15	DC Right of Way	22,615,888		
16	Use & Sales Tax	4,681,601		
17	FHUT	22,243		
18	DC Ballpark	16,500		
19	DC Reliable Energy Trust Fund	17,790,115		
20	Misc. Other	24,395		
21	Total "Other" Taxes (included on p. 263)	370,731,087		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	370,731,087		
23	Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Allocation of Property taxes to Transmission Function

Year Ended December 31, 2013

Assessable Plant

Transmission	$	849,239,283
Distribution	$	2,582,204,799
General	$	134,109,618
Total T,D&Genl	$	3,565,553,700

Plant ratios by Jurisdiction

Transmission Ratio	0.2381787949
Distribution ratio	0.7242086409
General Ratio	0.0376125642
	1.0000000000

Property Taxes	$	34,080,609
Transmission Property Tax	$	8,117,278
Distribution Property tax	$	24,681,472
General Property Tax	$	1,281,859
Total check	$	34,080,609

General Property Tax	$	1,281,859
Trans Labor Ratio		9.273%
Trans General		118,864

Total Transmission Property Taxes

Transmission	$	8,117,278
General	$	118,864
Total Transmission Property Taxes	$	8,236,143

Potomac Electric Power Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		11,507,275
2	Total Rent Revenues	(Sum Lines 1)	11,507,275
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 600,522
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		2,201,787
6	PJM Transitional Revenue Neutrality (Note 1)		
7	PJM Transitional Market Expansion (Note 1)		
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	14,309,584
12	Less line 17g		(8,102,829)
13	Total Revenue Credits		6,206,755
	<u>**Revenue Adjustment to determine Revenue Credit**</u>		
14	Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 173 of Appendix A.		
15	Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.		
16	Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).		
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.		11,507,275
17b	Costs associated with revenues in line 17a		4,698,383
17c	Net Revenues (17a - 17b)		6,808,892
17d	50% Share of Net Revenues (17c / 2)		3,404,446
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-
17f	Net Revenue Credit (17d + 17e)		3,404,446
17g	Line 17f less line 17a		(8,102,829)
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.		75,749,395
19	Amount offset in line 4 above		146,940,799
20	Total Account 454, 456 and 456.1		236,999,778
21	Note 4: SECA revenues booked in Account 447.		

Potomac Electric Power Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE			
A	100 Basis Point increase in ROE and Income Taxes		(Line 127 + Line 138)	81,129,473
B	100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base		(Line 39 + 58)	608,441,100
	Long Term Interest			
100	**Long Term Interest**		p117.62c through 67c	111,104,658
101	Less LTD Interest on Securitization E	(Note P)	Attachment 8	0
102	Long Term Interest		"(Line 100 - line 101)"	111,104,658
103	Preferred Dividends	enter positive	p118.29c	0
	Common Stock			
104	Proprietary Capital		p112.16c	1,922,346,859
105	Less Preferred Stock	enter negative	(Line 114)	0
106	Less Account 216.1	enter negative	p112.12c	-1,646,367
107	Common Stock		(Sum Lines 104 to 106)	1,920,700,492
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,909,500,000
109	Less Loss on Reacquired Debt	enter negative	p111.81c	-24,630,347
110	Plus Gain on Reacquired Debt	enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	8,564,525
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
113	Total Long Term Debt		(Sum Lines 108 to 112)	1,893,434,178
114	Preferred Stock		p112.3c	0
115	Common Stock		(Line 107)	1,920,700,492
116	Total Capitalization		(Sum Lines 113 to 115)	3,814,134,670
117	Debt %	Total Long Term Debt	(Line 113 / 116)	50%
118	Preferred %	Preferred Stock	(Line 114 / 116)	0%
119	Common %	Common Stock	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt	(Line 102 / 113)	0.0587
121	Preferred Cost	Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost (Note J from Appendix A)	Common Stock	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0291
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock	(Line 119 * 122)	0.0619
126	Total Return (R)		**(Sum Lines 123 to 125)**	**0.0911**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**55,410,344**

Composite Income Taxes

	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite			8.97%
130	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.83%
132	T/ (1-T)			69.00%
	ITC Adjustment			
133	Amortized Investment Tax Credit	enter negative	p266.8f	(873,695)
134	T/(1-T)		(Line 132)	69%
135	Net Plant Allocation Factor		(Line 18)	19.3704%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-286,018**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		26,005,147
138	**Total Income Taxes**			**25,719,129**

Potomac Electric Power Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 106,902,617	106,902,617	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	$ 2,804,723	2,804,723	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 2,984,000	2,984,000	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3.c				
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	$ 2,178,935	2,178,935	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	$ 42,753,029	0	42,753,029	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.189b	$ 9,380,223	0	9,380,223	Enter Details
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	$ 6,718,923,061	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 1,148,025,457	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 402,859,372	0	0	See Form 1

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	$ -	-	See Form 1

Potomac Electric Power Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 9,380,223	0	9,380,223	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	$ 9,380,223	0	9,380,223	FERC

Safety Related Advertising Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	$ 2,250,343	-	2,250,343	None

MultiState Workpaper

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Maryland	DC	Enter State	Enter State	Enter State	Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.969%	8.25%	9.975%	Enter %	Enter %	Enter %	Apportioned: MD 4.67%, DC 4.30%

Education and Out Reach Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	$ 2,250,343	0	2,250,343	None

Excluded Plant Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0	General Description of the Facilities
	Instructions:			Enter $	None
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process				
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	Example		Or Enter $	
A	Total investment in substation	1,000,000			
B	Identifiable investment in Transmission (provide workpapers)	500,000			
C	Identifiable investment in Distribution (provide workpapers)	400,000			
D	Amount to be excluded (A x (C / (B + C)))	444,444			
					Add more lines if necessary

Potomac Electric Power Company

Attachment 5 - Cost Support

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant related	37,344,924	9.27%	3,462,925	
	Plant Related	4,158,509	17.84%	741,971	
	Other		0.00%	-	
	Total Transmission Related Reserves	41,503,433		4,204,895	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Description of the Prepayments
45	Prepayments			To Line 45	
5	Wages & Salary Allocator		9.273%		
	Pension Liabilities, if any, in Account 242	-	9.273%	-	
	Prepayments	$ 26,938,808	9.273%	2,497,985	
	Prepaid Pensions if not included in Prepayments	$ 331,980,095	9.273%	30,783,889	
		358,918,903	9.27%	33,281,874	

Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5	$ -	5	$ -	$ -

Potomac Electric Power Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515	-	

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	6,533.4	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
Pepco zone				-	-	-
Total				-	-	-

Abandoned Tranmission Plant

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
A	Beginning Balance of Unamortized Transmission Plant	Per FERC Order	
B	Months Remaining in Amortization Period	Per FERC Order	
C	Monthly Ammortization	A/B	
D	Months in Year to be Amortized		
E	Amortization in Rate Year	C*D	Line 86a
F	Deductions		
G	End of Year Balance in Unamortized Transmission Plant	A-E-F	Line 43b

MAPP Abandonment recovery pursuant to ER13-607

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
		DPL	Pepco	Total
171a	2013-14 rate period	$ 9,750,649	$ 12,725,412	$ 22,476,061
171a	2014-15 rate period	$ 14,666,395	16,524,210	$ 31,190,605
171a	2015-16 rate period	$ 12,208,522	14,624,812	$ 26,833,334
	Total	$ 36,625,566	$ 43,874,434	$ 80,500,000

Potomac Electric Power Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non-Regulated	Total
Executive Management	$ 11,562,337	$ 10,010,186	$ 20,420,219	$ 4,233,966	$ 46,226,708
Procurement & Administrative Services	5,632,450	4,165,574	9,450,856	317,756	19,566,636
Financial Services & Corporate Expenses	12,850,395	9,859,694	19,011,916	2,033,696	43,755,701
Insurance Coverage and Services	2,213,905	1,986,871	2,788,985	953,842	7,943,603
Human Resources	5,038,304	3,260,389	7,121,984	886,448	16,307,125
Legal Services	3,059,464	2,466,012	6,423,114	392,003	12,340,593
Audit Services	794,646	539,535	1,635,686	165,684	3,135,551
Customer Services	48,387,200	35,710,808	31,764,265	5,264	115,867,537
Utility Communication Services	97,515	-	150,770	-	248,285
Information Technology	15,258,104	10,897,942	33,943,020	299,235	60,398,301
External Affairs	2,912,889	2,316,651	4,804,603	379,617	10,413,760
Environmental Services	1,565,438	1,288,953	1,896,091	114,341	4,864,823
Safety Services	354,376	372,034	549,507	-	1,275,917
Regulated Electric & Gas T&D	30,083,042	23,758,286	42,089,790	15,969	95,947,087
Internal Consulting Services	566,310	347,896	876,072	-	1,790,278
Interns	179,453	83,801	207,544	210	471,008
Cost of Benefits	13,046,438	8,259,393	20,727,891	-	42,033,722
Building Services	8,916	103,717	5,007,690	2,288,416	7,408,739
Total	**$ 153,611,182**	**$ 115,427,742**	**$ 208,870,003**	**$ 12,086,447**	**$ 489,995,374**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	Dec 31, 2013

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	60,366,527	148,288,038	215,438	208,870,003
2	Delmarva Power & Light Company	39,151,966	114,302,402	156,814	153,611,182
3	Atlantic City Electric Company	24,662,631	90,645,605	119,506	115,427,742
4	Pepco Energy Services, Inc.	2,777,499	6,713,524	11,618	9,502,641
5	Conectiv, LLC	11,767	55,656	563	67,986
6	Potomac Capital Investment Corporation	576,358	297,172	661	874,191
7	Thermal Energy Limited Partnership	15,648	601,358	572	617,578
8	ATS Operating Services, Inc.	114	291,725	285	292,124
9	Atlantic Southern Properties	14,398	171,009	248	185,655
10	Conectiv Energy Supply, Inc.	18,264	21,562	119	39,945
11	Pepco Holdings, Inc.	139,689	36,414	145	176,248
12	Conectiv Properties and Investments, Inc.	25,260	129,408	174	154,842
13	Conectiv Thermal Systems	2,917	100,349	102	103,368
14	Conectiv Communications, Inc.	69	8,798	11	8,878
15	Atlantic City Electric Transition Funding, LLC	30,739	2,906	16	33,661
16	Conectiv North East, LLC	257	4,446	5	4,708
17	Delaware Operating Services Company	228	13,936	8	14,172
18	ATE Investments, Inc.	1,848	969	4	2,821
19	Atlantic Generation, Inc.	109	928	2	1,039
20	Conectiv Services II, Inc.	344	6,113	3	6,460
21	Conectiv Solutions LLC	125	5		130
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	127,796,757	361,692,323	506,294	489,995,374

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2013
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	23,545,999	16,722,578	34,632,825	-	74,901,402	Not included
182.3	Other Regulatory Assets	10,488,915	114,841	11,696,727	-	22,300,483	Not included
184	Clearing Accounts - Other	(12,476)	(61,040)	78,748	(2,468)	2,764	Not included
408.1	Taxes other than inc taxes, utility operating inc	-	39,805	-	-	39,805	Not included
416-421	Other Income - Below the Line	374,987	626,685	587,151	12,088,915	13,677,738	Not included
426.1-426.5	Other Income Deductions - Below the Line	603,681	462,744	995,381	-	2,061,806	Not included
430	Interest-Debt to Associated Companies	229,913	175,178	315,777	-	720,868	Not included
431	Interest-Short Term Debt	(73,099)	(55,672)	(100,339)	-	(229,110)	Not included
556	System cont & load dispatch	1,602,698	1,401,597	1,249,833	-	4,254,128	Not included
557	Other expenses	1,311,562	1,194,307	1,669,382	-	4,175,251	Not included
560	Operation Supervision & Engineering	1,882,601	1,864,185	3,206,474	-	6,953,260	100% Inclusion
561	Load dispatching	-	48	-	-	48	100% Inclusion
561.1	Load Dispatching - Reliability	35,915	34,780	30,031	-	100,726	100% Inclusion
561.2	Load Dispatch - Monitor & Operate Transmission Sys	53,681	17,527	992,559	-	1,063,767	100% Inclusion
561.3	Load Dispatch - Transmission Service & Scheduling	47,778	54,385	28,496	-	130,659	100% Inclusion
561.5	Reliability, Planning and Standards	129,486	121,848	3,951	-	255,285	100% Inclusion
562	Station expenses	-	-	8,754	-	8,754	100% Inclusion
564	Underground Line Expenses - Transmission	-	-	6,434	-	6,434	100% Inclusion
566	Miscellaneous transmission expenses	457,843	240,714	463,170	-	1,161,727	100% Inclusion
568	Maintenance Supervision & Engineering	280,592	252,490	262,052	-	795,134	100% Inclusion
569.2	Maintenance of Computer Software	501,967	251,719	734,765	-	1,488,451	100% Inclusion
569.4	Maintenance of Transmission Plant	-	-	265	-	265	100% Inclusion
570	Maintenance of station equipment	150,049	86,648	405,920	-	642,617	100% Inclusion
571	Maintenance of overhead lines	132,737	177,852	244,888	-	555,477	100% Inclusion
572	Maintenance of underground lines	4,047	512	3,448	-	8,007	100% Inclusion
573	Maintenance of miscellaneous transmission plant	27,446	21,698	111,154	-	160,298	100% Inclusion
580	Operation Supervision & Engineering	658,487	331,800	755,181	-	1,745,468	Not included
581	Load dispatching	791,810	514,823	1,666,584	-	2,973,217	Not included
582	Station expenses	1,020,749	-	135,130	-	1,155,879	Not included
583	Overhead line expenses	73,167	132,571	27,597	-	233,335	Not included
584	Underground line expenses	26,046	-	112,600	-	138,646	Not included
585	Street lighting	2,232	-	91	-	2,323	Not included
586	Meter expenses	911,716	775,017	1,612,452	-	3,299,185	Not included
587	Customer installations expenses	48,804	73,395	494,290	-	616,489	Not included
588	Miscellaneous distribution expenses	3,840,313	4,228,331	6,315,909	-	14,384,553	Not included
589	Rents	27,645	21,112	-	-	48,757	Not included
590	Maintenance Supervision & Engineering	1,043,191	810,300	477,972	-	2,331,463	Not included
591	Maintain structures	-	-	3,880	-	3,880	Not included
592	Maintain equipment	481,027	422,133	1,051,748	-	1,954,908	Not included
593	Maintain overhead lines	880,924	696,824	1,702,388	-	3,280,136	Not included
594	Maintain underground line	76,399	58,003	671,570	-	805,972	Not included
595	Maintain line transformers	-	1,470	238,899	-	240,369	Not included
596	Maintain street lighting & signal systems	38,198	40,063	17,510	-	95,771	Not included
597	Maintain meters	17,551	34,757	64,712	-	117,020	Not included
598	Maintain distribution plant	30,723	17,358	885,881	-	933,962	Not included
800-894	Total Gas Accounts	2,213,518	-	-	-	2,213,518	Not included
902	Meter reading expenses	309,864	39,342	51,290	-	400,496	Not included
903	Customer records and collection expenses	36,340,896	35,227,261	31,444,855	-	103,013,012	Not included
907	Supervision - Customer Svc & Information	107,975	339,488	129,572	-	577,035	Not included
908	Customer assistance expenses	1,772,603	546,602	774,562	-	3,093,767	Not included
909	Informational & instructional advertising	111,858	28,138	157,175	-	297,171	Not included
913	Advertising expense	34,536	-	-	-	34,536	Not included
920	Administrative & General salaries	335,615	90,550	587,356	-	1,013,521	Wage & Salary Factor
921	Office supplies & expenses	49,363	39,388	77,162	-	165,913	Wage & Salary Factor
923	Outside services employed	48,324,843	39,986,311	81,108,695	-	169,419,849	Wage & Salary Factor
924	Property insurance	96,402	82,096	187,290	-	365,788	Net Plant Factor
925	Injuries & damages	1,937,057	1,600,813	3,065,515	-	6,603,385	Wage & Salary Factor
926	Employee pensions & benefits	7,077,618	3,685,817	11,260,050	-	22,023,485	Wage & Salary Factor
928	Regulatory commission expenses	1,376,532	485,623	2,624,783	-	4,486,938	Direct Transmission only
929	Duplicate charges-Credit	329,386	133,081	1,370,676	-	1,833,143	Wage & Salary Factor
930.1	General ad expenses	9,007	8,683	42,842	-	60,532	Direct Transmission only
930.2	Miscellaneous general expenses	1,130,320	998,849	2,006,066	-	4,135,235	Wage & Salary Factor
935	Maintenance of general plant	308,485	232,314	119,874	-	660,673	Wage & Salary Factor
	Total	153,611,182	115,427,742	208,870,003	12,086,447	489,995,374	

Potomac Electric Power Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

152,424,577 Rev Req based on Year 1 data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			47,203,050		11.5	-	-	542,835,080	-	-	-	45,236,257	-	
Feb			-		10.5	-	-	-	-	-	-	-	-	
Mar			(47,203,050)		9.5	-	-	(448,428,979)	-	-	-	(37,369,082)	-	
Apr	8,096,839		-		8.5	68,823,132	-	-	-	5,735,261	-	-	-	
May			-		7.5	-	-	-	-	-	-	-	-	
Jun	36,103,548		-		6.5	234,673,062	-	-	-	19,556,089	-	-	-	
Jul			-		5.5	-	-	-	-	-	-	-	-	
Aug			-		4.5	-	-	-	-	-	-	-	-	
Sep	2,800,000		-		3.5	9,800,000	-	-	-	816,667	-	-	-	
Oct			-		2.5	-	-	-	-	-	-	-	-	
Nov	8,669,220		-		1.5	13,003,830	-	-	-	1,083,653	-	-	-	
Dec	-		-		0.5	-	-	-	-	-	-	-	-	
Total	55,669,607	-	-	-		326,300,024	-	-	-	27,191,669	-	7,867,175	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										27,191,669	-	7,867,175	-	
Input to Line 21 of Appendix A										27,191,669	-		-	27,191,669
Input to Line 43a of Appendix A												7,867,175		7,867,175
Month In Service or Month for CWIP										6.14	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 27,191,669 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

156,359,235 Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 156,359,235

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

159,376,720 Rev Req based on Prior Year data Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2

For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 62,986,910 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	$1,520,492		47,203,050		11.5	17,485,662	-	542,835,080	-	1,457,138	-	45,236,257	-	
Feb	$1,174,758		0		10.5	12,334,955	-	-	-	1,027,913	-	-	-	
Mar	$11,127,991		-47,203,050		9.5	105,715,911	-	(448,428,979)	-	8,809,659	-	(37,369,082)	-	
Apr	$7,885,161				8.5	67,023,871	-	-	-	5,585,323	-	-	-	
May	$4,200,959				7.5	31,507,190	-	-	-	2,625,599	-	-	-	
Jun	$5,759,465				6.5	37,436,523	-	-	-	3,119,710	-	-	-	
Jul	$1,363,534				5.5	7,499,440	-	-	-	624,953	-	-	-	
Aug	$19,845,118				4.5	89,303,032	-	-	-	7,441,919	-	-	-	
Sep	$12,138				3.5	42,484	-	-	-	3,540	-	-	-	
Oct	$5,706,792				2.5	14,266,981	-	-	-	1,188,915	-	-	-	
Nov	$216,950				1.5	325,425	-	-	-	27,119	-	-	-	
Dec	$4,173,551				0.5	2,086,775	-	-	-	173,898	-	-	-	
Total	62,986,910	-	-	-		385,028,249	-	-	-	32,085,687	-	7,867,175	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										32,085,687	-	7,867,175	-	
								Input to Line 21 of Appendix A		32,085,687	-		-	32,085,687
								Input to Line 43a of Appendix A				7,867,175		7,867,175
								Month In Service or Month for CWIP		5.89	#DIV/0!	#DIV/0!	#DIV/0!	

157,096,534 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20

(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar	7,134,930				9.5	67,781,835	-	-	-	5,648,486	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct	59,051,650				2.5	147,629,125	-	-	-	12,302,427	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	66,186,580	-	-	-		215,410,960	-	-	-	17,950,913	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		17,950,913	-	-	-	
163,138,525								Input to Line 21 of Appendix A		17,950,913	-		-	17,950,913
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		8.75	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
157,096,534	-	155,391,116	=	1,705,418

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	142,118	0.2800%	11.5	4,576	146,694
Jul	Year 1	142,118	0.2800%	10.5	4,178	146,296
Aug	Year 1	142,118	0.2800%	9.5	3,780	145,899
Sep	Year 1	142,118	0.2800%	8.5	3,382	145,501
Oct	Year 1	142,118	0.2800%	7.5	2,984	145,103
Nov	Year 1	142,118	0.2800%	6.5	2,587	144,705
Dec	Year 1	142,118	0.2800%	5.5	2,189	144,307
Jan	Year 2	142,118	0.2800%	4.5	1,791	143,909
Feb	Year 2	142,118	0.2800%	3.5	1,393	143,511
Mar	Year 2	142,118	0.2800%	2.5	995	143,113
Apr	Year 2	142,118	0.2800%	1.5	597	142,715
May	Year 2	142,118	0.2800%	0.5	199	142,317
Total		1,705,418				1,734,069

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	1,734,069	0.2800%	147,149	1,591,775
Jul	Year 2	1,591,775	0.2800%	147,149	1,449,083
Aug	Year 2	1,449,083	0.2800%	147,149	1,305,991
Sep	Year 2	1,305,991	0.2800%	147,149	1,162,499
Oct	Year 2	1,162,499	0.2800%	147,149	1,018,605
Nov	Year 2	1,018,605	0.2800%	147,149	874,307
Dec	Year 2	874,307	0.2800%	147,149	729,606
Jan	Year 3	729,606	0.2800%	147,149	584,500
Feb	Year 3	584,500	0.2800%	147,149	438,987
Mar	Year 3	438,987	0.2800%	147,149	293,067
Apr	Year 3	293,067	0.2800%	147,149	146,738
May	Year 3	146,738	0.2800%	147,149	(0)
Total with interest				1,765,791	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	(133,608)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 163,138,525
Revenue Requirement for Year 3	163,004,917

10 May Year 3 Post results of Step 9 on PJM web site

$ 163,004,917 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 163,004,917

Potomac Electric Power Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	16.0888%
5	B	167	Net Plant Carrying Charge per 100 Basis Point in ROE without Deprecia	16.7837%
6	C		Line B less Line A	0.6949%

7 **FCR if a CIAC**

Line				
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Ta	5.8963%

9 **The FCR resulting from Formula in a given year is used for that year only.**

10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effecitve on Dece**

		Details		B0288 Brighton Sub	B0251 Bells Mill 230kV Capacitors
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes
13	Useful life of project	Life		35	35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150	0
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		16.0888%	16.0888%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		17.1312%	16.0888%
18	Columns A, B or C from Attachment 6	Investment		33,558,380	6,986,903
19	Line 18 divided by line 13	Annual Depreciation/ Amortization Exp		958,811	199,626
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.50	5.50

		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
33	Base FCR	2014	29,283,682	958,811	28,324,871	5,515,944	6,279,895	199,626	6,080,269	1,177,868
34	W Increased ROE	2014	29,283,682	958,811	28,324,871	5,811,190	6,279,895	199,626	6,080,269	1,177,868
35	Base FCR	2015	28,324,871	958,811	27,366,060	5,361,683	6,080,269	199,626	5,880,643	1,145,751
36	W Increased ROE	2015	28,324,871	958,811	27,366,060	5,646,935	6,080,269	199,626	5,880,643	1,145,751
37	Base FCR	2016	27,366,060	958,811	26,407,249	5,207,422	5,880,643	199,626	5,681,018	1,113,634
38	W Increased ROE	2016	27,366,060	958,811	26,407,249	5,482,679	5,880,643	199,626	5,681,018	1,113,634
39	Base FCR	2017	26,407,249	958,811	25,448,438	5,053,160	5,681,018	199,626	5,481,392	1,081,516
40	W Increased ROE	2017	26,407,249	958,811	25,448,438	5,318,424	5,681,018	199,626	5,481,392	1,081,516
41	Base FCR	2018	25,448,438	958,811	24,489,627	4,898,899	5,481,392	199,626	5,281,766	1,049,399
42	W Increased ROE	2018	25,448,438	958,811	24,489,627	5,154,169	5,481,392	199,626	5,281,766	1,049,399
43	Base FCR	2019	24,489,627	958,811	23,530,816	4,744,638	5,281,766	199,626	5,082,140	1,017,281
44	W Increased ROE	2019	24,489,627	958,811	23,530,816	4,989,913	5,281,766	199,626	5,082,140	1,017,281
45	Base FCR	2020	23,530,816	958,811	22,572,006	4,590,377	5,082,140	199,626	4,882,514	985,164
46	W Increased ROE	2020	23,530,816	958,811	22,572,006	4,825,658	5,082,140	199,626	4,882,514	985,164
47	Base FCR	2021	22,572,006	958,811	21,613,195	4,436,116	4,882,514	199,626	4,682,889	953,047
48	W Increased ROE	2021	22,572,006	958,811	21,613,195	4,661,402	4,882,514	199,626	4,682,889	953,047
49	Base FCR	2022	21,613,195	958,811	20,654,384	4,281,854	4,682,889	199,626	4,483,263	920,929
50	W Increased ROE	2022	21,613,195	958,811	20,654,384	4,497,147	4,682,889	199,626	4,483,263	920,929
51	Base FCR	2023	20,654,384	958,811	19,695,573	4,127,593	4,483,263	199,626	4,283,637	888,812
52	W Increased ROE	2023	20,654,384	958,811	19,695,573	4,332,891	4,483,263	199,626	4,283,637	888,812
53	Base FCR	2024	19,695,573	958,811	18,736,762	3,973,332	4,283,637	199,626	4,084,011	856,694
54	W Increased ROE	2024	19,695,573	958,811	18,736,762	4,168,636	4,283,637	199,626	4,084,011	856,694
55	Base FCR	2025	18,736,762	958,811	17,777,951	3,819,071	4,084,011	199,626	3,884,385	824,577
56	W Increased ROE	2025	18,736,762	958,811	17,777,951	4,004,380	4,084,011	199,626	3,884,385	824,577
57	Base FCR	2026	17,777,951	958,811	16,819,140	3,664,810	3,884,385	199,626	3,684,760	792,460
58	W Increased ROE	2026	17,777,951	958,811	16,819,140	3,840,125	3,884,385	199,626	3,684,760	792,460
59	Base FCR	2027	16,819,140	958,811	15,860,330	3,510,548	3,684,760	199,626	3,485,134	760,342
60	W Increased ROE	2027	16,819,140	958,811	15,860,330	3,675,870	3,684,760	199,626	3,485,134	760,342
61		....		....	.....	....		....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

mber 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by

B0252 Northern System Rel -3 230 Caps				BO319 Burches Hill 500/230 kV transformer - second 1000 MVA				BO367.1/BO367.2 Reconductor Dickerson-Quince Orchard 230 kV				BO512.7 Chalk Point 230 kV Breaker 1A			
Yes				No				Yes				Yes			
35				35				35				35			
No				No				No				No			
0				150				150				0			
16.0888%				16.0888%				16.0888%				16.0888%			
16.0888%				17.1312%				17.1312%				16.0888%			
5,013,166				36,700,000				20,000,000				2,000,000			
143,233				1,048,571				571,429				57,143			
5.50				8.00				8.00				8.00			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
4,505,881	143,233	4,362,648	845,131	34,253,333	1,048,571	33,204,762	6,390,821	18,666,667	571,429	18,095,238	3,482,736	1,866,667	57,143	1,809,524	348,274
4,505,881	143,233	4,362,648	845,131	34,253,333	1,048,571	33,204,762	6,736,933	18,666,667	571,429	18,095,238	3,671,353	1,866,667	57,143	1,809,524	348,274
4,362,648	143,233	4,219,415	822,087	33,204,762	1,048,571	32,156,190	6,222,118	18,095,238	571,429	17,523,810	3,390,800	1,809,524	57,143	1,752,381	339,080
4,362,648	143,233	4,219,415	822,087	33,204,762	1,048,571	32,156,190	6,557,300	18,095,238	571,429	17,523,810	3,573,461	1,809,524	57,143	1,752,381	339,080
4,219,415	143,233	4,076,181	799,042	32,156,190	1,048,571	31,107,619	6,053,416	17,523,810	571,429	16,952,381	3,298,864	1,752,381	57,143	1,695,238	329,886
4,219,415	143,233	4,076,181	799,042	32,156,190	1,048,571	31,107,619	6,377,668	17,523,810	571,429	16,952,381	3,475,568	1,752,381	57,143	1,695,238	329,886
4,076,181	143,233	3,932,948	775,998	31,107,619	1,048,571	30,059,048	5,884,713	16,952,381	571,429	16,380,952	3,206,928	1,695,238	57,143	1,638,095	320,693
4,076,181	143,233	3,932,948	775,998	31,107,619	1,048,571	30,059,048	6,198,036	16,952,381	571,429	16,380,952	3,377,676	1,695,238	57,143	1,638,095	320,693
3,932,948	143,233	3,789,715	752,953	30,059,048	1,048,571	29,010,476	5,716,010	16,380,952	571,429	15,809,524	3,114,992	1,638,095	57,143	1,580,952	311,499
3,932,948	143,233	3,789,715	752,953	30,059,048	1,048,571	29,010,476	6,018,403	16,380,952	571,429	15,809,524	3,279,784	1,638,095	57,143	1,580,952	311,499
3,789,715	143,233	3,646,481	729,909	29,010,476	1,048,571	27,961,905	5,547,308	15,809,524	571,429	15,238,095	3,023,056	1,580,952	57,143	1,523,810	302,306
3,789,715	143,233	3,646,481	729,909	29,010,476	1,048,571	27,961,905	5,838,771	15,809,524	571,429	15,238,095	3,181,891	1,580,952	57,143	1,523,810	302,306
3,646,481	143,233	3,503,248	706,864	27,961,905	1,048,571	26,913,333	5,378,605	15,238,095	571,429	14,666,667	2,931,120	1,523,810	57,143	1,466,667	293,112
3,646,481	143,233	3,503,248	706,864	27,961,905	1,048,571	26,913,333	5,659,138	15,238,095	571,429	14,666,667	3,083,999	1,523,810	57,143	1,466,667	293,112
3,503,248	143,233	3,360,015	683,820	26,913,333	1,048,571	25,864,762	5,209,903	14,666,667	571,429	14,095,238	2,839,184	1,466,667	57,143	1,409,524	283,918
3,503,248	143,233	3,360,015	683,820	26,913,333	1,048,571	25,864,762	5,479,506	14,666,667	571,429	14,095,238	2,986,107	1,466,667	57,143	1,409,524	283,918
3,360,015	143,233	3,216,782	660,775	25,864,762	1,048,571	24,816,190	5,041,200	14,095,238	571,429	13,523,810	2,747,248	1,409,524	57,143	1,352,381	274,725
3,360,015	143,233	3,216,782	660,775	25,864,762	1,048,571	24,816,190	5,299,873	14,095,238	571,429	13,523,810	2,888,214	1,409,524	57,143	1,352,381	274,725
3,216,782	143,233	3,073,548	637,730	24,816,190	1,048,571	23,767,619	4,872,497	13,523,810	571,429	12,952,381	2,655,312	1,352,381	57,143	1,295,238	265,531
3,216,782	143,233	3,073,548	637,730	24,816,190	1,048,571	23,767,619	5,120,241	13,523,810	571,429	12,952,381	2,790,322	1,352,381	57,143	1,295,238	265,531
3,073,548	143,233	2,930,315	614,686	23,767,619	1,048,571	22,719,048	4,703,795	12,952,381	571,429	12,380,952	2,563,376	1,295,238	57,143	1,238,095	256,338
3,073,548	143,233	2,930,315	614,686	23,767,619	1,048,571	22,719,048	4,940,608	12,952,381	571,429	12,380,952	2,692,430	1,295,238	57,143	1,238,095	256,338
2,930,315	143,233	2,787,082	591,641	22,719,048	1,048,571	21,670,476	4,535,092	12,380,952	571,429	11,809,524	2,471,440	1,238,095	57,143	1,180,952	247,144
2,930,315	143,233	2,787,082	591,641	22,719,048	1,048,571	21,670,476	4,760,976	12,380,952	571,429	11,809,524	2,594,537	1,238,095	57,143	1,180,952	247,144
2,787,082	143,233	2,643,848	568,597	21,670,476	1,048,571	20,621,905	4,366,389	11,809,524	571,429	11,238,095	2,379,504	1,180,952	57,143	1,123,810	237,950
2,787,082	143,233	2,643,848	568,597	21,670,476	1,048,571	20,621,905	4,581,343	11,809,524	571,429	11,238,095	2,496,645	1,180,952	57,143	1,123,810	237,950
2,643,848	143,233	2,500,615	545,552	20,621,905	1,048,571	19,573,333	4,197,687	11,238,095	571,429	10,666,667	2,287,568	1,123,810	57,143	1,066,667	228,757
2,643,848	143,233	2,500,615	545,552	20,621,905	1,048,571	19,573,333	4,401,711	11,238,095	571,429	10,666,667	2,398,753	1,123,810	57,143	1,066,667	228,757
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FERC to become effective June 1, 2008 and November 1, 2008 respectively. Per FERC order in Docket No. ER13-607 the ROE for the MAPP abandoned plant is 10.8% effective March 1, 2013.

BO512.8 Chalk Point 230 kV Breaker 1B				BO512.9 Chalk Point 230 kV Breaker 2A				B0512.12 Chalk Point 230 kV Breaker 3A				BO478 Burches Hill-Palmer Cr Upgrade 23090, 91, 92, 93			
Yes				Yes				Yes				Yes			
35				35				35				35			
No				No				No				No			
0				0				0				150			
16.0888%				16.0888%				16.0888%				16.0888%			
16.0888%				16.0888%				16.0888%				17.1312%			
2,000,000				2,000,000				2,000,000				15,875,382			
57,143				57,143				57,143				453,582			
8.00				8.00				12.00				6.00			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
1,866,667	57,143	1,809,524	348,274	1,866,667	57,143	1,809,524	348,274	1,885,714	57,143	1,828,571	351,338	15,195,008	453,582	14,741,426	2,825,302
1,866,667	57,143	1,809,524	348,274	1,866,667	57,143	1,809,524	348,274	1,885,714	57,143	1,828,571	351,338	15,195,008	453,582	14,741,426	2,978,960
1,809,524	57,143	1,752,381	339,080	1,809,524	57,143	1,752,381	339,080	1,828,571	57,143	1,771,429	342,145	14,741,426	453,582	14,287,844	2,752,326
1,809,524	57,143	1,752,381	339,080	1,809,524	57,143	1,752,381	339,080	1,828,571	57,143	1,771,429	342,145	14,741,426	453,582	14,287,844	2,901,256
1,752,381	57,143	1,695,238	329,886	1,752,381	57,143	1,695,238	329,886	1,771,429	57,143	1,714,286	332,951	14,287,844	453,582	13,834,261	2,679,350
1,752,381	57,143	1,695,238	329,886	1,752,381	57,143	1,695,238	329,886	1,771,429	57,143	1,714,286	332,951	14,287,844	453,582	13,834,261	2,823,552
1,695,238	57,143	1,638,095	320,693	1,695,238	57,143	1,638,095	320,693	1,714,286	57,143	1,657,143	323,757	13,834,261	453,582	13,380,679	2,606,374
1,695,238	57,143	1,638,095	320,693	1,695,238	57,143	1,638,095	320,693	1,714,286	57,143	1,657,143	323,757	13,834,261	453,582	13,380,679	2,745,848
1,638,095	57,143	1,580,952	311,499	1,638,095	57,143	1,580,952	311,499	1,657,143	57,143	1,600,000	314,564	13,380,679	453,582	12,927,097	2,533,398
1,638,095	57,143	1,580,952	311,499	1,638,095	57,143	1,580,952	311,499	1,657,143	57,143	1,600,000	314,564	13,380,679	453,582	12,927,097	2,668,144
1,580,952	57,143	1,523,810	302,306	1,580,952	57,143	1,523,810	302,306	1,600,000	57,143	1,542,857	305,370	12,927,097	453,582	12,473,514	2,460,422
1,580,952	57,143	1,523,810	302,306	1,580,952	57,143	1,523,810	302,306	1,600,000	57,143	1,542,857	305,370	12,927,097	453,582	12,473,514	2,590,440
1,523,810	57,143	1,466,667	293,112	1,523,810	57,143	1,466,667	293,112	1,542,857	57,143	1,485,714	296,177	12,473,514	453,582	12,019,932	2,387,446
1,523,810	57,143	1,466,667	293,112	1,523,810	57,143	1,466,667	293,112	1,542,857	57,143	1,485,714	296,177	12,473,514	453,582	12,019,932	2,512,736
1,466,667	57,143	1,409,524	283,918	1,466,667	57,143	1,409,524	283,918	1,485,714	57,143	1,428,571	286,983	12,019,932	453,582	11,566,350	2,314,470
1,466,667	57,143	1,409,524	283,918	1,466,667	57,143	1,409,524	283,918	1,485,714	57,143	1,428,571	286,983	12,019,932	453,582	11,566,350	2,435,032
1,409,524	57,143	1,352,381	274,725	1,409,524	57,143	1,352,381	274,725	1,428,571	57,143	1,371,429	277,789	11,566,350	453,582	11,112,767	2,241,494
1,409,524	57,143	1,352,381	274,725	1,409,524	57,143	1,352,381	274,725	1,428,571	57,143	1,371,429	277,789	11,566,350	453,582	11,112,767	2,357,329
1,352,381	57,143	1,295,238	265,531	1,352,381	57,143	1,295,238	265,531	1,371,429	57,143	1,314,286	268,596	11,112,767	453,582	10,659,185	2,168,518
1,352,381	57,143	1,295,238	265,531	1,352,381	57,143	1,295,238	265,531	1,371,429	57,143	1,314,286	268,596	11,112,767	453,582	10,659,185	2,279,625
1,295,238	57,143	1,238,095	256,338	1,295,238	57,143	1,238,095	256,338	1,314,286	57,143	1,257,143	259,402	10,659,185	453,582	10,205,603	2,095,542
1,295,238	57,143	1,238,095	256,338	1,295,238	57,143	1,238,095	256,338	1,314,286	57,143	1,257,143	259,402	10,659,185	453,582	10,205,603	2,201,921
1,238,095	57,143	1,180,952	247,144	1,238,095	57,143	1,180,952	247,144	1,257,143	57,143	1,200,000	250,209	10,205,603	453,582	9,752,020	2,022,566
1,238,095	57,143	1,180,952	247,144	1,238,095	57,143	1,180,952	247,144	1,257,143	57,143	1,200,000	250,209	10,205,603	453,582	9,752,020	2,124,217
1,180,952	57,143	1,123,810	237,950	1,180,952	57,143	1,123,810	237,950	1,200,000	57,143	1,142,857	241,015	9,752,020	453,582	9,298,438	1,949,590
1,180,952	57,143	1,123,810	237,950	1,180,952	57,143	1,123,810	237,950	1,200,000	57,143	1,142,857	241,015	9,752,020	453,582	9,298,438	2,046,513
1,123,810	57,143	1,066,667	228,757	1,123,810	57,143	1,066,667	228,757	1,142,857	57,143	1,085,714	231,821	9,298,438	453,582	8,844,856	1,876,614
1,123,810	57,143	1,066,667	228,757	1,123,810	57,143	1,066,667	228,757	1,142,857	57,143	1,085,714	231,821	9,298,438	453,582	8,844,856	1,968,809
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BO499 Burches Hill Sub: Add 3rd 500/230kV				BO526 Ritchie-Benning: Install (2) 230kV Lines				BO701.1 Benning Sub: Add 3rd 230/69kV, 250MVA				BO496 Brighton Sub: Upgrade T1 500/230kv Transormer			
Yes				Yes				Yes				Yes			
35				35				35				35			
No				No				No				No			
150				0				0				150			
16.0888%				16.0888%				16.0888%				16.0888%			
17.1312%				16.0888%				16.0888%				17.1312%			
29,544,357				58,581,170				5,226,954				19,021,804			
844,124				1,673,748				149,342				543,480			
6.00				6.00				6.00				2.00			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
28,278,170	844,124	27,434,046	5,257,935	56,070,548	1,673,748	54,396,801	10,425,543	5,002,942	149,342	4,853,600	930,228	18,754,205	543,480	18,210,725	3,473,368
28,278,170	844,124	27,434,046	5,543,895	56,070,548	1,673,748	54,396,801	10,425,543	5,002,942	149,342	4,853,600	930,228	18,754,205	543,480	18,210,725	3,663,189
27,434,046	844,124	26,589,921	5,122,125	54,396,801	1,673,748	52,723,053	10,156,257	4,853,600	149,342	4,704,259	906,201	18,210,725	543,480	17,667,244	3,385,929
27,434,046	844,124	26,589,921	5,399,287	54,396,801	1,673,748	52,723,053	10,156,257	4,853,600	149,342	4,704,259	906,201	18,210,725	543,480	17,667,244	3,570,084
26,589,921	844,124	25,745,797	4,986,316	52,723,053	1,673,748	51,049,305	9,886,971	4,704,259	149,342	4,554,917	882,173	17,667,244	543,480	17,123,764	3,298,489
26,589,921	844,124	25,745,797	5,254,679	52,723,053	1,673,748	51,049,305	9,886,971	4,704,259	149,342	4,554,917	882,173	17,667,244	543,480	17,123,764	3,476,980
25,745,797	844,124	24,901,672	4,850,506	51,049,305	1,673,748	49,375,558	9,617,685	4,554,917	149,342	4,405,576	858,146	17,123,764	543,480	16,580,284	3,211,050
25,745,797	844,124	24,901,672	5,110,070	51,049,305	1,673,748	49,375,558	9,617,685	4,554,917	149,342	4,405,576	858,146	17,123,764	543,480	16,580,284	3,383,875
24,901,672	844,124	24,057,548	4,714,696	49,375,558	1,673,748	47,701,810	9,348,399	4,405,576	149,342	4,256,234	834,119	16,580,284	543,480	16,036,804	3,123,610
24,901,672	844,124	24,057,548	4,965,462	49,375,558	1,673,748	47,701,810	9,348,399	4,405,576	149,342	4,256,234	834,119	16,580,284	543,480	16,036,804	3,290,771
24,057,548	844,124	23,213,423	4,578,887	47,701,810	1,673,748	46,028,062	9,079,113	4,256,234	149,342	4,106,892	810,091	16,036,804	543,480	15,493,324	3,036,171
24,057,548	844,124	23,213,423	4,820,854	47,701,810	1,673,748	46,028,062	9,079,113	4,256,234	149,342	4,106,892	810,091	16,036,804	543,480	15,493,324	3,197,667
23,213,423	844,124	22,369,299	4,443,077	46,028,062	1,673,748	44,354,314	8,809,827	4,106,892	149,342	3,957,551	786,064	15,493,324	543,480	14,949,844	2,948,731
23,213,423	844,124	22,369,299	4,676,245	46,028,062	1,673,748	44,354,314	8,809,827	4,106,892	149,342	3,957,551	786,064	15,493,324	543,480	14,949,844	3,104,562
22,369,299	844,124	21,525,174	4,307,268	44,354,314	1,673,748	42,680,567	8,540,541	3,957,551	149,342	3,808,209	762,037	14,949,844	543,480	14,406,364	2,861,292
22,369,299	844,124	21,525,174	4,531,637	44,354,314	1,673,748	42,680,567	8,540,541	3,957,551	149,342	3,808,209	762,037	14,949,844	543,480	14,406,364	3,011,458
21,525,174	844,124	20,681,050	4,171,458	42,680,567	1,673,748	41,006,819	8,271,255	3,808,209	149,342	3,658,868	738,010	14,406,364	543,480	13,862,884	2,773,852
21,525,174	844,124	20,681,050	4,387,029	42,680,567	1,673,748	41,006,819	8,271,255	3,808,209	149,342	3,658,868	738,010	14,406,364	543,480	13,862,884	2,918,353
20,681,050	844,124	19,836,925	4,035,649	41,006,819	1,673,748	39,333,071	8,001,969	3,658,868	149,342	3,509,526	713,982	13,862,884	543,480	13,319,404	2,686,413
20,681,050	844,124	19,836,925	4,242,420	41,006,819	1,673,748	39,333,071	8,001,969	3,658,868	149,342	3,509,526	713,982	13,862,884	543,480	13,319,404	2,825,249
19,836,925	844,124	18,992,801	3,899,839	39,333,071	1,673,748	37,659,324	7,732,683	3,509,526	149,342	3,360,185	689,955	13,319,404	543,480	12,775,923	2,598,974
19,836,925	844,124	18,992,801	4,097,812	39,333,071	1,673,748	37,659,324	7,732,683	3,509,526	149,342	3,360,185	689,955	13,319,404	543,480	12,775,923	2,732,144
18,992,801	844,124	18,148,676	3,764,030	37,659,324	1,673,748	35,985,576	7,463,397	3,360,185	149,342	3,210,843	665,928	12,775,923	543,480	12,232,443	2,511,534
18,992,801	844,124	18,148,676	3,953,204	37,659,324	1,673,748	35,985,576	7,463,397	3,360,185	149,342	3,210,843	665,928	12,775,923	543,480	12,232,443	2,639,040
18,148,676	844,124	17,304,552	3,628,220	35,985,576	1,673,748	34,311,828	7,194,111	3,210,843	149,342	3,061,502	641,901	12,232,443	543,480	11,688,963	2,424,095
18,148,676	844,124	17,304,552	3,808,595	35,985,576	1,673,748	34,311,828	7,194,111	3,210,843	149,342	3,061,502	641,901	12,232,443	543,480	11,688,963	2,545,935
17,304,552	844,124	16,460,427	3,492,411	34,311,828	1,673,748	32,638,080	6,924,825	3,061,502	149,342	2,912,160	617,873	11,688,963	543,480	11,145,483	2,336,655
17,304,552	844,124	16,460,427	3,663,987	34,311,828	1,673,748	32,638,080	6,924,825	3,061,502	149,342	2,912,160	617,873	11,688,963	543,480	11,145,483	2,452,831
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....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

B1125 Convert Buzzard to Ritchie Line - 138kV to 230kV

Yes
35

No

0

16.0888%

16.0888%

59,051,650

1,687,190

10.00

Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
59,051,650	281,198	58,770,452	9,736,662	$ 51,457,696		$ 51,457,696
59,051,650	281,198	58,770,452	9,736,662	$ 52,917,111	$ 52,917,111	
58,770,452	1,687,190	57,083,262	10,871,205	$ 51,495,865		$ 51,495,865
58,770,452	1,687,190	57,083,262	10,871,205	$ 52,909,208	$ 52,909,208	
57,083,262	1,687,190	55,396,072	10,599,756	$ 50,128,042		$ 50,128,042
57,083,262	1,687,190	55,396,072	10,599,756	$ 51,495,312	$ 51,495,312	
55,396,072	1,687,190	53,708,882	10,328,307	$ 48,760,219		$ 48,760,219
55,396,072	1,687,190	53,708,882	10,328,307	$ 50,081,417	$ 50,081,417	
53,708,882	1,687,190	52,021,692	10,056,859	$ 47,392,396		$ 47,392,396
53,708,882	1,687,190	52,021,692	10,056,859	$ 48,667,522	$ 48,667,522	
52,021,692	1,687,190	50,334,502	9,785,410	$ 46,024,572		$ 46,024,572
52,021,692	1,687,190	50,334,502	9,785,410	$ 47,253,627	$ 47,253,627	
50,334,502	1,687,190	48,647,312	9,513,961	$ 44,656,749		$ 44,656,749
50,334,502	1,687,190	48,647,312	9,513,961	$ 45,839,731	$ 45,839,731	
48,647,312	1,687,190	46,960,122	9,242,512	$ 43,288,926		$ 43,288,926
48,647,312	1,687,190	46,960,122	9,242,512	$ 44,425,836	$ 44,425,836	
46,960,122	1,687,190	45,272,932	8,971,064	$ 41,921,103		$ 41,921,103
46,960,122	1,687,190	45,272,932	8,971,064	$ 43,011,941	$ 43,011,941	
45,272,932	1,687,190	43,585,742	8,699,615	$ 40,553,280		$ 40,553,280
45,272,932	1,687,190	43,585,742	8,699,615	$ 41,598,045	$ 41,598,045	
43,585,742	1,687,190	41,898,552	8,428,166	$ 39,185,457		$ 39,185,457
43,585,742	1,687,190	41,898,552	8,428,166	$ 40,184,150	$ 40,184,150	
41,898,552	1,687,190	40,211,362	8,156,718	$ 37,817,633		$ 37,817,633
41,898,552	1,687,190	40,211,362	8,156,718	$ 38,770,255	$ 38,770,255	
40,211,362	1,687,190	38,524,172	7,885,269	$ 36,449,810		$ 36,449,810
40,211,362	1,687,190	38,524,172	7,885,269	$ 37,356,359	$ 37,356,359	
38,524,172	1,687,190	36,836,982	7,613,820	$ 35,081,987		$ 35,081,987
38,524,172	1,687,190	36,836,982	7,613,820	$ 35,942,464	$ 35,942,464	
....	....	.....	....			$ -
....	.....	.....	....		$ -	
					$ 781,437,138	$ 759,758,475

Potomac Electric Power Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4E - PPL Formula Update

ATTACHMENT H-8G

PPL Electric Utilities Corporation

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	2013 Data
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	11,907,492
2	Total Wages Expense		p354.28.b	96,334,689
3	Less A&G Wages Expense		p354.27.b	3,174,605
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	93,160,084
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**12.7818%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g	7,131,239,542
7	Accumulated Depreciation (Total Electric Plant)	(Note J)	p219.29.c	2,369,630,299
8	Accumulated Amortization	(Note A)	p200.21.c	51,520,392
9	Total Accumulated Depreciation		(Line 7 + 8)	2,421,150,691
10	Net Plant		(Line 6 - Line 9)	4,710,088,851
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 25 - Line 24)	2,158,545,157
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**30.2689%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 33 - Line 24)	1,609,804,226
14	**Net Plant Allocator**		(Line 13 / Line 10)	**34.1778%**
	Plant Calculations			
	Plant In Service			
15	Transmission Plant In Service	(Note B)	p207.58.g	1,884,733,404
16	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6	
17	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)	(Note B)	Attachment 6	178,486,406
18	**Total Transmission Plant**		(Line 15 - Line 16 + Line 17)	**2,063,219,810**
19	General		p207.99.g	647,740,222
20	Intangible		p205.5.g	98,052,203
21	Total General and Intangible Plant		(Line 19 + Line 20)	745,792,425
22	Wage & Salary Allocator		(Line 5)	12.7818%
23	**Total General and Intangible Functionalized to Transmission**		(Line 21 * Line 22)	**95,325,347**
24	**Land Held for Future Use**	(Note C) (Note P)	Attachment 5	**39,993,431**
25	**Total Plant In Rate Base**		**(Line 18 + Line 23 + Line 24)**	**2,198,538,588**
	Accumulated Depreciation			
26	Transmission Accumulated Depreciation	(Note J)	p219.25.c	**514,801,428**
27	Accumulated General Depreciation	(Note J)	p219.28.c	214,010,501
28	Accumulated Amortization		(Line 8)	51,520,392
29	Total Accumulated Depreciation		(Line 27 + 28)	265,530,893
30	Wage & Salary Allocator		(Line 5)	12.7818%
31	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 29 * Line 30)	33,939,503
32	**Total Accumulated Depreciation**		**(Sum Lines 26 + 31)**	**548,740,931**
33	**Total Net Property, Plant & Equipment**		**(Line 25 - Line 32)**	**1,649,797,657**

Exhibit 1

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
34	**ADIT net of FASB 106 and 109**		Attachment 1	**-229,656,615**
	CWIP for Incentive Transmission Projects			
35	CWIP Balances for Current Rate Year	(Note H)	Attachment 6	**485,337,753**
	Prepayments			
36	Prepayments	(Note A) (Note O)	Attachment 5	**1,029,170**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	p227.16.c	2,720,786
38	Wage & Salary Allocator		(Line 5)	12.7818%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	347,764
40	Transmission Materials & Supplies		p227.8.c	9,443,296
41	**Total Materials & Supplies Allocated to Transmission**		(Line 39 + Line 40)	**9,791,060**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 70)	68,870,841
43	1/8th Rule		1/8	12.5%
44	**Total Cash Working Capital Allocated to Transmission**		(Line 42 * Line 43)	**8,608,855**
45	**Total Adjustment to Rate Base**		(Lines 34 + 35 + 36 + 41 + 44)	**275,110,223**
46	**Rate Base**		(Line 33 + Line 45)	**1,924,907,880**

Operations & Maintenance Expense

	Transmission O&M			
47	Transmission O&M		Attachment 5	114,613,281
48	Less Account 565		Attachment 5	66,146,409
49	Plus Charges billed to Transmission Owner and booked to Account 565	(Note N)	Attachment 5	0
50	**Transmission O&M**		(Lines 47 - 48 + 49)	**48,466,872**
	Allocated Administrative & General Expenses			
51	Total A&G		323.197b	155,673,612
52	Less: Administrative & General Expenses on Securitization Bonds	(Note O)	Attachment 8	0
53	Plus: Fixed PBOP expense	(Note J)	Attachment 5	10,028,618
54	Less: Actual PBOP expense		Attachment 5	2,544,321
55	Less Property Insurance Account 924		p323.185.b	710,108
56	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	4,713,028
57	Less General Advertising Exp Account 930.1		p323.191.b	0
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	Administrative & General Expenses		Sum (Lines 51 + 53) - Line 52 - Sum (Lines 54 to 58)	157,734,773
60	Wage & Salary Allocator		(Line 5)	12.7818%
61	**Administrative & General Expenses Allocated to Transmission**		(Line 59 * Line 60)	**20,161,269**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note K)	Attachment 5	0
64	**Subtotal - Accounts 928 and 930.1 - Transmission Related**		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924	(Note G)	Attachment 5	710,108
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 924 and 930.1 - General		(Line 65 + Line 66)	710,108
68	Net Plant Allocator		(Line 14)	34.1778%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**242,699**
70	**Total Transmission O&M**		**(Lines 50 + 61 + 64 + 69)**	**68,870,841**

Exhibit 1

Depreciation & Amortization Expense

	Depreciation Expense			
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Attachment 5	**31,570,125**
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Attachment 5	18,321,717
73	Intangible Amortization	(Note A)	p336.1.d&e	19,488,811
74	Total		(Line 72 + Line 73)	37,810,528
75	Wage & Salary Allocator		(Line 5)	12.7818%
76	**General Depreciation & Intangible Amortization Allocated to Transmission**		(Line 74 * Line 75)	**4,832,848**
77	**Total Transmission Depreciation & Amortization**		**(Lines 71 + 76)**	**36,402,973**

Taxes Other than Income Taxes

78	**Taxes Other than Income Taxes**	Attachment 2	**2,812,985**
79	**Total Taxes Other than Income Taxes**	**(Line 78)**	**2,812,985**

Return \ Capitalization Calculations

	Long Term Interest				
80	Long Term Interest			p117.62.c through 66.c	110,066,328
81	Less LTD Interest on Securitization Bonds		(Note O)	Attachment 8	0
82	**Long Term Interest**			(Line 80 - Line 81)	**110,066,328**
83	**Preferred Dividends**		enter positive	p118.29.c	-
	Common Stock				
84	Proprietary Capital			p112.16.c	2,355,327,070
85	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	7,745
86	Less Preferred Stock			(Line 94)	0
87	Less Account 216.1			p112.12.c	9,915,664
88	**Common Stock**			(Line 84 - 85 - 86 - 87)	**2,345,403,661**
	Capitalization				
89	Long Term Debt			p112.18.c, 19.c & 21.c	2,324,040,000
90	Less Loss on Reacquired Debt			p111.81.c	56,594,413
91	Plus Gain on Reacquired Debt			p113.61.c	0
92	Less LTD on Securitization Bonds		(Note O)	Attachment 8	0
93	Total Long Term Debt			(Line 89 - 90 + 91 - 92)	2,267,445,587
94	Preferred Stock			p112.3.c	0
95	Common Stock			(Line 88)	2,345,403,661
96	**Total Capitalization**			(Sum Lines 93 to 95)	**4,612,849,248**
97	Debt %	Total Long Term Debt		(Line 93 / Line 96)	49.2%
98	Preferred %	Preferred Stock		(Line 94 / Line 96)	0.0%
99	Common %	Common Stock		(Line 95 / Line 96)	50.8%
100	Debt Cost	Total Long Term Debt		(Line 82 / Line 93)	0.0485
101	Preferred Cost	Preferred Stock		(Line 83 / Line 94)	0.0000
102	Common Cost	Common Stock	(Note J)	Fixed	0.1168
103	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * Line 100)	0.0239
104	Weighted Cost of Preferred	Preferred Stock		(Line 98 * Line 101)	0.0000
105	Weighted Cost of Common	Common Stock		(Line 99 * Line 102)	0.0594
106	**Rate of Return on Rate Base (ROR)**			(Sum Lines 103 to 105)	**0.0832**
107	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 106)**	**160,244,314**

Composite Income Taxes

	Income Tax Rates			
108	FIT=Federal Income Tax Rate	(Note I)		35.00%
109	SIT=State Income Tax Rate or Composite			9.99%
110	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
111	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%
112	T / (1-T)			70.92%
	ITC Adjustment			
113	Amortized Investment Tax Credit - Transmission Related		Attachment 5	-338,740
114	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 113 * (1 / (1 - Line 111))	**-578,978**
115	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 112 * Line 107 * (1- (Line 103 / Line 106))]	**81,073,156**
116	**Total Income Taxes**		**(Line 114 + Line 115)**	**80,494,178**

Revenue Requirement

	Summary			
117	Net Property, Plant & Equipment		(Line 33)	1,649,797,657
118	Total Adjustment to Rate Base		(Line 45)	275,110,223
119	Rate Base		(Line 46)	1,924,907,880
120	Total Transmission O&M		(Line 70)	68,870,841
121	Total Transmission Depreciation & Amortization		(Line 77)	36,402,973
122	Taxes Other than Income		(Line 79)	2,812,985
123	Investment Return		(Line 107)	160,244,314
124	Income Taxes		(Line 116)	80,494,178
125	**Gross Revenue Requirement**		**(Sum Lines 120 to 124)**	**348,825,291**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Transmission Plant In Service		(Line 15)	1,884,733,404
127	Excluded Transmission Facilities	(Note M)	Attachment 5	0
128	Included Transmission Facilities		(Line 126 - Line 127)	1,884,733,404
129	Inclusion Ratio		(Line 128 / Line 126)	100.00%
130	Gross Revenue Requirement		(Line 125)	348,825,291
131	**Adjusted Gross Revenue Requirement**		(Line 129 * Line 130)	**348,825,291**
	Revenue Credits			
132	**Revenue Credits**		Attachment 3	**44,685,802**
133	**Net Revenue Requirement**		**(Line 131 - Line 132)**	**304,139,489**
	Net Plant Carrying Charge			
134	Gross Revenue Requirement		(Line 130)	**348,825,291**
135	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**2,033,756,135**
136	Net Plant Carrying Charge		(Line 134 / Line 135)	**17.1518%**
137	Net Plant Carrying Charge without Depreciation		(Line 134 - Line 71) / Line 135	**15.5995%**
138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 134 - Line 71 - Line 107 - Line 116) / Line 135	**3.7623%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
139	Gross Revenue Requirement Less Return and Taxes		(Line 130 - Line 123 - Line 124)	**108,086,799**
140	Increased Return and Taxes		Attachment 4	**257,466,883**
141	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 139 + Line 140)	**365,553,682**
142	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**2,033,756,135**
143	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 141 / Line 142)	**17.9743%**
144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 141 - Line 71) / Line 142	**16.4220%**
145	**Net Revenue Requirement**		(Line 133)	**304,139,489**
146	True-up amount		Attachment 6	**(28,277,787)**
147	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**-**
148	**Net Zonal Revenue Requirement**		(Line 145 + 146 + 147)	**275,861,702**
	Network Zonal Service Rate			
149	1 CP Peak	(Note L)	PJM Data	**7,392.2**
150	Rate ($/MW-Year)		(Line 148 / 149)	**$ 37,318**
151	**Network Service Rate ($/MW/Year)**		**(Line 150)**	**$ 37,318**

Notes

A Electric portion only.

B Line 16, for the Reconciliation, includes New Transmission Plant that actually was placed in service weighted by the number of months it actually was in service.
Line 17 includes New Transmission Plant to be placed in service in the current calendar year.

C Includes Transmission portion only.

D Includes all EPRI Annual Membership Dues.

E Includes all Regulatory Commission Expenses.

F Includes Safety-related advertising included in Account 930.1.

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at page 351.h.
Property Insurance excludes prior period adjustment in the first year of the formula's operation and reconciliation for the first year.

H CWIP can be included only if authorized by the Commission.

I The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes.
The calculation of the Reconciliation revenue requirement according to Step 7 of Attachment 6 ("Estimate and Reconciliation Worksheet") shall reflect the actual tax rates in effect for the Rate Year being reconciled ("Test Year"). When statutory marginal tax rates change during such Test Year, the effective tax rate used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

J ROE will be as follows: (i.) 11.60% for the period November 1, 2008 through May 31, 2009; (ii.) 11.64% for the period June 1, 2009 through May 31, 2010; (iii.) 11.68% on June 1, 2010 through May 31, 2011 and thereafter. No change in ROE will be made absent a filing at FERC.
PBOP expense is fixed until changed as the result of a filing at FERC.
Depreciation rates shown in Attachment 9 are fixed until changed as the result of a filing at FERC.
Upon request, PPL Electric Utilities Corporation will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to Form No. 1 amounts.
As set forth in Attachment 5, added to the depreciation expense will be actual removal costs (net of salvage) amortized over five years.

K Education and outreach expenses related to transmission (e.g., siting or billing).

L As provided for in Section 34.1 of the PJM OATT, the PJM established billing determinants will not be revised or updated in the annual rate reconciliations.

M Amount of transmission plant excluded from rates per Attachment 5.

N Includes only charges incurred for system integration, such as those under the EHV Agreement, and transmission costs paid to others that benefit transmission customers.

O Amounts associated with transition bonds issued to securitize the recovery of retail stranded costs are removed from account balances, pursuant to an Order entered by the Pennsylvania Public Utility Commission on May 21, 1999 at Docket No. R-00994637, in accordance with Pennsylvania's Electric Generation Customer Choice and Competition Act.

P Any gain from the sale of land included in Land Held for Future Use in the Formula Rate received during the Rate Year shall be used to reduce the ATRR in the Rate Year. The Formula Rate shall not include any losses on sales of such land.

PPL Electric Utilities Corporation

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Transmission Related	*Plant Related*	*Labor Related*	*Total Transmission ADIT*	
ADIT- 282	(252,824,038)	0	(59,365,269)		From Acct. 282 total, below
ADIT-283	0	(23,483,003)	(590,440)		From Acct. 283 total, below
ADIT-190	35,373,476	0	27,252,200		From Acct. 190 total, below
Subtotal	(217,450,562)	(23,483,003)	(32,703,509)		Sum lines 1 through 3
Wages & Salary Allocator			12.7818%		
Net Plant Allocator		34.1778%			
ADIT	(217,450,562)	(8,025,971)	(4,180,082)	(229,656,615)	Sum Cols. D, E, F; Enter as negative Appendix A, line 42.
	row 4	row 5 * row 4	row 5 * row 4		

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A *ADIT-190*	B *Total*	C *Gas, Prod, Dist Or Other Related*	D *Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Account 190						
Accumulated Deferred Investment Tax Credits (Non-Transmission)	807,779	807,779				Basis difference between book plant and tax plant basis related to investment tax credits on distribution property.
Accumulated Deferred Investment Tax Credits (Transmission)	138,931		138,931			Basis difference between book plant and tax plant basis related to investment tax credits on transmission property.
Regulatory Liability - Income Taxes Related to ITC (Non-Tx)	572,889	572,889				Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on distribution property.
Regulatory Liability - Income Taxes Related to ITC (Tx)	98,529		98,529			Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on transmission property.
Contributions in Aid of Construction (Non-Tx)	85,947,986	85,947,986				Distribution related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Contributions in Aid of Construction (Tx-related)	23,010,810		23,010,810			Transmission related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Pensions and Post-Retirement	7,439,310	7,439,310				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes .
FAS158 Regulatory Liability	106,755,584	106,755,584				Liability recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Bad Debts	9,580,305	9,580,305				Retail related book expense not deductible for tax return purposes .
Service Company Labor Related Costs	22,527,302				22,527,302	Book expense not deductible for tax return purposes - labor related to all functions.
Service Company Other Related Costs	(13,715,895)	(13,715,895)				Book expense not deductible for tax return purposes.
Vacation Pay	4,439,239				4,439,239	Book expense not deductible for tax return purposes - labor related to all functions.
Deferred Compensation	285,659				285,659	Book expense not deductible for tax return purposes - labor related to all functions.
Taxes Other Than Income Taxes	7,366,901	7,366,901				Book expense not deductible for tax return purposes - retail related gross receipts and sales & use taxes.
RAR Adjustments	(3,874,725)	(3,874,725)				Distribution related IRS audit adjustments.
Environmental Liability	1,886,709	1,886,709				Distribution related book expense for manufactured gas plants not deductible for tax return purposes.
Post Employment Liabilities	3,131,278	3,131,278				Book expense not deductible for tax return purposes.
State NOL Carryforwards	34,748,688	34,748,688				State net operating loss carryforward.
Tax Credit Carryforward	115,901	115,901				Tax credits carryforward to a future period.
Conservation Program Regulatory Asset	6,226,953	6,226,953				Distribution related expense deferred for book purposes and deducted for tax purposes.
Universal Service Rider over/undercollection	3,986,569	3,986,569				Distribution related expense deferred for book purposes and deducted for tax purposes.
Generation Service Charge over/undercollection	9,742,598	9,742,598				Distribution related expense deferred for book purposes and deducted for tax purposes.
Transmission Formula Rate over/undercollection	8,363,106		8,363,106			Transmission related expense deferred for book purposes and deducted for tax purposes.
Transmission Service Charge over/undercollection	3,186,154	3,186,154				Distribution related expense deferred for book purposes and deducted for tax purposes.
Distribution System Improvement Charge over/undercollection	205,521	205,521				Distribution related expense deferred for book purposes and deducted for tax purposes.
Competitive Enhancement Rider over/undercollections	218,213	218,213				Distribution related expense deferred for book purposes and deducted for tax purposes.
Storm Damage over/undercollection	579,032	579,032				Distribution related expense deferred for book purposes and deducted for tax purposes.
Book Contingencies	1,524,886	1,524,886				Distribution related book expense not deductible for tax return purposes.
Federal NOL Carryforward	72,043,242	68,043,682	3,999,560			Federal net operating loss carryforward.
Deferred Intercompany Transactions	(1,515,733)	(1,515,733)				Retail related income recorded for book purposes not includable in taxable income - related to receivables factoring.
Subtotal - p234	395,823,721	332,960,585	35,610,936	0	27,252,200	
Less FASB 109 Above if not separately removed	1,618,128	1,380,668	237,460			
Less FASB 106 Above if not separately removed	6,010,170	6,010,170				
Total	388,195,423	325,569,747	35,373,476	0	27,252,200	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Exhibit 1

PPL Electric Utilities Corporation

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod, Dist Or Other Related*	*Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Account 282						
ACRS/MACRS Property (Non-Transmission)	(585,414,280)	(585,414,280)				Deductions for distribution related tax depreciation in excess of book depreciation at federal rate.
ACRS/MACRS Property (General Plant)	(54,861,705)				(54,861,705)	Deductions for general plant related tax depreciation in excess of book depreciation at applicable federal and state rates.
ACRS/MACRS Property (Transmission)	(226,747,477)		(226,747,477)			Deductions for transmission related method/life, book and tax recovery differences on pre-ACRS/MACRS property, ACRS/MACRS property and unamortized net negative salvage at federal and state rates.
FAS109 regulatory assets/liabilities related to plant	(182,454,758)	(182,454,758)				Asset recorded for regulatory purposes to adjust plant related deferred taxes to current federal and state rates.
Basis adjustments between book and tax plant (Non-Tx)	(307,618,940)	(307,618,940)				Basis difference between Distribution related book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (General Plant)	2,469,535				2,469,535	Basis difference between book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (Tx-related)	(26,031,151)		(26,031,151)			Basis difference between Transmission related plant and tax plant basis at federal & state rates.
RAR adjustments related to plant (Non-Transmission)	13,605,820	13,605,820				Settled IRS audit adjustments related to Distribution plant.
RAR adjustments related to plant (Transmission)	(45,410)		(45,410)			Settled IRS audit adjustments related to Transmission plant.
RAR adjustments related to plant (General Plant)	(6,973,099)				(6,973,099)	Settled IRS audit adjustments related to General plant.
Effectively Settled Audit Adjustments	8,964,787	8,964,787				Agreed to IRS audit adjustments related to Distribution plant.
Non-Utility Property	(97,629)	(97,629)				Difference between net book plant and net tax plant resulting from deductions for non-utility related tax depreciation in excess of book depreciation and cost basis differences between book plant and tax plant at federal and state tax rates.
Subtotal - p275	(1,365,204,307)	(1,053,015,000)	(252,824,038)	0	(59,365,269)	
Less FASB 109 Above if not separately removed	(182,454,758)	(182,454,758)				
Less FASB 106 Above if not separately removed	0					
Total	(1,182,749,549)	(870,560,242)	(252,824,038)	0	(59,365,269)	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PPL Electric Utilities Corporation

A	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod, Dist Or Other Related*	*Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Account 283						
Reacquired debt costs	(23,483,003)			(23,483,003)		Plant related expense deferred for book purposes and deducted for tax purposes.
FAS 109 regulatory assets/liabilities	(129,399,075)	(129,399,075)				Asset recorded for regulatory purposes related to book and tax basis plant and non-plant differences.
Pension and post-retirement	(65,943,862)	(65,943,862)				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes.
FAS158 Regulatory Asset	(106,755,585)	(106,755,585)				Asset recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Storms Deferrals	(21,879,358)	(21,879,358)				Distribution related expense deferred for book purposes and deducted for tax purposes.
RAR Adjustments	1,306,086	1,306,086				Distribution related IRS audit adjustments.
Clearing accounts	(590,440)				(590,440)	Expense deferred for book purposes and deducted for tax purposes.
Receivables Factoring	(5,074,543)	(5,074,543)				Retail related income recorded for book purposes not includable in taxable income.
Prepaid Insurance	(1,038,175)	(1,038,175)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Competitive Enhancement Rider over/undercollections	(168,833)	(168,833)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Unrealized gains/losses	(5,492)	(5,492)				Equity adjustment for book purposes not includable in taxable income.
Default Service Plan Regulatory Asset	(478,091)	(478,091)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Conservation Program Regulatory Asset	(1,889,049)	(1,889,049)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Deferred intercompany gain - trademark sale	(367,324)	(367,324)				Income recorded for book purposes not includable in taxable income.
Smart Meter Technology Regulatory Asset	(336,439)	(336,439)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Subtotal - p277	(356,103,183)	(332,029,740)	0	(23,483,003)	(590,440)	
Less FASB 109 Above if not separately removed	(129,399,075)	(129,399,075)				
Less FASB 106 Above if not separately removed	0	0				
Total	(226,704,108)	(202,630,665)	0	(23,483,003)	(590,440)	

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PPL Electric Utilities Corporation

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	**Page 263 Col (i)**	**Allocator**	**Allocated Amount**
	Plant Related		**Net Plant Allocator**	
1	Real Property (State, Municipal or Local)	2,488,506		
2	PURTA	1,893,429		
3				
4				
5				
6				
7				
8	**Total Plant Related**	4,381,935	34.1778%	1,497,648
	Labor Related		**Wages & Salary Allocator**	
9	Federal FICA	7,058,883		
10	Federal Unemployment	46,035		
11	State Unemployment	338,747		
12				
13				
14	**Total Labor Related**	7,443,665	12.7818%	951,431
	Other Included		**Net Plant Allocator**	
15	PA Capital Stock Tax	1,064,709		
16	Local Business License Tax	35		
17				
18				
19	**Total Other Included**	1,064,744	34.1778%	363,906
20	**Total Included (Lines 8 + 14 + 19)**	12,890,344		2,812,985
	Currently Excluded			
21	Gross Receipts	97,751,705		
22	Sales and Use	(202,836)		
23				
24				
25				
26				
27				
28	**Subtotal, Excluded**	97,548,869		
29	**Total, Included and Excluded (Line 20 + Line 28)**	110,439,213		
30	**Total Other Taxes from p114.14.c less Tax on Securitization Bonds**	110,439,213		
31	Difference (Line 29 - Line 30)	-		

Criteria for Allocation:

- A Other taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail, they shall not be included.
- B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail, they shall not be included.
- C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.
- D Other taxes, except as provided for in A, B and C above, which are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service, will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated, as described in footnote B above.
- E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Exhibit 1
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PPL Electric Utilities Corporation

Attachment 3 - Revenue Credit Worksheet

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related		2,334,069
	Account 456 - Other Electric Revenues (Note 1)		
2	Transmission for Others (Note 3)		-
3	Schedule 12 Revenues (Note 3)		34,537,114
4	Schedule 1A		2,676,865
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (Note 3)		-
6	Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (e.g. Schedule 8)		3,268,430
7	Professional Services provided to others		1,222,680
8	Facilities Charges including Interconnection Agreements (Note 2)		646,644
9	Gross Revenue Credits	(Sum Lines 1-10)	44,685,802
10	Amount offset from Note 3 below		-

11 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula, will be included as a revenue credit or included in the peak on line 150 of Appendix A.

12 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

13 Note 3: If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support, e.g., revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited directly by PJM to zonal customers.

PPL Electric Utilities Corporation

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE			
A	100 Basis Point increase in ROE and Income Taxes		Line 29 + Line 39 from below	257,466,883
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Attachment A Line 46)	1,924,907,880
	Long Term Interest			
2	Long Term Interest		(Attachment A Line 80)	110,066,328
3	Less LTD Interest on Securitization Bonds		Attachment 8	-
4	Long Term Interest		(Line 2 - Line 3)	110,066,328
5	**Preferred Dividends**	enter positive	p118.29.c	0
	Common Stock			
6	Proprietary Capital		p112.16.c	2,355,327,070
7	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	7,745
8	Less Preferred Stock		(Attachment A Line 86)	0
9	Less Account 216.1		p112.12.c	9,915,664
10	Common Stock		(Line 6 - 7 - 8 - 9)	2,345,403,661
	Capitalization			
11	Long Term Debt		p112.18.c, 19.c & 21.c	2,324,040,000
12	Less Loss on Reacquired Debt		p111.81.c	56,594,413
13	Plus Gain on Reacquired Debt		p113.61.c	0
14	Less LTD on Securitization Bonds		Attachment 8	0
15	Total Long Term Debt		(Line 11 - 12 + 13 - 14)	2,267,445,587
16	Preferred Stock		p112.3.c	0
17	Common Stock		(Line 10)	2,345,403,661
18	Total Capitalization		(Sum Lines 15 to 17)	4,612,849,248
19	Debt %	Total Long Term Debt	(Line 15 / Line 18)	49.2%
20	Preferred %	Preferred Stock	(Line 16 / Line 18)	0.0%
21	Common %	Common Stock	(Line 17 / Line 18)	50.8%
22	Debt Cost	Total Long Term Debt	(Line 4 / Line 15)	0.0485
23	Preferred Cost	Preferred Stock	(Line 5 / Line 16)	0.0000
24	Common Cost	Common Stock	Fixed	0.1268
25	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 19 * Line 22)	0.0239
26	Weighted Cost of Preferred	Preferred Stock	(Line 20 * Line 23)	0.0000
27	Weighted Cost of Common	Common Stock	(Line 21 * Line 24)	0.0645
28	**Rate of Return on Rate Base (ROR)**		(Sum Lines 25 to 27)	**0.0883**
29	**Investment Return = Rate Base * Rate of Return**		**(Line 1 * Line 28)**	**170,031,511**

Composite Income Taxes

	Income Tax Rates			
30	FIT=Federal Income Tax Rate			35.00%
31	SIT=State Income Tax Rate or Composite			9.99%
32	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
33	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%
34	CIT = T / (1-T)			70.92%
35	1 / (1-T)			170.92%
	ITC Adjustment			
36	Amortized Investment Tax Credit		Attachment 5	(338,740)
37	**ITC Adjust. Allocated to Trans. - Grossed Up**		(Line 36 * (1 / (1 - Line 33))	**-578,978**
38	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		88,014,351
39	**Total Income Taxes**			**87,435,373**

Exhibit 1

PPL Electric Utilities Corporation

Attachment 5 - Cost Support

ITC Adjustment

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
113	**Amortized Investment Tax Credit**		Company Records	-1,094,983	-338,740	-756,243	Enter Negative

Transmission / Non-transmission Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related Major Items	Transmission Related Minor Items	Non-transmission Related	Details
24	**Land Held for Future Use**	(Note C)	p.214.d - p214.6.d &	42,908,419	35,657,563	4,335,868	2,914,988	
			Company Records		0	0		Removal of land held for future use (if any) that is included in CWIP balance
		(Note P)	Company Records		0	0		Gains from the sale of Land Held for Future Use
					35,657,563	4,335,868		Balance for Appendix A

Adjustments to A & G Expense

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Total	Prior Period Adjustment	Adjusted Total	Details
	Allocated Administrative & General Expenses					
53	Fixed PBOP expense	FERC Authorized	10,028,618			
54	Actual PBOP expense	Company Records	2,544,321			Current year actual PBOP expense
65	Property Insurance Account 924	p323.185.b	710,108	0	710,108	Annual Premium associated with storm insurance excluding recoveries related to prior periods.
						(See FM 1 note to page 320 line 185)

Regulatory Expense Related to Transmission Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G						
62	Regulatory Commission Exp Account 928	(Note G)	p350-151h	4,713,028	0	4,713,028	

Safety Related Advertising Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	

MultiState Workpaper

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates							
			PA					
109	SIT=State Income Tax Rate or Composite	(Note I)	9.99%					

Education and Out Reach Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
63	General Advertising Exp Account 930.1	(Note K)	p323.191.b	-		-	-

PPL Electric Utilities Corporation

Attachment 5 - Cost Support

Excluded Plant Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
127	Excluded Transmission Facilities	(Note M)			**General Description of the Facilities**
	Instructions:			**Enter $**	
1	Remove all investment below 69 kV or generator step-up transformers included in transmission plant in service that are not a result of the RTEP process			**0**	**None**
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher, as well as below 69 kV, the following formula will be used:		**Example**	**Or** **Enter $**	
A	Total investment in substation		1,000,000		
B	Identifiable investment in Transmission (provide workpaper		500,000		
C	Identifiable investment in Distribution (provide workpapers)		400,000		
D	Amount to be excluded (A x (C / (B + C))		444,444		
					Add more lines if necessary

Prepayments and Prepaid Pension Asset

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Prepayments on Securitization Bonds Adjustment	POLR and Retail Related Adjustment	Prepayments	W&S Allocator	Functionalized to TX	Description of the Prepayments
36	**Prepayments**									
	Prepayments	(Note A) (Note O)	Form 1 -- p111.57.c	40,070,906	0	32,019,041	8,051,865	12.7818%	1,029,170	Less amounts related to POLR, Retail Issues and Bond Securitization.

Adjustments to Transmission O&M

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Total	Adjustments	Transmission Related	Details
47	Transmission O&M	p.321.112.b	115,258,861	645,580	114,613,281	Adjustment for Ancillary Services p321.88b and p321.92b.
48	Less Account 565	p.321.96.b	66,146,409	0	66,146,409	**None**

Facility Credits under Section 30.9 of the PJM OATT

	Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Amount	Description & PJM Documentation
	Net Revenue Requirement		
147	Facility Credits under Section 30.9 of the PJM OATT	-	**None**

PJM Load Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
149	1 CP Peak	(Note L)	PJM Data	**7,392.2**	

Depreciation Expense

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Actual Cost of Removal, Net of Salvage Costs						
					Year 1	Year 2	Year 3	Year 4	Year 5		5 - Year
					2008	2009	2010	2011	2012	Total	Amortization
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	28,653,543							
	Transmission Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	2,916,582	1,433,010	2,342,429	1,932,133	3,323,131	5,552,205	14,582,908	2,916,582
	Total Transmission Depreciation Expense Including Amortization of Limited Term I	(Note J)	Company Records	31,570,125							
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	19,501,892							
	General Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	-1,180,175	-937,714	-2,236,807	-1,205,818	-563,798	-956,740	-5,900,877	-1,180,175
	Total General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	18,321,717							

PPL Electric Utilities Corporation

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2007)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2008)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2008 - May 31, 2009)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2008)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2009)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2009 - May 31, 2010)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2007)

$ 207,960,288 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 16, 17 or 35 of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2008)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Copperstone Substation (b0468)	(C) Monthly Additions Northeast Pocono Reliability Project CWIP	(D) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(F) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(G) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(H) Weighting	(I) Other Plant In Service Amount (A x H)	(J) Copperstone Substation Amount (B x H) (b0468)	(K) NPR CWIP Amount (C x H)	(L) Susq-Rose CWIP Amount (D x H) < 500kV (b0487.1)	(M) Susq-Rose PIS Amount (E x H) < 500kV (b0487.1)	(N) Susq-Rose CWIP Amount (F x H) >= 500kV (b0487)	(O) Susq-Rose PIS Amount (G x H) >= 500kV (b0487)	(P) Other Plant In Service (I / 12)	(Q) Copperstone Substation (J / 12) (b0171.2)	(R) NPR CWIP (K / 12)	(S) Susq-Rose CWIP (L / 12) < 500kV (b0487.1)	(T) Susq-Rose PIS (M / 12) < 500kV (b0487.1)	(U) Susq-Rose CWIP (N / 12) >= 500kV (b0487)	(V) Susq-Rose PIS (O / 12) >= 500kV (b0487)	Total
CWIP Balance Dec (prior yr.)				763,531		78,249,508		12			-	9,162,374		938,994,099				-	763,531		78,249,508		
Jan	13,118,042	23,639	0	(115,211)	272,202	12,615,433	1,881,343	11.5	150,857,486	271,852	-	(1,324,927)	3,130,323	145,077,480	21,635,444.50	12,571,457	22,654	-	(110,411)	260,860	12,089,790	1,802,954	
Feb	7,939,606	366	0	274,967	109,843	12,160,827	104,399	10.5	83,365,867	3,847	-	2,887,154	1,153,352	127,688,684	1,096,190	6,947,156	321	-	240,596	96,113	10,640,724	91,349	
Mar	33,162,755	3,686	0	(7,883)	259	22,710,120	174,590	9.5	315,046,173	35,017	-	(74,889)	2,461	215,746,140	1,658,605	26,253,848	2,918	-	(6,241)	205	17,978,845	138,217	
Apr	28,805,462	20,415	0	(247,138)	492,020	17,169,176	192,431	8.5	244,846,431	173,528	-	(2,100,673)	4,182,170	145,937,996	1,635,664	20,403,869	14,461	-	(175,056)	348,514	12,161,500	136,305	
May	13,207,095		0	44,897	-	16,958,018	11,673	7.5	99,053,210	-	-	336,728	-	127,185,135	87,548	8,254,434	-	-	28,061	-	10,598,761	7,296	
Jun	50,222,188		30,423,848	44,897	-	15,963,850	2,400,220	6.5	326,444,220	-	197,755,014	291,831	-	103,765,025	15,601,430	27,203,685	-	16,479,585	24,319	-	8,647,085	1,300,119	
Jul	18,078,755		8,678,100	44,897	-	19,652,382	50,216	5.5	99,433,150	-	47,729,550	246,934	-	108,088,101	276,188	8,286,096	-	3,977,463	20,578	-	9,007,342	23,016	
Aug	7,307,471		6,202,400	44,897	-	22,157,288	50,216	4.5	32,883,621	-	27,910,800	202,037	-	99,707,796	225,972	2,740,302	-	2,325,900	16,836	-	8,308,983	18,831	
Sep	4,160,607		6,225,962	186,032	-	18,581,523	50,216	3.5	14,562,125	-	21,790,868	651,112	-	65,035,331	175,756	1,213,510	-	1,815,906	54,259	-	5,419,611	14,646	
Oct	34,252,711		5,398,500	102,596	179,404	14,102,372	20,066,429	2.5	85,631,778	-	13,496,250	256,490	448,510	35,255,930	50,166,073	7,135,981	-	1,124,688	21,374	37,376	2,937,994	4,180,506	
Nov	38,376,383		-1,952,301	35,118	-	20,816,591	50,216	1.5	57,564,575	-	(2,928,452)	52,677	-	31,224,887	75,324	4,797,048	-	(244,038)	4,390	-	2,602,074	6,277	
Dec	72,349,142		2,890,000	-	-	17,987,599	50,216	0.5	36,174,571	-	1,445,000	-	-	8,993,800	25,108	3,014,548	-	120,417	-	-	749,483	2,092	
Total	320,980,217	48,107	57,866,509	1,171,600	1,053,728	289,124,687	25,082,165		1,545,863,205	484,244	307,199,030	10,586,846	8,916,815	2,152,700,401	92,659,301	128,821,934	40,354	25,599,919	882,237	743,068	179,391,700	7,721,608	-
New Transmission Plant Additions and CWIP (weighted by months in service)																							
														Input to Line 17 of Appendix A		128,821,934	40,354			743,068		7,721,608	137,326,964
														Input to Line 35 of Appendix A				25,599,919	882,237		179,391,700		205,873,856
														Month In Service or Month for CWIP		7.18	1.93	6.69	2.96	3.54	4.55	8.31	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 252,535,502 — Must run Appendix A to get this number (with inputs on lines 17 and 35 of Attachment A)

4 May Year 2 Post results of Step 3 on PJM web site

$ 252,535,502 — Must run Appendix A to get this number (with inputs on lines 17 and 35 of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2008 - May 31, 2009)

$ 252,535,502

Exhibit 1

6 April Year 3 TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2008)

$ 220,796,523 Rev Req based on Prior Year data

Must run Appendix A to get this number (without inputs in lines 16, 17 or 35 of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2

For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 360,786,270 Input to Formula Line 16

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Copperstone Substation (b0468)	(C) Monthly Additions Northeast Pocono Reliability Project CWIP	(D) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(F) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(G) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(H) Weighting
CWIP Balance Dec (prior yr.)				763,531		78,249,508		12
Jan	13,118,042	23,639		-96,422	272,202	12,596,644	1,881,343	11.5
Feb	7,939,606	366		384,885	109,843	12,050,909	104,399	10.5
Mar	33,162,755	3,686		-47,449	259	22,749,686	174,590	9.5
Apr	28,805,463	20,415		245,996	-	17,170,290	192,431	8.5
May	61,682,403	0		52,823	92	27,396,834	160,818	7.5
Jun	38,623,783	12,385	23,955,981	57,004	-	17,754,222	235,568	6.5
Jul	26,578,147	8,797	8,892,861	61,127	-	16,725,913	2,557,696	5.5
Aug	15,554,200	3,062	5,802,299	101,547	-	24,415,639	14,966,237	4.5
Sep	38,064,307	0	4,077,929	259,190	7,505	18,225,869	82,098	3.5
Oct	13,803,159	0	6,370,561	346,884	1,538	23,568,645	3,281,622	2.5
Nov	22,650,333	0	2,281,675	126,246	0	22,726,630	1,585,355	1.5
Dec	35,013,189	0	2,414,496	212,759	0	24,042,166	104,935	0.5
Total	334,995,388	72,351	53,795,802	2,468,121	391,439	317,672,955	25,327,092	
New Transmission Plant Additions and CWIP (weighted by months in service)								

	(I) Other Plant In Service Amount (A x H)	(J) Copperstone Substation Amount (B x H) (b0468)	(K) NPR CWIP Amount (C x H)	(L) Susq-Rose CWIP Amount (D x H) < 500kV (b0487.1)	(M) Susq-Rose PIS Amount (E x H) < 500kV (b0487.1)	(N) Susq-Rose CWIP Amount (F x H) >= 500kV (b0487)	(O) Susq-Rose PIS Amount (G x H) >= 500kV (b0487)	(P) Other Plant In Service (I / 12)	(Q) Copperstone Substation (J / 12) (b0171.2)	(R) NPR CWIP (K / 12)	(S) Susq-Rose CWIP (L / 12) < 500kV (b0487.1)	(T) Susq-Rose PIS (M / 12) < 500kV (b0487.1)	(U) Susq-Rose CWIP (N / 12) >= 500kV (b0487)	(V) Susq-Rose PIS (O / 12) >= 500kV (b0487)	Total
CWIP Balance Dec (prior yr.)				9,162,374		938,994,099					763,531		78,249,508		
Jan	150,857,486	271,852	-	(1,108,853)	3,130,323	144,861,406	21,635,445	12,571,457	22,654	-	(92,404)	260,860	12,071,784	1,802,954	
Feb	83,365,867	3,847	-	4,041,293	1,153,352	126,534,545	1,096,190	6,947,156	321	-	336,774	96,113	10,544,545	91,349	
Mar	315,046,173	35,017	-	(450,766)	2,461	216,122,017	1,658,605.00	26,253,848	2,918	-	(37,564)	205	18,010,168	138,217	
Apr	244,846,435	173,532	-	2,090,966	-	145,947,465	1,635,664	20,403,870	14,461	-	174,247	-	12,162,289	136,305	
May	462,618,024	-	-	396,173	690	205,476,255	1,206,135	38,551,502	-	-	33,014	58	17,123,021	100,511	
Jun	251,054,593	80,502	155,713,877	370,526	-	115,402,443	1,531,192	20,921,216	6,708	12,976,156	30,877	-	9,616,870	127,599	
Jul	146,179,809	48,383	48,910,736	336,199	-	91,992,522	14,067,328	12,181,651	4,032	4,075,895	28,017	-	7,666,043	1,172,277	
Aug	69,993,900	13,780	26,110,346	456,962	-	109,870,376	67,348,067	5,832,825	1,148	2,175,862	38,080	-	9,155,865	5,612,339	
Sep	133,225,074	-	14,272,752	907,165	26,268	63,790,542	287,343	11,102,089	-	1,189,396	75,597	2,189	5,315,878	23,945	
Oct	34,507,897	-	15,926,403	867,210	3,845	58,921,613	8,204,055	2,875,658	-	1,327,200	72,268	320	4,910,134	683,671	
Nov	33,975,500	-	3,422,513	189,369	-	34,089,945	2,378,033	2,831,292	-	285,209	15,781	-	2,840,829	198,169	
Dec	17,506,594	(0)	1,207,248	106,380	-	12,021,083	52,468	1,458,883	(0)	100,604	8,865	-	1,001,757	4,372	
Total	1,943,177,351	626,913	265,563,872	17,364,996	4,316,938	2,264,024,308	121,100,522	161,931,446	52,243	22,130,323	1,447,083	359,745	188,668,692	10,091,710	
Input to Line 17 of Appendix A								161,931,446	52,243			359,745		10,091,710	172,435,144
Input to Line 35 of Appendix A										22,130,323	1,447,083		188,668,692		212,246,098
Month In Service or Month for CWIP								6.20	3.34	7.06	4.96	0.97	4.87	7.22	

$ 223,663,211 Result of Formula for Reconciliation

Must run Appendix A to get this number (with inputs in lines 16, 17 and 35 of Appendix A)

(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 8		The forecast in Prior Year		
225,224,540	-	252,535,502	=	(27,310,962)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of the Current Yr 0.2800%

Month	Yr	1/12 of Step 8 (See Note #1)	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(2,275,913)	0.2800%	11.5	(73,284)	(2,349,198)
Jul	Year 1	(2,275,913)	0.2800%	10.5	(66,912)	(2,342,825)
Aug	Year 1	(2,275,913)	0.2800%	9.5	(60,539)	(2,336,453)
Sep	Year 1	(2,275,913)	0.2800%	8.5	(54,167)	(2,330,080)
Oct	Year 1	(2,275,913)	0.2800%	7.5	(47,794)	(2,323,708)
Nov	Year 1	(2,275,913)	0.2800%	6.5	(41,422)	(2,317,335)
Dec	Year 1	(2,275,913)	0.2800%	5.5	(35,049)	(2,310,963)
Jan	Year 2	(2,275,913)	0.2800%	4.5	(28,677)	(2,304,590)
Feb	Year 2	(2,275,913)	0.2800%	3.5	(22,304)	(2,298,217)
Mar	Year 2	(2,275,913)	0.2800%	2.5	(15,931)	(2,291,845)
Apr	Year 2	(2,275,913)	0.2800%	1.5	(9,559)	(2,285,472)
May	Year 2	(2,275,913)	0.2800%	0.5	(3,186)	(2,279,100)
Total		(27,310,962)				(27,769,786)

Note #1: For the initial rate year, enter zero for the first five months, June Year 1 through October Year 1. Enter 1/12 of Step 8 for the months Nov Year 1 through May Year 2.

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(27,769,786)	0.2800%	(2,356,482)	(25,491,059)
Jul	Year 2	(25,491,059)	0.2800%	(2,356,482)	(23,205,952)
Aug	Year 2	(23,205,952)	0.2800%	(2,356,482)	(20,914,446)
Sep	Year 2	(20,914,446)	0.2800%	(2,356,482)	(18,616,525)
Oct	Year 2	(18,616,525)	0.2800%	(2,356,482)	(16,312,169)
Nov	Year 2	(16,312,169)	0.2800%	(2,356,482)	(14,001,360)
Dec	Year 2	(14,001,360)	0.2800%	(2,356,482)	(11,684,082)
Jan	Year 3	(11,684,082)	0.2800%	(2,356,482)	(9,360,315)
Feb	Year 3	(9,360,315)	0.2800%	(2,356,482)	(7,030,042)
Mar	Year 3	(7,030,042)	0.2800%	(2,356,482)	(4,693,244)
Apr	Year 3	(4,693,244)	0.2800%	(2,356,482)	(2,349,903)
May	Year 3	(2,349,903)	0.2800%	(2,356,482)	(0)
Total with interest				(28,277,787)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(28,277,787)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$	-
Revenue Requirement for Year 3		(28,277,787)

9 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2009)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Northeast Pocono Reliability Project CWIP	(C) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(D) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(F) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(G) Weighting	(H) Other Plant In Service Amount (A x G)	(I) NPR CWIP Amount (B x G)	(J) Susq-Rose CWIP Amount (C x G) < 500kV (b0487.1)	(K) Susq-Rose PIS Amount (D x G) < 500kV (b0487.1)	(L) Susq-Rose CWIP Amount (E x G) >= 500kV (b0487)	(M) Susq-Rose PIS Amount (F x G) >= 500kV (b0487)	(N) Other Plant In Service (H/ 12)	(O) NPR CWIP (I / 12)	(P) Susq-Rose CWIP (J / 12) < 500kV (b0487.1)	(Q) Susq-Rose PIS (K / 12) < 500kV (b0487.1)	(R) Susq-Rose CWIP (L / 12) >= 500kV (b0487)	(S) Susq-Rose PIS (M / 12) >= 500kV (b0487)	Total
CWIP Balance Dec (prior yr.)		53,795,802	2,468,121		317,672,955		12		645,549,624	29,617,454		3,812,075,463			53,795,802	2,468,121		317,672,955		
Jan	11,989,158	4,291,137	107,907	-	30,317,794	292,205	11.5	137,875,316	49,348,076	1,240,931	-	348,654,631	3,360,354	11,489,610	4,112,340	103,411	-	29,054,553	280,029	
Feb	7,438,508	1,955,056	164,141	-	24,851,064	317,599	10.5	78,104,333	20,528,088	1,723,481	-	260,936,172	3,334,793	6,508,694	1,710,674	143,623	-	21,744,681	277,899	
Mar	33,762,897	4,794,455	228,240	-	23,758,793	138,840	9.5	320,747,526	45,547,323	2,168,280	-	225,708,534	1,318,979	26,728,960	3,795,610	180,690	-	18,809,044	109,915	
Apr	11,875,708	6,483,552	254,449	-	17,317,183	14,679,448	8.5	100,943,519	55,110,192	2,162,817	-	147,196,056	124,775,310	8,411,960	4,592,516	180,235	-	12,266,338	10,397,943	
May	34,091,815	10,841,732	(326,329)	526,329	15,491,830	643,895	7.5	255,688,614	81,312,990	(2,447,468)	3,947,468	116,188,725	4,829,213	21,307,385	6,776,083	(203,956)	328,956	9,682,394	402,434	
Jun	20,675,379	22,736,919	(125,459)	480,187	12,019,037	3,209,140	6.5	134,389,965	147,789,974	(815,484)	3,121,216	78,123,741	20,859,410	11,199,164	12,315,831	(67,957)	260,101	6,510,312	1,738,284	
Jul	22,021,878	9,290,735	461,158	-	10,140,413	758,837	5.5	121,120,328	51,099,043	2,536,369	-	55,772,272	4,173,604	10,093,361	4,258,254	211,364	-	4,647,689	347,800	
Aug	10,538,936	9,917,474	550,000	-	9,395,219	75,216	4.5	47,425,214	44,628,633	2,475,000	-	42,278,486	338,472	3,952,101	3,719,053	206,250	-	3,523,207	28,206	
Sep	13,951,522	5,986,623	700,000	-	(134,203,424)	148,511,752	3.5	48,830,326	20,953,181	2,450,000	-	(469,711,984)	519,791,132	4,069,194	1,746,098	204,167	-	(39,142,665)	43,315,928	
Oct	47,633,686	-21,096,888	850,000	-	11,076,427	75,216	2.5	119,084,215	(52,742,220)	2,125,000	-	27,691,068	188,040	9,923,685	(4,395,185)	177,083	-	2,307,589	15,670	
Nov	46,300,454	4,453,927	770,908	-	9,203,433	75,216	1.5	69,450,681	6,680,891	1,156,362	-	13,805,150	112,824	5,787,557	556,741	96,364	-	1,150,429	9,402	
Dec	33,233,228	4,250,029	(2,537,335)	2,743,613	8,559,692	75,216	0.5	16,616,614	2,125,015	(1,268,668)	1,371,807	4,279,846	37,608	1,384,718	177,085	(105,722)	114,317	356,654	3,134	
Total	293,513,170	117,700,553	3,565,801	3,750,129	355,600,416	168,852,580		1,450,276,650	1,117,930,807	43,124,074	8,440,490	4,662,998,156	683,119,738	120,856,388	93,160,901	3,593,673	703,374	388,583,180	56,926,645	
New Transmission Plant Additions and CWIP (weighted by months in service)																				
Input to Line 17 of Appendix A														120,856,388			703,374		56,926,645	178,486,406
Input to Line 35 of Appendix A															93,160,901	3,593,673		388,583,180		485,337,753
Month In Service or Month for CWIP														7.06	2.50	(0.09)	9.75	(1.11)	7.95	

10 May Year 3 Post results of Step 9 on PJM web site

$ 304,139,489 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2009 - May 31, 2010)

$ 304,139,489

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3	A	137	Net Plant Carrying Charge without Depreciation	15.5995%
4	B	144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	16.4220%
5	C		Line B less Line A	0.8225%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	3.7623%

8 **The FCR resulting from Formula in a given year is used for that year only.**
9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

Line		Details		Susquehanna - Roseland CWIP (b0487) >= 500kV	Actual Susquehanna - Roseland PIS (b0487) >= 500kV	Projected Susquehanna - Roseland PIS (b0487) >= 500kV	Hosensack Wavetrap (b0171.2)	Alburtis Wavetrap (b0172.1)	Juniata Wavetrap (b0284.2)	Susquehanna - Roseland CWIP (b0487.1) < 500kV	Actual Susquehanna - Roseland PIS (b0487.1) < 500kV	Projected Susquehanna - Roseland PIS (b0487.1) < 500kV	Stanton 4th Transformer (b0791)	Actual Copperstone Substation (b0468)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No	No	No	No	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	125	0	0	0	125	125	125	0	0
15	From line 3 above if "No" on line 13 and from line 7 above if "Yes" on line 13	11.68% ROE		15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%	15.5995%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		16.6276%	16.6276%	16.6276%	15.5995%	15.5995%	15.5995%	16.6276%	16.6276%	16.6276%	15.5995%	15.5995%
17	Project subaccount of Plant in Service Account 101 or 10 if not yet classified	Investment		388,583,180	50,645,750	168,852,580	86,626	62,067	123,504	3,593,673	3,234,918	3,750,129	3,733,895	22,735,783
18	Line 17 divided by line 12	Annual Depreciation Exp		-	1,205,851	4,020,300	2,063	1,478	2,941	-	77,022	89,289	88,902	541,328
19	Month in which project is placed in service (e.g. Jan=	Month In Service or Month for CWIP		-		7.95				-		9.75		

Line			Susquehanna - Roseland CWIP (b0487) >= 500kV				Actual Susquehanna - Roseland PIS (b0487) >= 500kV				Projected Susquehanna - Roseland PIS (b0487) >= 500kV			
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	5,534,456	-	5,534,456	433,646	-	-	-	-	-	-	-	-
22	W Increased ROE	2008	5,534,456	-	5,534,456	453,742	-	-	-	-	-	-	-	-
23	W 11.68 % ROE	2009	25,703,638	-	25,703,638	3,744,759	-	-	-	-	-	-	-	-
24	W Increased ROE	2009	25,703,638	-	25,703,638	3,928,397	-	-	-	-	-	-	-	-
25	W 11.68 % ROE	2010	32,334,326	-	32,334,326	7,002,386	1,707,870	17,350	1,690,519	173,557	-	-	-	-
26	W Increased ROE	2010	32,334,326	-	32,334,326	7,346,302	1,707,870	17,350	1,690,519	181,229	-	-	-	-
27	W 11.68 % ROE	2011	41,267,823	-	41,267,823	8,153,565	1,690,519	40,664	1,649,856	366,637	-	-	-	-
28	W Increased ROE	2011	41,267,823	-	41,267,823	8,573,934	1,690,519	40,664	1,649,856	383,443	-	-	-	-
29	W 11.68 % ROE	2012	49,100,120	-	49,100,120	10,122,908	6,771,105	164,250	6,606,855	1,526,377	-	-	-	-
30	W Increased ROE	2012	49,100,120	-	49,100,120	10,644,117	6,771,105	164,250	6,606,855	1,596,510	-	-	-	-
31	W 11.68 % ROE	2013	188,668,692	-	188,668,692	32,050,437	24,904,453	602,825	24,301,628	4,731,108	-	-	-	-
32	W Increased ROE	2013	188,668,692	-	188,668,692	33,942,591	24,904,453	602,825	24,301,628	4,974,829	-	-	-	-
33	W 11.68 % ROE	2014	388,583,180	-	388,583,180	60,616,914	49,338,189	1,205,851	48,132,338	8,714,240	168,852,580	1,690,421	167,162,159	12,654,808
34	W Increased ROE	2014	388,583,180	-	388,583,180	64,612,213	49,338,189	1,205,851	48,132,338	9,209,123	168,852,580	1,690,421	167,162,159	13,377,477
35	W 11.68 % ROE	2015		-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015		-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016		-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016		-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017		-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017		-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018		-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018		-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019		-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019		-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020		-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020		-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021		-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021		-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022		-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022		-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023		-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023		-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024		-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024		-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025		-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025		-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026		-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026		-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027		-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027		-	-	-	-	-	-	-	-	-	-	-
61														
62														

Line			Hosensack Wavetrap (b0171.2)				Alburtis Wavetrap (b0172.1)				Juniata Wavetrap (b0284.2)			
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811	-	-	-	-
22	W Increased ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811	-	-	-	-
23	W 11.68 % ROE	2009	85,172	2,063	83,109	19,836	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
24	W Increased ROE	2009	85,172	2,063	83,109	19,836	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
25	W 11.68 % ROE	2010	83,109	2,063	81,047	19,614	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
26	W Increased ROE	2010	83,109	2,063	81,047	19,614	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
27	W 11.68 % ROE	2011	81,047	2,063	78,984	17,668	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
28	W Increased ROE	2011	81,047	2,063	78,984	17,668	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
29	W 11.68 % ROE	2012	78,984	2,063	76,922	17,921	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
30	W Increased ROE	2012	78,984	2,063	76,922	17,921	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
31	W 11.68 % ROE	2013	76,922	2,063	74,859	14,779	55,165	1,478	53,687	10,598	111,742	2,941	108,801	21,423
32	W Increased ROE	2013	76,922	2,063	74,859	14,779	55,165	1,478	53,687	10,598	111,742	2,941	108,801	21,423
33	W 11.68 % ROE	2014	74,859	2,063	72,797	13,418	53,687	1,478	52,209	9,622	108,801	2,941	105,861	19,454
34	W Increased ROE	2014	74,859	2,063	72,797	13,418	53,687	1,478	52,209	9,622	108,801	2,941	105,861	19,454
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
61														
62														

Line			Susquehanna - Roseland CWIP (b0487.1) < 500kV				Actual Susquehanna - Roseland PIS (b0487.1) < 500kV				Projected Susquehanna - Roseland PIS (b0487.1) < 500kV			
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-
22	W Increased ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-
23	W 11.68 % ROE	2009	395,068	-	395,068	43,820	-	-	-	-	-	-	-	-
24	W Increased ROE	2009	395,068	-	395,068	45,969	-	-	-	-	-	-	-	-
25	W 11.68 % ROE	2010	983,014	-	983,014	212,883	2,138,193	15,476	2,122,717	155,221	-	-	-	-
26	W Increased ROE	2010	983,014	-	983,014	223,339	2,138,193	15,476	2,122,717	162,084	-	-	-	-
27	W 11.68 % ROE	2011	338,809	-	338,809	66,941	2,122,717	50,909	2,071,807	460,250	-	-	-	-
28	W Increased ROE	2011	338,809	-	338,809	70,392	2,122,717	50,909	2,071,807	481,355	-	-	-	-
29	W 11.68 % ROE	2012	362,626	-	362,626	74,762	2,547,287	62,474	2,484,814	574,764	-	-	-	-
30	W Increased ROE	2012	362,626	-	362,626	78,611	2,547,287	62,474	2,484,814	601,141	-	-	-	-
31	W 11.68 % ROE	2013	1,447,083	-	1,447,083	245,826	2,703,748	67,702	2,636,046	515,505	-	-	-	-
32	W Increased ROE	2013	1,447,083	-	1,447,083	260,339	2,703,748	67,702	2,636,046	541,942	-	-	-	-
33	W 11.68 % ROE	2014	3,593,673	-	3,593,673	560,594	3,018,143	77,022	2,941,121	535,821	3,750,129	24,188	3,725,941	181,638
34	W Increased ROE	2014	3,593,673	-	3,593,673	597,543	3,018,143	77,022	2,941,121	566,061	3,750,129	24,188	3,725,941	192,016
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
61														
62														

Line			Stanton 4th Transformer (b0791)				Actual Copperstone Substation (b0468)						
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
21	W 11.68 % ROE	2008	-	-	-	-	-	-	-	-	$ 455,377		$ 455,377
22	W Increased ROE	2008	-	-	-	-	-	-	-	-	$ 475,473	$ 475,473	
23	W 11.68 % ROE	2009	-	-	-	-	-	-	-	-	$ 3,851,361		$ 3,851,361
24	W Increased ROE	2009	-	-	-	-	-	-	-	-	$ 4,037,148	$ 4,037,148	
25	W 11.68 % ROE	2010	-	-	-	-	-	-	-	-	$ 7,606,140		$ 7,606,140
26	W Increased ROE	2010	-	-	-	-	-	-	-	-	$ 7,975,046	$ 7,975,046	
27	W 11.68 % ROE	2011	3,733,895	25,673	3,708,222	237,250	918,555	11,846	906,709	108,883	$ 9,449,462		$ 9,449,462
28	W Increased ROE	2011	3,733,895	25,673	3,708,222	237,250	918,555	11,846	906,709	108,883	$ 9,911,193	$ 9,911,193	
29	W 11.68 % ROE	2012	3,708,222	88,902	3,619,320	835,093	906,709	21,870	884,838	204,296	$ 13,394,951		$ 13,394,951
30	W Increased ROE	2012	3,708,222	88,902	3,619,320	835,093	906,709	21,870	884,838	204,296	$ 14,016,520	$ 14,016,520	
31	W 11.68 % ROE	2013	3,619,320	88,902	3,530,418	688,638	22,244,731	539,606	21,705,126	4,226,803	$ 42,505,119		$ 42,505,119
32	W Increased ROE	2013	3,619,320	88,902	3,530,418	688,638	22,244,731	539,606	21,705,126	4,226,803	$ 44,681,943	$ 44,681,943	
33	W 11.68 % ROE	2014	3,530,418	88,902	3,441,515	625,760	21,776,090	541,328	21,234,762	3,853,838	$ 87,786,109		$ 87,786,109
34	W Increased ROE	2014	3,530,418	88,902	3,441,515	625,760	21,776,090	541,328	21,234,762	3,853,838	$ 93,076,527	$ 93,076,527	
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	$ -		$ -
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	$ -	$ -	
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	$ -		$ -
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	$ -	$ -	
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	$ -		$ -
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	$ -	$ -	
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	$ -		$ -
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	$ -	$ -	
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	$ -		$ -
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	$ -	$ -	
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	$ -		$ -
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	$ -	$ -	
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	$ -		$ -
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	$ -	$ -	
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	$ -		$ -
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	$ -	$ -	
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	$ -		$ -
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	$ -	$ -	
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	$ -		$ -
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	$ -	$ -	
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	$ -		$ -
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	$ -	$ -	
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	$ -		$ -
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	$ -	$ -	
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	$ -		$ -
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	$ -	$ -	
61													$ -
62												$ -	

On the formulas used in the Columns for lines 22+ are as follows
For Plant in service: (first year means first year the project is placed in service)
"Beginning" is the investment on line 17 for the first year and is the "Ending" for the prior year after the first year
"Depreciation" is the annual depreciation in line 18 divided by twelve times the difference of thirteen minus line 19 in the first year and line 18 thereafter if "no" on line 13. "Depreciation" is "0" (zero) if "Yes" on line 13
"Ending" is "Beginning" less "Depreciation"
Revenue is "Ending" times line 16 for the current year times the quotient line 19 divided by 13 plus "Depreciation" for the first year and "Ending" times line 16 plus "Depreciation" thereafter

For CWIP:
Beginning is the line 17 for that year
Depreciation is not used
Ending is the same as Beginning
Revenue is Ending times line 16 for the current year

Exhibit 1
Page 17 of 19

PPL Electric Utilities Corporation

Attachment 8 - Company Exhibit - Securitization Worksheet

Line #			
	Prepayments		
36	**Less Prepayments on Securitization Bonds**	0	(See FM 1, note to page 110, line 57)
	Administrative and General Expenses		
52	**Less Administrative and General Expenses on Securitization Bonds**	0	(See FM 1, note to page 114, line 4)
	Taxes Other Than Income		
78	**Less Taxes Other Than Income on Securitization Bonds**	0	(See FM 1, note to page 114, line 14)
	Long Term Interest		
81	**Less LTD Interest on Securitization Bonds**	0	(See FM 1, note to page 114, lines 62 + 63)
	Capitalization		
92	**Less LTD on Securitization Bonds**	0	(See FM 1, note to page 112, line 18)

Calculation of the above Securitization Adjustments

The amounts above are associated with transition bonds issued to securitize the recovery of retail stranded costs, pursuant to an Order entered by the Pennsylvania Public Utility Commission on May 21, 1999 at Docket No. R-00994637, in accordance with Pennsylvania's Electric Generation Customer Choice and Competition Act.

PPL Electric Utilities Corporation

Attachment 9 - Depreciation Rates

(A) Number	(B) Plant Type	(C) Estimated Life	(D) Mortality Curve	(E) Current Age	(F) Remaining Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	Transmission									
350.4	Land Rights	70	S4	11.9	58.10	1.7722	130,617,954	39,900,055	90,717,899	1,607,682
352	Structures and Improvements	55	R4	13.7	41.30	2.8312	39,408,219	17,017,096	22,391,123	633,938
353	Station Equipment	47	R1	8.2	38.80	2.5732	651,945,487	172,715,967	479,229,520	12,331,566
354	Towers and Fixtures	65	R3	6.1	58.90	1.6667	530,270,259	136,822,481	393,447,778	6,557,676
354.2	Towers and Fixtures - Clearing Land and Rights of Way	70	R4	9.3	60.70	1.7075	20,004,500	6,914,758	13,089,742	223,510
355	Poles and Fixtures	55	R1.5	12.6	42.40	2.6192	104,406,634	42,621,671	61,784,963	1,618,277
355.2	Poles and Fixtures - Clearing Land and Rights of Way	70	R4	15.9	54.10	1.7904	8,730,844	3,973,328	4,757,516	85,180
356	Overhead Conductors and Devices	55	R3	6.8	48.20	2.1493	337,031,700	120,159,829	216,871,871	4,661,192
357	Underground Conduit	50	R4	5.5	44.50	2.1904	12,329,210	2,442,897	9,886,313	216,545
358	Underground Conductors and Devices	40	R3	16.8	23.20	3.1687	27,220,574	8,562,172	18,658,402	591,226
359	Roads and Trails	70	R4	13.0	57.00	1.6931	10,443,672	2,957,266	7,486,406	126,751
	General									
389.4	Land Rights	65	R4	36.1	28.90	3.5971	4,399	1,597	2,802	101
390.2	Structures and Improvements - Buildings	55	S0	37.5	17.50	2.2111	364,805,034	76,126,524	288,678,510	6,383,027
390.21	Structures and Improvements - Leaseholds	10	NA		5.50	-	741,658	374,439	367,219	0
390.4	Structures and Improvements - Air Conditioning	30	R2	7.8	22.20	4.1556	41,541,771	12,144,478	29,397,293	1,221,645
391.2	Office Furniture and Equipment - Furniture	20	NA		11.30	4.9275	22,000,591	8,396,898	13,603,693	1,084,087
391.4	Office Furniture and Equipment - Mechanical Equipment	15	NA		9.50	6.6705	2,851,312	918,118	1,933,194	190,195
391.6	Office Furniture and Equipment - Computer Equipment - General	5	NA		3.10	18.9374	4,853,681	604,866	4,248,816	919,161
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System	7	NA		-	14.2800	38,155,394	38,155,394	0	0
392.1	Transportation Equipment - 5 Years	5	R4	2.2	2.80	42.2609	6,432,789	3,917,411	2,515,378	1,063,021
392.2	Transportation Equipment - 8 Years	8	S3	2.4	5.60	38.0222	18,898,886	12,725,518	6,173,368	2,347,253
392.3	Transportation Equipment - 10 Years	11	R2.5	4.7	6.30	6.5158	75,252,903	38,828,749	36,424,154	2,373,335
392.4	Transportation Equipment - Trailers	16	L1	(3.0)	19.00	8.9256	6,848,729	2,477,888	4,370,841	390,124
392.5	Transportation Equipment - 15 Years	14	L2	3.6	10.40	13.2955	3,703,120	1,501,824	2,201,296	292,674
392.6	Transportation Equipment - 20 Years	18	L1.5	12.8	5.20	11.4298	653,799	165,698	488,101	55,789
393	Store Equipment	25	NA		11.60	5.1104	2,807,016	1,104,407	1,702,609	143,449
394	Tools, Shop and Garage Equipment - Distribution Line Crews	20	NA		10.00	5.6735	4,845,263	1,956,855	2,888,408	274,894
394.2	Tools, Shop and Garage Equipment - Tools	20	NA		7.10	7.2446	285,256	128,938	156,318	20,666
394.4	Tools, Shop and Garage Equipment - Construction Department	20	NA		11.10	5.8264	1,353,414	572,586	780,828	78,855
394.6	Tools, Shop and Garage Equipment - Other	20	NA		12.30	4.8968	22,345,920	7,074,004	15,271,916	1,094,237
394.8	Tools, Shop and Garage Equipment - Garage Tools Support	20	NA		6.80	8.4276	3,349,049	1,932,232	1,416,817	282,246
395	Laboratory Equipment	20	NA		13.30	4.9502	4,574,077	1,481,523	3,092,554	226,425
396	Power Operated Equipment	15	NA		9.70	7.0898	2,238,835	1,155,482	1,083,353	158,729
397	Communication Equipment	15	NA		11.80	12.2378	5,729,518	4,136,871	1,592,647	701,166
398	Miscellaneous Equipment	20	NA		13.00	6.7999	2,953,171	587,468	2,365,703	200,814
	Intangible									
303.2	Intangible Computer Software	5	NA		2.80	20.00	96,393,731	50,397,981	45,995,750	19,488,811
303.4	Other Amortized Property	15	NA		-	-	1,035,137	1,035,137	-	-

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance.
2 Column (E) is based on the Estimated Life in Column (C) less the Remaining Life in Column (F) for those accounts for which using a Mortality Curve is identified.
3 Column (F) is the average remaining life of the assets in the account based on their vintage.
4 Column (G) is the depreciation rate from the Mortality Curve specified based on data in Columns (C) and (D).
5 Columns (H) and (I) are the depreciable gross plant investment and accumulated depreciation in the account or subaccount.
6 Column (J) is the depreciable net plant in the account or subaccount.
7 Column (K) is Column (G) multiplied by Column (J) for those accounts that have an identified Mortality Curve.
8 Each year, PPL Electric will provide a copy of the annual report submitted to the PA PUC that shows the calculation of the depreciation rates and expenses derived from Columns (C) and (D).
9 Every 5 years, PPL Electric will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.
10 Column (K) for Accounts Nos. 303.2 and 303.4 are calculated using individual asset depreciation and, therefore, are not derived values.
11 Column (K) for Account No. 392.3 is net of capitalized depreciation expense. See the applicable note in FERC Form No. 1.
12 For those General Plant accounts that do not have Mortality Curves as indicated by "NA" in Column (D), additional detail is provided in Attachment 9 - Supplemental General Plant Depreciation Details.

PPL Electric Utilities Corporation

Attachment 9 - Supplemental
General Plant Depreciation Details

(A) Number	(B) Plant Type	(C) Estimated Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	General						
390.21	Structures and Improvements - Leaseholds - Net Method	10	-	741,658	374,439	367,219	0
391.2	Office Furniture and Equipment - Furniture - Gross Method	20	4.6897	18,297,909	5,425,836	12,872,073	858,123
391.2	Office Furniture and Equipment - Furniture - Net Method	20	30.8854	3,702,682	2,971,062	731,620	225,964
				22,000,591	8,396,898	13,603,693	1,084,087
391.4	Office Furniture and Equipment - Mechanical Equipment - Gross Method	15	6.5754	2,846,396	915,498	1,930,898	187,163
391.4	Office Furniture and Equipment - Mechanical Equipment - Net Method	15	132.0567	4,916	2,620	2,296	3,032
				2,851,312	918,118	1,933,194	190,195
391.6	Office Furniture and Equipment - Computer Equipment - General- Gross Method	5	18.9374	4,853,681	604,866	4,248,815	919,161
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System- Gross Method	7	14.2800	38,155,394	38,155,394	0	0
393	Store Equipment - Gross Method	25	3.2312	1,697,736	469,131	1,228,605	54,857
393	Store Equipment - Net Method	25	18.6902	1,109,280	635,276	474,004	88,592
				2,807,016	1,104,407	1,702,609	143,449
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Gross Method	20	5.0000	2,371,043	827,368	1,543,675	118,552
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Net Method	20	11.6262	2,474,221	1,129,488	1,344,733	156,342
				4,845,264	1,956,856	2,888,408	274,894
394.2	Tools, Shop and Garage Equipment - Tools - Gross Method	20	5.0000	133,692	35,258	98,434	6,685
394.2	Tools, Shop and Garage Equipment - Tools - Net Method	20	24.1534	151,564	93,680	57,884	13,981
				285,256	128,938	156,318	20,666
394.4	Tools, Shop and Garage Equipment - Construction Department - Gross Method	20	5.8163	1,345,463	568,227	777,236	78,257
394.4	Tools, Shop and Garage Equipment - Construction Department - Net Method	20	16.6667	7,951	4,359	3,592	599
				1,353,414	572,586	780,828	78,855
394.6	Tools, Shop and Garage Equipment - Gross Method	20	4.7280	19,565,411	4,552,978	15,012,433	925,058
394.6	Tools, Shop and Garage Equipment - Net Method	20	65.1988	2,780,509	2,521,026	259,483	169,180
				22,345,920	7,074,004	15,271,916	1,094,238
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Gross Method	20	4.8755	1,464,256	232,911	1,231,345	71,389
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Net Method	20	113.6865	1,884,792	1,699,320	185,472	210,857
				3,349,048	1,932,231	1,416,817	282,246
395	Laboratory Equipment - Gross Method	20	4.9757	2,965,369	698,991	2,266,378	147,548
395	Laboratory Equipment - Net Method	20	9.5473	1,608,708	782,533	826,175	78,877
				4,574,077	1,481,524	3,092,553	226,425
396	Power Operated Equipment - Gross Method	15	4.9855	1,264,202	315,705	948,497	63,027
396	Power Operated Equipment - Net Method	15	70.9662	974,633	839,777	134,856	95,702
				2,238,835	1,155,482	1,083,353	158,729
397	Communication Equipment - Gross Method	15	12.5412	5,048,939	3,671,858	1,377,081	633,196
397	Communication Equipment - Net Method	15	31.5309	680,579	465,013	215,566	67,970
				5,729,518	4,136,871	1,592,647	701,166
398	Miscellaneous Equipment - Gross Method	20	4.1292	2,155,956	262,446	1,893,510	89,025
398	Miscellaneous Equipment - Net Method	20	23.6745	797,215	325,021	472,194	111,789
				2,953,171	587,467	2,365,704	200,814

Notes:

1 This schedule shows additional detail for those General Plant accounts that do not have a Mortality Curve. The calculation of Depreciation Expense by the Gross Plant Method (i.e., Column (G) multiplied by Column (H)) and the Net Plant Method (i.e., Column (G) multiplied by Column (J)) is shown separately for the assets in each account subject to each such method. Assets purchased new are depreciated using the Gross Plant Method. Assets purchased used are depreciated using the Net Plant Method (i.e., over their remaining economic life).

Attachment 4F - AEP East Formula Rate Summary Update

Attachment 4F

Formula Rate Update for AEP East subsidiaries in PJM

To be Effective July 1, 2014 through June 30, 2015
Docket No ER08-1329

Pursuant to PJM OATT Attachment H-14A (Formula Rate Implementation Protocols), AEP has calculated its Annual Transmission Revenue Requirements (ATRR) to produce the "Annual Update" for the Rate Year beginning July 1, 2014 through June 30, 2015. All the files pertaining to the Annual Update are to be posted on the PJM website in PDF format. The first file provides the ATRR and rates for Network transmission service and Scheduling System Control and Dispatch Service (Schedule 1A), and the annual transmission revenue requirement for RTEP projects (Schedule 12). An informational filing will also be submitted to the FERC.

AEP network service rate will increase effective July 1, 2014 from $29,042.93 per MW per year to $30,513.51 per MW per year with the AEP annual revenue requirement increasing from $676,950,019 to $697,120,761.

The AEP Schedule 1A rate increased from $.0829 per MWh to $.1267 per MWh.

An annual revenue requirement of $21,353,699 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b0839 (Twin Branch) $1,264,988
2. b0318 (Amos 765/138 kV Transformer) $1,729,223
3. b0504 (Hanging Rock) $1,093,199
4. b0570 (East Side Lima) $118,418
5. b1034.1 (Torrey-West Canton) $1,815,845
6. b1034.6 (138kV circuit South Canton Station) $523,012
7. b1231 (West Moulton Station) $1,658,442
8. b1465.2 (Rockport Jefferson 300 MVAR bank) $81,506
9. b1465.3 (Rockport Jefferson 765 kV line) $4,094,860
10. b1712.2 (Altavista-Leesville 138kV line) $(58,182)
11. b1864.1 (OPCo Kammer 345/138 kV transformers) $(173,597)
12. b1864.2 (West Bellaire-Brues 138 kV circuit) of $42,103
13. b2020 (Rebuild Amos-Kanawha River) $184,681
14. b2021 (APCo Kanawha River Gen Retirement Upgrades) $222,712
15. b1659.14 (Ft. Wayne Relocate) $239,172
16. b2048 (Tanners Creek-Transformer Replacement) $265,282
17. b2021 (OPCo 345/138kV Transformer) $7,415,172
18. b2032 (Rebuild 138kV Elliott Tap-Poston) $28,898
19. b1034.2 (Loop South Canton-Wayview) $646,572
20. b1034.7 (Replace circuit breakers Torrey/Wagenhals) $146,035
21. b1970 (Reconductor Kammer-West Bellaire) $99,055
22. b2018 (Loop Conesville-Bixby 345kV) $98,401
23. b1864.1 (WPCo 345/138kV transformer Kammer) $(182,098)

Formula Rate Update for AEP East subsidiaries in PJM

To be Effective July 1, 2014 through June 30, 2015
Docket No ER08-1329

In accordance with orders of the Federal Energy Regulatory Commission ("FERC") and Public Utilities Commission of Ohio that approved corporate separation of generation assets and associated liabilities, Ohio Power Company ("OPCo") transferred its generation assets and related generation liabilities to AEP Generation Resources, Inc. ("AGR") on December 31, 2013. In accordance with orders of the FERC, Kentucky Public Service Commission, the Public Service Commission of West Virginia and the Virginia State Corporation Commission, AGR immediately transferred its two-thirds interest in Amos Plant, Unit 3, to Appalachian Power Company, and a one-half interest in the Mitchell Plant to Kentucky Power Company. Notes to the financial statements associated with these transfers are detailed in the *2013 FERC Form 1s* of the companies.

Formula Rate Update for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective July 1, 2014
Docket No ER10-355

Pursuant to Attachment H-20A (Formula Rate Implementation Protocols) in PJM Tariff, AEP has calculated its Annual Transmission Revenue Requirements (ATRR) to produce the "Annual Update" for the Rate Year beginning July 1, 2014 through June 30, 2015. All the files pertaining to the Annual Update are also posted on the PJM website in PDF format along with supporting workpapers. The first file provides the ATRR and rates for Network transmission service and Scheduling System Control and Dispatch Service, Schedule 1A.

AEP network service rate will increase effective July 1, 2014 from $2,992.32 per MW per year or $8.20/MW Day to $7,083.07 per MW per year or $19.41/MW Day with the AEP annual revenue requirement increasing from $69,746,794 to $161,821,872.

The AEP Transmission Companies' Schedule 1A rates are not applicable because they are handled via AEP Operating Companies.

An annual revenue requirement of $26,033,561 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b1465.4 (Rockport Jefferson) of $777,399
2. b1465.2 (Rockport Jefferson-MVAR Bank) $2,722,822
3. b2048 (Tanners Creek 345/138 kV transformer) $1,041,979
4. b0570 (Lima-Sterling) $1,695,532
5. b1231 (Wapakoneta-West Moulton) $576,377
6. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $1,424,506
7. b1034.8 (South Canton Wagenhals Station) $1,087,714
8. b1864.2 (West Bellaire-Brues 138 kV Circuit) $230,215
9. b1870 (Ohio Central Transformer) $1,571,352
10. b1032.2 (Two 138kV outlets to Delano/Camp Sherman) $322,176
11. b1034.2 (Loop existing South Canton-Wayview 138kV) $580,874
12. b1034.3 (345/138kV 450 MVA transformer Canton Central) $1,611,055

Formula Rate Update for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective July 1, 2014
Docket No ER10-355

13. b1970 (Reconductor Kammer-West Bellaire) $1,502,768
14. b2018 (Loop Conesville-Bixby 345 kV) $597,332
15. b2021 (OHTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $2,052,447
16. b2032 (Rebuild 138kV Elliott Tap Poston line) $2,808,368
17. b1661 (765kV circuit breaker Wyoming station) $541,349
18. b1864.1 (Add 2 345/138kV transformers at Kammer) $2,795,819
19. b2021 (WVTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $2,093,479