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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

June 24, 2015

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, 2013
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2014
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2015

Docket Nos. EO03050394, ER12060485, ER13050378, ER14040370

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

Hon. Irene Kim Asbury, Secretary
Board of Public Utilities
44 South Clinton Avenue, 9th Fl
Post Office Box 350
Trenton, NJ 08625-0350

Dear Secretary Asbury:

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-RSCP and BGS-CIEP tariff rates effective September 1, 2015. 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

[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, 2015 and will remain in effect until changed. The BGS-RSCP and BGS-CIEP rates included in the amended tariff sheets for each EDC are revised to reflect costs effective on June 1, 2015 for TECs resulting from all of the FERC-approved Filings, except the AEP-East filing which is effective on July 1, 2015.

Attachment 2 shows the cost impact for the 2015/2016 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, 2015 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, 2015. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-RSCP 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-RSCP and BGS- CIEP SMAs, which mandate that BGS-RSCP 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, ER12060485, ER13050378, ER14040370

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Kim M. Durham Citigroup Energy Inc. 2800 Post Oak Boulevard Suite 500 Houston, TX 77056		

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

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) 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	$0.113331	$0.121264	$0.115737	$0.123839
RS – in excess of 600 kWh	0.113331	0.121264	0.124719	0.133449
RHS – first 600 kWh	0.089008	0.095239	0.086516	0.092572
RHS – in excess of 600 kWh	0.089008	0.095239	0.098527	0.105424
RLM On-Peak	0.176738	0.189110	0.189251	0.202499
RLM Off-Peak	0.058104	0.062171	0.055793	0.059699
WH	0.058283	0.062363	0.057569	0.061599
WHS	0.058754	0.062867	0.058870	0.062991
HS	0.107183	0.114686	0.111842	0.119671
BPL	0.054147	0.057937	0.051661	0.055277
BPL-POF	0.054147	0.057937	0.051661	0.055277
PSAL	0.054147	0.057937	0.051661	0.055277

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.

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
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 $5.2621
Charge including New Jersey Sales and Use Tax (SUT) $5.6304

Charge applicable in the months of October through May...$5.2621
Charge including New Jersey Sales and Use Tax (SUT) $5.6304

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 ....$ 72,688.29 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 .... $ 107.25 per MW per month
Virginia Electric and Power Company ....$ 91.91 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ 15.60 per MW per month
PPL Electric Utilities Corporation..$ 56.28 per MW per month
American Electric Power Service Corporation ....$ 10.54 per MW per month
Atlantic City Electric Company. ....$ 11.77 per MW per month
Delmarva Power and Light Company...$ 6.75 per MW per month
Potomac Electric Power Company. ....$ 11.37 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months...$ 6.3690
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.8148

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).

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 ....$ 72,688.29 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 .... $ 107.25 per MW per month
Virginia Electric and Power Company .... $ 91.91 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. .... $ 15.60 per MW per month
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Delmarva Power and Light Company... $ 6.75 per MW per month
Potomac Electric Power Company. .... $ 11.37 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months.. $ 6.3690
Charge including New Jersey Sales and Use Tax (SUT) .... $ 6.8148

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.

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial 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, 2015, a TRAILCO4-TEC surcharge of **$0.000444** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000044** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000088** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000026** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000040** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000209** 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 1, 2015, a PATH3-TEC surcharge of **$0.000060** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000354** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001637** 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: $0.000027 (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.

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, 2015, 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	**$0.000058**	**$0.000005**	**$0.000012**
GT	**$0.000261**	**$0.000026**	**$0.000051**
GP	**$0.000295**	**$0.000029**	**$0.000059**
GS and GST	**$0.000444**	**$0.000044**	**$0.000088**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000003**	**$0.000005**	**$0.000027**
GT	**$0.000015**	**$0.000024**	**$0.000122**
GP	**$0.000017**	**$0.000027**	**$0.000139**
GS and GST	**$0.000026**	**$0.000040**	**$0.000209**

Effective March 1, 2015, 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	**$0.000007**	**$0.000047**	**$0.000215**
GT	**$0.000035**	**$0.000210**	**$0.000969**
GP	**$0.000041**	**$0.000238**	**$0.001095**
GS and GST	**$0.000060**	**$0.000354**	**$0.001637**

4) BGS Reconciliation Charge per KWH: ($0.000077) (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	0.957 ¢ per kWh	0.957 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, 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 ....@	0.672 ¢ per kWh	0.672 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.688 ¢ per kWh	0.688 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Surcharges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

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 .....@	0.637 ¢ per kWh	0.637 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges, as described in General Information Section Nos. 33, 34, and 35, respectively, 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 ... @	0.641 ¢ per kWh	0.641 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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 @	0.389 ¢ per kWh	0.389 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35 respectively, shall be assessed on all kWh delivered hereunder.

(Continued)

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 3.159 ¢ per kWh during the billing months of October through May and 5.106 ¢ per kWh during the summer billing months and a Transmission Charge of 0.552 ¢ per kWh and a Transmission Surcharge of 0.389 ¢ 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), and (6) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

This special provision is closed to new customers effective August 1, 2014.

(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 2015/2016 TrailCo Schedule 12 Charges

Attachment 2B

Cost Allocation of 2015/2016 Delmarva Schedule 12 Charges

Attachment 2C

Cost Allocation of 2015/2016 ACE Schedule 12 Charges

Attachment 2D

Cost Allocation of 2015/2016 PEPCo Schedule 12 Charges

Attachment 2E

Cost Allocation of 2015/2016 PPL Schedule 12 Charges

Attachment 2F

Cost Allocation of 2015/2016 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.

PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
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 *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	June 2015- May 2016 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	JCP&L Zone Share[1]	PSE&G Zone Share[1] *per PJM Open Access Transmission Tariff*	RE Zone Share[1]	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 155,301,847.82	1.53%	3.54%	5.97%	0.25%	$2,376,118	$5,497,685	$9,271,520	$388,255	$17,533,579
Wylie Ridge [2]	b0218	$ 3,325,809.62	11.62%	15.28%	0.00%	0.00%	$386,459	$508,184	$0	$0	$894,643
Black Oak	b0216	$ 6,535,104.66	1.53%	3.54%	5.97%	0.25%	$99,987	$231,343	$390,146	$16,338	$737,813
Meadowbrook 200 MVAR capacitor	b0559	$ 560,954.25	1.53%	3.54%	5.97%	0.25%	$8,583	$19,858	$33,489	$1,402	$63,332
Replace Kammer 765/500 kV TXfmr	b0495	$ 5,332,913.64	1.53%	3.54%	5.97%	0.25%	$81,594	$188,785	$318,375	$13,332	$602,086
Doubs TXfmr 2	b0343	$ 686,839.65	1.85%	0.00%	0.00%	0.00%	$12,707	$0	$0	$0	$12,707
Doubs TXfmr 3	b0344	$ 622,667.98	1.86%	0.00%	0.00%	0.00%	$11,582	$0	$0	$0	$11,582
Doubs TXfmr 4	b0345	$ 828,661.86	1.85%	0.00%	0.00%	0.00%	$15,330	$0	$0	$0	$15,330
New Osage 138KV Ckt	b0674-b1023.3	$ 1,976,100.86	0.00%	0.00%	0.25%	0.01%	$0	$0	$4,940	$198	$5,138
Cap at Grover 230	b0556	$ 38,777.65	8.58%	18.16%	26.13%	0.97%	$3,327	$7,042	$10,133	$376	$20,878
Upgrade transformer 500/230	b1153	$ 3,539,337.95	3.72%	12.52%	20.44%	0.71%	$131,663	$443,125	$723,441	$25,129	$1,323,358
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 567,690.17	1.53%	3.54%	5.97%	0.25%	$8,686	$20,096	$33,891	$1,419	$64,092
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 15,599,254.15	1.53%	3.54%	5.97%	0.25%	$238,669	$552,214	$931,275	$38,998	$1,761,156
Build 250 MVAR svc at Altoona 230kV	b1801	$ 4,835,497.54	6.45%	8.12%	8.16%	0.33%	$311,890	$392,642	$394,577	$15,957	$1,115,066
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 785,906.53	0.00%	5.48%	0.00%	0.00%	$0	$43,068	$0	$0	$43,068
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 1,515,528.27	6.45%	8.12%	8.16%	0.33%	$97,752	$123,061	$123,667	$5,001	$349,481
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ 186,197.63	1.53%	3.54%	5.97%	0.25%	$2,849	$6,591	$11,116	$465	$21,022
							$3,787,194	**$8,033,694**	**$12,246,570**	**$506,871**	**$24,574,329**
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 15/16**	**2015TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2015 Impact (7 months)**	**2016 Impact (5 months)**	**2015-2016 Impact (12 months)**
PSE&G	$ 1,020,547.48	9,515.2	$ 107.25	$ 7,143,832	$ 5,102,737	$ 12,246,570
JCP&L	$ 669,474.51	5,636.9	$ 118.77	$ 4,686,322	$ 3,347,373	$ 8,033,694
ACE	$ 315,599.48	2,443.5	$ 129.16	$ 2,209,196	$ 1,577,997	$ 3,787,194
RE	$ 42,239.28	389.0	$ 108.58	$ 295,675	$ 211,196	$ 506,871
Total Impact on NJ Zones	**$ 2,047,860.75**			**$ 14,335,025**	**$ 10,239,304**	**$ 24,574,329**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT issued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.18	Replace Meadow Brook 138 kV breaker ‘MD-11’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.19	Replace Meadow Brook 138 kV breaker ‘MD-12’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.20	Replace Meadow Brook 138 kV breaker ‘MD-13’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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)

b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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)

b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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)

b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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)
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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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)
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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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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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%)

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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)
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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)

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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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1,95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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)
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%)

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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)
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%)

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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)
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%)

SCHEDULE 12 – APPENDIX

(5) Metropolitan Edison Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0215	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown		AEC (6.68%) / APS (3.95%) / ConEd (0.42%) / DPL (9.06%) / JCPL (16.78%) / ME (10.49%) / Neptune* (1.68%) / PECO (18.92%) / PPL (7.52%) / PSEG (22.57%) / RE (0.34%) / UGI (0.95%) / ECP** (0.64%)
b0404.1	Replace South Reading 230 kV breaker 107252		ME (100%)
b0404.2	Replace South Reading 230 kV breaker 100652		ME (100%)
b0575.1	Rebuild Hunterstown – Texas Eastern Tap 115 kV		ME (100%)
b0575.2	Rebuild Texas Eastern Tap – Gardners 115 kV and associated upgrades at Gardners including disconnect switches		ME (100%)
b0650	Reconductor Jackson – JE Baker – Taxville 115 kV line		ME (100%)
b0652	Install bus tie circuit breaker on Yorkana 115 kV bus and expand the Yorkana 230 kV ring bus by one breaker so that the Yorkana 230/115 kV banks 1, 3, and 4 cannot be lost for either B-14 breaker fault or a 230 kV line or bank fault with a stuck breaker		ME (100%)

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

(5) Metropolitan Edison Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0653	Construct a 230 kV Bernville station by tapping the North Temple – North Lebanon 230 kV line. Install a 230/69 kV transformer at existing Bernville 69 kV station		ME (100%)
b1000	Replace Portland 115kV breaker ‘95312’		ME (100%)
b1001	Replace Portland 115kV breaker ‘92712’		ME (100%)

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

(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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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

(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%)

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

(5) Metropolitan Edison Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2149	Upgrade substation riser on the Smith St. - York Inc. 115 kV line		ME (100%)
b2150	Upgrade York Haven structure 115 kV bus conductor on Middletown Jct. - Zions View 115 kV		ME (100%)

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

SCHEDULE 12 – APPENDIX

(7) Pennsylvania Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.1	Build 500 kV substation in PENELEC – Tap the Keystone – Juniata and Conemaugh – Juniata 500 kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0285.1	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0349	Upgrade Rolling Meadows-Gore Jct 115 kV		PENELEC (100%)
b0360	Construction of a ring bus on the 345 kV side of Wayne substation		PENELEC (100%)
b0365	Add a 50 MVAR, 230 kV cap bank at Altoona 230 kV		PENELEC (100%)
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0376	Install 300 MVAR capacitor at Conemaugh 500 kV substation		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0442	Spare Keystone 500/230 kV transformer		PENELEC (100%)
b0515	Replace Lewistown circuit breaker 1LY Yeagertown		PENELEC (100%)
b0516	Replace Lewistown circuit breaker 2LY Yeagertown		PENELEC (100%)
b0517	Replace Shawville bus section circuit breaker		PENELEC (100%)
b0518	Replace Homer City circuit breaker 201 Johnstown		PENELEC (100%)

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Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0519	Replace Keystone circuit breaker 4 Transformer - 20		PENELEC (100%)
b0549	Install 250 MVAR capacitor at Keystone 500 kV		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 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%)
b0551	Install 25 MVAR capacitor at Saxton 115 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%)
b0552	Install 50 MVAR capacitor at Altoona 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%)
b0553	Install 50 MVAR capacitor at Raystown 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%)

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0555	Install 100 MVAR capacitor at Johnstown 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%)
b0556	Install 50 MVAR capacitor at Grover 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%)
b0557	Install 75 MVAR capacitor at East Towanda 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%)
b0563	Install 25 MVAR capacitor at Farmers Valley 115 kV substation		PENELEC (100%)
b0564	Install 10 MVAR capacitor at Ridgeway 115 kV substation		PENELEC (100%)
b0654	Reconfigure the Cambria Slope 115 kV and Wilmore Junction 115 kV stations to eliminate Wilmore Junction 115 kV 3-terminal line		PENELEC (100%)
b0655	Reconfigure and expand the Glade 230 kV ring bus to eliminate the Glade Tap 230 kV 3-terminal line		PENELEC (100%)
b0656	Add three breakers to form a ring bus at Altoona 230 kV		PENELEC (100%)

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Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0794	Upgrade the Homer City 230 kV breaker 'Pierce Road'		PENELEC (100%)
b1005	Replace Glory 115 kV breaker '#7 XFMR'		PENELEC (100%)
b1006	Replace Shawville 115 kV breaker 'NO.14 XFMR'		PENELEC (100%)
b1007	Replace Shawville 115 kV breaker 'NO.15 XFMR'		PENELEC (100%)
b1008	Replace Shawville 115 kV breaker '#1B XFMR'		PENELEC (100%)
b1009	Replace Shawville 115 kV breaker '#2B XFMR'		PENELEC (100%)
b1010	Replace Shawville 115 kV breaker 'Dubois'		PENELEC (100%)
b1011	Replace Shawville 115 kV breaker 'Philipsburg'		PENELEC (100%)
b1012	Replace Shawville 115 kV breaker 'Garman'		PENELEC (100%)
b1059	Replace a CRS relay at Hooversville 115 kV station		PENELEC (100%)
b1060	Replace a CRS relay at Rachel Hill 115 kV station		PENELEC (100%)

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1153	Upgrade Conemaugh 500/230 kV transformer and add a new line from Conemaugh-Seward 230 kV		AEC (3.72%) / APS (6.23%) / BGE (16.75%) / ConEd (0.39%) / DL (0.32%) / JCPL (12.52%) / ME (6.87%) / PECO (11.49%) / PEPCO (0.55%) / PPL (15.36%) / PSEG (20.44%) / RE (0.71%) / NEPTUNE* (1.70%) / ECP** (2.95%)
b1153.1	Revise the reclosing on the Shelocta 115 kV breaker ‘Lucerne’		PENELEC (100%)
b1169	Replace Shawville 115 kV breaker ‘#1A XFMR’		PENELEC (100%)
b1170	Replace Shawville 115 kV breaker ‘#2A XFMR’		PENELEC (100%)
b1277	Build a new Osterburg East – Bedford North 115 kV Line, 5.7 miles of 795 ACSR		PENELEC (100%)
b1278	Install 25 MVAR Capacitor Bank at Somerset 115 kV		PENELEC (100%)
b1367	Replace the Cambria Slope 115/46 kV 50 MVA transformer with 75 MVA		PENELEC (100%)
b1368	Replace the Claysburg 115/46 kV 30 MVA transformer with 75 MVA		PENELEC (100%)
b1369	Replace the 4/0 CU substation conductor with 795 ACSR on the Westfall S21 Tap 46 kV line		PENELEC (100%)
b1370	Install a 3rd 115/46 kV transformer at Westfall		PENELEC (100%)
b1371	Reconductor 2.6 miels of the Claysburg – HCR 46 kV line with 636 ACSR		PENELEC (100%)

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1372	Replace 4/0 CU substation conductor with 795 ACSR on the Hollidaysburg – HCR 46 kV		PENELEC (100%)
b1373	Re-configure the Erie West 345 kV substation, add a new circuit breaker and relocate the Ashtabula line exit		PENELEC (100%)
b1374	Replace wave traps at Raritan River and Deep Run 115 kV substations with higher rated equipment for both B2 and C3 circuits		PENELEC (100%)
b1535	Reconductor 0.8 miles of the Gore Junction – ESG Tap 115 kV line with 795 ACSS		PENELEC (100%)
b1607	Reconductor the New Baltimore - Bedford North 115 kV		PENELEC (100%)
b1608	Construct a new 345/115 kV substation and loop the Mansfield - Everts 115 kV		APS (8.57%) / ConEd (0.47%) / PECO (1.71%) / PENELEC (89.25%)
b1609	Construct Four Mile Junction 230/115 kV substation. Loop the Erie South - Erie East 230 kV line, Buffalo Road - Corry East and Buffalo Road - Erie South 115 kV lines		APS (4.86%) / PENELEC (95.14%)
b1610	Install a new 230 kV breaker at Yeagertown		PENELEC (100%)
b1713	Install a 345 kV breaker at Erie West and relocate Ashtabula 345 kV line		PENELEC (100%)

* Neptune Regional Transmission System, LLC

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1769	Install a 75 MVAR cap bank on the Four Mile 230 kV bus		PENELEC (100%)
b1770	Install a 50 MVAR cap bank on the Buffalo Road 115 kV bus		PENELEC (100%)
b1802	Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 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%)
b1821	Replace the Erie South 115 kV breaker ‘Union City’		PENELEC (100%)
b1943	Construct a 115 kV ring bus at Claysburg Substation. Bedford North and Saxton lines will no longer share a common breaker		PENELEC (100%)
b1944	Reconductor Eclipse substation 115 kV bus with 1033 kcmil conductor		PENELEC (100%)
b1945	Install second 230/115 kV autotransformer at Johnstown		PENELEC (100%)
b1966	Replace the 1200 Amp Line trap at Lewistown on the Raystown-Lewistown 230 kV line and replace substation conductor at Lewistown		PENELEC (100%)
b1967	Replace the Blairsville 138/115 kV transformer		PENELEC (100%)
b1990	Install a 25 MVAR 115 kV Capacitor at Grandview		PENELEC (100%)
b1991	Construct Farmers Valley 345/230 kV and 230/115 kV substation. Loop the Homer City-Stolle Road 345 kV line into Farmers Valley		PENELEC (100%)

* Neptune Regional Transmission System, LLC

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1992	Reconductor Cambria Slope-Summit 115kV with 795 ACSS Conductor		PENELEC (100%)
b1993	Relocate the Erie South 345 kV line terminal		APS (10.09%) / ECP** (0.45%) / HTP (0.49%) / JCPL (5.14%) / Neptune* (0.54%) / PENELEC (70.71%) / PSEG (12.10%) / RE (0.48%)
b1994	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation		APS (33.20%) / ECP** (0.44%) / HTP (0.44%) / JCPL (8.64%) / ME (5.52%) / Neptune (0.86%) / PENELEC (36.81%) / PSEG (13.55%) / RE (0.54%)
b1995	Change CT Ratio at Claysburg		PENELEC (100%)
b1996.1	Replace 600 Amp Disconnect Switches on Ridgeway-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)
b1996.2	Reconductor Ridgway and Whetstone 115 kV Bus		PENELEC (100%)
b1996.3	Replace Wave Trap at Ridgway		PENELEC (100%)
b1996.4	Change CT Ratio at Ridgway		PENELEC (100%)
b1997	Replace 600 Amp Disconnect Switches on Dubois-Harvey Run-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)
b1998	Install a 75 MVAR 115 kV Capacitor at Shawville		PENELEC (100%)

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

Pennsylvania Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2016	Reconductor bus at Wayne 115 kV station		PENELEC (100%)

PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
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 2015 - May 2016 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**
New 500 kV MAPP TX line - Delmarva portion	b0512	$ 12,208,522	1.53%	3.54%	5.97%	0.25%	$186,790	$432,182	$728,849	$30,521	$1,378,342
Replace line trap-Keeney	b0272.1	$ 28,671	1.53%	3.54%	5.97%	0.25%	$439	$1,015	$1,712	$72	$3,237
Add two breakers-Keeney	b0751	$ 665,859	1.53%	3.54%	5.97%	0.25%	$10,188	$23,571	$39,752	$1,665	$75,175
Totals							**$197,417**	**$456,768**	**$770,312**	**$32,258**	**$1,456,755**
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 15/16**	**2015TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2015 Impact (7 months)**	**2016 Impact (5 months)**	**2015-2016 Impact (12 months)**
PSE&G	$ 64,192.68	9,515.2	$ 6.75	$ 449,349	$ 320,963	$ 770,312
JCP&L	$ 38,064.00	5,636.9	$ 6.75	$ 266,448	$ 190,320	$ 456,768
ACE	$ 16,451.39	2,443.5	$ 6.73	$ 115,160	$ 82,257	$ 197,417
RE	$ 2,688.14	389.0	$ 6.91	$ 18,817	$ 13,441	$ 32,258
Total Impact on NJ Zones	**$ 121,396.21**			**$ 849,773**	**$ 606,981**	**$ 1,456,755**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT issued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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,		DPL (100%)

	and run a new 69 kV line down to Harbeson 69 kV		

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%) / PEC (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%)

PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
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 2015 - May 2016 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	JCP&L Zone Share[1]	PSE&G Zone Share[1]	RE Zone Share[1] *per PJM Open Access Transmission Tariff*	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	$ 664,237	88.94%	9.38%	0.00%	0.00%	$590,772	$62,305	$0	$0	$653,078
Replace Monroe 230/69 kV TXfmrs	b0276	$ 1,014,863	91.28%	0.00%	8.29%	0.23%	$926,367	$0	$84,132	$2,334	$1,012,833
Reconductor Union - Corson 138 kV	b0211	$ 1,731,500	64.81%	25.70%	6.31%	0.00%	$1,122,185	$444,996	$109,258	$0	$1,676,438
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 3,473,132	1.53%	3.54%	5.97%	0.25%	$53,139	$122,949	$207,346	$8,683	$392,117
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 2,476,471	64.81%	25.70%	6.31%	0.00%	$1,605,001	$636,453	$156,265	$0	$2,397,719
Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)	b1398.5	$ 610,057	0.00%	12.82%	31.46%	1.25%	$0	$78,209	$191,924	$7,626	$277,759
	b1398.5.3.1	$ 1,891,255	0.00%	12.82%	31.46%	1.25%	$0	$242,459	$594,989	$23,641	$861,088
Totals							**$4,297,464**	**$1,587,371**	**$1,343,914**	**$42,283**	**$7,271,033**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 15/16	(l) 2015TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2015 Impact (7 months)	(o) 2016 Impact (5 months)	(p) 2015-2016 Impact (12 months)
PSE&G	$ 111,992.82	9,515.2	$ 11.77	$ 783,950	$ 559,964	$ 1,343,914
JCP&L	$ 132,280.92	5,636.9	$ 23.47	$ 925,966	$ 661,405	$ 1,587,371
ACE	$ 358,122.02	2,443.5	$ 146.56	$ 2,506,854	$ 1,790,610	$ 4,297,464
RE	$ 3,523.62	389.0	$ 9.06	$ 24,665	$ 17,618	$ 42,283
Total Impact on NJ Zones	**$ 605,919.38**			**$ 4,241,436**	**$ 3,029,597**	**$ 7,271,033**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT issued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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.

PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
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 *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2015- May 2016 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 kV MAPP TX line - PEPCO portion	b0512	$ 14,624,812	1.53%	3.54%	5.97%	0.25%	$223,760	$517,718	$873,101	$36,562	$1,651,141
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 3,526,442	1.78%	2.67%	3.81%	0.00%	$62,771	$94,156	$134,357	$0	$291,284
Replace 230 1A breaker	b0512.7	$ 334,317	1.53%	3.54%	5.97%	0.25%	$5,115	$11,835	$19,959	$836	$37,744
Replace 230 1B breaker	b0512.8	$ 334,317	1.53%	3.54%	5.97%	0.25%	$5,115	$11,835	$19,959	$836	$37,744
Replace 230 2A breaker	b0512.9	$ 334,317	1.53%	3.54%	5.97%	0.25%	$5,115	$11,835	$19,959	$836	$37,744
Replace 230 3A breaker	b0512.12	$ 337,330	1.53%	3.54%	5.97%	0.25%	$5,161	$11,941	$20,139	$843	$38,085
Ritchie-Benning 230 lines	b0526	$ 10,012,958	0.77%	1.39%	2.10%	0.08%	$77,100	$139,180	$210,272	$8,010	$434,562
Totals							**$384,136**	**$798,500**	**$1,297,746**	**$47,923**	**$2,528,305**
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 15/16**	**2015TX Peak Load** *per PJM website*	**Rate in \$/MW-mo.**	**2015 Impact (7 months)**	**2016 Impact (5 months)**	**2015-2016 Impact (12 months)**
PSE&G	$ 108,145.47	9,515.2	$ 11.37	$ 757,018	$ 540,727	$ 1,297,746
JCP&L	$ 66,541.70	5,636.9	$ 11.80	$ 465,792	$ 332,709	$ 798,500
ACE	$ 32,011.36	2,443.5	$ 13.10	$ 224,080	$ 160,057	$ 384,136
RE	$ 3,993.59	389.0	$ 10.27	$ 27,955	$ 19,968	$ 47,923
Total Impact on NJ Zones	**$ 210,692.12**			**$ 1,474,845**	**$ 1,053,461**	**$ 2,528,305**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT issued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL 4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0,28%) / ECP** (0.20%)

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC
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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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC
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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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP**

			(0.20%)

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

Potomac Electric Power Company (cont.)

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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

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%)

PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
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 *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	June 2015- May 2016 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	JCP&L Zone Share[1]	PSE&G Zone Share[1]	RE Zone Share[1] *per PJM Open Access Transmission Tariff*	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
New 500 KV Susquehana-Roseland Line	b0487	$ 102,063,888.50	1.53%	3.54%	5.97%	0.25%	$1,561,577	$3,613,062	$6,093,214	$255,160	$11,523,013
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 11,679.59	1.53%	3.54%	5.97%	0.25%	$179	$413	$697	$29	$1,319
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 8,375.30	1.53%	3.54%	5.97%	0.25%	$128	$296	$500	$21	$946
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 16,934.08	1.53%	3.54%	5.97%	0.25%	$259	$599	$1,011	$42	$1,912
New S-R additions < 500kV[2]	b0487.1	$ 2,559,720.51	0.00%	0.00%	5.13%	0.19%	$0	$0	$131,314	$4,863	$136,177
New substation and transformers Middletown	b0468	$ 3,355,282.98	0.00%	4.55%	5.93%	0.22%	$0	$152,665	$198,968	$7,382	$359,015
Totals							**$1,562,143**	**$3,767,036**	**$6,425,704**	**$267,497**	**$12,022,381**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 15/16	(l) 2015 Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2015 Impact (7 months)	(o) 2016 Impact (5 months)	(p) 2015-2016 Impact (12 months)
PSE&G	$ 535,475.36	9,515.2	$ 56.28	$ 3,748,328	$ 2,677,377	$ 6,425,704
JCP&L	$ 313,919.70	5,636.9	$ 55.69	$ 2,197,438	$ 1,569,599	$ 3,767,036
ACE	$ 130,178.62	2,443.5	$ 53.28	$ 911,250	$ 650,893	$ 1,562,143
RE	$ 22,291.44	389.0	$ 57.30	$ 156,040	$ 111,457	$ 267,497
Total Impact on NJ Zones	**$ 1,001,865.12**			**$ 7,013,056**	**$ 5,009,326**	**$ 12,022,381**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT issued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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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** East Coast Power, L.L.C.

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

* Neptune Regional Transmission System, LLC

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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

PJM Schedule 12 - Transmission Enhancement Charges for July 2015 - June 2016
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 2015 - June 2016 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
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 1,080,039	1.73%	4.02%	6.57%	0.28%	$18,685	$43,418	$70,959	$3,024	$136,085
Rockport Reactor Bank	b1465.2	$ 2,192,954	1.73%	4.02%	6.57%	0.28%	$37,938	$88,157	$144,077	$6,140	$276,312
Transpose Rockport-Sullivan 765KV line	b1465.3	$ 5,091,283	1.73%	4.02%	6.57%	0.28%	$88,079	$204,670	$334,497	$14,256	$641,502
Switching changes Sullivan 765KV station	b1465.4	$ 1,570,128	1.73%	4.02%	6.57%	0.28%	$27,163	$63,119	$103,157	$4,396	$197,836
765kV circuit breaker at Wyoming station	b1661	$ 769,141	1.73%	4.02%	6.57%	0.28%	$13,306	$30,919	$50,533	$2,154	$96,912
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 979,741	0.00%	0.00%	4.52%	0.18%	$0	$0	$44,284	$1,764	$46,048
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 10,926,992	0.00%	1.39%	2.00%	0.08%	$0	$151,885	$218,540	$8,742	$379,167
Add four 765 kV Breakers at Kammar	b1962	$ 2,412,097	1.73%	4.02%	6.57%	0.28%	$41,729	$96,966	$158,475	$6,754	$303,924
Ft. Wayne Relocate	b1659.14	$ (124,488)	1.73%	4.02%	6.57%	0.28%	($2,154)	($5,004)	($8,179)	($349)	($15,685)
Reconductor West Bellaire	b1970	$ 3,030,113	0.00%	1.68%	2.87%	0.11%	$0	$50,906	$86,964	$3,333	$141,203
Totals							**$224,747**	**$725,035**	**$1,203,307**	**$50,213**	**$2,203,303**
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 15/16	2015TX Peak Load *per PJM website*	Rate in $/MW-mo.	2015 Impact (7 months)	2016 Impact (5 months)	2015-2016 Impact (12 months)
PSE&G	$ 100,275.60	9,515.2	$ 10.54	$ 701,929	$ 501,378	$ 1,203,307
JCP&L	$ 60,419.62	5,636.9	$ 10.72	$ 422,937	$ 302,098	$ 725,035
ACE	$ 18,728.91	2,443.5	$ 7.66	$ 131,102	$ 93,645	$ 224,747
RE	$ 4,184.46	389.0	$ 10.76	$ 29,291	$ 20,922	$ 50,213
Total Impact on NJ Zones	**$ 183,608.59**			**$ 1,285,260**	**$ 918,043**	**$ 2,203,303**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2015 allocation share percentages are from PJM OATT isssued 5/7/2015
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2016, 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.4	Replace Amos 138 kV breaker ‘C’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.5	Replace Amos 138 kV breaker ‘C1’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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)
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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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%)

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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%)

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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.

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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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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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / ECP** (0.20%)
b1660	Install a 765/500 kV transformer at Cloverdale		AEC (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15 %) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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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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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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%)

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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%)

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)

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 (1.73%) / AEP (14.41%) / APS (5.47%) / ATSI (8.29%) / BGE (4.31%) / ComEd (14.04%) / ConEd (0.57%) / Dayton (2.15%) / DEOK (3.25%) / DL (1.86%) / DPL (2.53%) / Dominion (11.83%) / EKPC (0.00%) / HTP (0.01%) / JCPL (4.02%) / ME (1.90%) / NEPTUNE* (0.42%) / PECO (5.43%) / PENELEC (1.95%) / PEPCO (4.12%) / PPL (4.66%) / PSEG (6.57%) / RE (0.28%) / 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 2015/2016 Schedule 12 Charges into Rates - JCP&L
Attachment 3B
Translation of 2015/2016 Schedule 12 Charges into Rates - PSE&G
Attachment 3C
Translation of 2015/2016 Schedule 12 Charges into Rates - RECO

Attachment 3a

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO4-TEC Surcharge) effective September 1, 2015
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2015 - May 2016

2015/2016 Average Monthly TRAILCO4-TEC Costs Allocated to JCP&L Zone	$	669,474.51	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
TRAILCO4-Transmission Enhancement Rate ($/MW-month)	$	118.77	

				Effective September 1, 2015:	
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)	4963.0	7,073,254	17,035,674,708	$ 0.000415	$ 0.000444
Primary	354.2	504,805	1,826,846,521	$ 0.000276	$ 0.000295
Transmission @ 34.5 kV	307.0	437,536	1,792,646,137	$ 0.000244	$ 0.000261
Transmission @ 230 kV	12.7	18,100	333,251,266	$ 0.000054	$ 0.000058
Total	5636.9	8,033,694	20,988,418,632		

(1) Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months TRAILCO Project costs from June 2015 through May 2016
(3) September 2015 through August 2016

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

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	TRAILCO4-Transmission Enhancement Costs to RSCP Suppliers	$	7,291,451	= Line 3 x $118.77 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.42	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed Delmarva Project Transmission Enhancement Charge (Delmarva2-TEC Surcharge) effective September 1, 2015
To reflect FERC-approved Delmarva Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2015 - May 2016

2015/2016 Average Monthly Delmarva2-TEC Costs Allocated to JCP&L Zone	$	38,064.00	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
Delmarva2-Transmission Enhancement Rate ($/MW-month)	$	6.75	

Effective September 1, 2015:

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)	4963.0	402,161	17,035,674,708	$ 0.000024	$ 0.000026
Primary	354.2	28,701	1,826,846,521	$ 0.000016	$ 0.000017
Transmission @ 34.5 kV	307.0	24,877	1,792,646,137	$ 0.000014	$ 0.000015
Transmission @ 230 kV	12.7	1,029	333,251,266	$ 0.000003	$ 0.000003
Total	5636.9	456,768	20,988,418,632		

(1) Cost Allocation of Delmarva Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months Delmarva Project costs from June 2015 through May 2016
(3) September 2015 through August 2016

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

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	Delmarva2-Transmission Enhancement Costs to RSCP Suppliers	$	414,567	= Line 3 x $6.75 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 ACE Project Transmission Enhancement Charge (ACE2-TEC Surcharge) effective September 1, 2015
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2015 - May 2016

2015/2016 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	132,280.92	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
ACE2-Transmission Enhancement Rate ($/MW-month)	$	23.47	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective September 1, 2015: ACE2-TEC Surcharge ($/kWh)	ACE2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4963.0	1,397,598	17,035,674,708	$ 0.000082	$ 0.000088
Primary	354.2	99,744	1,826,846,521	$ 0.000055	$ 0.000059
Transmission @ 34.5 kV	307.0	86,452	1,792,646,137	$ 0.000048	$ 0.000051
Transmission @ 230 kV	12.7	3,576	333,251,266	$ 0.000011	$ 0.000012
Total	5636.9	1,587,371	20,988,418,632		

(1) Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months ACE Project costs from June 2015 through May 2016
(3) September 2015 through August 2016

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	ACE2-Transmission Enhancement Costs to RSCP Suppliers	$	1,440,712	= Line 3 x $23.47 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.08	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO2-TEC Surcharge) effective September 1, 2015
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2015 - May 2016

2015/2016 Average Monthly PEPCO2-TEC Costs Allocated to JCP&L Zone	$	66,541.70	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
PEPCO2-Transmission Enhancement Rate ($/MW-month)	$	11.80	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective September 1, 2015:** PEPCO2-TEC Surcharge ($/kWh)	PEPCO2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4963.0	703,038	17,035,674,708	$ 0.000041	$ 0.000044
Primary	354.2	50,175	1,826,846,521	$ 0.000027	$ 0.000029
Transmission @ 34.5 kV	307.0	43,488	1,792,646,137	$ 0.000024	$ 0.000026
Transmission @ 230 kV	12.7	1,799	333,251,266	$ 0.000005	$ 0.000005
Total	5636.9	798,500	20,988,418,632		

(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months PEPCO Project costs from June 2015 through May 2016
(3) September 2015 through August 2016

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

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	PEPCO2-Transmission Enhancement Costs to RSCP Suppliers	$	724,726	= Line 3 x $11.80 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL2-TEC Surcharge) effective September 1, 2015
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2015 - May 2016

2015/2016 Average Monthly PPL2-TEC Costs Allocated to JCP&L Zone	$	313,919.70	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
PPL2-Transmission Enhancement Rate ($/MW-month)	$	55.69	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective September 1, 2015:** PPL2-TEC Surcharge ($/kWh)	PPL2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4963.0	3,316,681	17,035,674,708	$ 0.000195	$ 0.000209
Primary	354.2	236,705	1,826,846,521	$ 0.000130	$ 0.000139
Transmission @ 34.5 kV	307.0	205,162	1,792,646,137	$ 0.000114	$ 0.000122
Transmission @ 230 kV	12.7	8,487	333,251,266	$ 0.000025	$ 0.000027
Total	5636.9	3,767,036	20,988,418,632		

(1) Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months PPL Project costs from June 2015 through May 2016
(3) September 2015 through August 2016

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

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	PPL2-Transmission Enhancement Costs to RSCP Suppliers	$	3,418,995	= Line 3 x $55.69 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.20	= 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, 2015
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective July 2015 - June 2016

2015/2016 Average Monthly AEP-East2-TEC Costs Allocated to JCP&L Zone	$	60,419.62	(1)
2015 JCP&L Zone Transmission Peak Load (MW)		5636.9	
AEP-East2-Transmission Enhancement Rate ($/MW-month)	$	10.72	

				Effective September 1, 2015:	
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)	4963.0	638,356	17,035,674,708	$ 0.000037	$ 0.000040
Primary	354.2	45,558	1,826,846,521	$ 0.000025	$ 0.000027
Transmission @ 34.5 kV	307.0	39,487	1,792,646,137	$ 0.000022	$ 0.000024
Transmission @ 230 kV	12.7	1,634	333,251,266	$ 0.000005	$ 0.000005
Total	5636.9	725,035	20,988,418,632		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2015/2016
(2) Based on 12 months AEP-East Project costs from July 2015 through June 2016
(3) September 2015 through August 2016

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

Line No.				
1	BGS-RSCP Eligible Sales June through May @ Customer		15,815,514	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node		17,498,443	MWH
3	BGS-RSCP Eligible Transmission Obligation		5,116	MW
4	AEP-East2-Transmission Enhancement Costs to RSCP Suppliers	$	658,049	= Line 3 x $10.72 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Project

TEC Charges for June 2015 - May 2016	$	12,246,570	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2	
Term (Months)		12	
OATT rate	$	107.25	/MW/month
converted to $/MW/yr =	$	1,287.00	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.379757	$ 0.204741	$ 0.373603	$ -	$ -	$ 0.329449	$ -	$ -
in $/kWh - rounded to 6 places	**0.00038**	**0.000205**	**0.000374**	**0**	**0**	**0.000329**	**0**	**0**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6392.2 MW			= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust	23,723,046 MWh			= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes	25,441,259 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 8,226,761		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.3234	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.32	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 8,141,203		unrounded	= (6) * (3)
8	Difference due to rounding	$ (85,559)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
Calculation of costs and monthly PJM charges for Delmarva Projects

TEC Charges for June 2015 - May 2016	$	770,312		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2		
Term (Months)		12		
OATT rate	$	6.75	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	81.00	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.023901	$ 0.012886	$ 0.023513	$ -	$ -	$ 0.020735	$ -	$ -
in $/kWh - rounded to 6 places	**0.000024**	**0.000013**	**0.000024**	**0**	**0**	**0.000021**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6392.2	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	517,768		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0204	/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	$	508,825		unrounded	= (6) * (3)
8	Difference due to rounding	$	(8,943)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2015 - May 2016	$	1,343,914	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2	
Term (Months)		12	
OATT rate	$	11.77	/MW/month
converted to $/MW/yr =	$	141.24	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.041676	$ 0.022469	$ 0.041001	$ -	$ -	$ 0.036155	$ -	$ -
in $/kWh - rounded to 6 places	**0.000042**	**0.000022**	**0.000041**	**0**	**0**	**0.000036**	**0**	**0**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6392.2	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust	23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes	25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 902,834		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0355	/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	$ 1,017,650		unrounded	= (6) * (3)
8	Difference due to rounding	$ 114,816		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2015 - May 2016	$	1,297,746	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2	
Term (Months)		12	
OATT rate	$	11.37	/MW/month
converted to $/MW/yr =	$	136.44	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.040260	$ 0.021705	$ 0.039607	$ -	$ -	$ 0.034926	$ -	$ -
in $/kWh - rounded to 6 places	**0.000040**	**0.000022**	**0.00004**	**0**	**0**	**0.000035**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6392.2	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	872,152		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0343	/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	$	763,238		unrounded	= (6) * (3)
8	Difference due to rounding	$	(108,914)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2015 - May 2016
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2015 - May 2016	$	6,425,704	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2	
Term (Months)		12	
OATT rate	$	56.28	/MW/month
converted to $/MW/yr =	$	675.36	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.199279	$ 0.107439	$ 0.196050	$ -	$ -	$ 0.172880	$ -	$ -
in $/kWh - rounded to 6 places	**0.000199**	**0.000107**	**0.000196**	**0**	**0**	**0.000173**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6392.2	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	4,317,036		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.1697	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.17	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	4,325,014		unrounded	= (6) * (3)
8	Difference due to rounding	$	7,978		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for July 2015 - June 2016
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for June 2015 - May 2016	$	1,203,307	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,515.2	
Term (Months)		12	
OATT rate	$	10.54	/MW/month
converted to $/MW/yr =	$	126.48	/MW/yr

all values show w/o NJ SUT

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW		3579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh		12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge									
in $/MWh	$	0.037321	$ 0.020121	$ 0.036716	$ -	$ -	$ 0.032377	$ -	$ -
in $/kWh - rounded to 6 places		**0.000037**	**0.00002**	**0.000037**	**0**	**0**	**0.000032**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6392.2	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	808,485		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0318	/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	$	763,238		unrounded	= (6) * (3)
8	Difference due to rounding	$	(45,248)		unrounded	= (7) - (4)

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2015
To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2015 to May 2016

2014/2015 Average Monthly ACE-TEC Costs Allocated to RECO	$	3,524	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	8.35	

	Col. 1	Col. 2		Col.3=Col.2 x $3,524 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	25,133	713,293,000	$	0.00004	$	0.00004
SC2 Secondary	115.5	27.36%	$	11,568	547,849,000	$	0.00002	$	0.00002
SC2 Primary	15.2	3.60%	$	1,524	80,998,000	$	0.00002	$	0.00002
SC3	0.1	0.01%	$	6	272,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	388	16,381,000	$	0.00002	$	0.00002
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	3,664	258,080,000	$	0.00001	$	0.00001
Total	422.1 (2)	100.00%	$	42,283	1,629,009,000				

(1) Attachment 2 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2015 through May 2016
(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	38,628.53	= Line 3 x $8.35 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.03	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective September 1, 2015
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2015 to May 2016

2014/2015 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	4,184	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	9.91	

	Col. 1	Col. 2		Col.3=Col.2 x $4,184 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	29,847	713,293,000	$	0.00004	$	0.00004
SC2 Secondary	115.5	27.36%	$	13,738	547,849,000	$	0.00003	$	0.00003
SC2 Primary	15.2	3.60%	$	1,810	80,998,000	$	0.00002	$	0.00002
SC3	0.1	0.01%	$	7	272,000	$	0.00003	$	0.00003
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	461	16,381,000	$	0.00003	$	0.00003
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	4,351	258,080,000	$	0.00002	$	0.00002
Total	422.1 (2)	100.00%	$	50,214	1,629,009,000				

(1) Attachment 2 - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for June 2015 through May 2016
(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	45,845.36	= Line 3 x $9.91 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.04	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Delmarva) effective September 1, 2015
To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2014 to May 2015

2014/2015 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	2,688	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	6.37	

	Col. 1	Col. 2		Col.3=Col.2 x $2,688 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	19,174	713,293,000	$	0.00003	$	0.00003
SC2 Secondary	115.5	27.36%	$	8,825	547,849,000	$	0.00002	$	0.00002
SC2 Primary	15.2	3.60%	$	1,163	80,998,000	$	0.00001	$	0.00001
SC3	0.1	0.01%	$	5	272,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	296	16,381,000	$	0.00002	$	0.00002
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	2,795	258,080,000	$	0.00001	$	0.00001
Total	422.1 (2)	100.00%	$	32,258	1,629,009,000				

(1) Attachment 2 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2015 through May 2016
(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	29,468.71	= Line 3 x $6.37 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective September 1, 2015

To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2015 to May 2016

2014/2015 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	3,994	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	9.46	

	Col. 1	Col. 2		Col.3=Col.2 x $3,994 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	28,485	713,293,000	$	0.00004	$	0.00004
SC2 Secondary	115.5	27.36%	$	13,111	547,849,000	$	0.00002	$	0.00002
SC2 Primary	15.2	3.60%	$	1,727	80,998,000	$	0.00002	$	0.00002
SC3	0.1	0.01%	$	7	272,000	$	0.00003	$	0.00003
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	440	16,381,000	$	0.00003	$	0.00003
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	4,153	258,080,000	$	0.00002	$	0.00002
Total	422.1 (2)	100.00%	$	47,923	1,629,009,000				

(1) Attachment 2 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2015 through May 2016

(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	43,763.58	= Line 3 x $9.46 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.04	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PPL) effective September 1, 2015
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2015 to May 2016

2014/2015 Average Monthly PPL-TEC Costs Allocated to RECO	$	22,291	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	52.81	

	Col. 1	Col. 2		Col.3=Col.2 x $22,291 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	159,000	713,293,000	$	0.00022	$	0.00024
SC2 Secondary	115.5	27.36%	$	73,184	547,849,000	$	0.00013	$	0.00014
SC2 Primary	15.2	3.60%	$	9,641	80,998,000	$	0.00012	$	0.00013
SC3	0.1	0.01%	$	37	272,000	$	0.00014	$	0.00015
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	2,454	16,381,000	$	0.00015	$	0.00016
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	23,181	258,080,000	$	0.00009	$	0.00010
Total	422.1 (2)	100.00%	$	267,497	1,629,009,000				

(1) Attachment 2 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2015 through May 2016
(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	244,308.12	= Line 3 x $52.81 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.20	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective September 1, 2015
To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2015 to May 2016

2014/2015 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	42,239	(1)
2014 RECO Zone Transmission Peak Load (MW)		422.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	100.07	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)		Col.3=Col.2 x $42,239 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Sep 2015- Aug 2016 (kWh)		Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)		Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	250.9	59.44%	$	301,284	713,293,000	$	0.00042	$	0.00045
SC2 Secondary	115.5	27.36%	$	138,674	547,849,000	$	0.00025	$	0.00027
SC2 Primary	15.2	3.60%	$	18,268	80,998,000	$	0.00023	$	0.00025
SC3	0.1	0.01%	$	71	272,000	$	0.00026	$	0.00028
SC4	0.0	0.00%	$	-	6,538,000	$	-	$	-
SC5	3.9	0.92%	$	4,649	16,381,000	$	0.00028	$	0.00030
SC6	0.0	0.00%	$	-	5,598,000	$	-	$	-
SC7	36.6	8.67%	$	43,924	258,080,000	$	0.00017	$	0.00018
Total	422.1 (2)	100.00%	$	506,870	1,629,009,000				

(1) Attachment 2 - Cost Allocation of TrAILCo Schedule 12 Charges to RECO Zone for June 2015 through May 2016
(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)		1,315,339	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,225,531	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	462,940.99	= Line 3 x $100.07 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.38	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective September 1, 2015
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) For 2015
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) For 2015
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) For 2015
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 2015
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) For 2015
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 2015
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	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
Delmarva - TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00006	0.00004	0.00004	0.00004	0.00000	0.00004	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00022	0.00013	0.00012	0.00014	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(8)	0.00776	0.00552	0.00571	0.00518	0.00000	0.00519	0.00000	0.00316
TrAILCo - TEC	(9)	0.00042	0.00025	0.00023	0.00026	0.00000	0.00028	0.00000	0.00017
VEPCo - TEC	(10)	0.00035	0.00025	0.00026	0.00024	0.00000	0.00024	0.00000	0.00014
Total ($/kWh and excl SUT)		$0.00896	$0.00628	$0.00643	$0.00596	$0.00000	$0.00600	$0.00000	$0.00364
Total (¢/kWh and excl SUT)		0.896 ¢	0.628 ¢	0.643 ¢	0.596 ¢	0.000 ¢	0.600 ¢	0.000 ¢	0.364 ¢

(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	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
Delmarva - TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00006	0.00004	0.00004	0.00004	0.00000	0.00004	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00024	0.00014	0.00013	0.00015	0.00000	0.00016	0.00000	0.00010
PSE&G - TEC	(8)	0.00830	0.00591	0.00611	0.00554	0.00000	0.00555	0.00000	0.00338
TrAILCo - TEC	(9)	0.00045	0.00027	0.00025	0.00028	0.00000	0.00030	0.00000	0.00018
VEPCo - TEC	(10)	0.00037	0.00027	0.00028	0.00026	0.00000	0.00026	0.00000	0.00015
Total ($/kWh and incl SUT)		$0.00957	$0.00672	$0.00688	$0.00637	$0.00000	$0.00641	$0.00000	$0.00389
Total (¢/kWh and incl SUT)		0.957 ¢	0.672 ¢	0.688 ¢	0.637 ¢	0.000 ¢	0.641 ¢	0.000 ¢	0.389 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2015.
(2) ACE-TEC rates calculated in Attachment 5 of the joint filing.
(3) AEP-East-TEC ratescalculated 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 11, 2015 in Docket No. ER14121414.
(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 11, 2015 in Docket No. ER14121414.
(9) TrAILCo-TEC rates calculated in Attachment 5 of the joint filing.
(10) VEPCo-TEC rates pursuant to the Board’s Order dated February 11, 2015 in Docket No. ER14121414.

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

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May 15, 2015

By eFiling

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Trans-Allegheny Interstate Line Company
Electronic Informational Filing of 2015 Formula Rate Annual Update
Docket Nos. ER07-562-000, ER15-____-000

Dear Secretary Bose:

Pursuant to the Commission's order dated May 31, 2007 in Docket No. ER07-562-000[1] and the uncontested settlement approved by the Commission in an order dated July 21, 2008 in Docket No. ER07-562-004,[2] Trans-Allegheny Interstate Line Company ("TrAILCo") hereby submits for informational purposes its 2015 Annual Update to recalculate its annual transmission revenue requirements ("Annual Update"). The Annual Update includes (i) a reconciliation of the annual transmission revenue requirements for the 2014 Rate Year[3] (Attachment 1), (ii) the annual transmission revenue requirements for the 2015 Rate Year to become effective on June 1, 2015 (Attachment 2), and (iii) a detailed accounting of transfers between construction work in progress ("CWIP") and Plant in Service as required by the May 31 Order (Attachment 3).

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1 *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 at P 59 (2007) ("May 31 Order").

2 *Trans-Allegheny Interstate Line Co.*, 124 FERC ¶ 61,075 (2008).

3 The "Rate Year" begins on June 1 of a given calendar year and continues through May 31 of the subsequent calendar year.

TrAILCo's tariff on file with the Commission specifies that:

> [o]n or before May 15 of each year, TrAILCo shall recalculate its Annual Transmission Revenue Requirements, producing the "Annual Update" for the upcoming Rate Year, and post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page.
>
> If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.[4]

The Annual Update attached hereto and submitted to PJM Interconnection, L.L.C. for posting on its Internet website via link to the Transmission Services page includes a recalculation of TrAILCo's annual transmission revenue requirements.[5] The 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) (2015). In addition, please note that TrAILCo has made no material changes in its accounting policies and practices from those in effect during the previous Rate Year and upon which the current rate is based.

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

Respectfully submitted,

/s/ John S. Moot
John S. Moot

Attorney for
Trans-Allegheny Interstate Line Company

Enclosures

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4 PJM Interconnection, L.L.C., Open Access Transmission Tariff as filed with the Commission in Docket No. ER10-2710 on September 17, 2010 ("PJM Tariff"), Attachment H-18B, Sections 1(b), (c) (effective June 1, 2007).

5 The input for lines 85 and 91 of Appendix A of the Annual Update are different from the amounts on the referenced lines of the FERC Form No. 1 as a result of the Commission order directing the FirstEnergy companies not to apply purchase accounting adjustments as reflected on Attachment 4 hereto. *See FirstEnergy Corp.*, 133 FERC ¶ 61,222 at P 72 (2010).

ATTACHMENT 1

Reconciliation of

Annual Transmission Revenue Requirements

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	TrAILCo
				2014 Reconciliation
	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	1,446,364,152
7	Total Plant In Service		(Line 6)	1,446,364,152
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	95,908,418
9	Total Accumulated Depreciation		(Line 8)	95,908,418
10	Net Plant		(Line 7 - Line 9)	1,350,455,734
11	Transmission Gross Plant		(Line 15 + Line 21)	1,446,364,152
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	1,350,455,734
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	1,379,892,602
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	0
17	**Total Transmission Plant**		(Line 15 + Line 16)	**1,379,892,602**
18	General & Intangible		Attachment 5	66,471,550
19	Total General & Intangible		(Line 18)	66,471,550
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**66,471,550**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**1,446,364,152**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	85,759,374
24	Accumulated General Depreciation		Attachment 5	4,576,702
25	Accumulated Intangible Amortization		Attachment 5	5,572,343
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	10,149,044
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**10,149,044**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**95,908,418**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**1,350,455,734**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109 Enter Negative		Attachment 1	-185,003,191
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**-185,003,191**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**3,110,605**
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	**158,892**
	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)	971,197
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**121,400**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**-181,612,295**
46	**Rate Base**		(Line 30 + Line 45)	**1,168,843,439**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	4,932,317
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	1,374,120
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)	**3,558,197**
	A&G Expenses			
53	Total A&G		p323.197.b	-3,961,120
54	Less Property Insurance Account 924		p323.185.b	50,085
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)	-4,011,205
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**-4,011,205**
	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	50,085
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	50,085
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**50,085**
	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	1,374,120
73	Total Account 566		Sum (Lines 70 to 72)	**1,374,120**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**971,197**

Depreciation & Amortization Expense

	Depreciation Expense			
75	Transmission Depreciation Expense		Attachment 5	27,824,330
76	General Depreciation		Attachment 5	1,444,875
77	Intangible Amortization	(Note A)	Attachment 5	1,484,865
78	Total		(Line 76 + Line 77)	2,929,740
79	Wage & Salary Allocator		(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**		(Line 78 * Line 79)	**2,929,740**
81	**Total Transmission Depreciation & Amortization**		**(Lines 75 + 80)**	**30,754,070**

Taxes Other than Income

82	**Transmission Related Taxes Other than Income**	Attachment 2	**10,984,149**
83	**Total Taxes Other than Income**	**(Line 82)**	**10,984,149**

Return / Capitalization Calculations

84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	820,500,305
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)	820,500,305
	Capitalization				
90	Long Term Debt		(Note N)		549,584,218
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	0
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	0
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	549,584,218
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	820,500,305
97	**Total Capitalization**			(Sum Lines 94 to 96)	1,370,084,523
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	40.1132%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0000%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	59.8868%
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)	0.0196
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0701
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.0897**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**104,808,190**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			8.29%
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)} =		40.39%
113	T/ (1-T)			67.75%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**55,485,825**
115	**Total Income Taxes**		**(Line 114)**	**55,485,825**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	1,350,455,734
117	Total Adjustment to Rate Base		(Line 45)	-181,612,295
118	**Rate Base**		(Line 46)	**1,168,843,439**
119	Total Transmission O&M		(Line 74)	971,197
120	Total Transmission Depreciation & Amortization		(Line 81)	30,754,070
121	Taxes Other than Income		(Line 83)	10,984,149
122	Investment Return		(Line 108)	104,808,190
123	Income Taxes		(Line 115)	55,485,825
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**203,003,430**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	1,446,364,152
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	1,446,364,152
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	203,003,430
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**203,003,430**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	2,678,014
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**200,325,416**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**200,325,416**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**1,297,243,833**
135	FCR		(Line 133 / Line 134)	**15.4424%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**13.2975%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**13.2975%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**0.9410%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**40,031,402**
140	Increased Return and Taxes		Attachment 4	**172,036,227**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**212,067,628**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**1,297,243,833**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**16.3476%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**14.2027%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**14.2027%**
146	**Net Revenue Requirement**		(Line 132)	**200,325,416.28**
147	Reconciliation amount		Attachment 6	**0.00**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**9,377,938.48**
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)	**209,703,354.76**
	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

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

Line	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
	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**	415,524,705	428,633,111	422,078,908	[redacted]	422,078,908	-	-	422,078,908	
2 **ADIT-283 From Account Total Below**	28,494,606	39,662,909	34,078,758		33,445,583	-	-	33,445,583	
3 **ADIT-190 From Account Total Below**	(286,572,920)	(256,320,086)	(271,446,503)		(270,521,300)	-	-	(270,521,300)	Enter Negative
4 **Subtotal**					185,003,191	-	-	185,003,191	
5 **Wages & Salary Allocator**							100.0000%		
6 **Gross Plant Allocator**						100.0000%			
7 **ADIT**					185,003,191	-	-	185,003,191	

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 0 < 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
Charitable Contribution Carryforward	3,761	8,371	6,066			6,066			Disallowance in current year for charitable deduction due to tax loss, tax attribute carries forward five years
Federal Long Term - NOL	-	140,451,171	70,225,586			70,225,586			Result of bonus depreciation
Federal Short-Term NOL	258,092,677	86,296,783	172,194,730			172,194,730			Result of bonus depreciation
IBNR - Workers Compensation	109,219	-	54,610			54,610			Actual amount of reserve for workers' compensation
Long Term Disability Accrual	24,415	-	12,208			12,208			Long term disability accrual
Merger Costs D&O Insurance	2,299	1,871	2,085		2,085				Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
Merger Costs Licenses	107,065	85,383	96,224		96,224				Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
NOL Deferred Tax Asset - LT PA	-	5,009,642	2,504,821			2,504,821			Result of bonus depreciation
NOL Deferred Tax Asset PA	6,625,569	567,331	3,596,450			3,596,450			Result of bonus depreciation
NOL Deferred Tax Asset WV	20,852,421	17,735,335	19,293,878			19,293,878			Result of bonus depreciation
Pension/OPEB: Other Def Cr. Or Dr.	-	2,203,787	1,101,894			1,101,894			Pension related temporary difference associated with Service Company allocations
Power Tax True-Up Adjustment	81,454	-	40,727			40,727			System adjustment to reclass balances to correct FERC accounts
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
Purch Acct-LTD FMV	-	1,240,669	620,335		620,335				Reflects the adjustments and subsequent amortization of the regulatory asset associated with the adjusted debt balances resulting from the FE/AYE merger (Offset is PAA - LT Regulatory Asset Amort below in 283)
Reevaluation Adjustment	413,120	-	206,560		206,560				Temporary difference resulting from purchase accounting transactions
State Income Tax Deductible	-	2,190,351	1,095,176			1,095,176			Deductions related to state income taxes
Unamortized Discount	-	529,392	264,696			264,696			Unamortized discounts on long-term debt
FASB 109 Gross-Up	-	-	-		-				Reclass of the tax portion (gross-up) for property items included in account 282
Subtotal	286,572,920	256,320,086	271,446,503	-	925,204	270,521,300	-	-	
Less FASB 109 included above	-	-	-	-	-	-	-	-	
Less FASB 106 included above									
Total	286,572,920	256,320,086	271,446,503	-	925,204	270,521,300	-	-	

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	1,757,820	2,575,691	2,166,756			2,166,756			Allowance for borrowed funds used during construction (ABFUDC)
Accelerated Tax Depreciation	-	490,609,438	245,304,719			245,304,719			Additional tax deprecation over book
Property Related - Tax Depreciation	72,202,243	-	36,101,122			36,101,122			Tax depreciation
FASB 109 Fixed Asset Adjustment	-	-	-			-			Increase in AOFDC
FASB 109 Gross-Up	-	21,430,125	10,715,063			10,715,063			Reclass of the tax portion (gross-up) for property items included in account 282
Book Depreciation Expense	(34,270,107)	-	(17,135,054)			(17,135,054)			Book depreciation
Amortization Expense - Intangible Plant	(1,865,544)	-	(932,772)			(932,772)			Book depreciation / amortization
Bonus Depreciation	409,438,305	-	204,719,153			204,719,153			Tax depreciation
CIACS Taxable	(799,612)	-	(399,806)			(399,806)			Taxable CIAC
Tax Interest Capitalized	(33,033,740)	-	(16,516,870)			(16,516,870)			Actual amount of tax interest capitalized
Power Tax Adjustment	152,981	(588,777)	(217,898)			(217,898)			System adjustment to reclass balances to correct FERC accounts
A&G Expenses Capitalized	1,004,786	2,314,345	1,659,566			1,659,566			Accounting change relating to A&G expense
Estimated Property Regulatory Asset Adjustment	1,341,207	-	670,604			670,604			Property True-Up
Book Profit/Loss on Retirement	(61,299)	-	(30,650)			(30,650)			Result of gain or loss on asset retirements
Repair & Maintenance 481 a Adjustment	2,788,907	3,337,031	3,062,969			3,062,969			Portion of Repairs & Maintenance 481a Adjustment offset in Account 182
Repair & Maintenance Deduction	245,561	-	122,781			122,781			Portion of Repairs & Maintenance deduction offset in Account 182
Additional State Depreciation VA	287,806	-	143,903			143,903			Temporary difference for additional state depreciation allowed for VA tax return
Additional State Depreciation MD	(4,144,928)	-	(2,072,464)			(2,072,464)			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	242,761	5,618,518	2,930,640			2,930,640			Portion of AFUDC Equity that relates to property and booked to account 282
Cost of Removal	55,011	(2,704,317)	(1,324,653)			(1,324,653)			Temporary difference arising for removal of plant/property
MACRS/ACRS Property Retired Retail	1,524,917	-	762,459			762,459			Result of gain or loss on asset retirements
Capitalized Vertical Tree Trimming	16,784	22,838	19,811			19,811			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
Other Basis Differences	(3,624,549)	(72,551,656)	(38,088,103)			(38,088,103)			Other property related temporary differences
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	415,524,705	450,063,236	432,793,971			432,793,971			
Less FASB 109 included above	-	21,430,125	10,715,063	-	-	10,715,063			
Less FASB 106 included above	-	-	-			-			
Total	415,524,705	428,633,111	422,078,908			422,078,908			

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**	**End of Year Balance**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
	p276.19.b	**p277.19.k**							
Accrued Taxes: Property Taxes	1,318,026	3,352,114	2,335,070			2,335,070			West Virginia property tax payment
Adjustment to Deferred Federal Tax	6,888	-	3,444			3,444			Adjustment to true-up deferred federal tax
AFUDC Equity Flow Through	156,301	-	78,151			78,151			The tax portion (gross-up) of the AFUDC Equity booked in account 282
Deferred Charge EIB	2,291	6,775	4,533			4,533			Allocated portion of total liabilities relating to captive insurance
Deferred Revenue - Pole Attachment	-	243	122			122			Deferred revenues associated with attachments to FirstEnergy poles
FASB 109 Gross-up	17,174,299	-	8,587,150			8,587,150			Reclass of the tax portion (gross-up) for property items included in account 282
Intercompany Charge AESC	2,066,632	-	1,033,316			1,033,316			Intercompany charges from the service company
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
Other Adjustments	(10,555,131)	-	(5,277,566)			(5,277,566)			System adjustment to reclass balances to correct FERC accounts
PAA - 221 Debt Amort	-	22,771	11,386		11,386				Reflects the adjustments and subsequent amortization of adjusted debt balances associated with the FE/AYE merger
PAA - LT Regulatory Asset Amort	-	1,240,668	620,334		620,334				Reflects the adjustments and subsequent amortization of adjusted regulatory asset balances associated with the FE/AYE merger
PJM Receivable	32,724,308	34,655,162	33,689,735			33,689,735			Comparison of actual to forecast revenues - non-property related
Reserve for EIB	45,318	-	22,659			22,659			Adjustment for reserve for EIB in Goodwill carried over to current year
SC01 Timing Allocation	-	385,176	192,588			192,588			Timing differences related to service company allocations
State Income Tax - Federal Deferred Only	1,711,721	-	855,861			855,861			Temporary difference resulting from the timing between when state income taxes are paid and when they are deductible on the federal tax return
Unamortized Loss on Reacquired Debt	1,015,123	-	507,562			507,562			Unamortized debt expenses for existing debt that is refinanced and amortized over the life of the new debt
Vegetation Management - Transmission	218	-	109			109			Vegetation Management Transmission Corridor capital cost and depreciation expenses required for the regulatory financial statement schedules
Subtotal	45,668,905	39,662,909	42,665,907		633,175	42,032,732	-	-	
Less FASB 109 included above	17,174,299	-	8,587,150	-	-	8,587,150			
Less FASB 106 included above									
Total	28,494,606	39,662,909	34,078,758		633,175	33,445,583	-	-	

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	2014 State Property WV	p263.1.1(i)	4,146,727	100.0000%	$ 4,146,727
1.2	2013 State Property WV	p263.40(i)	4,149,894	100.0000%	4,149,894
1.3	2014 State Property PA (PURTA)	p263.25(i)	27,000	100.0000%	27,000
1.4	2013 State Property PA (PURTA)	p263.26(i)	2,595	100.0000%	2,595
1.5					-
1.6	2013 Local Property WV	p263.1.6(i)	14,519	100.0000%	14,519
1.7	2014 Local Property WV	p263.1.7(i)	13,960	100.0000%	13,960
1.8	2014 Local Property VA	p263.1.10(i)	1,403,987	100.0000%	1,403,987
1.9	2014 Local Property PA	p263.1.13(i)	3,579	100.0000%	3,579
2.1	2013 Local Property MD	p263.1.16(i)	611,569	100.0000%	611,569
2.2	2014 Local Property MD	p263.1.17(i)	610,517	100.0000%	610,517
2.3	2014 Capital Stock Tax/Franchise MD	p263.9(i)	300	100.0000%	300
2.4	2013 Capital Stock Tax/Franchise PA	p263.22(i)	-8,116	100.0000%	-8,116
2.5	2014 Capital Stock Tax/Franchise PA	p263.23(i)	29,475	100.0000%	29,475
2.6					
2.7	2013 WV Franchise Tax	p263.37(i)	-16,428	100.0000%	-16,428
3.1	2014 WV Franchise Tax	p263.38(i)	15,639	100.0000%	15,639
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	p263.18(i)	1,146	100.0000%	1,146
6.1	State License WV			100.0000%	0
6.5	Federal Excise Tax	p263.3(i)	1,206	100.0000%	1,206
8	**Total Plant Related**		11,007,569	100.0000%	11,007,569
	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	2011 MD GRT	p263.11(i)	-6,447		-6,447
16	2012 MD GRT	p263.12(i)	-8,622		-8,622
17	2013 MD GRT	p263.13(i)	-8,351		-8,351
18					
19	**Total Other Included**		-23,420	100.0000%	-23,420
20	**Total Included (Lines 8 + 14 + 19)**		10,984,149		**10,984,149** Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded				
21	Federal Income Tax	p263.2(i)	2,094,347		
22	Corporate Net Income Tax MD	p263.7(i)	-478,760		
23	Corporate Net Income Tax PA	p263.17(i)	1,625,392		
24	Corporate Net Income Tax VA	p263.30(i)	-237,626		
25	Corporate Net Income Tax WV	p263.34(i)	-1,642,085		
26					
27					
28					
29					
30					
31	**Subtotal, Excluded**		1,361,268		
32	**Total, Included and Excluded (Line 20 + Line 31)**		12,345,417		
33	**Total Other Taxes from p114.14.c**		10,984,149		
34	**Difference (Line 32 - Line 33)**		1,361,268		

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		2,678,014	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)	2,678,014	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	2,678,014	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		2,678,014	

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)		172,036,227	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		1,168,843,439
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		820,500,305
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		820,500,305
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		549,584,218
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		0
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		0
12	Total Long Term Debt		Appendix A, Line 94		549,584,218
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		820,500,305
15	Total Capitalization		Appendix A, Line 97		1,370,084,523
16	Debt %	Total Long Term Debt	Appendix A, Line 98		40.1132%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0.0000%
18	Common %	Common Stock	Appendix A, Line 100		59.8868%
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)		0.0196
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0761
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.0957**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**111,808,023**

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	8.29%
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	40.39%
31	T/ (1-T)		Appendix A, Line 113	67.75%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		60,228,203
33	**Total Income Taxes**		**(Line 32)**	**60,228,203**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

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

	Calculation of Transmission Plant In Service	Source		13 Month Balance for Reconciliation Total	EOY Balance for Estimate Total	Black Oak	Wylie Ridge	502 Junction - Territorial Line	Potter SS	OsageWhiteley
	December	p206.58.b	For 2013	1,259,599,755		46,608,150	17,447,442	1,066,179,959	2,024,007	24,832,065
	January	company records	For 2014	1,259,351,317		46,608,150	17,447,442	1,065,982,112	2,024,007	24,778,518
	February	company records	For 2014	1,259,458,130		46,608,150	17,447,442	1,066,198,161	2,024,007	24,798,580
	March	company records	For 2014	1,273,944,125		46,608,150	17,447,442	1,066,250,629	2,024,007	24,799,928
	April	company records	For 2014	1,273,906,126		46,608,150	17,447,442	1,066,262,800	2,024,007	24,805,443
	May	company records	For 2014	1,291,089,258		46,629,901	17,447,442	1,066,665,904	2,024,007	24,809,572
	June	company records	For 2014	1,457,224,846		46,629,901	17,447,442	1,066,660,797	2,024,007	24,812,877
	July	company records	For 2014	1,462,189,797		46,629,901	17,558,636	1,067,544,778	2,024,007	24,812,889
	August	company records	For 2014	1,461,069,064		46,629,901	17,558,636	1,067,546,950	2,024,007	24,818,581
	September	company records	For 2014	1,459,104,799		46,629,901	17,558,636	1,067,552,541	2,024,007	24,817,288
	October	company records	For 2014	1,466,086,130		46,629,901	17,558,636	1,067,599,815	2,024,007	24,763,211
	November	company records	For 2014	1,476,064,041		46,629,901	17,558,636	1,067,519,965	2,024,007	24,763,211
	December	p207.58.g	For 2014	1,539,516,439	1,539,516,439	46,629,901	17,965,415	1,070,838,672	2,024,007	24,759,276
15	**Transmission Plant In Service**			**1,379,892,602**	**1,539,516,439**	**46,621,535**	**17,530,053**	**1,067,138,699**	**2,024,007**	**24,797,803**

	Calculation of Transmission Plant In Service	Meadowbrook Transformer	North Shenandoah	Bedington Transformer	Meadowbrook Capacitor	Kammer	Doubs #2 Trans	Doubs #3 Trans	Doubs #4 Trans
	December	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	January	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	February	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	March	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	April	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	May	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	June	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	July	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	August	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	September	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	October	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	November	8,202,934	80,682	7,723,538	6,496,239	39,562,936	5,149,271	4,686,053	5,700,307
	December	8,202,934	80,682	7,723,538	6,496,239	39,629,071	5,149,271	4,686,053	5,700,307
15	**Transmission Plant In Service**	**8,202,934**	**80,682**	**7,723,538**	**6,496,239**	**39,543,865**	**5,149,271**	**4,686,053**	**5,700,307**

Details

13 Month Plant Balance For reconciliation

Cabot SS	Armstrong	Farmers Valley Capacitor	Harvey Run Capacitor	Doubs SS	Meadowbrook SS	Grandview Capacitor	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake - Homer City	Altoona
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,240,036	-	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,242,992	-	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,113,695	-	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,113,741	14,432,132	-	-	-	-
7,123,323	1,350,836	934,909	832,122	3,306,399	484,588	636,089	10,117,589	14,387,432	11,588	-	-	-
7,123,323	1,350,836	934,916	832,122	4,634,278	484,588	636,089	10,117,589	28,151,270	25,241	1,648,772	-	-
7,123,323	13,153,352	934,916	832,122	4,873,705	59,633,787	636,089	10,117,589	27,849,702	28,697	1,784,047	10,750,043	34,854,327
7,123,323	13,688,202	934,916	832,108	4,891,737	59,726,402	636,089	10,117,589	27,847,222	1,195,821	1,769,915	10,275,429	34,324,500
7,123,323	13,462,827	934,916	832,201	4,859,948	60,228,050	636,089	10,117,589	27,847,222	1,196,013	1,770,871	9,038,217	34,373,048
7,123,323	8,067,343	934,916	832,201	4,873,250	60,381,844	636,089	10,117,589	27,847,222	1,199,337	1,774,272	11,734,615	34,879,463
7,123,323	14,430,681	934,916	832,201	4,876,868	59,986,727	636,556	10,117,595	27,849,570	1,199,337	1,774,272	12,261,214	34,862,794
7,123,323	16,639,863	934,916	832,202	4,873,250	60,594,811	636,556	10,117,595	27,855,012	1,199,375	1,774,657	14,421,778	34,887,422
7,123,323	15,863,978	934,916	832,202	4,877,582	60,049,287	657,175	10,117,608	27,021,750	1,199,375	1,757,271	13,035,331	34,900,798
7,123,323	**7,954,712**	**934,887**	**832,095**	**4,253,278**	**32,577,572**	**645,995**	**10,136,061**	**19,314,503**	**558,061**	**1,081,083**	**6,270,510**	**18,698,642**

Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total	
-	-	-	-	-	-	-	-	-	-	1,259,599,755	
-	-	-	-	-	-	-	-	-	-	1,259,351,317	
-	-	-	-	-	-	-	-	-	-	1,259,458,130	
-	-	-	-	-	-	-	-	-	-	1,273,944,125	
-	-	-	-	-	-	-	-	-	-	1,273,906,126	
-	-	-	-	-	-	-	-	-	-	1,291,089,258	
3,170,597	398,203	44,043,682	1,892,233	-	-	-	-	-	-	1,457,224,846	
3,319,486	409,366	43,841,160	5,112,912	-	-	-	-	-	-	1,462,189,797	
3,320,194	404,381	43,893,966	4,878,727	-	-	-	-	-	-	1,461,069,064	
3,320,415	420,891	43,926,572	4,879,677	-	-	-	-	-	-	1,459,104,799	
3,320,415	451,629	43,936,132	4,908,565	434,357	-	-	-	-	-	1,466,086,130	
3,320,562	458,675	43,924,684	4,907,284	434,357	5,030,042	-	-	-	-	1,476,064,041	
3,320,565	446,617	43,870,078	4,929,429	434,006	5,629,441	52,352,651	9,381,128	891,214	5,349	1,539,516,439	
1,776,326	**229,982**	**23,648,944**	**2,423,756**	**100,209**	**819,960**	**4,027,127**	**721,625**	**68,555**	**411**	**1,379,892,602**	**1,439,606,621**

Trans-Allegheny Interstate Line

Attachment 5 - Cost Supp

				Link to Appendix A, line 15	**Link to Appendix A, line 15**
	Calculation of Distribution Plant In Service	Source			
	December	p206.75.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p207.75.g	For 2014	-	-
	Distribution Plant In Service			-	-
	Calculation of Intangible Plant In Service	Source			
	December	p204.5.b	For 2013	10,393,869	
	December	p205.5.g	For 2014	10,398,271	10,398,271
18	**Intangible Plant In Service**			**10,396,070**	**10,398,271**
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of General Plant In Service	Source			
	December	p206.99.b	For 2013	56,186,164	-
	December	p207.99.g	For 2014	55,964,796	**55,964,796**
18	**General Plant In Service**			**56,075,480**	**55,964,796**
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of Production Plant In Service	Source			
	December	p204.46b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p205.46.g	For 2014	-	-
	Production Plant In Service			-	-
6	**Total Plant In Service**	Sum of averages above		**1,446,364,152**	**1,605,879,506**
				Link to Appendix A, line 6	**Link to Appendix A, line 6**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

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

Line	Calculation of Transmission Accumulated Depreciation	Source		13 Month Balance for Reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p219.25.b	For 2013	72,434,228	
	January	company records	For 2014	74,538,994	
	February	company records	For 2014	76,648,165	
	March	company records	For 2014	78,759,554	
	April	company records	For 2014	80,887,320	
	May	company records	For 2014	83,013,513	
	June	company records	For 2014	85,307,027	
	July	company records	For 2014	87,745,558	
	August	company records	For 2014	90,187,163	
	September	company records	For 2014	92,651,656	
	October	company records	For 2014	95,143,692	
	November	company records	For 2014	97,645,175	
	December	p219.25.b	For 2014	99,909,818	99,909,818
23	**Transmission Accumulated Depreciation**			**85,759,374**	**99,909,818**
				Link to Appendix A, line 23	**Link to Appendix A, line 23**

Month	Black Oak	Wylie Ridge	502 Junction - Territorial Line	Potter SS	Osage Whiteley	Meadowbrook Transformer	North Shenandoah
December	8,048,836	(3,158,824)	61,652,257	36,085	271,800	944,069	(1,630,174)
January	8,163,118	(3,128,291)	63,394,779	38,952	322,246	958,424	(1,630,060)
February	8,277,399	(3,097,759)	65,138,053	41,819	372,661	972,779	(1,629,945)
March	8,391,681	(3,067,227)	66,882,169	44,687	423,097	987,135	(1,629,831)
April	8,505,963	(3,028,122)	68,632,677	47,554	473,569	1,001,490	(1,629,717)
May	8,620,244	(2,980,444)	70,374,954	50,421	521,594	1,015,845	(1,629,603)
June	8,734,526	(2,932,767)	72,117,548	53,289	569,627	1,030,200	(1,629,488)
July	8,848,808	(2,884,913)	73,859,516	56,156	617,659	1,044,555	(1,629,374)
August	8,963,089	(2,836,883)	75,602,285	59,023	665,698	1,058,910	(1,629,260)
September	9,077,371	(2,788,852)	77,346,501	61,891	713,741	1,073,265	(1,629,145)
October	9,191,652	(2,740,822)	79,090,778	64,758	761,727	1,087,620	(1,629,031)
November	9,305,934	(2,692,518)	80,834,965	67,625	809,658	1,101,976	(1,628,917)
December	9,420,216	(2,643,941)	82,246,430	70,493	857,590	1,116,331	(1,628,802)
Transmission Accumulated Depreciation	**8,734,526**	**(2,921,643)**	**72,090,224**	**53,289**	**567,744**	**1,030,200**	**(1,629,488)**

Month	Bedington Transformers	Meadowbrook Capacitor	Kammer	Doubs #2 Trans	Doubs #3 Trans	Doubs #4 Trans	Cabot SS
December	754,136	584,992	3,504,039	319,366	239,958	447,084	286,459
January	767,652	597,082	3,573,224	327,274	246,774	459,548	298,919
February	781,168	609,172	3,642,409	335,182	253,591	472,012	311,379
March	794,684	621,262	3,711,595	343,089	260,407	484,476	323,839
April	808,201	633,352	3,780,780	350,997	267,223	496,940	336,299
May	821,717	645,442	3,849,965	358,904	274,039	509,405	348,759
June	835,233	657,533	3,919,150	366,812	280,855	521,869	361,219
July	848,749	669,623	3,988,335	374,719	287,671	534,333	373,679
August	862,265	681,713	4,057,520	382,627	294,488	546,797	386,139
September	875,782	693,803	4,126,706	390,534	301,304	559,261	398,599
October	889,298	705,893	4,195,891	398,442	308,120	571,725	411,059
November	902,814	717,983	4,265,101	406,349	314,936	584,190	423,519
December	949,704	730,074	4,334,394	414,257	321,752	596,654	434,971
Transmission Accumulated Depreciation	**837,800**	**657,533**	**3,919,162**	**366,812**	**280,855**	**521,869**	**361,141**

Details

13 Month Balance For Reconciliation

Armstrong	Farmers Valley Capacitor	Harvey Run Capacitor	Doubs SS	Meadowbrook SS	Grandview Capacitor	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake - Homer City	Altoona
-	-	-	-	-	3,579	130,566	-	-	-	-	-
-	818	-	2,891	-	4,740	140,905	-	-	-	-	-
-	2,454	-	8,646	-	5,902	151,244	-	-	-	-	-
-	4,090	728	15,028	-	7,063	161,583	-	-	-	-	-
-	5,726	2,184	22,064	-	8,219	171,922	-	-	-	-	-
-	7,362	3,640	29,638	-	9,369	182,261	-	-	-	-	-
12,858	9,000	5,096	37,959	51,765	10,520	192,600	112	-	1,545	25,741	30,911
38,945	10,641	6,553	46,505	155,376	11,670	202,939	334	1,046	4,623	52,413	92,267
65,208	12,282	8,009	55,039	259,506	12,820	213,279	554	3,139	7,690	77,263	153,201
86,573	13,923	9,465	63,556	364,210	13,971	223,618	26,752	5,235	10,760	101,533	214,624
107,530	15,564	10,922	72,089	468,703	15,121	233,957	78,932	7,334	13,833	127,089	276,813
137,278	17,205	12,378	80,622	573,382	16,272	244,296	131,121	9,433	16,907	152,921	338,599
169,357	18,846	13,834	89,154	678,530	17,424	254,635	183,306	11,532	19,981	178,471	399,670
47,519	**9,070**	**5,601**	**40,245**	**196,267**	**10,513**	**192,600**	**32,393**	**2,901**	**5,795**	**55,033**	**115,853**

Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total
-	-	-	-	-	-	-	-	-	-	72,434,228
-	-	-	-	-	-	-	-	-	-	74,538,994
-	-	-	-	-	-	-	-	-	-	76,648,165
-	-	-	-	-	-	-	-	-	-	78,759,554
-	-	-	-	-	-	-	-	-	-	80,887,320
-	-	-	-	-	-	-	-	-	-	83,013,513
2,774	348	38,538	1,656	-	-	-	-	-	-	85,307,027
8,453	1,055	115,437	7,785	-	-	-	-	-	-	87,745,558
14,263	1,767	192,206	16,528	-	-	-	-	-	-	90,187,163
20,073	2,489	269,049	25,066	-	-	-	-	-	-	92,651,656
25,884	3,253	345,929	33,630	-	-	-	-	-	-	95,143,692
31,695	4,049	422,807	42,217	379	-	-	-	-	-	97,645,175
37,506	4,841	496,224	50,870	1,138	4,926	49,062	8,484	1,892	15	99,909,818
10,819	**1,369**	**144,630**	**13,673**	**117**	**379**	**3,774**	**653**	**146**	**1**	**85,759,374**

Trans-Allegheny Interstate Line

Attachment 5 - Cost Supp

Line	Description	Source	Year		
	Calculation of Distribution Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.26.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p219.26.b	For 2014	-	-
	Distribution Accumulated Depreciation			-	-
	Calculation of Intangible Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p200.21.b	For 2013	4,822,025	
	December	p200.21b	For 2014	6,322,660	6,322,660
25	**Accumulated Intangible Depreciation**			**5,572,343**	**6,322,660**
				Link to Appendix A, line 25	**Link to Appendix A, line 25**
	Calculation of General Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.28b	For 2013	3,876,568	
	December	p219.28.b	For 2014	5,276,835	5,276,835
24	**Accumulated General Depreciation**			**4,576,702**	**5,276,835**
				Link to Appendix A, line 24	**Link to Appendix A, line 24**
	Calculation of Production Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.20.b-24.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p219.20.b thru 219.24.b	For 2014	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**95,908,418**	**111,509,313**
				Link to Appendix A, line 8	**Link to Appendix A, line 8**

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 Beg of year	Electric Portion End of Year (for estimate)	Non-electric Portion Average of Beginning and Ending Balances	Details
	Materials and Supplies						
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	1,326,179,788	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	1,259,599,755	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	72,434,228	-	-	

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

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

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 6.5%	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)		8.2884%					

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

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, 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

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	148,535	169,249	158,892	100%	158,892	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		**148,535**	**169,249**	158,892		158,892	

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		1,374,120	
	Total Account 566 Miscellaneous Transmission Expenses	p.321.97.b	$ 1,374,120	

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

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
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43			2,455,602								
352	Structures & Improvements	50	-	R3	(10)	2.20	16,761		1,332,732							144	
	SVC	35	-			2.86											
353	Station Equipment						1,354,619	514,883	844,309	172,262	1,372	162,194	145,082	830,355	94,890	81,650	149,570
	Other	50	-	R2	(5)	2.10											
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96											
	SCADA	15	-	S3	0	6.67											
354	Towers & Fixtures	65	-	R4	(25)	1.92			7,231,604								
355	Poles & Fixtures	55	-	R2.5	(20)	2.18			2,860,498								
356	Overhead Conductors & Devices								6,247,177								
	Other	55	-	R2.5	(40)	2.80											
	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							1,371,379	514,883	20,971,922	172,262	1,372	162,194	145,082	830,355	94,890	81,794	149,570
Total Transmission Depreciation Expense (must tie to p336.7.f)	27,824,330																

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

Annual Depreciation Expense

Cabot SS	Grandview Capacitor	Potter	Osage Whitely	Armstrong	Farmers Valley	Harvey Run	Doubs SS	Meadowbrook SS	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake-Homer City	Altoona
										1,438				
152	199		10,541	3	680				124,069					
149,368	13,646	34,408	116,607	163,144	18,166	13,834	89,154	678,530		80,825	11,532	19,981		399,670
			64,904							2,515				
			393,738	6,211						98,527			178,471	
-														
149,520	13,844	34,408	585,789	169,357	18,846	13,834	89,154	678,530	124,069	183,306	11,532	19,981	178,471	399,670

Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total
										2,457,040
										1,485,280
										-
										-
37,506	4,841	499,627	50,823	1,138	4,926	43,519	8,484	1,892		6,792,808
										-
										-
										-
										-
										7,231,604
									15	2,927,931
										-
						5,543				6,929,666
										-
										-
										-
										-
										-
										-
37,506	4,841	499,627	50,823	1,138	4,926	49,062	8,484	1,892	15	27,824,330

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

GENERAL PLANT		Life	Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	Total
390	Structures & Improvements	50	R1	0	2.00	893,109
391	Office Furniture & Equipment	20	SQ	0	5.00	96,332
	Information Systems	10	SQ	0	10.00	308,838
	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	16,520
	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	130,077
398	Miscellaneous Equipment	15	SQ	0	6.67	-
Total General Plant						1,444,875
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	1,444,875					

INTANGIBLE PLANT		Life	Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	Total
303	Miscellaneous Intangible Plant	5	SQ	0	20.00	1,484,865
Total Intangible Plant						1,484,865
Total Intangible Plant Amoritization (must tie to p336.1 d & e)	1,484,865					

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

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	-	-	-		3,277,585	-	136,129,170
	2	-	-	-		-	-	-
	3	-	-	-		-	-	-
	4	-	-	-		-	-	-
	…							
	Total	-	-	-		3,277,585	-	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) Hunterstown SVC (in service)	(C) Waldo Run SS (in service)	(D) Doubs SS (in service)	(E) Meadowbrook SS (in service)	(F) Conemaugh (in service)	(G) Blairsville SS (in service)	(H) Four Mile Jct (in service)	(I) 502 Junction - Territorial Line (monthly additions) 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

Month End Balances

Other Projects PIS (Monthly additions)	Hunterstown SVC (in service)	Waldo Run SS (in service)	Doubs SS (in service)	Meadowbrook SS (in service)	Conemaugh (in service)	Blairsville SS (in service)	Four Mile Jct (in service)	502 Junction - Territorial Line (monthly additions) CWIP
	-	-	-	-	-	-	-	1,154,713
	-	-	-	-	-	-	-	956,866
	-	-	-	-	-	-	-	1,172,915
	-	-	-	-	27,808,501	-	-	1,225,384
	-	-	-	-	27,808,501	-	-	1,254,820
	-	-	-	-	27,808,501	-	-	2,531,069
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,756,659
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,794,400
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,830,250
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,866,365
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,902,747
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,939,398
	44,310,669	52,235,676	4,840,224	58,411,179	27,808,501	3,631,440	11,197,637	4,135,490
	310,174,683	**52,235,676**	**33,881,568**	**408,878,253**	**278,085,010**	**25,420,080**	**11,197,637**	**29,521,075**
	23,859,591	4,018,129	2,606,274	31,452,173	21,391,155	1,955,391	861,357	2,270,852
(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)			(Appendix A, Line 33)		

	(A)	(B) Johnstown SS (2nd xfmr) (in service)	(C) Yeagertown (in service)	(D)	(E) Altoona SVC (in service)	(F)	(G)	(H) Luxor	(I) Armstrong (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

Month End Balances

Other Projects PIS (Monthly additions)	Johnstown SS (2nd xfmr) (in service)	Yeagertown (in service)	(in service)	Altoona SVC (in service)	(in service)	(in service)	Luxor (in service)	Armstrong (in service)
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	35,057,738	-	-	1,154,387	-
	4,278,432	-	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	29,949,024	**2,769,258**	**-**	**280,461,904**	**-**	**-**	**15,007,031**	**77,482,965**

	(A)	(B) Grand Point & Guilford SS (in service)	(C) Moshannon (in service)	(D) Carbon Center (in service)	(E) Shawville (in service)	(F) Northwood (in service)	(G) Shuman Hill Sub (in service)	(H) Buffalo Road (in service)	(I) Pleasureville Capacitor (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

Month End Balances

Other Projects PIS (Monthly additions)	Grand Point & Guilford SS (in service)	Moshannon (in service)	Carbon Center (in service)	Shawville (in service)	Northwood (in service)	Shuman Hill Sub (in service)	Buffalo Road (in service)	Pleasureville Capacitor (in service)
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	1,603,191	-	-	-	-	-	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	313,774	782,425
	1,603,191	-	236,623	-	4,206,813	1,147,868	313,774	782,425
	1,603,191	-	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
	1,603,191	5,164,619	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
	12,825,528	**5,164,619**	**1,656,361**	**2,837,006**	**12,620,439**	**8,035,076**	**1,255,096**	**10,171,525**

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

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)
$ 3,057,443.64	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	528,073	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

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)
							502 Junction - Territorial Line (monthly additions)		
		(in service)	(in service)	(in service)	(in service)	(in service)	CWIP		
Dec (Prior Year CWIP) p216.b.43									
Jan 2014									
Feb									
Mar									
Apr									
May									
Jun									
Jul									
Aug									
Sep									
Oct									
Nov									
Dec									
Total		-	-	-	-	-	-	-	
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances

							502 Junction - Territorial Line (monthly additions)		
					(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-	-	-	-
Jan 2014		-	-	-	-	-	-	-	-
Feb		-	-	-	-	-	-	-	-
Mar		-	-	-	-	-	-	-	-
Apr		-	-	-	-	-	-	-	-
May		-	-	-	-	-	-	-	-
Jun		-	-	-	-	-	-	-	-
Jul		-	-	-	-	-	-	-	-
Aug		-	-	-	-	-	-	-	-
Sep		-	-	-	-	-	-	-	-
Oct		-	-	-	-	-	-	-	-
Nov		-	-	-	-	-	-	-	-
Dec		-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-		
New Transmission Plant Additions for Year 3 (13 month average balance)	-	-	-	-	-	-	-		

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)

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)
							502 Junction - Territorial Line (monthly additions)		
							CWIP		
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-		2,038,647		
Jan 2014	Actual	-	-	-	-		(152,601)		
Feb	Actual	-	-	-	-		(66,019)		
Mar	Actual	-	-	-	-		15,108		
Apr	Actual	-	-	-	-		79		
May	Actual	-	-	-	-		1,806,632		
Jun	Actual	-	-	-	-		(8,626)		
Jul	Actual	-	-	-	-		997,834		
Aug	Actual	-	-	-	-		6,005		
Sep	Actual	-	-	-	-		10,605		
Oct	Actual	-	-	-	-		(1,370,785)		
Nov	Actual	-	-	-	-		598		
Dec	Actual	-	-	-	-		106		
Total		-	-	-	-	-	3,277,585	-	-

Month End Balances

	Other Projects PIS (Monthly additions)						502 Junction - Territorial Line (monthly additions)		
							CWIP		
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-	2,038,647	-	-
Jan 2014		-	-	-	-	-	1,886,047	-	-
Feb		-	-	-	-	-	1,820,027	-	-
Mar		-	-	-	-	-	1,835,135	-	-
Apr		-	-	-	-	-	1,835,215	-	-
May		-	-	-	-	-	3,641,847	-	-
Jun		-	-	-	-	-	3,633,221	-	-
Jul		-	-	-	-	-	4,631,055	-	-
Aug		-	-	-	-	-	4,637,060	-	-
Sep		-	-	-	-	-	4,647,665	-	-
Oct		-	-	-	-	-	3,276,880	-	-
Nov		-	-	-	-	-	3,277,479	-	-
Dec		-	-	-	-	-	3,277,585	-	-
Total		**-**	**-**	**-**	**-**	**-**	**40,437,863**	**-**	**-**
		-	-	-	-	-	3,110,605	-	-

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
$ 209,703,354.76	296,464.50	1,048,721.60	838,173.26	667,575.63	730,838.27	5,567,552	921,484	1,077,826	1,126,056	228,782	6,752,347	3,234,449	162,737,191	3,807,783	1,220,817	141,956	123,737	649,383

Meadowbrook SS	Buffalo Road Capacitor	Handsome Lake-Homer City	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Altoona	Blairsville	Conemaugh Transformer	502 Junction Substation	Cabron Center	Hunterstown	Johnstown	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Pleasureville Capacitor
4,984,437	14,448	1,004,974	98,348	85,354	162,968	2,870,718	272,274	2,747,345	1,446,301	35,241	3,625,115	371,304	113,910	584,067	104,356	10,989	-

Yeagertown	Shawville	Northwood	Shuman Hill Sub
-	-	-	69

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		
209,703,355	-	206,491,970	=	3,211,384

<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	267,615	0.2700%	11.5	8,309	275,925
Jul	Year 1	267,615	0.2700%	10.5	7,587	275,202
Aug	Year 1	267,615	0.2700%	9.5	6,864	274,480
Sep	Year 1	267,615	0.2700%	8.5	6,142	273,757
Oct	Year 1	267,615	0.2700%	7.5	5,419	273,035
Nov	Year 1	267,615	0.2700%	6.5	4,697	272,312
Dec	Year 1	267,615	0.2700%	5.5	3,974	271,589
Jan	Year 2	267,615	0.2700%	4.5	3,252	270,867
Feb	Year 2	267,615	0.2700%	3.5	2,529	270,144
Mar	Year 2	267,615	0.2700%	2.5	1,806	269,422
Apr	Year 2	267,615	0.2700%	1.5	1,084	268,699
May	Year 2	267,615	0.2700%	0.5	361	267,977
Total		3,211,384				3,263,409

		Balance	Interest	Amort	Balance
Jun	Year 2	3,263,409	0.2700%	276,747	2,995,473
Jul	Year 2	2,995,473	0.2700%	276,747	2,726,814
Aug	Year 2	2,726,814	0.2700%	276,747	2,457,429
Sep	Year 2	2,457,429	0.2700%	276,747	2,187,317
Oct	Year 2	2,187,317	0.2700%	276,747	1,916,476
Nov	Year 2	1,916,476	0.2700%	276,747	1,644,903
Dec	Year 2	1,644,903	0.2700%	276,747	1,372,597
Jan	Year 3	1,372,597	0.2700%	276,747	1,099,556
Feb	Year 3	1,099,556	0.2700%	276,747	825,778
Mar	Year 3	825,778	0.2700%	276,747	551,261
Apr	Year 3	551,261	0.2700%	276,747	276,002
May	Year 3	276,002	0.2700%	276,747	(0)
Total with interest				3,320,965	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest	3,320,965	**Input to Appendix A, Line 143**
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$ -	
Revenue Requirement for Year 3	3,320,965	

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
$ 3,320,965	151	(62,359)	28,329	(15,614)	(11,808)	2,164	(319,367)	(315)	(190)	(32,333)	84,608	183,045	(676,158)	318,729	268,850	19,751	14,893	(132,032)

Meadowbrook SS	Buffalo Road Capacitor	Handsome Lake-Homer City	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Altoona	Blairsville	Conemaugh Transformer	502 Junction Substation	Cabron Center	Hunterstown	Johnstown	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Pleasureville Capacitor
814,090	1,820	1,039,267	8,412	(68,623)	34,446	36,618	15,814	(66,115)	1,495,653	19,127	506,128	70,876	63,804	57,906	(9,148)	11,364	(106,337)

Yeagertown	Shawville	Northwood	Shuman Hill Sub
(28,951)	(29,659)	(131,939)	(83,930)

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

$ 3,320,965

10 June Year 3 Results of Step 8 go into effect

$ 3,320,965

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

Line					
2	**Fixed Charge Rate (FCR) if not a CIAC**				
		Formula Line			
3	A	137	FCR without Depreciation and Pre-Commercial Costs	13.2975%	
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	14.2027%	
5	C		Line B less Line A	0.9052%	
6	**FCR if a CIAC**				
7	D	138	FCR without Depreciation, Return, nor Income Taxes	0.9410%	

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		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		13.2975%	13.2975%	13.2975%
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		14.2027%	13.2975%	14.2027%
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		998,159,080	20,451,696	37,887,009
17	Annual Depreciation Exp from Attachment 5			20,971,922	514,883	1,371,379

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
18																
19	See Calculations for each item below	Wo Incentive ROE	2011	132,730,271.28	20,971,921.74	0.00	0.00	153,702,193.02	2,719,565.70	514,883.12	0.00	3,234,448.82	5,038,027.60	1,371,379.44	0.00	6,409,407.04
20	See Calculations for each item below	W Incentive ROE	2011	141,765,269.37	20,971,921.74	0.00	0.00	162,737,191.11	2,719,565.70	514,883.12	0.00	3,234,448.82	5,380,967.98	1,371,379.44	0.00	6,752,347.42

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.

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Line																	
		PJM Upgrade ID: b0323				**PJM Upgrade ID: b0230**				**PJM Upgrade ID: b0229**				**PJM Upgrade ID: b0559**			
10		**North Shenandoah Transformer (Plant In Service)**				**Meadowbrook Transformer (Plant In Service)**				**Bedington Transformer (Plant In Service)**				**Meadowbrook Capacitor (Plant In Service)**			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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.	1,710,170				7,172,734				6,885,738				5,838,706			
17	Annual Depreciation Exp from Attachment 5	1,372				172,262				162,194				145,082			
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	227,410.00	1,371.60	0.00	228,781.60	953,794.80	172,261.56	0.00	1,126,056.36	915,631.44	162,194.30	0.00	1,077,825.74	776,402.39	145,082.04	0.00	921,484.43
20	See Calculations for each item below	227,410.00	1,371.60	0.00	228,781.60	953,794.80	172,261.56	0.00	1,126,056.36	915,631.44	162,194.30	0.00	1,077,825.74	776,402.39	145,082.04	0.00	921,484.43

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

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Line	Description	PJM Upgrade ID: b0495				PJM Upgrade ID: b0343				PJM Upgrade ID: b0344				PJM Upgrade ID: b0345			
10		Kammer Transformers (Plant In Service)				Doubs Replace Transformer #2				Doubs Replace Transformer #3				Doubs Replace Transformer #4			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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.	35,624,703				4,782,459				4,405,198				5,178,439			
17	Annual Depreciation Exp from Attachment 5	830,355				94,890				81,794				149,570			
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	4,737,197.24	830,354.87	0.00	5,567,552.11	635,947.79	94,890.48	0.00	730,838.27	585,781.47	81,794.16	0.00	667,575.63	688,603.22	149,570.04	0.00	838,173.26
20	See Calculations for each item below	4,737,197.24	830,354.87	0.00	5,567,552.11	635,947.79	94,890.48	0.00	730,838.27	585,781.47	81,794.16	0.00	667,575.63	688,603.22	149,570.04	0.00	838,173.26

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

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Line	Description	PJM Upgrade ID: b0704				PJM Upgrade ID: b1941				PJM Upgrade ID: b0563				PJM Upgrade ID: b0564			
10		Cabot SS - Install Autotransformer				Armstrong				Farmers Valley Capacitor				Harvey Run 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	13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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.	6,762,182				7,907,193				925,817				826,494			
17	Annual Depreciation Exp from Attachment 5	149,520				169,357				18,846				13,834			
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	899,201.60	149,520.00	0.00	1,048,721.60	1,051,459.57	169,357.41	0.00	1,220,816.98	123,110.52	18,845.60	0.00	141,956.12	109,903.10	13,834.29	0.00	123,737.39
20	See Calculations for each item below	899,201.60	149,520.00	0.00	1,048,721.60	1,051,459.57	169,357.41	0.00	1,220,816.98	123,110.52	18,845.60	0.00	141,956.12	109,903.10	13,834.29	0.00	123,737.39

For Plant in Service

"Pre-Commercial Exp" is equal to the amount of pre-commer
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: b1803	PJM Upgrade ID: b1243	PJM Upgrade ID: b0674, b1023, b1023.3	PJM Upgrade ID: b1804
10		Doubs SS	Potter SS	Osage Whiteley	Meadowbrook SS
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	13.2975%	13.2975%	13.2975%	13.2975%
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	13.2975%	13.2975%	13.2975%	13.2975%
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.	4,213,032	1,970,718	24,230,059	32,381,305
17	Annual Depreciation Exp from Attachment 5	89,154	34,408	585,789	678,530

PJM Upgrade ID: b1803 — Doubs SS

Line		Return	Depreciation	Reconciliation Amount	Revenue
18					
19	See Calculations for each item below	560,228.28	89,154.22	0.00	649,382.50
20	See Calculations for each item below	560,228.28	89,154.22	0.00	649,382.50

PJM Upgrade ID: b1243 — Potter SS

Line		Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue
18						
19	See Calculations for each item below	262,056	34,408	0	0	296,464.50
20	See Calculations for each item below	262,056	34,408	0	0	296,464.50

PJM Upgrade ID: b0674, b1023, b1023.3 — Osage Whiteley

Line		Return	Depreciation	Pre-Commercial Exp.	Reconciliation amount	Revenue
18						
19	See Calculations for each item below	3,221,994	585,789	0	0	3,807,783.22
20	See Calculations for each item below	3,221,994	585,789	0	0	3,807,783.22

PJM Upgrade ID: b1804 — Meadowbrook SS

Line		Return	Depreciation	Reconciliation Amount	Revenue
18					
19	See Calculations for each item below	4,305,906.24	678,530.35	0.00	4,984,436.59
20	See Calculations for each item below	4,305,906.24	678,530.35	0.00	4,984,436.59

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
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: b0674 & b1023.1				PJM Upgrade ID: b1153				PJM Upgrade ID: b1965			
10		Grandview Capacitor				502 Jct Substation				Conemaugh-Seward				Luxor			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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.	635,482				9,943,461				19,282,110				555,159			
17	Annual Depreciation Exp from Attachment 5	13,844				124,069				183,306				11,532			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliati on Amount	Revenue	Return	Depreciation	Reconciliati on Amount	Revenue	Return	Depreciation	Reconciliati on Amount	Revenue
19	See Calculations for each item below	84,503.29	13,844.26	0.00	98,347.55	1,322,232.38	124,069.08	0.00	1,446,301.46	2,564,039.83	183,305.66	0.00	2,747,345.49	73,822.31	11,531.77	0.00	85,354.08
20	See Calculations for each item below	84,503.29	13,844.26	0.00	98,347.55	1,322,232.38	124,069.08	0.00	1,446,301.46	2,564,039.83	183,305.66	0.00	2,747,345.49	73,822.31	11,531.77	0.00	85,354.08

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
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: b1839				PJM Upgrade ID: b1941				PJM Upgrade ID: b1801				PJM Upgrade ID: b1967			
10		Grandpoint & Guilford				Handsome Lake-Homer City				Altoona				Blairsville			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%			
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.	1,075,287				6,215,477				18,582,790				1,765,507			
17	Annual Depreciation Exp from Attachment 5	19,981				178,471				399,670				37,506			
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	142,986.42	19,981.24	0.00	162,967.66	826,503.44	178,470.87	0.00	1,004,974.31	2,471,047.72	399,669.93	0.00	2,870,717.65	234,768.36	37,505.90	0.00	272,274.26
20	See Calculations for each item below	142,986.42	19,981.24	0.00	162,967.66	826,503.44	178,470.87	0.00	1,004,974.31	2,471,047.72	399,669.93	0.00	2,870,717.65	234,768.36	37,505.90	0.00	272,274.26

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
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: b1672				**PJM Upgrade ID: b1800**				**PJM Upgrade ID: b1945**				**PJM Upgrade ID: b1770**				**PJM Upgrade ID: b1964**			
10		**Carbon Center**				**Hunterstown**				**Johnstown**				**Buffalo Road**				**Moshannon**			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				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				No			
13	Input the allowed ROE	11.70%				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	13.2975%				13.2975%				13.2975%				13.2975%				13.2975%			
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	13.2975%				13.2975%				13.2975%				13.2975%				13.2975%			
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.	228,612				23,504,314				2,410,083				100,092				819,581			
17	Annual Depreciation Exp from Attachment 5	4,841				499,627				50,823				1,138				4,926			
18		**Return**	**Depreciation**	**Reconciliation Amount**	**Revenue**	**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	30,399.73	4,841.29	0.00	35,241.02	3,125,487.78	499,627.14	0.00	3,625,114.92	320,480.89	50,823.35	0.00	371,304.24	13,309.80	1,138.23	0.00	14,448.03	108,983.88	4,925.76	0.00	113,909.64
20	See Calculations for each item below	30,399.73	4,841.29	0.00	35,241.02	3,125,487.78	499,627.14	0.00	3,625,114.92	320,480.89	50,823.35	0.00	371,304.24	13,309.80	1,138.23	0.00	14,448.03	108,983.88	4,925.76	0.00	113,909.64

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
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: b2433.1, b2433.2, b2433.3	PJM Upgrade ID: b1609, b1769	PJM Upgrade ID: b2343	PJM Upgrade ID: b2342
10		Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley
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	13.2975%	13.2975%	13.2975%	13.2975%
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	13.2975%	13.2975%	13.2975%	13.2975%
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.	4,023,353	720,973	68,409	410
17	Annual Depreciation Exp from Attachment 5	49,062	8,484	1,892	15

Line		Waldo Run Return	Waldo Run Depreciation	Waldo Run Reconciliation Amount	Waldo Run Revenue	Four Mile Junction Return	Four Mile Junction Depreciation	Four Mile Junction Reconciliation Amount	Four Mile Junction Revenue	West Union SS Return	West Union SS Depreciation	West Union SS Reconciliation Amount	West Union SS Revenue	Shuman Hill/Mobley Return	Shuman Hill/Mobley Depreciation	Shuman Hill/Mobley Reconciliation Amount	Shuman Hill/Mobley Revenue	Total	Incentive Charged	Revenue Credit	
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Total	Incentive Charged	Revenue Credit	$9,377,938.48
19	See Calculations for each item below	535,005.65	49,061.70	0.00	584,067.35	95,871.38	8,484.31	0.00	104,355.69	9,096.74	1,891.89	0.00	10,988.63	54.56	14.57	0.00	69.13	200,325,416.28		200,325,416.28	**Ax A Line 148**
20	See Calculations for each item below	535,005.65	49,061.70	0.00	584,067.35	95,871.38	8,484.31	0.00	104,355.69	9,096.74	1,891.89	0.00	10,988.63	54.56	14.57	0.00	69.13	209,703,354.76	209,703,354.76		

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
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 Deb **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

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

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Origination Fees	7,780,954
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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

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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]**:**

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

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 2

Annual Transmission Revenue Requirements

For 2015 Rate Year

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	TrAILCo 2015 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	1,605,879,506
7	Total Plant In Service		(Line 6)	1,605,879,506
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	111,509,313
9	Total Accumulated Depreciation		(Line 8)	111,509,313
10	Net Plant		(Line 7 - Line 9)	1,494,370,193
11	Transmission Gross Plant		(Line 15 + Line 21)	1,605,879,506
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	1,494,370,193
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	1,539,516,439
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	54,487,730
17	**Total Transmission Plant**		(Line 15 + Line 16)	**1,594,004,169**
18	General & Intangible		Attachment 5	66,363,067
19	Total General & Intangible		(Line 18)	66,363,067
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**66,363,067**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**1,660,367,236**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	99,909,818
24	Accumulated General Depreciation		Attachment 5	5,276,835
25	Accumulated Intangible Amortization		Attachment 5	6,322,660
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	11,599,495
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**11,599,495**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**111,509,313**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**1,548,857,923**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes				
31	ADIT net of FASB 106 and 109	Enter Negative		Attachment 1	-212,040,418
32	**Transmission Related Accumulated Deferred Income Taxes**			(Line 31)	**-212,040,418**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**		(Note B)	p216.b.43 as shown on Attachment 6	**464,225**
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	**158,892**
	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)	971,197
43	1/8th Rule			1/8	12.5%
44	**Transmission Related Cash Working Capital**			(Line 42 * Line 43)	**121,400**
45	**Total Adjustment to Rate Base**			(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**-211,295,902**
46	**Rate Base**			(Line 30 + Line 45)	**1,337,562,022**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	4,932,317
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	1,374,120
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)	**3,558,197**
	A&G Expenses			
53	Total A&G		p323.197.b	-3,961,120
54	Less Property Insurance Account 924		p323.185.b	50,085
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)	-4,011,205
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**-4,011,205**
	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	50,085
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	50,085
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**50,085**
	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	1,374,120
73	Total Account 566		Sum (Lines 70 to 72)	**1,374,120**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**971,197**

Depreciation & Amortization Expense

Line	Description		Note	Source	Amount
	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	27,824,330
76	General Depreciation			Attachment 5	1,444,875
77	Intangible Amortization		(Note A)	Attachment 5	1,484,865
78	Total			(Line 76 + Line 77)	2,929,740
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**2,929,740**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**30,754,070**

Taxes Other than Income

Line	Description		Note	Source	Amount
82	**Transmission Related Taxes Other than Income**			Attachment 2	**10,984,149**
83	**Total Taxes Other than Income**			**(Line 82)**	**10,984,149**

Return / Capitalization Calculations

Line	Description		Note	Source	Amount
84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	820,500,305
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)	820,500,305
	Capitalization				
90	Long Term Debt		(Note N)		549,584,218
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	0
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	0
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	549,584,218
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	820,500,305
97	**Total Capitalization**			(Sum Lines 94 to 96)	1,370,084,523
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	40.1132%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0000%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	59.8868%
101	Debt Cost	Total Long Term Debt			0.0394
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)	0.0158
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0701
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.0859**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**114,867,810**

Composite Income Taxes

Line	Description		Reference	Amount
	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			8.29%
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)} =		40.39%
113	T/ (1-T)			67.75%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**63,495,016**
115	**Total Income Taxes**		**(Line 114)**	**63,495,016**

REVENUE REQUIREMENT

Line	Description		Reference	Amount
	Summary			
116	Net Property, Plant & Equipment		(Line 30)	1,548,857,923
117	Total Adjustment to Rate Base		(Line 45)	-211,295,902
118	**Rate Base**		(Line 46)	**1,337,562,022**
119	Total Transmission O&M		(Line 74)	971,197
120	Total Transmission Depreciation & Amortization		(Line 81)	30,754,070
121	Taxes Other than Income		(Line 83)	10,984,149
122	Investment Return		(Line 108)	114,867,810
123	Income Taxes		(Line 115)	63,495,016
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**221,072,242**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	1,660,367,236
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	1,660,367,236
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	221,072,242
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**221,072,242**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	2,678,014
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**218,394,228**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**218,394,228**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**1,494,558,576**
135	FCR		(Line 133 / Line 134)	**14.6126%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**12.7509%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**12.7509%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**0.8168%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**40,031,402**
140	Increased Return and Taxes		Attachment 4	**191,799,986**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**231,831,388**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**1,494,558,576**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**15.5117%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**13.6500%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**13.6500%**
146	**Net Revenue Requirement**		(Line 132)	**218,394,227.53**
147	Reconciliation amount		Attachment 6	**3,320,964.81**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**9,226,873.54**
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)	**230,942,065.88**
	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

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

Line		B1	B2	B3	C	D	E	F	G	
				Trans-Allegheny Interstate Company						
		Beg of Year Total	***End of Year Total***	**End of Year Est. for Final** ***Total***	**Retail Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**Total ADIT**	
1	**ADIT- 282 From Account Total Below**	415,524,705	428,633,111	428,633,111	[redacted]	428,633,111	-	-	428,633,111	
2	**ADIT-283 From Account Total Below**	28,494,606	39,662,909	39,662,909	[redacted]	38,399,470	-	-	38,399,470	
3	**ADIT-190 From Account Total Below**	(286,572,920)	(256,320,086)	(256,320,086)	[redacted]	(254,992,163)	-	-	(254,992,163)	Enter Negative
4	**Subtotal**					212,040,418	-	-	212,040,418	
5	**Wages & Salary Allocator**							100.0000%		
6	**Gross Plant Allocator**						100.0000%			
7	**ADIT**					212,040,418	-	-	212,040,418	

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 0 < 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 Est. for Final Total	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Charitable Contribution Carryforward	3,761	8,371	8,371			8,371			Disallowance in current year for charitable deduction due to tax loss, tax attribute carries forward five years
Federal Long Term - NOL	-	140,451,171	140,451,171			140,451,171			Result of bonus depreciation
Federal Short-Term NOL	258,092,677	86,296,783	86,296,783			86,296,783			Result of bonus depreciation
IBNR - Workers Compensation	109,219	-	-			-			Actual amount of reserve for workers' compensation
Long Term Disability Accrual	24,415	-	-			-			Long term disability accrual
Merger Costs D&O Insurance	2,299	1,871	1,871		1,871				Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
Merger Costs Licenses	107,065	85,383	85,383		85,383				Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
NOL Deferred Tax Asset - LT PA	-	5,009,642	5,009,642			5,009,642			Result of bonus depreciation
NOL Deferred Tax Asset PA	6,625,569	567,331	567,331			567,331			Result of bonus depreciation
NOL Deferred Tax Asset WV	20,852,421	17,735,335	17,735,335			17,735,335			Result of bonus depreciation
Pension/OPEB: Other Def Cr. Or Dr.	-	2,203,787	2,203,787			2,203,787			Pension related temporary difference associated with Service Company allocations
Power Tax True-Up Adjustment	81,454	-	-			-			System adjustment to reclass balances to correct FERC accounts
Provision for Rate Refund	260,920	-	-			-			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
Purch Acct-LTD FMV	-	1,240,669	1,240,669		1,240,669				Reflects the adjustments and subsequent amortization of the regulatory asset associated with the adjusted debt balances resulting from the FE/AYE merger (Offset is PAA - LT Regulatory Asset Amort below in 283)
Reevaluation Adjustment	413,120	-	-		-				Temporary difference resulting from purchase accounting transactions
State Income Tax Deductible	-	2,190,351	2,190,351			2,190,351			Deductions related to state income taxes
Unamortized Discount	-	529,392	529,392			529,392			Unamortized discounts on long-term debt
FASB 109 Gross-Up	-	-	-		-				Reclass of the tax portion (gross-up) for property items included in account 282
Subtotal	286,572,920	256,320,086	256,320,086	-	1,327,923	254,992,163	-	-	
Less FASB 109 included above	-	-	-	-	-	-	-	-	
Less FASB 106 included above									
Total	286,572,920	256,320,086	256,320,086	-	1,327,923	254,992,163	-	-	

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 Est. 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	1,757,820	2,575,691	2,575,691			2,575,691			Allowance for borrowed funds used during construction (ABFUDC)
Accelerated Tax Depreciation	-	490,609,438	490,609,438			490,609,438			Additional tax deprecation over book
Property Related - Tax Depreciation	72,202,243	-	-			-			Tax depreciation
FASB 109 Fixed Asset Adjustment	-	-	-			-			Increase in AOFDC
FASB 109 Gross-Up	-	21,430,125	21,430,125			21,430,125			Reclass of the tax portion (gross-up) for property items included in account 2
Book Depreciation Expense	(34,270,107)	-	-			-			Book depreciation
Amortization Expense - Intangible Plant	(1,865,544)	-	-			-			Book depreciation / amortization
Bonus Depreciation	409,438,305	-	-			-			Tax depreciation
CIACS Taxable	(799,612)	-	-			-			Taxable CIAC
Tax Interest Capitalized	(33,033,740)	-	-			-			Actual amount of tax interest capitalized
Power Tax Adjustment	152,981	(588,777)	(588,777)			(588,777)			System adjustment to reclass balances to correct FERC accounts
A&G Expenses Capitalized	1,004,786	2,314,345	2,314,345			2,314,345			Accounting change relating to A&G expense
Estimated Property Regulatory Asset Adjustment	1,341,207	-	-			-			Property True-Up
Book Profit/Loss on Retirement	(61,299)	-	-			-			Result of gain or loss on asset retirements
Repair & Maintenance 481 a Adjustment	2,788,907	3,337,031	3,337,031			3,337,031			Portion of Repairs & Maintenance 481a Adjustment offset in Account 182
Repair & Maintenance Deduction	245,561	-	-			-			Portion of Repairs & Maintenance deduction offset in Account 182
Additional State Depreciation VA	287,806	-	-			-			Temporary difference for additional state depreciation allowed for VA tax retu
Additional State Depreciation MD	(4,144,928)	-	-			-			Temporary difference for additional state depreciation allowed for MD tax retu
Additional State Depreciation PA	(238,274)	-	-			-			Temporary difference for additional state depreciation allowed for PA tax retu
AFUDC Equity Flow Through	242,761	5,618,518	5,618,518			5,618,518			Portion of AFUDC Equity that relates to property and booked to account 282
Cost of Removal	55,011	(2,704,317)	(2,704,317)			(2,704,317)			Temporary difference arising for removal of plant/property
MACRS/ACRS Property Retired Retail	1,524,917	-	-			-			Result of gain or loss on asset retirements
Capitalized Vertical Tree Trimming	16,784	22,838	22,838			22,838			Temporary difference that is capitalized for book purposes but deductible for tax purposes
Life Insurance - Capital Portion	(481)	-	-			-			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)	-	-			-			Reversal of book gains and losses
Vegetation Management - Transmission	(218)	-	-			-			Vegetation management transmission corridor capital cost and depreciation expenses required for the regulatory financial statement schedules
Other Basis Differences	(3,624,549)	(72,551,656)	(72,551,656)			(72,551,656)			Other property related temporary differences
TBBS Property Adjustment	2,700,000	-	-			-			Adjustment to property in order to align Tax Basis Balance Sheet
T&D Repairs	109,727	-	-			-			Repair deduction on capitalized book asset deductible for tax purposes under Rev. Proc. 2011-43
Subtotal	415,524,705	450,063,236	450,063,236			450,063,236			
Less FASB 109 included above	-	21,430,125	21,430,125	-	-	21,430,125			
Less FASB 106 included above	-	-	-			-			
Total	415,524,705	428,633,111	428,633,111			428,633,111			

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 Est. for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Accrued Taxes: Property Taxes	1,318,026	3,352,114	3,352,114			3,352,114			West Virginia property tax payment
Adjustment to Deferred Federal Tax	6,888	-	-			-			Adjustment to true-up deferred federal tax
AFUDC Equity Flow Through	156,301	-	-			-			The tax portion (gross-up) of the AFUDC Equity booked in account 282
Deferred Charge EIB	2,291	6,775	6,775			6,775			Allocated portion of total liabilities relating to captive insurance
Deferred Revenue - Pole Attachment	-	243	243			243			Deferred revenues associated with attachments to FirstEnergy poles
FASB 109 Gross-up	17,174,299	-	-			-			Reclass of the tax portion (gross-up) for property items included in account 282
Intercompany Charge AESC	2,066,632	-	-			-			Intercompany charges from the service company
Merger Costs - Indebtedness	2,911	-	-		-				Costs incurred as a result of Allegheny merging with FirstEnergy which are not to be included within the revenue requirement
Other Adjustments	(10,555,131)	-	-			-			System adjustment to reclass balances to correct FERC accounts
PAA - 221 Debt Amort	-	22,771	22,771		22,771				Reflects the adjustments and subsequent amortization of adjusted debt balances associated with the FE/AYE merger
PAA - LT Regulatory Asset Amort	-	1,240,668	1,240,668		1,240,668				Reflects the adjustments and subsequent amortization of adjusted regulatory asset balances associated with the FE/AYE merger
PJM Receivable	32,724,308	34,655,162	34,655,162			34,655,162			Comparison of actual to forecast revenues - non-property related
Reserve for EIB	45,318	-	-			-			Adjustment for reserve for EIB in Goodwill carried over to current year
SC01 Timing Allocation	-	385,176	385,176			385,176			Timing differences related to service company allocations
State Income Tax - Federal Deferred Only	1,711,721	-	-			-			Temporary difference resulting from the timing between when state income taxes are paid and when they are deductible on the federal tax return
Unamortized Loss on Reacquired Debt	1,015,123	-	-			-			Unamortized debt expenses for existing debt that is refinanced and amortized over the life of the new debt
Vegetation Management - Transmission	218	-	-			-			Vegetation Management Transmission Corridor capital cost and depreciation expenses required for the regulatory financial statement schedules
Subtotal	45,668,905	39,662,909	39,662,909		1,263,439	38,399,470	-	-	
Less FASB 109 included above	17,174,299	-	-	-	-	-			
Less FASB 106 included above									
Total	28,494,606	39,662,909	39,662,909		1,263,439	38,399,470	-	-	

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	2014 State Property WV	p263.1.1(i)	4,146,727	100.0000%	$ 4,146,727
1.2	2013 State Property WV	p263.40(i)	4,149,894	100.0000%	4,149,894
1.3	2014 State Property PA (PURTA)	p263.25(i)	27,000	100.0000%	27,000
1.4	2013 State Property PA (PURTA)	p263.26(i)	2,595	100.0000%	2,595
1.5					-
1.6	2013 Local Property WV	p263.1.6(i)	14,519	100.0000%	14,519
1.7	2014 Local Property WV	p263.1.7(i)	13,960	100.0000%	13,960
1.8	2014 Local Property VA	p263.1.10(i)	1,403,987	100.0000%	1,403,987
1.9	2014 Local Property PA	p263.1.13(i)	3,579	100.0000%	3,579
2.1	2013 Local Property MD	p263.1.16(i)	611,569	100.0000%	611,569
2.2	2014 Local Property MD	p263.1.17(i)	610,517	100.0000%	610,517
2.3	2014 Capital Stock Tax/Franchise MD	p263.9(i)	300	100.0000%	300
2.4	2013 Capital Stock Tax/Franchise PA	p263.22(i)	-8,116	100.0000%	-8,116
2.5	2014 Capital Stock Tax/Franchise PA	p263.23(i)	29,475	100.0000%	29,475
2.6					
2.7	2013 WV Franchise Tax	p263.37(i)	-16,428	100.0000%	-16,428
3.1	2014 WV Franchise Tax	p263.38(i)	15,639	100.0000%	15,639
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	p263.18(i)	1,146	100.0000%	1,146
6.1	State License WV			100.0000%	0
6.5	Federal Excise Tax	p263.3(i)	1,206	100.0000%	1,206
8	**Total Plant Related**		11,007,569	100.0000%	11,007,569
	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	2011 MD GRT	p263.11(i)	-6,447		-6,447
16	2012 MD GRT	p263.12(i)	-8,622		-8,622
17	2013 MD GRT	p263.13(i)	-8,351		-8,351
18					
19	**Total Other Included**		-23,420	100.0000%	-23,420
20	**Total Included (Lines 8 + 14 + 19)**		10,984,149		**10,984,149** Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded				
21	Federal Income Tax	p263.2(i)	2,094,347		
22	Corporate Net Income Tax MD	p263.7(i)	-478,760		
23	Corporate Net Income Tax PA	p263.17(i)	1,625,392		
24	Corporate Net Income Tax VA	p263.30(i)	-237,626		
25	Corporate Net Income Tax WV	p263.34(i)	-1,642,085		
26					
27					
28					
29					
30					
31	**Subtotal, Excluded**		1,361,268		
32	**Total, Included and Excluded (Line 20 + Line 31)**		12,345,417		
33	**Total Other Taxes from p114.14.c**		10,984,149		
34	**Difference (Line 32 - Line 33)**		1,361,268		

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		2,678,014	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)	2,678,014	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	2,678,014	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		2,678,014	

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)		191,799,986	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		1,337,562,022
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		820,500,305
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		820,500,305
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		549,584,218
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		0
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		0
12	Total Long Term Debt		Appendix A, Line 94		549,584,218
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		820,500,305
15	Total Capitalization		Appendix A, Line 97		1,370,084,523
16	Debt %	Total Long Term Debt	Appendix A, Line 98		40.1132%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0.0000%
18	Common %	Common Stock	Appendix A, Line 100		59.8868%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0394
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)		0.0158
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0761
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.0919**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**122,878,046**

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	8.29%
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	40.39%
31	T/ (1-T)		Appendix A, Line 113	67.75%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		68,921,940
33	**Total Income Taxes**		**(Line 32)**	**68,921,940**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

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

	Calculation of Transmission Plant In Service	Source		13 Month Balance for Reconciliation Total	EOY Balance for Estimate Total
	December	p206.58.b	For 2013	1,259,599,755	
	January	company records	For 2014	1,259,351,317	
	February	company records	For 2014	1,259,458,130	
	March	company records	For 2014	1,273,944,125	
	April	company records	For 2014	1,273,906,126	
	May	company records	For 2014	1,291,089,258	
	June	company records	For 2014	1,457,224,846	
	July	company records	For 2014	1,462,189,797	
	August	company records	For 2014	1,461,069,064	
	September	company records	For 2014	1,459,104,799	
	October	company records	For 2014	1,466,086,129	
	November	company records	For 2014	1,476,064,041	
	December	p207.58.g	For 2014	1,539,516,439	1,539,516,439
15	**Transmission Plant In Service**			**1,379,892,602**	**1,539,516,439**

	Calculation of Transmission Plant In Service	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
	December	46,608,150	17,447,442	1,066,179,959	2,024,007	24,832,065	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	January	46,608,150	17,447,442	1,065,982,112	2,024,007	24,778,518	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	February	46,608,150	17,447,442	1,066,198,161	2,024,007	24,798,580	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	March	46,608,150	17,447,442	1,066,250,629	2,024,007	24,799,928	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	April	46,608,150	17,447,442	1,066,262,800	2,024,007	24,805,443	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	May	46,629,901	17,447,442	1,066,665,904	2,024,007	24,809,572	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	June	46,629,901	17,447,442	1,066,660,797	2,024,007	24,812,877	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	July	46,629,901	17,558,636	1,067,544,778	2,024,007	24,812,889	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	August	46,629,901	17,558,636	1,067,546,950	2,024,007	24,818,581	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	September	46,629,901	17,558,636	1,067,552,541	2,024,007	24,817,288	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	October	46,629,901	17,558,636	1,067,599,815	2,024,007	24,763,211	8,202,934	80,682	7,723,538	6,496,239	39,534,385	5,149,271	4,686,053	5,700,307
	November	46,629,901	17,558,636	1,067,519,965	2,024,007	24,763,211	8,202,934	80,682	7,723,538	6,496,239	39,562,936	5,149,271	4,686,053	5,700,307
	December	46,629,901	17,965,415	1,070,838,672	2,024,007	24,759,276	8,202,934	80,682	7,723,538	6,496,239	39,629,071	5,149,271	4,686,053	5,700,307
15	**Transmission Plant In Service**	**46,621,535**	**17,530,053**	**1,067,138,699**	**2,024,007**	**24,797,803**	**8,202,934**	**80,682**	**7,723,538**	**6,496,239**	**39,543,865**	**5,149,271**	**4,686,053**	**5,700,307**

Details

13 Month Plant Balance For reconciliation

Cabot SS	Armstrong	Farmers Valley Capacitor	Harvey Run Capacitor	Doubs SS	Meadowbrook SS	Grandview Capacitor	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake - Homer City
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,240,036	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,242,992	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,113,695	-	-	-	-
7,123,323	1,350,836	934,823	831,938	3,306,399	484,588	662,780	10,113,741	14,432,132	-	-	-
7,123,323	1,350,836	934,909	832,122	3,306,399	484,588	636,089	10,117,589	14,387,432	11,588	-	-
7,123,323	1,350,836	934,916	832,122	4,634,278	484,588	636,089	10,117,589	28,151,270	25,241	1,648,772	-
7,123,323	13,153,352	934,916	832,122	4,873,705	59,633,787	636,089	10,117,589	27,849,702	28,697	1,784,047	10,750,043
7,123,323	13,688,202	934,916	832,108	4,891,737	59,726,402	636,089	10,117,589	27,847,222	1,195,821	1,769,915	10,275,429
7,123,323	13,462,827	934,916	832,201	4,859,948	60,228,050	636,089	10,117,589	27,847,222	1,196,013	1,770,871	9,038,217
7,123,323	8,067,343	934,916	832,201	4,873,250	60,381,844	636,089	10,117,589	27,847,222	1,199,337	1,774,272	11,734,615
7,123,323	14,430,681	934,916	832,201	4,876,868	59,986,727	636,556	10,117,595	27,849,570	1,199,337	1,774,272	12,261,214
7,123,323	16,639,863	934,916	832,202	4,873,250	60,594,811	636,556	10,117,595	27,855,012	1,199,375	1,774,657	14,421,778
7,123,323	15,863,978	934,916	832,202	4,877,582	60,049,287	657,175	10,117,608	27,021,750	1,199,375	1,757,271	13,035,331
7,123,323	**7,954,712**	**934,887**	**832,095**	**4,253,278**	**32,577,572**	**645,995**	**10,136,061**	**19,314,503**	**558,061**	**1,081,083**	**6,270,510**

Altoona	Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total	
-	-	-	-	-	-	-	-	-	-	-	1,259,599,754.89	
-	-	-	-	-	-	-	-	-	-	-	1,259,351,316.60	
-	-	-	-	-	-	-	-	-	-	-	1,259,458,130.14	
-	-	-	-	-	-	-	-	-	-	-	1,273,944,124.83	
-	-	-	-	-	-	-	-	-	-	-	1,273,906,125.76	
-	-	-	-	-	-	-	-	-	-	-	1,291,089,257.92	
34,854,327	3,170,597	398,203	44,043,682	1,892,233	-	-	-	-	-	-	1,457,224,846.06	
34,324,500	3,319,486	409,366	43,841,160	5,112,912	-	-	-	-	-	-	1,462,189,796.57	
34,373,048	3,320,194	404,381	43,893,966	4,878,727	-	-	-	-	-	-	1,461,069,064.11	
34,879,463	3,320,415	420,891	43,926,572	4,879,677	-	-	-	-	-	-	1,459,104,799.22	
34,862,794	3,320,415	451,629	43,936,132	4,908,565	434,357	-	-	-	-	-	1,466,086,129.44	
34,887,422	3,320,562	458,675	43,924,684	4,907,284	434,357	5,030,042	-	-	-	-	1,476,064,041.13	
34,900,798	3,320,565	446,617	43,870,078	4,929,429	434,006	5,629,441	52,352,651	9,381,128	891,214	5,349	1,539,516,438.94	
18,698,642	**1,776,326**	**229,982**	**23,648,944**	**2,423,756**	**100,209**	**819,960**	**4,027,127**	**721,625**	**68,555**	**411**	**1,379,892,601.97**	1,439,606,621.06

Trans-Allegheny Interstate Line

Attachment 5 - Cost Supp

				Link to Appendix A, line 15	**Link to Appendix A, line 15**
	Calculation of Distribution Plant In Service	Source			
	December	p206.75.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p207.75.g	For 2014	-	-
	Distribution Plant In Service			-	-
	Calculation of Intangible Plant In Service	Source			
	December	p204.5.b	For 2013	10,393,869	
	December	p205.5.g	For 2014	10,398,271	10,398,271
18	**Intangible Plant In Service**			**10,396,070**	**10,398,271**
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of General Plant In Service	Source			
	December	p206.99.b	For 2013	56,186,164	-
	December	p207.99.g	For 2014	55,964,796	**55,964,796**
18	**General Plant In Service**			**56,075,480**	**55,964,796**
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of Production Plant In Service	Source			
	December	p204.46b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p205.46.g	For 2014	-	-
	Production Plant In Service			-	-
6	**Total Plant In Service**	Sum of averages above		**1,446,364,152**	**1,605,879,506**
				Link to Appendix A, line 6	**Link to Appendix A, line 6**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

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

	Calculation of Transmission Accumulated Depreciation	Source		13 Month Balance for Reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p219.25.b	For 2013	72,434,228	
	January	company records	For 2014	74,538,994	
	February	company records	For 2014	76,648,165	
	March	company records	For 2014	78,759,554	
	April	company records	For 2014	80,887,320	
	May	company records	For 2014	83,013,513	
	June	company records	For 2014	85,307,027	
	July	company records	For 2014	87,745,558	
	August	company records	For 2014	90,187,163	
	September	company records	For 2014	92,651,656	
	October	company records	For 2014	95,143,692	
	November	company records	For 2014	97,645,175	
	December	p219.25.b	For 2014	99,909,818	99,909,818
23	**Transmission Accumulated Depreciation**			**85,759,374**	**99,909,818**

	Black Oak	Wylie Ridge	502 Junction - Territorial Line	Potter SS	Osage Whiteley	Meadowbrook Transformer	North Shenandoah
December	8,048,836	(3,158,824)	61,652,257	36,085	271,800	944,069	(1,630,174)
January	8,163,118	(3,128,291)	63,394,779	38,952	322,246	958,424	(1,630,060)
February	8,277,399	(3,097,759)	65,138,053	41,819	372,661	972,779	(1,629,945)
March	8,391,681	(3,067,227)	66,882,169	44,687	423,097	987,135	(1,629,831)
April	8,505,963	(3,028,122)	68,632,677	47,554	473,569	1,001,490	(1,629,717)
May	8,620,244	(2,980,444)	70,374,954	50,421	521,594	1,015,845	(1,629,603)
June	8,734,526	(2,932,767)	72,117,548	53,289	569,627	1,030,200	(1,629,488)
July	8,848,808	(2,884,913)	73,859,516	56,156	617,659	1,044,555	(1,629,374)
August	8,963,089	(2,836,883)	75,602,285	59,023	665,698	1,058,910	(1,629,260)
September	9,077,371	(2,788,852)	77,346,501	61,891	713,741	1,073,265	(1,629,145)
October	9,191,652	(2,740,822)	79,090,778	64,758	761,727	1,087,620	(1,629,031)
November	9,305,934	(2,692,518)	80,834,965	67,625	809,658	1,101,976	(1,628,917)
December	9,420,216	(2,643,941)	82,246,430	70,493	857,590	1,116,331	(1,628,802)
Transmission Accumulated Depreciation	**8,734,526**	**(2,921,643)**	**72,090,224**	**53,289**	**567,744**	**1,030,200**	**(1,629,488)**

	Bedington Transformers	Meadowbrook Capacitor	Kammer	Doubs #2 Trans	Doubs #3 Trans	Doubs #4 Trans
December	754,136	584,992	3,504,039	319,366	239,958	447,084
January	767,652	597,082	3,573,224	327,274	246,774	459,548
February	781,168	609,172	3,642,409	335,182	253,591	472,012
March	794,684	621,262	3,711,595	343,089	260,407	484,476
April	808,201	633,352	3,780,780	350,997	267,223	496,940
May	821,717	645,442	3,849,965	358,904	274,039	509,405
June	835,233	657,533	3,919,150	366,812	280,855	521,869
July	848,749	669,623	3,988,335	374,719	287,671	534,333
August	862,265	681,713	4,057,520	382,627	294,488	546,797
September	875,782	693,803	4,126,706	390,534	301,304	559,261
October	889,298	705,893	4,195,891	398,442	308,120	571,725
November	902,814	717,983	4,265,101	406,349	314,936	584,190
December	949,704	730,074	4,334,394	414,257	321,752	596,654
Transmission Accumulated Depreciation	**837,800**	**657,533**	**3,919,162**	**366,812**	**280,855**	**521,869**

Details

13 Month Balance For Reconciliation

Cabot SS	Armstrong	Farmers Valley Capacitor	Harvey Run Capacitor	Doubs SS	Meadowbrook SS	Grandview Capacitor	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake - Homer City
286,459	-	-	-	-	-	3,579	130,566	-	-	-	-
298,919	-	818	-	2,891	-	4,740	140,905	-	-	-	-
311,379	-	2,454	-	8,646	-	5,902	151,244	-	-	-	-
323,839	-	4,090	728	15,028	-	7,063	161,583	-	-	-	-
336,299	-	5,726	2,184	22,064	-	8,219	171,922	-	-	-	-
348,759	-	7,362	3,640	29,638	-	9,369	182,261	-	-	-	-
361,219	12,858	9,000	5,096	37,959	51,765	10,520	192,600	112	-	1,545	25,741
373,679	38,945	10,641	6,553	46,505	155,376	11,670	202,939	334	1,046	4,623	52,413
386,139	65,208	12,282	8,009	55,039	259,506	12,820	213,279	554	3,139	7,690	77,263
398,599	86,573	13,923	9,465	63,556	364,210	13,971	223,618	26,752	5,235	10,760	101,533
411,059	107,530	15,564	10,922	72,089	468,703	15,121	233,957	78,932	7,334	13,833	127,089
423,519	137,278	17,205	12,378	80,622	573,382	16,272	244,296	131,121	9,433	16,907	152,921
434,971	169,357	18,846	13,834	89,154	678,530	17,424	254,635	183,306	11,532	19,981	178,471
361,141	**47,519**	**9,070**	**5,601**	**40,245**	**196,267**	**10,513**	**192,600**	**32,393**	**2,901**	**5,795**	**55,033**

Altoona	Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total
-	-	-	-	-	-	-	-	-	-	-	72,434,228
-	-	-	-	-	-	-	-	-	-	-	74,538,994
-	-	-	-	-	-	-	-	-	-	-	76,648,165
-	-	-	-	-	-	-	-	-	-	-	78,759,554
-	-	-	-	-	-	-	-	-	-	-	80,887,320
-	-	-	-	-	-	-	-	-	-	-	83,013,513
30,911	2,774	348	38,538	1,656	-	-	-	-	-	-	85,307,027
92,267	8,453	1,055	115,437	7,785	-	-	-	-	-	-	87,745,558
153,201	14,263	1,767	192,206	16,528	-	-	-	-	-	-	90,187,163
214,624	20,073	2,489	269,049	25,066	-	-	-	-	-	-	92,651,656
276,813	25,884	3,253	345,929	33,630	-	-	-	-	-	-	95,143,692
338,599	31,695	4,049	422,807	42,217	379	-	-	-	-	-	97,645,175
399,670	37,506	4,841	496,224	50,870	1,138	4,926	49,062	8,484	1,892	15	99,909,818
115,853	**10,819**	**1,369**	**144,630**	**13,673**	**117**	**379**	**3,774**	**653**	**146**	**1**	**85,759,374**

Trans-Allegheny Interstate Line (

Attachment 5 - Cost Supp

Line	Description	Source	Year	Link to Appendix A, line 23	Link to Appendix A, line 23
	Calculation of Distribution Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.26.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p219.26.b	For 2014	-	-
	Distribution Accumulated Depreciation			-	-
	Calculation of Intangible Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p200.21.b	For 2013	4,822,025	
	December	p200.21b	For 2014	6,322,660	6,322,660
25	**Accumulated Intangible Depreciation**			**5,572,343**	**6,322,660**
				Link to Appendix A, line 25	**Link to Appendix A, line 25**
	Calculation of General Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.28b	For 2013	3,876,568	
	December	p219.28.b	For 2014	5,276,835	5,276,835
24	**Accumulated General Depreciation**			**4,576,702**	**5,276,835**
				Link to Appendix A, line 24	**Link to Appendix A, line 24**
	Calculation of Production Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.20.b-24.b	For 2013	-	
	January	company records	For 2014	-	
	February	company records	For 2014	-	
	March	company records	For 2014	-	
	April	company records	For 2014	-	
	May	company records	For 2014	-	
	June	company records	For 2014	-	
	July	company records	For 2014	-	
	August	company records	For 2014	-	
	September	company records	For 2014	-	
	October	company records	For 2014	-	
	November	company records	For 2014	-	
	December	p219.20.b thru 219.24.b	For 2014	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**95,908,418**	**111,509,313**
				Link to Appendix A, line 8	**Link to Appendix A, line 8**

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
				Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	
	Materials and Supplies						
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	1,326,179,788	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	1,259,599,755	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	72,434,228	-	-	

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

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

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 6.5%	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)	8.2884%					

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

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, 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

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	148,535	169,249	158,892	100%	158,892	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		148,535	169,249	158,892		158,892	

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		1,374,120	
	Total Account 566 Miscellaneous Transmission Expenses	p.321.97.b	$ 1,374,120	

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

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
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43			2,455,602								
352	Structures & Improvements	50	-	R3	(10)	2.20	16,761		1,332,732							144	
	SVC	35	-			2.86											
353	Station Equipment						1,354,619	514,883	844,309	172,262	1,372	162,194	145,082	830,355	94,890	81,650	149,570
	Other	50	-	R2	(5)	2.10											
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96											
	SCADA	15	-	S3	0	6.67											
354	Towers & Fixtures	65	-	R4	(25)	1.92			7,231,604								
355	Poles & Fixtures	55	-	R2.5	(20)	2.18			2,860,498								
356	Overhead Conductors & Devices								6,247,177								
	Other	55	-	R2.5	(40)	2.80											
	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							1,371,379	514,883	20,971,922	172,262	1,372	162,194	145,082	830,355	94,890	81,794	149,570

Total Transmission Depreciation Expense (must tie to p336.7.f) | 27,824,330

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

Annual Depreciation Expense

Cabot SS	Grandview Capacitor	Potter	Osage Whitely	Armstrong	Farmers Valley	Harvey Run	Doubs SS	Meadowbrook SS	502 Jct Substation	Conemaugh-Seward	Luxor	Grandpoint & Guilford	Handsome Lake-Homer City
										1,438			
152	199		10,541	3	680				124,069				
149,368	13,646	34,408	116,607	163,144	18,166	13,834	89,154	678,530		80,825	11,532	19,981	
			64,904							2,515			
			393,738	6,211						98,527			178,471
-													
149,520	13,844	34,408	585,789	169,357	18,846	13,834	89,154	678,530	124,069	183,306	11,532	19,981	178,471

Altoona	Blairsville	Carbon Center	Hunterstown	Johnstown	Buffalo Road	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Shuman Hill/Mobley	Total
											2,457,040
											1,485,280
											-
											-
399,670	37,506	4,841	499,627	50,823	1,138	4,926	43,519	8,484	1,892		6,792,808
											-
											-
											-
											-
											7,231,604
										15	2,927,931
											-
							5,543				6,929,666
											-
											-
											-
											-
											-
											-
399,670	37,506	4,841	499,627	50,823	1,138	4,926	49,062	8,484	1,892	15	27,824,330

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

GENERAL PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
390	Structures & Improvements	50	R1	0	2.00	893,109
391	Office Furniture & Equipment	20	SQ	0	5.00	96,332
	Information Systems	10	SQ	0	10.00	308,838
	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	16,520
	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	130,077
398	Miscellaneous Equipment	15	SQ	0	6.67	-
Total General Plant						1,444,875
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	1,444,875					

INTANGIBLE PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
303	Miscellaneous Intangible Plant	5	SQ	0	20.00	1,484,865
Total Intangible Plant						1,484,865
Total Intangible Plant Amoritization (must tie to p336.1 d & e)	1,484,865					

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

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	-	-	-		3,277,585	-	136,129,170
	2	-	-	-		-	-	-
	3	-	-	-		-	-	-
	4	-	-	-		-	-	-
	...							
	Total	-	-	-		3,277,585	-	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)
		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

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)	(in service)	(in service)	(in service)	CWIP
	-	-	-	-	-	-	-	1,154,713
	-	-	-	-	-	-	-	956,866
	-	-	-	-	-	-	-	1,172,915
	-	-	-	-	27,808,501	-	-	1,225,384
	-	-	-	-	27,808,501	-	-	1,254,820
	-	-	-	-	27,808,501	-	-	2,531,069
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,756,659
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,794,400
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,830,250
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,866,365
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,902,747
	44,310,669	-	4,840,224	58,411,179	27,808,501	3,631,440	-	2,939,398
	44,310,669	52,235,676	4,840,224	58,411,179	27,808,501	3,631,440	11,197,637	4,135,490
	310,174,683	**52,235,676**	**33,881,568**	**408,878,253**	**278,085,010**	**25,420,080**	**11,197,637**	**29,521,075**
	23,859,591	4,018,129	2,606,274	31,452,173	21,391,155	1,955,391	861,357	2,270,852
(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)
		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

Month End Balances

Other Projects PIS (Monthly additions)	Johnstown SS (2nd xfmr)	Yeagertown		Altoona SVC			Luxor	Armstrong
	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	-	-	-	1,154,387	-
	-	-	-	35,057,738	-	-	1,154,387	-
	4,278,432	-	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	4,278,432	461,543	-	35,057,738	-	-	1,154,387	11,068,995
	29,949,024	**2,769,258**	**-**	**280,461,904**	**-**	**-**	**15,007,031**	**77,482,965**

	(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)	(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

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)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	-	-	-	-	-	-	-	782,425
	1,603,191	-	-	-	-	-	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	-	782,425
	1,603,191	-	236,623	-	-	1,147,868	313,774	782,425
	1,603,191	-	236,623	-	4,206,813	1,147,868	313,774	782,425
	1,603,191	-	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
	1,603,191	5,164,619	236,623	1,418,503	4,206,813	1,147,868	313,774	782,425
	12,825,528	**5,164,619**	**1,656,361**	**2,837,006**	**12,620,439**	**8,035,076**	**1,255,096**	**10,171,525**
	2,303,771.08	213,019.85	-	21,573,992.62	-	-	1,154,387.00	

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

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)
$ 3,057,443.64	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	528,073	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

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)
		Rider Sub (West Milford)		Monocacy SS	Bartonville SS Capacitor	Mainsburg SS	Johnstown Sub Capacitor	Grover SS	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	-	-	-	-	-	-	-	106
Jan 2015	Actual	-	-	-	-	-	-	-	6,009,487
Feb	Actual	-	-	-	-	-	-	-	(6,007,300)
Mar	Budget	-	-	-	-	-	-	-	-
Apr	Budget	-	-	-	-	-	-	-	-
May	Budget	-	-	-	-	-	-	-	-
Jun	Budget	-	-	-	754,538	22,073,337	788,782	564,788	-
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	-	-	34,366,931	-	-	-	-	-
Nov	Budget	-	-	-	-	-	-	-	-
Dec	Budget	18,411,593	-	-	-	-	-	-	-
Total		18,411,593	-	34,366,931	754,538	22,073,337	788,782	564,788	2,293
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances

Other Projects PIS (Monthly additions)	Rider Sub (West Milford)	0	Monocacy SS	Bartonville SS Capacitor	Mainsburg SS	Johnstown Sub Capacitor	Grover SS	502 Junction - Territorial Line (monthly additions)
	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP
	-	-	-	-	-	-	-	106
	-	-	-	-	-	-	-	6,009,593
	-	-	-	-	-	-	-	2,293
	-	-	-	-	-	-	-	2,293
	-	-	-	-	-	-	-	2,293
	-	-	-	-	-	-	-	2,293
	-	-	-	754,538	22,073,337	788,782	564,788	2,293
	-	-	-	754,538	22,073,337	788,782	564,788	2,293
	-	-	-	754,538	22,073,337	788,782	564,788	2,293
	-	-	-	754,538	22,073,337	788,782	564,788	2,293
	-	-	34,366,931	754,538	22,073,337	788,782	564,788	2,293
	-	-	34,366,931	754,538	22,073,337	788,782	564,788	2,293
	18,411,593	-	34,366,931	754,538	22,073,337	788,782	564,788	2,293
	18,411,593	**-**	**103,100,793**	**5,281,766**	**154,513,359**	**5,521,474**	**3,953,516**	**6,034,920**
	1,416,276	-	7,930,830	406,290	11,885,643	424,729	304,117	464,225

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Claysburg Ring Bus	Yeagertown	Conemaugh Capacitor	Squab Hollow SS	Squab Hollow SVC	Shingletown Capacitor	Nyswaner	Shawville
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	-
Jan 2015	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	-
Apr	Budget	-	-	-	-	-	-	-	-
May	Budget	-	-	-	-	-	-	-	-
Jun	Budget	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	-	1,974,739
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	-	-	-	-	-	-	945,000	-
Nov	Budget	-	-	-	-	-	-	-	-
Dec	Budget	-	-	-	-	-	-	-	-
Total		2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	945,000	1,974,739
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances

Other Projects PIS (Monthly additions)	Claysburg Ring Bus	Yeagertown	Conemaugh Capacitor	Squab Hollow SS	Squab Hollow SVC	Shingletown Capacitor	Nyswaner	Shawville
	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	-	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	-	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	-	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	-	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	945,000	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	945,000	1,974,739
	2,904,800	1,030,589	2,711,928	14,697,836	35,103,448	822,802	945,000	1,974,739
	20,333,600	**7,214,123**	**18,983,494**	**102,884,852**	**245,724,136**	**5,759,614**	**2,835,000**	**13,823,173**
	1,564,123.08	554,932.54	1,460,268.73	7,914,219.38	18,901,856.62	443,047.23	218,076.92	1,063,321.00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)		(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	-
Jan 2015	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	-
Apr	Actual	-	-	-	-	-	-	-	-
May	Budget	-	-	-	-	-	-	-	-
Jun	Budget	-	-	-	-	-	-	-	-
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	-	-	-	-	-	-	-	-
Nov	Budget	-	-	-	-	-	-	-	-
Dec	Budget	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances

Other Projects PIS (Monthly additions)	0	0	0	0	0	0	0	0
				(in service)	(in service)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	-	-	-	-	-	-	-	-

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)	Hunterstown	Farmers Valley	Harvey Run	Doubs SS	Potter SS (Monthly Additions)	Osage Whiteley (Monthly Additions)	Meadowbrook SS	502 Junction - Territorial Line (Monthly additions)
$ 3,142,765	6,450,496.74	219,346.51	1,075,868.34	1,025,920.05	880,320.91	5,330,749	698,648	638,282	800,333	1,002,346	6,030,191	135,653	118,184	699,723	283,499	3,633,473	8,248,845	155,978,006

502 Junction Substation	Waldo Run	Conemaugh	Blairsville	Four Mile Junction	Johnstown	Yeagertown	Grandview Capacitor	Altoona SVC	Luxor	Grandpoint & Guilford	Moshannon	Carbon Center	Shawville	Northwood	Shuman Hill	Buffalo Road	Pleasureville Capacitor	Grover SS Capacitor
$ 1,381,688.46	6,718,248.12	3,605,452.90	456,125.96	1,203,582.19	672,884.34	70,759	95,418	4,798,880	162,993	241,502	722,103	61,172	135,583	-	695	56,333	-	38,778

Total Revenue Requirement	Handsome Lake - Homer City	West Union	Rider Sub (West Milford)	Oak Mound to Waldo Double Circuit	Monocacy SS	Bartonville SS Capacitor	Mainsburg SS	Johnstown Sub Capacitor	Claysburg Ring Bus	Conemaugh Capacitor	Squab Hollow SS	Squab Hollow SVC	Shingletown Capacitor	Nyswaner	Armstrong
$ 227,621,101.07	1,817,838.25	115,288.54	180,588.20	0.00	1,011,253.44	51,806	1,515,528	54,157	199,440	186,198	1,009,135	2,410,160	56,493	27,807	2,170,565

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)
							Line (monthly additions)		
		(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-		2,038,647		
Jan 2014	Actual	-	-	-	-		(152,601)		
Feb	Actual	-	-	-	-		(66,019)		
Mar	Actual	-	-	-	-		15,108		
Apr	Actual	-	-	-	-		79		
May	Actual	-	-	-	-		1,806,632		
Jun	Actual	-	-	-	-		(8,626)		
Jul	Actual	-	-	-	-		997,834		
Aug	Actual	-	-	-	-		6,005		
Sep	Actual	-	-	-	-		10,605		
Oct	Actual	-	-	-	-		(1,370,785)		
Nov	Actual	-	-	-	-		598		
Dec	Actual	-	-	-	-		106		
Total		-	-	-	-	-	3,277,585	-	-

Month End Balances

(Monthly additions)	0	0	0	0		(monthly additions)		
				(in service)	(in service)	CWIP		
	-	-	-	-	-	2,038,647	-	-
	-	-	-	-	-	1,886,047	-	-
	-	-	-	-	-	1,820,027	-	-
	-	-	-	-	-	1,835,135	-	-
	-	-	-	-	-	1,835,215	-	-
	-	-	-	-	-	3,641,847	-	-
	-	-	-	-	-	3,633,221	-	-
	-	-	-	-	-	4,631,055	-	-
	-	-	-	-	-	4,637,060	-	-
	-	-	-	-	-	4,647,665	-	-
	-	-	-	-	-	3,276,880	-	-
	-	-	-	-	-	3,277,479	-	-
	-	-	-	-	-	3,277,585	-	-
	-	**-**	**-**	**-**	**-**	**40,437,863**	**-**	**-**
	-	-	-	-	-	3,110,605	-	-

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
$ 209,703,354.76	296,464.50	1,048,721.60	838,173.26	667,575.63	730,838.27	5,567,552	921,484	1,077,826	1,126,056	228,782	6,752,347	3,234,449	162,737,191	3,807,783	1,220,817	141,956	123,737	649,383

Meadowbrook SS	Buffalo Road Capacitor	Handsome Lake-Homer City	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Altoona	Blairsville	Conemaugh Transformer	502 Junction Substation	Cabron Center	Hunterstown	Johnstown	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Pleasureville Capacitor
4,984,437	14,448	1,004,974	98,348	85,354	162,968	2,870,718	272,274	2,747,345	1,446,301	35,241	3,625,115	371,304	113,910	584,067	104,356	10,989	-

Yeagertown	Shawville	Northwood	Shuman Hill Sub
-	-	-	69

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		
209,703,355	-	206,491,970	=	3,211,384

<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	267,615	0.2700%	11.5	8,309	275,925
Jul	Year 1	267,615	0.2700%	10.5	7,587	275,202
Aug	Year 1	267,615	0.2700%	9.5	6,864	274,480
Sep	Year 1	267,615	0.2700%	8.5	6,142	273,757
Oct	Year 1	267,615	0.2700%	7.5	5,419	273,035
Nov	Year 1	267,615	0.2700%	6.5	4,697	272,312
Dec	Year 1	267,615	0.2700%	5.5	3,974	271,589
Jan	Year 2	267,615	0.2700%	4.5	3,252	270,867
Feb	Year 2	267,615	0.2700%	3.5	2,529	270,144
Mar	Year 2	267,615	0.2700%	2.5	1,806	269,422
Apr	Year 2	267,615	0.2700%	1.5	1,084	268,699
May	Year 2	267,615	0.2700%	0.5	361	267,977
Total		3,211,384				3,263,409

		Balance	Interest	Amort	Balance
Jun	Year 2	3,263,409	0.2700%	276,747	2,995,473
Jul	Year 2	2,995,473	0.2700%	276,747	2,726,814
Aug	Year 2	2,726,814	0.2700%	276,747	2,457,429
Sep	Year 2	2,457,429	0.2700%	276,747	2,187,317
Oct	Year 2	2,187,317	0.2700%	276,747	1,916,476
Nov	Year 2	1,916,476	0.2700%	276,747	1,644,903
Dec	Year 2	1,644,903	0.2700%	276,747	1,372,597
Jan	Year 3	1,372,597	0.2700%	276,747	1,099,556
Feb	Year 3	1,099,556	0.2700%	276,747	825,778
Mar	Year 3	825,778	0.2700%	276,747	551,261
Apr	Year 3	551,261	0.2700%	276,747	276,002
May	Year 3	276,002	0.2700%	276,747	(0)
Total with interest				3,320,965	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest	3,320,965	**Input to Appendix A, Line 143**
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$ 227,621,101	
Revenue Requirement for Year 3	230,942,066	

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)
$ 3,320,965	151	(62,359)	28,329	(15,614)	(11,808)	2,164	(319,367)	(315)	(190)

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
(32,333)	84,608	183,045	(676,158)	318,729	268,850	19,751	14,893	(132,032)

Meadowbrook SS	Buffalo Road Capacitor	Handsome Lake-Homer City	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Altoona	Blairsville	Conemaugh Transformer	502 Junction Substation
814,090	1,820	1,039,267	8,412	(68,623)	34,446	36,618	15,814	(66,115)	1,495,653

Cabron Center	Hunterstown	Johnstown	Moshannon	Waldo Run	Four Mile Junction	West Union SS	Pleasureville Capacitor
19,127	506,128	70,876	63,804	57,906	(9,148)	11,364	(106,337)

Yeagertown	Shawville	Northwood	Shuman Hill Sub
(28,951)	(29,659)	(131,939)	(83,930)

9 May Year 3 Post results of Step 8 on PJM web site
$ 230,942,066

10 June Year 3 Results of Step 8 go into effect
$ 230,942,066

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	12.7509%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	13.6500%
5	C		Line B less Line A	0.8991%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxes	0.8168%

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		12.7509%	12.7509%	12.7509%
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		13.6500%	12.7509%	13.6500%
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		989,056,467	20,609,356	37,209,685
17	Annual Depreciation Exp from Attachment !			20,971,922	514,883	1,371,379

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
18																
19	See Calculations for each item below	Wo Incentive ROE	2011	126,113,752.23	20,971,921.74	0.00	(676,157.76)	146,409,516.21	2,627,881.48	514,883.12	183,045.03	3,325,809.62	4,744,575.38	1,371,379.44	84,607.92	6,200,562.74
20	See Calculations for each item below	W Incentive ROE	2011	135,006,083.84	20,971,921.74	0.00	(676,157.76)	155,301,847.82	2,627,881.48	514,883.12	183,045.03	3,325,809.62	5,079,117.30	1,371,379.44	84,607.92	6,535,104.66

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.

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		PJM Upgrade ID: b0323				PJM Upgrade ID: b0230				PJM Upgrade ID: b0229			
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	12.7509%				12.7509%				12.7509%			
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	12.7509%				12.7509%				12.7509%			
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.	1,709,484				7,086,603				6,773,833			
17	Annual Depreciation Exp from Attachment !	1,372				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	217,974.91	1,371.60	(32,332.74)	187,013.77	903,606.78	172,261.56	(189.57)	1,075,678.76	863,725.75	162,194.30	(315.23)	1,025,604.82
20	See Calculations for each item below	217,974.91	1,371.60	(32,332.74)	187,013.77	903,606.78	172,261.56	(189.57)	1,075,678.76	863,725.75	162,194.30	(315.23)	1,025,604.82

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 A

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Line	Description	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	12.7509%	12.7509%	12.7509%	12.7509%
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	12.7509%	12.7509%	12.7509%	12.7509%
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.	5,766,165	35,294,677	4,735,014	4,364,301
17	Annual Depreciation Exp from Attachment !	145,082	830,355	94,890	81,794

Line	Description	b0559 Return	b0559 Depreciation	b0559 Reconciliation Amount	b0559 Revenue	b0495 Return	b0495 Depreciation	b0495 Reconciliation Amount	b0495 Revenue	b0343 Return	b0343 Depreciation	b0343 Reconciliation Amount	b0343 Revenue	b0344 Return	b0344 Depreciation	b0344 Reconciliation Amount	b0344 Revenue
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	735,238.87	145,082.04	(319,366.66)	560,954.25	4,500,394.36	830,354.87	2,164.41	5,332,913.64	603,757.58	94,890.48	(11,808.41)	686,839.65	556,488.28	81,794.16	(15,614.46)	622,667.98
20	See Calculations for each item below	735,238.87	145,082.04	(319,366.66)	560,954.25	4,500,394.36	830,354.87	2,164.41	5,332,913.64	603,757.58	94,890.48	(11,808.41)	686,839.65	556,488.28	81,794.16	(15,614.46)	622,667.98

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 A

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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	12.7509%				12.7509%				12.7509%				12.7509%			
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	12.7509%				12.7509%				12.7509%				12.7509%			
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.	5,103,654				6,688,352				15,694,621				916,070			
17	Annual Depreciation Exp from Attachment !	149,570				149,520				169,357				18,846			
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	650,762.54	149,570.04	28,329.29	828,661.86	852,826.15	149,520.00	(62,358.96)	939,987.19	2,001,207.82	169,357.41	268,849.83	2,439,415.05	116,807.30	18,845.60	19,751.07	155,403.97
20	See Calculations for each item below	650,762.54	149,570.04	28,329.29	828,661.86	852,826.15	149,520.00	(62,358.96)	939,987.19	2,001,207.82	169,357.41	268,849.83	2,439,415.05	116,807.30	18,845.60	19,751.07	155,403.97

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 A

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Line		PJM Upgrade ID: b0564			
10		Harvey Run Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	818,367			
17	Annual Depreciation Exp from Attachment !	13,834			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	104,349.31	13,834.29	14,893.45	133,077.05
20	See Calculations for each item below	104,349.31	13,834.29	14,893.45	133,077.05

Line		PJM Upgrade ID: b1803			
10		Doubs SS			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	4,788,428			
17	Annual Depreciation Exp from Attachment !	89,154			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	610,568.35	89,154.22	(132,032.40)	567,690.17
20	See Calculations for each item below	610,568.35	89,154.22	(132,032.40)	567,690.17

Line		PJM Upgrade ID: b1243				
10		Potter SS				
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				
13	Input the allowed ROE	11.70%				
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%				
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	12.7509%				
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.	1,953,515				
17	Annual Depreciation Exp from Attachment !	34,408				
18		Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue
19	See Calculations for each item below	249,091	34,408	0	151	283,649.71
20	See Calculations for each item below	249,091	34,408	0	151	283,649.71

Line		PJM Upgrade ID: b0674, b1023, b1023.3				
10		Osage Whiteley				
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				
13	Input the allowed ROE	11.70%				
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%				
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	12.7509%				
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.	23,901,686				
17	Annual Depreciation Exp from Attachment !	585,789				
18		Return	Depreciation	Pre-Commercial Exp.	Reconciliation amount	Revenue
19	See Calculations for each item below	3,047,684	585,789	0	318,729	3,952,201.73
20	See Calculations for each item below	3,047,684	585,789	0	318,729	3,952,201.73

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 A

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Line	Description	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	12.7509%	12.7509%	12.7509%	12.7509%
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	12.7509%	12.7509%	12.7509%	12.7509%
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.	59,370,757	43,373,854	52,303,590	26,838,444
17	Annual Depreciation Exp from Attachment !	678,530	499,627	49,062	183,306

Line	Description	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
		Meadobrook SS				Hunterstown			
19	See Calculations for each item below	7,570,315	678,530	814,090	9,062,935.16	5,530,563	499,627	506,128	6,536,318.99
20	See Calculations for each item below	7,570,315	678,530	814,090	9,062,935.16	5,530,563	499,627	506,128	6,536,318.99

Line	Description	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
		Waldo Run SS				Conemaugh			
19	See Calculations for each item below	6,669,186	49,062	57,906	6,776,153.63	3,422,147	183,306	(66,115)	3,539,337.95
20	See Calculations for each item below	6,669,186	49,062	57,906	6,776,153.63	3,422,147	183,306	(66,115)	3,539,337.95

(Column headings Return / Depreciation / Reconciliation amount / Revenue are printed on line 18.)

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 A

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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	12.7509%				12.7509%				12.7509%				12.7509%			
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	12.7509%				12.7509%				12.7509%				12.7509%			
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.	3,283,059				9,372,644				4,878,560				554,933			
17	Annual Depreciation Exp from Attachment !	37,506				8,484				50,823				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	418,620	37,506	15,814	471,939.69	1,195,098	8,484	(9,148)	1,194,434.39	622,061	50,823	70,876	743,759.89	70,759	0	(28,951)	41,808.10
20	See Calculations for each item below	418,620	37,506	15,814	471,939.69	1,195,098	8,484	(9,148)	1,194,434.39	622,061	50,823	70,876	743,759.89	70,759	0	(28,951)	41,808.10

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 A

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Line	Description				
		PJM Upgrade ID: b1990			
10		Grandview Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	639,751			
17	Annual Depreciation Exp from Attachment !	13,844			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	81,574	13,844	8,412	103,830.40
20	See Calculations for each item below	81,574	13,844	8,412	103,830.40

Line	Description				
		PJM Upgrade ID: b1801			
10		Altoona SVC			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	34,501,128			
17	Annual Depreciation Exp from Attachment !	399,670			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	4,399,210	399,670	36,618	4,835,497.54
20	See Calculations for each item below	4,399,210	399,670	36,618	4,835,497.54

Line	Description				
		PJM Upgrade ID: b1965			
10		Luxor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	1,187,844			
17	Annual Depreciation Exp from Attachment !	11,532			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	151,461	11,532	(68,623)	94,370.06
20	See Calculations for each item below	151,461	11,532	(68,623)	94,370.06

Line	Description				
		PJM Upgrade ID: b1839			
10		Grand Point & Guilford			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	1,737,290			
17	Annual Depreciation Exp from Attachment !	19,981			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	221,520	19,981	34,446	275,947.18
20	See Calculations for each item below	221,520	19,981	34,446	275,947.18

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 A

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Line		PJM Upgrade ID: b1964	PJM Upgrade ID: b1672	PJM Upgrade ID: b1998	PJM Upgrade ID: b1999, b2002	PJM Upgrade ID: b2342
10		Moshannon	Carbon Center	Shawville	Northwood	Shuman Hill Sub
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	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	No
13	Input the allowed ROE	11.70%	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	12.7509%	12.7509%	12.7509%	12.7509%	12.7509%
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	12.7509%	12.7509%	12.7509%	12.7509%	12.7509%
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.	5,624,515	441,776	1,063,321	0	5,334
17	Annual Depreciation Exp from Attachment !	4,926	4,841	0	0	15

Line		Moshannon Return	Moshannon Depreciation	Moshannon Reconciliation amount	Moshannon Revenue	Carbon Center Return	Carbon Center Depreciation	Carbon Center Reconciliation amount	Carbon Center Revenue	Shawville Return	Shawville Depreciation	Shawville Reconciliation amount	Shawville Revenue
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	717,177	4,926	63,804	785,906.53	56,330	4,841	19,127	80,299.09	135,583	0	(29,659)	105,924.02
20	See Calculations for each item below	717,177	4,926	63,804	785,906.53	56,330	4,841	19,127	80,299.09	135,583	0	(29,659)	105,924.02

Line		Northwood Return	Northwood Depreciation	Northwood Reconciliation amount	Northwood Revenue	Shuman Hill Sub Return	Shuman Hill Sub Depreciation	Shuman Hill Sub Reconciliation amount	Shuman Hill Sub Revenue
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	0	0	(131,939)	(131,938.88)	680	15	(83,930)	(83,235.55)
20	See Calculations for each item below	0	0	(131,939)	(131,938.88)	680	15	(83,930)	(83,235.55)

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 A

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Line		PJM Upgrade ID: b1770	PJM Upgrade ID: b2148	PJM Upgrade ID: b0556	PJM Upgrade ID: b1023.1	PJM Upgrade ID: b1941
10		Buffalo Road	Pleasureville Capacitor	Grover SS Capacitor	502 Junction Substation	Handsome Lake - Homer City
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	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	No
13	Input the allowed ROE	11.70%	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	12.7509%	12.7509%	12.7509%	12.7509%	12.7509%
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	12.7509%	12.7509%	12.7509%	12.7509%	12.7509%
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.	432,868	0	304,117	9,862,973	12,856,860
17	Annual Depreciation Exp from Attachment !	1,138	0	0	124,069	178,471

Line		PJM Upgrade ID: b1770 Return	Depreciation	Reconciliation amount	Revenue	PJM Upgrade ID: b2148 Return	Depreciation	Reconciliation amount	Revenue
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	55,195	1,138	1,820	58,152.59	0	0	(106,337)	(106,337.00)
20	See Calculations for each item below	55,195	1,138	1,820	58,152.59	0	0	(106,337)	(106,337.00)

Line		PJM Upgrade ID: b0556 Return	Depreciation	Reconciliation amount	Revenue
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	38,778	0	0	38,777.65
20	See Calculations for each item below	38,778	0	0	38,777.65

Line		PJM Upgrade ID: b1023.1 Return	Depreciation	Reconciliation amount	Revenue	PJM Upgrade ID: b1941 Return	Depreciation	Reconciliation amount	Revenue
18		Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	1,257,619	124,069	1,495,653	2,877,341.30	1,639,367	178,471	1,039,267	2,857,104.77
20	See Calculations for each item below	1,257,619	124,069	1,495,653	2,877,341.30	1,639,367	178,471	1,039,267	2,857,104.77

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 A

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Line	Description	PJM Upgrade ID: b2343				PJM Upgrade ID: b1840				PJM Upgrade ID: b2235				PJM Upgrade ID: b2260			
10		West Union				Rider Sub (West Milford)				Monocacy SS				Bartonville SS 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	12.7509%				12.7509%				12.7509%				12.7509%			
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	12.7509%				12.7509%				12.7509%				12.7509%			
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.	889,322				1,416,276				7,930,830				406,290			
17	Annual Depreciation Exp from Attachment !	1,892				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	113,397	1,892	11,364	126,652.13	180,588	0	0	180,588.20	1,011,253	0	0	1,011,253.44	51,806	0	0	51,805.65
20	See Calculations for each item below	113,397	1,892	11,364	126,652.13	180,588	0	0	180,588.20	1,011,253	0	0	1,011,253.44	51,806	0	0	51,805.65

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 A

Line	Description	PJM Upgrade ID: b1802			
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10		Mainsburg SS			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	11,885,643			
17	Annual Depreciation Exp from Attachment !	0			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	1,515,528	0	0	1,515,528.27
20	See Calculations for each item below	1,515,528	0	0	1,515,528.27

Line	Description	PJM Upgrade ID: b0555			
10		Johnstown Sub Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	424,729			
17	Annual Depreciation Exp from Attachment !	0			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	54,157	0	0	54,156.81
20	See Calculations for each item below	54,157	0	0	54,156.81

Line	Description	PJM Upgrade ID: b1943			
10		Claysburg Ring Bus			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	1,564,123			
17	Annual Depreciation Exp from Attachment !	0			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	199,440	0	0	199,440.01
20	See Calculations for each item below	199,440	0	0	199,440.01

Line	Description	PJM Upgrade ID: b0376			
10		Conemaugh Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	1,460,269			
17	Annual Depreciation Exp from Attachment !	0			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	186,198	0	0	186,197.63
20	See Calculations for each item below	186,198	0	0	186,197.63

Line	Description	PJM Upgrade ID: b2364 & b2364.1			
10		Squab Hollow SS			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	12.7509%			
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	12.7509%			
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.	7,914,219			
17	Annual Depreciation Exp from Attachment !	0			
18		Return	Depreciation	Reconciliation amount	Revenue
19	See Calculations for each item below	1,009,135	0	0	1,009,135.41
20	See Calculations for each item below	1,009,135	0	0	1,009,135.41

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 A

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Line	Description	PJM Upgrade ID: b2362	PJM Upgrade ID: b2156	PJM Upgrade ID: b2546	PJM Upgrade ID: bxxx
10		Squab Hollow SVC	Shingletown Capacitor	Nyswaner	
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	12.7509%	12.7509%	12.7509%	
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	12.7509%	12.7509%	12.7509%	
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.	18,901,857	443,047	218,077	
17	Annual Depreciation Exp from Attachment !	0	0	0	

Line	Description	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Total	Incentive Charged	Revenue Credit	$9,226,873.54
18																					
19	See Calculations for each item below	2,410,160	0	0	2,410,159.72	56,493	0	0	56,492.58	27,807	0	0	27,806.80	0.00	0.00	0.00	0.00	221,715,192.34		221,715,192.34	**Ax A Line 148**
20	See Calculations for each item below	2,410,160	0	0	2,410,159.72	56,493	0	0	56,492.58	27,807	0	0	27,806.80	0.00	0.00	0.00	0.00	230,942,065.88	230,942,065.88		

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 A

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

YEAR ENDED 12/31/2014

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	t=N **Long Term Debt : 12/31/2015** First Mortgage Bonds:	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)	
(1)	3.85%, Senior Unsecured Notes	12/11/2014	6/1/2025	$ 550,000,000	$ 545,707,344	$ 546,138,841	12	$ 546,138,841	100.00%	3.94%	3.94%	
	Total			$ 550,000,000		$ 546,138,841		$ 546,138,841	100.000%		3.94%	**

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 12/31/2015

			(aa)	(bb)	(cc)	(dd)	14	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)	(ll)
	Long Term Debt I	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)
(1)	3.85%, Senior Unsecure	No	12/11/2014	6/1/2025	$ 550,000,000	$ (418,000)		$ 3,874,656	-	xxx	$ 545,707,344	99.2195	0.03850	$ 21,175,000	3.94%
														-	
	TOTALS				$ 550,000,000	(418,000)		$ 3,874,656	-	xxx	$ 545,707,344			$ 21,175,000	

* 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]:

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

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

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]:

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

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]:

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

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 3

Accounting of Transfers Between

CWIP and Plant In Service

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
			502 Junction to Territorial Line		
13418596	478437863	35500	Line Construction 1	(96,684.51)	January 1, 2014
	478437863	35500	Line Construction 1	(134,420.59)	February 1, 2014
	478437863	35500	Line Construction 1	1,665.65	March 1, 2014
	478437863	35500	Line Construction 1	1,216.27	April 1, 2014
	478437863	35500	Line Construction 1	2,043.59	June 1, 2014
	478437863	35500	Line Construction 1	271,339.83	July 1, 2014
	478437863	35500	Line Construction 1	1,996.02	August 1, 2014
	478437863	35500	Line Construction 1	641.58	September 1, 2014
	478437863	35500	Line Construction 1	1,817.97	October 1, 2014
	478437863	35500	Line Construction 1	(39,257.49)	November 1, 2014
	478437863	35500	Line Construction 1	431.21	December 1, 2014
			Total	10,789.53	
13412255	478229242	35500	Line Construction 2	(181,704.32)	January 1, 2014
	478229242	35500	Line Construction 2	432,090.14	February 1, 2014
	478229242	35500	Line Construction 2	33,043.98	March 1, 2014
	478229242	35500	Line Construction 2	10,356.57	April 1, 2014
	478229242	35500	Line Construction 2	18,830.96	May 1, 2014
	478229242	35500	Line Construction 2	1,462.93	June 1, 2014
	478229242	35500	Line Construction 2	418,181.74	July 1, 2014
	478229242	35500	Line Construction 2	176.41	August 1, 2014
	478229242	35500	Line Construction 2	4,949.53	September 1, 2014
	478229242	35500	Line Construction 2	45,455.10	October 1, 2014
	478229242	35500	Line Construction 2	(9,640.55)	November 1, 2014
	478229242	35500	Line Construction 2	4,769.52	December 1, 2014
			Total	777,972.01	
13419997	478541318	35500	Line Construction 3	(45,286.16)	January 1, 2014
	478541318	35500	Line Construction 3	3,196.50	March 1, 2014
	478541318	35500	Line Construction 3	(1,441,336.00)	May 1, 2014
	478541318	35500	Line Construction 3	1,441,336.00	October 1, 2014
			Total	(42,089.66)	

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
13418659	478437918	35500	Line Construction 5	(5,531.79)	January 1, 2014
	478437918	35500	Line Construction 5	71,110.43	July 1, 2014
	478437918	35500	Line Construction 5	(11,378.14)	November 1, 2014
			Total	54,200.50	
13418878	478439181	35500	Line Construction 13	3,747.37	July 1, 2014
	478439181	35500	Line Construction 13	(603.16)	November 1, 2014
			Total	3,144.21	
13418900	478439187	35500	Line Construction 14	4,550.37	July 1, 2014
	478439187	35500	Line Construction 14	(732.42)	November 1, 2014
			Total	3,817.95	
13418901	478439208	35500	Line Construction 15	3,893.37	July 1, 2014
	478439208	35500	Line Construction 15	(626.67)	November 1, 2014
			Total	3,266.70	
13416100	478316423	35500	Line Construction 16	(5,418.36)	January 1, 2014
	478316423	35500	Line Construction 16	(100.00)	March 1, 2014
	478316423	35500	Line Construction 16	12,294.75	July 1, 2014
	478316423	35500	Line Construction 16	(1,912.74)	November 1, 2014
			Total	4,863.65	
13419823	478518838	35300	SS Construction 4	283,439.76	January 1, 2014
	478518838	35300	SS Construction 4	24,879.93	July 1, 2014
	478518838	35300	SS Construction 4	(4,004.59)	November 1, 2014
			Total	304,315.10	
13421050	484756194	35300	SS Construction 17	414.56	January 1, 2014
	484756194	35300	SS Construction 17	(18,256.66)	February 1, 2014
	484756194	35300	SS Construction 17	285.46	April 1, 2014
	484756194	35300	SS Construction 17	73,982.69	July 1, 2014
	484756194	35300	SS Construction 17	(11,693.56)	November 1, 2014
			Total	44,732.49	
			Total 502 Junction to Territorial Line	1,165,012.48	

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
			Other Projects		
13395935	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	(25,983.26)	January 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	16,577.92	February 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	916.05	March 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	521.80	April 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	13.23	August 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	(8,909.42)	October 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	0.44	November 1, 2014
	477989701	35610	Osage-Whiteley(WP) - 8.5mi new 138k	0.46	December 1, 2014
				(16,862.78)	
13395937	477989703	35610	Osage-Whiteley(MP) - 5.8-mi new 138	1,967.30	January 1, 2014
	477989703	35610	Osage-Whiteley(MP) - 5.8-mi new 138	4,993.19	April 1, 2014
	477989703	35610	Osage-Whiteley(MP) - 5.8-mi new 138	0.44	November 1, 2014
	477989703	35610	Osage-Whiteley(MP) - 5.8-mi new 138	0.46	December 1, 2014
				6,961.39	
13411476	478195268	35300	Osage-Whiteley 138kV Line (WV) (b10	(31,244.41)	January 1, 2014
	478195268	35300	Osage-Whiteley 138kV Line (WV) (b10	308.79	February 1, 2014
	478195268	35300	Osage-Whiteley 138kV Line (WV) (b10	432.65	March 1, 2014
	478195268	35300	Osage-Whiteley 138kV Line (WV) (b10	131.22	December 1, 2014
				(30,371.75)	
13420642	478543198	35300	33007026 Whiteley SS: Add Line Term	1,713.06	January 1, 2014
	478543198	35300	33007026 Whiteley SS: Add Line Term	3,175.37	February 1, 2014
	478543198	35300	33007026 Whiteley SS: Add Line Term	(119.29)	August 1, 2014
	478543198	35300	33007026 Whiteley SS: Add Line Term	(1,347.91)	September 1, 2014
				3,421.23	
13448299	486072630	35300	502 Jct Substation - Install 500/13	2,955.70	January 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	(129,297.19)	February 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	45.91	March 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	3,848.27	April 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	0.28	September 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	5.66	October 1, 2014
	486072630	35300	502 Jct Substation - Install 500/13	13.49	December 1, 2014
				(122,427.88)	
13645811	505210064	35300	SN - Grandview: Install a 31.8 MVAR	962.81	January 1, 2014
	505210064	35300	SN - Grandview: Install a 31.8 MVAR	(6,998.48)	April 1, 2014
				(6,035.67)	
13419076	478440131	35300	33006884 - Wylie Ridge SS: Install	111,193.75	July 1, 2014
13356601	506387005	35300	Altoona Sub - Install 250 MVAR SVC	34,854,326.69	June 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	(529,827.09)	July 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	48,548.23	August 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	506,414.92	September 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	(16,668.68)	October 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	24,627.76	November 1, 2014
	506387005	35300	Altoona Sub - Install 250 MVAR SVC	13,376.05	December 1, 2014
				34,900,797.88	
13806707	519318731	35300	Armstrong SS: New 345-138kv Yard	13,153,351.64	June 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	534,850.50	July 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	(225,374.66)	August 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	(5,395,484.71)	September 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	6,363,337.97	October 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	2,209,182.44	November 1, 2014
	519318731	35300	Armstrong SS: New 345-138kv Yard	(791,168.29)	December 1, 2014
				15,848,694.89	
13752323	514900842	35300	Black Oak SVC - Replace Firewalls	21,750.64	May 1, 2014

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
13609510	533838718	35300	Blairsville Replace 138/115 kV	1,905,741.74	June 1, 2014
	533838718	35300	Blairsville Replace 138/115 kV	(26,766.11)	July 1, 2014
				1,878,975.63	
13625256	504032903	35300	Buffalo Road 115kV	433,413.49	November 1, 2014
	504032903	35300	Buffalo Road 115kV	592.35	December 1, 2014
				434,005.84	
13123150	511281973	35500	Build 230 kV Line - Conemaugh to Seward	13,636,325.39	September 1, 2014
	511281973	35500	Build 230 kV Line - Conemaugh to Seward	11,352.44	October 1, 2014
	511281973	35500	Build 230 kV Line - Conemaugh to Seward	(1,990.68)	November 1, 2014
	511281973	35500	Build 230 kV Line - Conemaugh to Seward	(4,544.09)	December 1, 2014
				13,641,143.06	
13969059	527945981	35300	Carbon Center SS: Install 230 kV	398,202.91	June 1, 2014
	527945981	35300	Carbon Center SS: Install 230 kV	11,163.37	July 1, 2014
	527945981	35300	Carbon Center SS: Install 230 kV	(7,605.07)	August 1, 2014
	527945981	35300	Carbon Center SS: Install 230 kV	14,183.38	September 1, 2014
	527945981	35300	Carbon Center SS: Install 230 kV	30,145.89	October 1, 2014
				446,090.48	
13123835	542480347	35300	Conemaugh - Install 3 Singe Phase	11,646,209.69	September 1, 2014
	542480347	35300	Conemaugh - Install 3 Singe Phase	(6,634.71)	October 1, 2014
	542480347	35300	Conemaugh - Install 3 Singe Phase	7,507.22	November 1, 2014
	542480347	35300	Conemaugh - Install 3 Singe Phase	(2,970.00)	December 1, 2014
				11,644,112.20	
13695717	511415980	35300	Doubs SS - Install #2 Cap	610,053.52	May 1, 2014
	511415980	35300	Doubs SS - Install #2 Cap	239,426.84	June 1, 2014
	511415980	35300	Doubs SS - Install #2 Cap	15,228.41	July 1, 2014
	511415980	35300	Doubs SS - Install #2 Cap	(13,613.44)	August 1, 2014
	511415980	35300	Doubs SS - Install #2 Cap	(1,369.08)	September 1, 2014
				849,726.25	
13575877	500926008	35300	Doubs SS - Install #4 Cap	3,303,432.97	January 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	(29,103.97)	February 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	744,996.81	March 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	182.03	April 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	(59.75)	August 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	14,515.09	September 1, 2014
	500926008	35300	Doubs SS - Install #4 Cap	14,458.72	October 1, 2014
				4,048,421.90	
13316638	511281421	35300	Farmers Valley-Add	934,823.26	January 1, 2014
	511281421	35300	Farmers Valley-Add	85.43	April 1, 2014
	511281421	35300	Farmers Valley-Add	6.87	May 1, 2014
				934,915.56	
13241102	499618586	35300	Four Mile Junction 230/115 kV	9,381,133.14	December 1, 2014
13632172	504740994	35300	Grand Point Substation - Install	947,426.50	June 1, 2014
	504740994	35300	Grand Point Substation - Install	(7,104.92)	July 1, 2014
	504740994	35300	Grand Point Substation - Install	418.26	August 1, 2014
	504740994	35300	Grand Point Substation - Install	202.92	November 1, 2014
	504740994	35300	Grand Point Substation - Install	4.17	December 1, 2014
				940,946.93	
13632180	504741016	35300	Guilford Substation - Install 2nd	818,486.29	June 1, 2014
	504741016	35300	Guilford Substation - Install 2nd	(7,027.00)	July 1, 2014
	504741016	35300	Guilford Substation - Install 2nd	2.78	August 1, 2014
	504741016	35300	Guilford Substation - Install 2nd	17.59	September 1, 2014
	504741016	35300	Guilford Substation - Install 2nd	0.94	November 1, 2014
	504741016	35300	Guilford Substation - Install 2nd	3.85	December 1, 2014
				811,484.45	

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
13744988	514254724	35610	Handsome Lake - Homery City 345kV	10,750,043.07	June 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	(474,614.48)	July 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	(1,237,212.02)	August 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	2,696,398.83	September 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	526,598.94	October 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	2,160,563.31	November 1, 2014
	514254724	35610	Handsome Lake - Homery City 345kV	(1,386,446.34)	December 1, 2014
				13,035,331.31	
13484528	511281432	35300	Harvey Run: Install 21.7	831,937.64	March 1, 2014
	511281432	35300	Harvey Run: Install 21.7	184.60	April 1, 2014
	511281432	35300	Harvey Run: Install 21.7	(14.01)	July 1, 2014
	511281432	35300	Harvey Run: Install 21.7	92.30	August 1, 2014
	511281432	35300	Harvey Run: Install 21.7	0.99	November 1, 2014
				832,201.52	
13450738	508029758	35300	Hunterstown: 500kV SVC - Install	44,000,635.59	June 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	(199,588.97)	July 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	52,805.86	August 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	32,606.44	September 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	9,560.28	October 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	(3,176,851.33)	November 1, 2014
	508029758	35300	Hunterstown: 500kV SVC - Install	2,677.93	December 1, 2014
				40,721,845.80	
14146125	538009795	35300	Hunterstown: SVC Alstom	43,046.73	June 1, 2014
	538009795	35300	Hunterstown: SVC Alstom	(2,933.46)	July 1, 2014
	538009795	35300	Hunterstown: SVC Alstom	226.91	November 1, 2014
	538009795	35300	Hunterstown: SVC Alstom	1.66	December 1, 2014
				40,341.84	
13627512	504570748	35300	Johnstown Substation - Install 2nd	1,892,232.60	June 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	3,220,679.40	July 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	(234,185.39)	August 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	950.16	September 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	18,890.27	October 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	(1,281.13)	November 1, 2014
	504570748	35300	Johnstown Substation - Install 2nd	2,302.97	December 1, 2014
				4,899,588.88	
13526185	495300103	35300	Kammer SS: T2 Xfmr	28,550.54	November 1, 2014
	495300103	35300	Kammer SS: T2 Xfmr	66,135.62	December 1, 2014
				94,686.16	
13584710	501418347	35300	Luxor 138kV - Install 44 Mvar Cap	1,195,820.98	July 1, 2014
	501418347	35300	Luxor 138kV - Install 44 Mvar Cap	192.46	August 1, 2014
	501418347	35300	Luxor 138kV - Install 44 Mvar Cap	3,324.05	September 1, 2014
	501418347	35300	Luxor 138kV - Install 44 Mvar Cap	37.95	November 1, 2014
				1,199,375.44	
13695951	511416938	35300	Meadowbrook SS - Inst SVC Facilities	9,374,018.37	June 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	258,492.89	July 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	459,882.85	August 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	90,092.05	September 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	(407,169.32)	October 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	737,227.09	November 1, 2014
	511416938	35300	Meadowbrook SS - Inst SVC Facilities	12,293.40	December 1, 2014
				10,524,837.33	
13448261	486072606	35300	Meadowbrook SS - Install SVC	49,785,861.59	June 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	(166,116.64)	July 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	41,765.20	August 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	63,701.67	September 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	12,051.66	October 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	(129,142.81)	November 1, 2014
	486072606	35300	Meadowbrook SS - Install SVC	(83,671.07)	December 1, 2014

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

Work Order ID	Work Order Number	FERC Account 101/106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			TrAIL Projects		
				49,524,449.60	
13442047	485846085	35011	Meadowbrook SS - Land Purchase for SVC	483,164.66	January 1, 2014
	485846085	35011	Meadowbrook SS - Land Purchase for SVC	(6,556.14)	February 1, 2014
	485846085	35011	Meadowbrook SS - Land Purchase for SVC	(2,701.07)	March 1, 2014
	485846085	35011	Meadowbrook SS - Land Purchase for SVC	238.77	July 1, 2014
				474,146.22	
13609744	503025824	35300	Moshannon 230 kV	5,629,440.75	December 1, 2014
14199237	540737695	35300	Relay - Waldo Run SS to Lamberton SS	73,813.30	December 1, 2014
13123478	511281243	35022	ROW - 230 kV Line Conemaugh to Seward	187,480.12	June 1, 2014
	511281243	35022	ROW - 230 kV Line Conemaugh to Seward	(2,479.55)	July 1, 2014
	511281243	35022	ROW - 230 kV Line Conemaugh to Seward	523.96	September 1, 2014
	511281243	35022	ROW - 230 kV Line Conemaugh to Seward	59.36	October 1, 2014
	511281243	35022	ROW - 230 kV Line Conemaugh to Seward	5.66	November 1, 2014
				185,589.55	
13386253	542482642	35300	Seward 230 kV - Conemaugh Construct	1,367,581.92	September 1, 2014
	542482642	35300	Seward 230 kV - Conemaugh Construct	136,533.05	October 1, 2014
	542482642	35300	Seward 230 kV - Conemaugh Construct	(82.08)	November 1, 2014
				1,504,032.89	
13641031	504991184	35610	Siting Work for Armstrong SS	1,810,885.32	March 1, 2014
	504991184	35610	Siting Work for Armstrong SS	65,949.94	April 1, 2014
	504991184	35610	Siting Work for Armstrong SS	151,327.22	May 1, 2014
	504991184	35610	Siting Work for Armstrong SS	16,434.63	June 1, 2014
	504991184	35610	Siting Work for Armstrong SS	(11,288.28)	July 1, 2014
	504991184	35610	Siting Work for Armstrong SS	7,757.19	August 1, 2014
	504991184	35610	Siting Work for Armstrong SS	(2,012,633.66)	September 1, 2014
	504991184	35610	Siting Work for Armstrong SS	(16,269.78)	November 1, 2014
	504991184	35220	Siting Work for Armstrong SS	3,120.85	December 1, 2014
				15,283.43	
13661476	506017368	35300	SS - Blairsville E. Replace	1,264,855.30	June 1, 2014
	506017368	35300	SS - Blairsville E. Replace	175,655.55	July 1, 2014
	506017368	35300	SS - Blairsville E. Replace	707.09	August 1, 2014
	506017368	35300	SS - Blairsville E. Replace	221.33	September 1, 2014
	506017368	35300	SS - Blairsville E. Replace	147.40	November 1, 2014
	506017368	35300	SS - Blairsville E. Replace	2.54	December 1, 2014
				1,441,589.21	
14010237	542480815	35300	SS - Conemaugh-Seward 230 kV	185,832.43	September 1, 2014
	542480815	35300	SS - Conemaugh-Seward 230 kV	(138,962.63)	October 1, 2014
	542480815	35300	SS - Conemaugh-Seward 230 kV	2.03	November 1, 2014
				46,871.83	
14020629	530998617	35300	Purchase Land Waldo Run Sub	1,300,046.66	December 1, 2014
14082160	536767657	35610 & 35011	138kV Glen Falls - Lamberton	5,216,695.22	December 1, 2014
14019830	530917549	35300	Waldo Run Substation	45,762,096.29	December 1, 2014
13752842	654797141	35300	West Union SS: Instal 138 kV Cap	732,345.77	December 1, 2014
13520143	494614107	35300	Wylie Ridge SS: Rep #6 Xfmr	90,534.30	July 1, 2014
			Total Other Projects	279,073,220.44	
			Total Additions	**280,238,232.92**	

ATTACHMENT 4

Worksheet Removing Purchase Accounting Entries

Trans-Allegheny Interstate Line Company
Capitalization Calculation Removing Purchase Accounting Entries
2014 Reconciliation of Transmission Revenue Requirement Formula Rate

The purpose of this worksheet is to comply with a Commission order requiring the removal of purchase accounting entries from other paid-in capital and retained earnings recorded in financial records. No adjustments to account 216 due to Purchase Acctg Entries existed in 2014.

Return/Capitalization Calculations

Description	Account	Source	Amount
Preferred Dividends	437	2014 FERC Form 1, p118.29.c	$ -
Common Stock			
Proprietary Capital			
Common Stock	201	2014 FERC Form 1, p112.2.c	1,000
Other Paid-in Capital	208 - 211	2014 FERC Form 1, p112.7.c	809,298,114
Adjustments to account 211 due to Purchase Acctg Entries		2013 FERC Form 1, p253.7.b	-
Retained Earnings	215, 215.1, 216	2014 FERC Form 1, p112.11.c	11,201,191
Remove adjustments to account 216 due to Purchase Acctg Entries:		2014 FERC Form 1, p118.10.d	-
Remove adjustments to account 216 due to Purchase Acctg Entries:		2014 FERC Form 1, p118.10.c	-
Less Unappropriated Undistributed Subsidiary Earnings	216.1	2014 FERC Form 1, p112.12.c	-
Less Accumulated Other Comprehensive Income	219	2014 FERC Form 1, p112.15.c	-
Less Preferred Stock Issued	204	2014 FERC Form 1, p112.3.c	-
Total Common Stock			$ 820,500,305
Capitalization			
Long Term Debt	221-226	2014 FERC Form 1, p112.24.c	$ 549,584,218
Less Unamortized Loss on Reacquired Debt	189	2014 FERC Form 1, p111.81.c	-
Plus Unamortized Gain on Reacquired Debt	257	2014 FERC Form 1, p113.61.c	-
Less ADIT associated with Gain or Loss	283	2014 FERC Form 1, Schedule Page 276	-
Total Long Term Debt			549,584,218
Preferred Stock	204	2014 FERC Form 1, p112.3.c	-
Common Stock			820,500,305
Total Capitalization			$ 1,370,084,523
Debt %		Total Long Term Debt / Total Capitalization	40.1132%
Preferred %		Preferred Stock / Total Capitalization	0.00%
Common %		Common Stock / Total Capitalization	59.8868%

Attachment 4B-Delmarva Formula Rate Update

Pepco Holdings, Inc

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May 15, 2015

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 2015 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 2015 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

[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 2015 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

[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

Line	Description		Notes	FERC Form 1 Page # or Instruction	2014
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 2,235,652
2	Total Wages Expense			p354.28b	$ 34,313,374
3	Less A&G Wages Expense			p354.27b	$ 3,377,539
4	Total			(Line 2 - 3)	30,935,835
5	**Wages & Salary Allocator**			(Line 1 / 4)	**7.2267%**
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g (see attachment 5)	$ 3,192,117,914
7	Common Plant In Service - Electric			(Line 24)	82,032,638
8	Total Plant In Service			(Sum Lines 6 & 7)	3,274,150,552
9	Accumulated Depreciation (Total Electric Plant)			p219.29c (see attachment 5)	$ 887,220,973
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 16,730,843
11	Accumulated Common Amortization - Electric		(Note A)	p356	14,756,945
12	Accumulated Common Plant Depreciation - Electric		(Note A)	p356	$ 50,295,314
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	969,004,075
14	Net Plant			(Line 8 - 13)	2,305,146,477
15	Transmission Gross Plant			(Line 29 - Line 28)	1,159,115,438
16	**Gross Plant Allocator**			(Line 15 / 8)	**35.4020%**
17	Transmission Net Plant			(Line 39 - Line 28)	835,403,954
18	**Net Plant Allocator**			(Line 17 / 14)	**36.2408%**
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 1,106,861,017
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	34,972,552
22	**Total Transmission Plant In Service**			(Line 19 - 20 + 21)	**1,141,833,569**
23	General & Intangible			p205.5.g & p207.99.g (see attachment 5)	157,105,239
24	Common Plant (Electric Only)		(Notes A & B)	p356	82,032,638
25	Total General & Common			(Line 23 + 24)	239,137,877
26	Wage & Salary Allocation Factor			(Line 5)	7.22674%
27	**General & Common Plant Allocated to Transmission**			(Line 25 * 26)	**17,281,870**
28	**Plant Held for Future Use (Including Land)**		(Note C)	p214	**0**
29	**TOTAL Plant In Service**			**(Line 22 + 27 + 28)**	**1,159,115,438**
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 315,157,898
31	Accumulated General Depreciation			p219.28.c (see attachment 5)	$ 36,577,148
32	Accumulated Intangible Amortization			(Line 10)	16,730,843
33	Accumulated Common Amortization - Electric			(Line 11)	14,756,945
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	50,295,314
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	118,360,250
36	Wage & Salary Allocation Factor			(Line 5)	7.22674%
37	**General & Common Allocated to Transmission**			(Line 35 * 36)	**8,553,586**
38	**TOTAL Accumulated Depreciation**			**(Line 30 + 37)**	**323,711,484**
39	**TOTAL Net Property, Plant & Equipment**			**(Line 29 - 38)**	**835,403,954**
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-218,839,378
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	-3,565,147
42	Net Plant Allocation Factor			(Line 18)	36.24%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**			(Line 41 * 42) + Line 40	**-220,131,416**
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	-3,256,349
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	14,108,076
46	**Total Prepayments Allocated to Transmission**			(Line 45)	**14,108,076**
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	$ 1,337,066
48	Wage & Salary Allocation Factor			(Line 5)	7.227%
49	Total Transmission Allocated			(Line 47 * 48)	96,626
50	Transmission Materials & Supplies			p227.8c	2,393,774
51	**Total Materials & Supplies Allocated to Transmission**			(Line 49 + 50)	**2,490,400**
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	17,856,240
53	1/8th Rule			x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**			(Line 52 * 53)	**2,232,030**
	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)	**-204,557,259**
59	**Rate Base**			(Line 39 + 58)	**630,846,696**

O&M

Line	Description	Note	Source		Amount
	Transmission O&M				
60	Transmission O&M		p321.112.b (see attachment 5)	$	13,510,520
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)		**13,510,520**
	Allocated General & Common Expenses				
67	Common Plant O&M	(Note A)	p356		0
68	Total A&G		p323.197.b (see attachment 5)	$	63,403,531
69	Less Property Insurance Account 924		p323.185b		428,408
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b		5,526,205
71	Less General Advertising Exp Account 930.1		p323.191b		54,489
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b		6,301,065
73	Less EPRI Dues	(Note D)	p352-353		135,782
74	**General & Common Expenses**		(Lines 67 + 68) - Sum (69 to 73)		50,957,582
75	Wage & Salary Allocation Factor		(Line 5)		7.2267%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)		**3,682,571**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b		507,890
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**507,890**
80	Property Insurance Account 924		p323.185b		428,408
81	General Advertising Exp Account 930.1	(Note F)	p323.191b		0
82	Total		(Line 80 + 81)		428,408
83	Net Plant Allocation Factor		(Line 18)		36.24%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)		**155,259**
85	**Total Transmission O&M**		**(Line 66 + 76 + 79 + 84)**		**17,856,240**

Depreciation & Amortization Expense

Line	Description	Note	Source	Amount
	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	25,643,218
86a	Amortization of Abandoned Transmission Plant		Attachment 5	0
87	General Depreciation		p336.10b&c	6,020,028
88	Intangible Amortization	(Note A)	p336.1d&e	28,053
89	Total		(Line 87 + 88)	6,048,081
90	Wage & Salary Allocation Factor		(Line 5)	7.2267%
91	**General Depreciation Allocated to Transmission**		(Line 89 * 90)	**437,079**
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	3,347,736
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	3,347,736
95	Wage & Salary Allocation Factor		(Line 5)	7.2267%
96	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 94 * 95)	**241,932**
97	**Total Transmission Depreciation & Amortization**		**(Line 86 + 91 + 96)**	**26,322,229**

Taxes Other than Income

Line	Description	Source	Amount
98	**Taxes Other than Income**	Attachment 2	**6,737,756**
99	**Total Taxes Other than Income**	**(Line 98)**	**6,737,756**

Return / Capitalization Calculations

Line	Description		Note	Source		Amount
	Long Term Interest					
100	Long Term Interest			p117.62c through 67c	$	49,729,877
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
102	**Long Term Interest**			"(Line 100 - line 101)"		49,729,877
103	**Preferred Dividends**		enter positive	p118.29c		-
	Common Stock					
104	Proprietary Capital			p112.16c		1,165,514,531
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)		1,167,692,310
	Capitalization					
108	Long Term Debt			p112.17c through 21c		1,173,230,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c		-11,518,147
110	Plus Gain on Reacquired Debt		enter positive	p113.61c		0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1		1,171,979
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8		0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)		1,162,883,832
114	Preferred Stock			p112.3c		0
115	Common Stock			(Line 107)		1,167,692,310
116	**Total Capitalization**			(Sum Lines 113 to 115)		2,330,576,142
117	Debt %	Total Long Term Debt		(Line 113 / 116)		49.90%
118	Preferred %	Preferred Stock		(Line 114 / 116)		0.00%
119	Common %	Common Stock		(Line 115 / 116)		50.10%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)		0.0428
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)		0.0213
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)		0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)		0.0566
126	**Total Return (R)**			(Sum Lines 123 to 125)		**0.0780**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**		**49,177,396**

Composite Income Taxes

Line	Description	Formula	Note	Source	Amount
	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)	36.2408%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-54,099**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**24,265,058**
138	**Total Income Taxes**			**(Line 136 + 137)**	**24,210,958**

REVENUE REQUIREMENT

Line	Description	Note	Source	Amount
	Summary			
139	Net Property, Plant & Equipment		(Line 39)	835,403,954
140	Adjustment to Rate Base		(Line 58)	-204,557,259
141	**Rate Base**		(Line 59)	**630,846,696**
142	O&M		(Line 85)	17,856,240
143	Depreciation & Amortization		(Line 97)	26,322,229
144	Taxes Other than Income		(Line 99)	6,737,756
145	Investment Return		(Line 127)	49,177,396
146	Income Taxes		(Line 138)	24,210,958
147	**Gross Revenue Requirement**		**(Sum Lines 142 to 146)**	**124,304,579**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,106,861,017
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,106,861,017
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	124,304,579
153	**Adjusted Gross Revenue Requirement**		(Line 151 * 152)	**124,304,579**
	Revenue Credits & Interest on Network Credits			
154	**Revenue Credits**		Attachment 3	7,923,085
155	**Interest on Network Credits**	(Note N)	PJM Data	-
156	**Net Revenue Requirement**		**(Line 153 - 154 + 155)**	**116,381,494**
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	**116,381,494**
158	Net Transmission Plant		(Line 19 - 30)	**791,703,119**
159	Net Plant Carrying Charge		(Line 157 / 158)	**14.7001%**
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	**11.4611%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	**2.1915%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	**42,993,140**
163	Increased Return and Taxes		Attachment 4	**78,696,445**
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	**121,689,586**
165	Net Transmission Plant		(Line 19 - 30)	**791,703,119**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	**15.3706%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	**12.1316%**
168	**Net Revenue Requirement**		(Line 156)	**116,381,494**
169	True-up amount		Attachment 6	**2,821,486**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	**625,498**
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	**12,208,522**
172	**Net Zonal Revenue Requirement**		(Line 168 + 169 +170+ 171+171a)	**132,037,000**
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	**3,875**
174	Rate ($/MW-Year)		(Line 172 / 173)	**34,074**
175	**Network Service Rate ($/MW/Year)**		**(Line 174)**	**34,074**

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	-	(682,359,489)	-	(682,359,489)
ADIT-283	(9,887,404)	(3,174,586)	(81,902,215)	(94,964,205)
ADIT-190	778,505	108,656,593	5,737,895	115,172,993
Subtotal	(9,108,899)	(576,877,482)	(76,164,320)	(662,150,701)
Wages & Salary Allocator			7.2267%	
Gross Plant Allocator		35.40202%		
ADIT	(9,108,899)	(204,226,282)	(5,504,196)	(218,839,378)
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 (1,171,979)

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 *ADIT-190*	B *Total*	C *Gas, Prod Or Other Distribution Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Allowance for Doubtful Accounts	4,447,323	4,447,323				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	1,462,799	1,462,799				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.
Claims Reserve	979,881	137,183		842,698		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Deferred ITC	1,718,406	240,577		1,477,829		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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	1,181,246	1,181,246				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.
Merrill Creek	6,576,642	6,576,642				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. This contra account represents an adjustment to the Merrill Creek Rent deferred tax generated relating to rent deductible for tax purposes upon economic performance. 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. 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.
OPEB	9,991,435	1,398,801			8,592,634	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Other (190)	(13,055)	10,084		(25,586)	2,447	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. Related to Gas, Production or Other.
Other Labor Related Accruals	6,669,126	933,678			5,735,448	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. Affects company personnel across all functions.
Reg Liab - FERC Formula Adj.	778,505		778,505			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 Liab - Other	4,355,308	4,355,308				Represents various costs which we are, or will be through a future rate case, getting recovery through rate base.
Renewable Energy Credits	4,525,912	4,525,912				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.
FAS 109 Deferred Taxes - 190	1,309,796	183,371		1,126,424		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Federal and State NOL	125,394,745	17,555,264		107,839,481		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Subtotal - p234	**169,378,069**	**43,008,188**	**778,505**	**111,260,846**	**14,330,530**	
Less FASB 109 Above if not separately removed	3,028,201	423,948	-	2,604,253	-	
Less FASB 106 Above if not separately removed	9,991,435	1,398,801	-	-	8,592,634	
Total	**156,358,432**	**41,185,439**	**778,505**	**108,656,593**	**5,737,895**	

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*
Plant Related - APB 11 Deferred Taxes	(749,142,191)	(66,782,702)		(682,359,489)		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
Plant Related - FAS109 Deferred Taxes	(28,676,767)	(4,014,746)		(24,662,021)		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Subtotal - p275	(777,818,958)	(70,797,448)	-	(707,021,510)	-	
Less FASB 109 Above if not separately removed	(28,676,767)	(4,014,746)	-	(24,662,021)	-	
Less FASB 106 Above if not separately removed	-					
Total	(749,142,191)	(66,782,702)	-	(682,359,489)	-	

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	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod Or Other Distribution Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Blueprint for the Future	(6,373,100)	(6,373,100)				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	(2,012,779)	(2,012,779)				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	(7,468)	(7,468)				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.
Interest on Contingent Taxes	(1,268,490)	(177,589)		(1,090,901)		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. Estimated book interest income on prior year taxes not included for tax purposes.
Materials Reserve	(559,980)	(78,397)			(481,583)	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Merger Costs	(6,569,285)	(6,569,285)				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.
Pension	(89,335,198)	(12,506,928)			(76,828,270)	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. Affects company personnel across all functions.
Property Taxes	(2,422,889)	(339,204)		(2,083,685)		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Unregulated related.
Reacquired Debt	(1,171,979)	(1,171,979)				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.
Reg Asset - DSM	(30,290,749)	(30,290,749)				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.
Reg Asset - FERC Formula Rate Adj.	(1,920,776)		(1,920,776)			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- Other Reg Assets	(65,034,771)	(60,442,409)			(4,592,362)	Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. Represents various costs which we are, or will be through a future rate case, getting recovery through rate base.
Reg Asset - Transmission MAPP	(7,966,628)		(7,966,628)			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- COPCO Acquisition Adjustment	(9,124,912)	(9,124,912)				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.
FAS 109 Deferred Taxes - 283	(20,284,485)	(2,839,828)		(17,444,657)		Gas, Prod or Other Distribution Related portions are identified in the Gas, Prod or Other Distribution Related column. 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.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(244,343,490)	(131,934,628)	(9,887,404)	(20,619,243)	(81,902,215)	
Less FASB 109 Above if not separately removed	(20,284,485)	(2,839,828)	-	(17,444,657)	-	
Less FASB 106 Above if not separately removed	-					
Total	(224,059,005)	(129,094,800)	(9,887,404)	(3,174,586)	(81,902,215)	

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	2014 Activity Amortization	
Rate Base Treatment					
Balance to line 41 of Appendix A	Total		3,565,147	476,426	Post 1980
Amortization					
Amortization to line 133 of Appendix A	Total		635,199	88,888	Pre 1981
Total			4,200,345	565,314	
Total Form No. 1 (p 266 & 267)			4,200,345	565,320	
Difference /1		check	0	(6)	

/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)	18,409,705		
2	Personal property	-		
3	Federal/State Excise	19,923		
4				
5				
6				
Total Plant Related		18,429,628	35.4020%	6,524,461
Labor Related			***Wages & Salary Allocator***	
7	Federal FICA & Unemployment	2,858,435		
8	Unemployment	93,043		
9				
10				
11				
Total Labor Related		2,951,478	7.2267%	213,296
Other Included			***Gross Plant Allocator***	
12	Miscellaneous	-		
13				
14				
Total Other Included		0	35.4020%	0
Total Included		21,381,106		6,737,756
Excluded				
15	State Franchise Tax	7,967,238		
16	Gross Receipts	232,974		
17	Sales and Use	1,423,532		
18	Utility Tax for Delmarva	6,245,291		
19	City License	3,131		
20				
21	Total "Other" Taxes (included on p. 263)	37,253,271		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	37,253,271		
23	Difference	0		

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)		1,793,109
2	Total Rent Revenues	(Sum Line 1)	1,793,109
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 1,476,063
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)		1,487,707
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)		4,425,456
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	9,182,334
12	Less line 17g		(1,259,249)
13	Total Revenue Credits		7,923,085

<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.	1,793,109
17b	Costs associated with revenues in line 17a	725,389
17c	Net Revenues (17a - 17b)	1,067,720
17d	50% Share of Net Revenues (17c / 2)	533,860
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)	533,860
17g	Line 17f less line 17a	(1,259,249)
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.	4,002,874
19	Amount offset in line 4 above	118,809,499
20	Total Account 454, 456 and 456.1	131,994,707
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)	78,696,445
B		100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	630,846,696
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	49,729,877
101	Less LTD Interest on Securitization Bonds			Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	49,729,877
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	1,165,514,531
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)	1,167,692,310
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,173,230,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-11,518,147
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,171,979
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,162,883,832
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,167,692,310
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,330,576,142
117	Debt %	Total Long Term Debt		(Line 113 / 116)	49.90%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	50.10%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0428
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)	0.0213
124	Weighted Cost o	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost o	Common Stock		(Line 119 * 122)	0.0616
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0830**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**52,338,137**

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)	36.2408%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-54,099**
137	**Income Tax Component =**		CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		**26,412,408**
138	**Total Income Taxes**			**(Line 136 + 137)**	**26,358,308**

Delmarva Power & Light Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	35,429,777	16,730,843	18,698,934	See Form 1
11	Accumulated Common Amortization - Electric	(Note A)	p356	17,457,635	14,756,945	2,700,690	See Form 1
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	60,060,313	50,295,314	9,764,999	See Form 1
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	101,362,459	82,032,638	19,329,821	See Form 1
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	4,200,345	3,805,532	394,813	See Form 1
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,380,425	1,337,066	43,359	96.859% Electric, 3.141% 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	3,347,736	3,347,736	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

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	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:
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	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	3,192,265,902	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Servie without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	1,106,861,017	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	82,032,638	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	315,157,898	0	0	See Form 1

EPRI Dues Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	135,782	135,782	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	5,526,205	507,890	5,018,315	FERC Form 1 page 351 lines 7 (h) and 8 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	5,526,205	507,890	5,018,315	FERC Form 1 page 351 lines 7 (h) and 8 (h)

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	54,489	0	54,489	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	54,489	0	54,489	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	35,461,746	7.227%	2,562,728	
Plant Related	1,959,269	35.402%	693,621	
Other		0.00%	-	
Total Transmission Related Reserves	37,421,015		3,256,349	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Allocator	To Line 45	Description of the Prepayments
45 Prepayments					
Pension Liabilities, if any, in Account 242		-	6.070%	-	
Prepayments	$	12,179,032	6.070%	739,323	
Prepaid Pensions if not included in Prepayments	$	220,226,332	6.070%	13,368,753	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
		232,405,364	6.07%	14,108,076	
5 Wages & Salary Allocator		7.227%			
Electric vs Gas		84%	Based on Modified Wisconsin Method		
Modified Wages & Salaries Allocator		6.070%			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	3,875.0	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

Supporting documentation for FERC Form 1 reconciliation

Compliance with FERC Order on the Exelon Merger					
Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Merger Costs	Non Merger Related
60	Transmission O&M	p321.112.b	13,511,928	1,408	13,510,520
68	Total A&G	p323.197.b	64,649,616	1,246,085	63,403,531

ARO Exclusion - Cost Support			Form 1 Amount	ARO's	Non-ARO's
Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	ARO's	Non-ARO's
6	Electric Plant in Service	p207.104g	3,192,265,902	147,988	3,192,117,914
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	887,299,590	78,617	887,220,973
23	General & Intangible	p205.5.g & p207.99.g	157,253,227	147,988	157,105,239
31	Accumulated General Depreciation	p219.28.c	36,655,765	78,617	36,577,148

Delmarva Power & Light Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 13,882,162	$ 11,785,623	$ 24,382,713	$ 5,667,656	$ 55,718,155
Procurement & Administrative Services	7,001,366	4,598,470	10,475,398	343,584	22,418,818
Financial Services & Corporate Expenses	13,502,547	10,768,241	20,331,591	2,392,152	46,994,531
Insurance Coverage and Services	2,519,625	2,187,093	3,305,370	887,190	8,899,278
Human Resources	3,653,925	2,428,050	5,847,877	1,046,090	12,975,941
Legal Services	2,651,005	2,242,024	6,008,665	1,200,772	12,102,467
Audit Services	980,075	750,029	1,750,164	234,556	3,714,825
Customer Services	50,507,172	38,945,027	33,693,424	59,420	123,205,044
Utility Communication Services	56,240	-	87,358	-	143,598
Information Technology	15,350,317	11,421,231	34,068,152	334,163	61,173,863
External Affairs	3,329,577	2,605,534	5,487,511	670,032	12,092,654
Environmental Services	1,774,836	1,370,486	1,976,135	117,173	5,238,631
Safety Services	380,152	421,829	615,823	-	1,417,804
Regulated Electric & Gas T&D	33,672,104	25,702,737	45,555,831	330,416	105,261,089
Internal Consulting Services	699,514	376,268	1,019,829	1,904	2,097,515
Interns	208,653	118,776	144,867	180	472,476
Cost of Benefits	12,791,136	7,921,448	21,384,267	1,993,351	44,090,202
Building Services	4,513	110,543	4,224,537	-	4,339,592
Total	**$ 162,964,920**	**$ 123,753,411**	**$ 220,359,512**	**$ 15,278,638**	**$ 522,356,481**

Name of Respondent PHI Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2014

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	57,214,714	162,918,093	226,705	220,359,512
2	Delmarva Power & Light Company	39,247,411	123,549,735	167,774	162,964,920
3	Atlantic City Electric Company	24,854,235	98,773,234	125,942	123,753,411
4	Pepco Energy Services, Inc.	2,653,237	5,856,129	9,444	8,518,810
5	Conectiv, LLC	3,919	46,852	59	50,830
6	Potomac Capital Investment Corporation	146,353	120,086	661	267,100
7	Thermal Energy Limited Partnership	16,405	723,744	728	740,877
8	ATS Operating Services, Inc.	106	322,506	331	322,943
9	Atlantic Southern Properties, Inc.	7,201	184,696	197	192,094
10	Conectiv Energy Supply, Inc.	20,415	8,175	36	28,626
11	Pepco Holdings, Inc.	4,226,510	595,934	1,568	4,824,012
12	Conectiv Properties and Investments, Inc.	694	156,517	166	157,377
13	Conectiv Thermal Systems, Inc.	4,666	108,488	117	113,271
14	Conectiv Communications, Inc.	53	10,556	10	10,619
15	Atlantic City Electric Transition Funding LLC	31,698	5,736	35	37,469
16	Conectiv North East, LLC	253	4,677	5	4,935
17	Delaware Operating Services Company, LLC	177	118	8	303
18	ATE Investment, Inc.	773	1,097	3	1,873
19	Atlantic Generation, Inc.	80	13	1	94
20	Conectiv Services II, Inc.	33	7,227	7	7,267
21	Conectiv Solutions LLC	136	2		138
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	128,429,069	393,393,615	533,797	522,356,481

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2014
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	25,452,371	16,528,974	35,163,211	-	77,144,556	Not Included
182.3	Other Regulatory Assets	7,284,203	200,422	10,839,283	-	18,323,908	Not Included
184	Clearing Accounts - Other	(4,608)	(24,809)	126,528	(66,205)	30,906	Not Included
408.1	Taxes other than inc taxes, utility operating inc	1,811	15,040	1,849	-	18,699	Not Included
416-421	Other Income -Below the Line	266,750	465,608	570,194	15,344,844	16,647,396	Not Included
426.1-426.5	Other Income Deductions - Below the Line	3,271,318	2,695,830	5,494,225	-	11,461,373	Not Included
430	Interest-Debt to Associated Companies	346,840	260,349	468,738	-	1,075,927	Not Included
431	Interest-Short Term Debt	(179,066)	(134,408)	(242,033)	-	(555,506)	Not Included
556	System cont & load dispatch	2,177,755	1,891,923	1,705,407	-	5,775,084	Not Included
557	Other expenses	1,173,401	1,130,377	1,461,250	-	3,765,028	Not Included
560	Operation Supervision & Engineering	2,417,695	2,277,855	3,665,108	-	8,360,658	100% Included
561	Load dispatching	-	11	-	-	11	100% Included
561.1	Load Dispatching - Reliability	13,206	11,642	-	-	24,847	100% Included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	69,383	23,030	1,008,010	-	1,100,423	100% Included
561.3	Load Dispatch - Transmission Service & Scheduling	39,057	34,330	28,667	-	102,053	100% Included
561.5	Reliability, Planning and Standards	257,243	232,961	132,446	-	622,650	100% Included
563	Overhead line expenses			345	-	345	100% Included
562	Station expenses	-	-	8,533	-	8,533	100% Included
564	Underground Line Expenses - Transmission	-	-	6,641	-	6,641	100% Included
566	Miscellaneous transmission expenses	412,227	313,802	334,811	-	1,060,840	100% Included
568	Maintenance Supervision & Engineering	158,431	130,076	258,084	-	546,591	100% Included
569	Maint of structures	-	-	-	-	-	100% Included
569.2	Maintenance of Computer Software	571,924	291,641	454,366	-	1,317,931	100% Included
569.4	Maintenance of Transmission Plant	-	-	940	-	940	100% Included
570	Maintenance of station equipment	156,492	86,339	378,208	-	621,039	100% Included
571	Maintenance of overhead lines	146,461	170,076	249,124	-	565,660	100% Included
572	Maintenance of underground lines	35	272	9,974	-	10,281	100% Included
573	Maintenance of miscellaneous transmission plant	26,096	33,049	155,743	-	214,887	100% Included
580	Operation Supervision & Engineering	730,625	350,609	623,416	-	1,704,650	Not Included
581	Load dispatching	838,385	546,354	1,547,494	-	2,932,233	Not Included
582	Station expenses	837,194	-	115,333	-	952,527	Not Included
583	Overhead line expenses	77,312	125,967	29,852	-	233,131	Not Included
584	Underground line expenses	23,803	-	282,831	-	306,634	Not Included
585	Street lighting	11,177	-	41	-	11,218	Not Included
586	Meter expenses	786,669	575,817	1,622,146	-	2,984,632	Not Included
587	Customer installations expenses	69,822	341,159	487,591	-	898,572	Not Included
588	Miscellaneous distribution expenses	4,998,231	5,390,134	8,479,619	-	18,867,983	Not Included
589	Rents	30,570	6,315	20,959	-	57,844	Not Included
590	Maintenance Supervision & Engineering	865,163	720,247	338,570	-	1,923,980	Not Included
591	Maintain structures	-	-	1,937	-	1,937	Not Included
592	Maintain equipment	535,979	522,925	975,362	-	2,034,266	Not Included
593	Maintain overhead lines	1,107,894	653,471	1,798,778	-	3,560,142	Not Included
594	Maintain underground line	97,908	64,967	692,235	-	855,111	Not Included
595	Maintain line transformers	67	1,811	220,800	-	222,677	Not Included
596	Maintain street lighting & signal systems	44,641	37,249	8,246	-	90,136	Not Included
597	Maintain meters	27,120	31,452	41,070	-	99,642	Not Included
598	Maintain distribution plant	61,416	18,767	854,752	-	934,935	Not Included
800-894	Total Gas Accounts	2,210,101	-	-	-	2,210,101	Not Included
902	Meter reading expenses	188,544	49,162	49,142	-	286,847	Not Included
903	Customer records and collection expenses	41,899,731	39,033,339	33,166,986	-	114,100,056	Not Included
907	Supervision - Customer Svc & Information	82,458	10,418	108,745	-	201,620	Not Included
908	Customer assistance expenses	2,073,545	590,689	903,301	-	3,567,535	Not Included
909	Informational & instructional advertising	66,371	19,518	64,417	-	150,306	Not Included
912	Demonstrating and selling expense	7,962			-	7,962	Not Included
913	Advertising expense	30,520	-	-	-	30,520	Not Included
920	Administrative & General salaries	325,663	95,547	645,155	-	1,066,365	Wage & Salary Factor
921	Office supplies & expenses	14,314	12,513	24,279	-	51,106	Wage & Salary Factor
923	Outside services employed	48,702,231	40,630,932	84,352,816	-	173,685,978	Wage & Salary Factor
924	Property insurance	2,246	1,684	3,080	-	7,010	Net Plant Factor
925	Injuries & damages	2,046,510	1,624,059	3,293,661	-	6,964,230	Wage & Salary Factor
926	Employee pensions & benefits	6,990,629	3,656,906	11,806,837	-	22,454,372	Wage & Salary Factor
928	Regulatory commission expenses	1,280,938	532,794	1,787,129	-	3,600,860	Direct Transmission Only
929	Duplicate charges-Credit	240,484	131,613	1,078,264	-	1,450,360	Wage & Salary Factor
930.1	General ad expenses	273	-	13,789	-	14,062	Direct Transmission Only
930.2	Miscellaneous general expenses	1,268,142	1,121,501	2,354,056	-	4,743,699	Wage & Salary Factor
931	Rents	0	-	1	-	1	Wage & Salary Factor
935	Maintenance of general plant	331,262	221,104	287,172	-	839,538	Wage & Salary Factor
	Total	**162,964,920**	**123,753,411**	**220,359,512**	**15,278,638**	**522,356,481**	

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)

118,062,101 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	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)										29,145,949	-	-	-	
								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!	

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

$ 29,145,949 Input to Formula Line 21

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

121,126,876 — 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)

$ 121,126,876

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

128,137,506 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 $ 134,192,122 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	4,829,617				11.5	55,540,597	-	-	-	4,628,383	-	-	-	
Feb	2,515,124				10.5	26,408,800	-	-	-	2,200,733	-	-	-	
Mar	18,096,749				9.5	171,919,120	-	-	-	14,326,593	-	-	-	
Apr	18,907,684				8.5	160,715,317	-	-	-	13,392,943	-	-	-	
May	15,707,479				7.5	117,806,095	-	-	-	9,817,175	-	-	-	
Jun	2,139,364				6.5	13,905,867	-	-	-	1,158,822	-	-	-	
Jul	3,416,990				5.5	18,793,444	-	-	-	1,566,120	-	-	-	
Aug	1,538,848				4.5	6,924,815	-	-	-	577,068	-	-	-	
Sep	13,839,065				3.5	48,436,729	-	-	-	4,036,394	-	-	-	
Oct	701,537				2.5	1,753,842	-	-	-	146,153	-	-	-	
Nov	6,467,261				1.5	9,700,891	-	-	-	808,408	-	-	-	
Dec	46,032,403				0.5	23,016,202	-	-	-	1,918,017	-	-	-	
Total	134,192,122	-	-	-		654,921,717	-	-	-	54,576,810	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										54,576,810	-	-	-	
								Input to Line 21 of Appendix A		54,576,810	-		-	54,576,810
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		7.12	#DIV/0!	#DIV/0!	#DIV/0!	

120,063,737 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	55,956,082				7.5	419,670,618	-	-	-	34,972,552	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec	-				0.5	-	-	-	-	-	-	-	-	
Total	55,956,082	-	-	-		419,670,618	-	-	-	34,972,552	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		34,972,552	-	-	-	
129,215,514								Input to Line 21 of Appendix A		34,972,552	-		-	34,972,552
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		4.50	#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		
120,063,737	-	117,338,718	=	2,725,019

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	227,085	0.2800%	11.5	7,312	234,397
Jul	Year 1	227,085	0.2800%	10.5	6,676	233,761
Aug	Year 1	227,085	0.2800%	9.5	6,040	233,125
Sep	Year 1	227,085	0.2800%	8.5	5,405	232,490
Oct	Year 1	227,085	0.2800%	7.5	4,769	231,854
Nov	Year 1	227,085	0.2800%	6.5	4,133	231,218
Dec	Year 1	227,085	0.2800%	5.5	3,497	230,582
Jan	Year 2	227,085	0.2800%	4.5	2,861	229,946
Feb	Year 2	227,085	0.2800%	3.5	2,225	229,310
Mar	Year 2	227,085	0.2800%	2.5	1,590	228,675
Apr	Year 2	227,085	0.2800%	1.5	954	228,039
May	Year 2	227,085	0.2800%	0.5	318	227,403
Total		2,725,019				2,770,799

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	2,770,799	0.2800%	235,124	2,543,434
Jul	Year 2	2,543,434	0.2800%	235,124	2,315,431
Aug	Year 2	2,315,431	0.2800%	235,124	2,086,791
Sep	Year 2	2,086,791	0.2800%	235,124	1,857,510
Oct	Year 2	1,857,510	0.2800%	235,124	1,627,587
Nov	Year 2	1,627,587	0.2800%	235,124	1,397,020
Dec	Year 2	1,397,020	0.2800%	235,124	1,165,808
Jan	Year 3	1,165,808	0.2800%	235,124	933,949
Feb	Year 3	933,949	0.2800%	235,124	701,440
Mar	Year 3	701,440	0.2800%	235,124	468,280
Apr	Year 3	468,280	0.2800%	235,124	234,467
May	Year 3	234,467	0.2800%	235,124	-
Total with interest				2,821,486	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		2,821,486
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	129,215,514
Revenue Requirement for Year 3		132,037,000

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

$ 132,037,000 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)

$ 132,037,000

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	11.461%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	12.132%
6	C		Line B less Line A	0.6705%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.1915%

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 for specif**

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		11.4611%	11.4611%	11.4611%	11.4611%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		12.4668%	12.4668%	12.4668%	12.4668%
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	B0241.3 Beginning	B0241.3 Depreciation	B0241.3 Ending	B0241.3 Revenue	B0494.1-4 Beginning	B0494.1-4 Depreciation	B0494.1-4 Ending	B0494.1-4 Revenue
35	Base FCR	2015	12,380,814	419,689	11,961,125	1,790,571	2,612,102	88,546	2,523,556	377,774
36	W Increased ROE	2015	12,380,814	419,689	11,961,125	1,910,864	2,612,102	88,546	2,523,556	403,154
37	Base FCR	2016	11,961,125	419,689	11,541,437	1,742,470	2,523,556	88,546	2,435,010	367,626
38	W Increased ROE	2016	11,961,125	419,689	11,541,437	1,858,542	2,523,556	88,546	2,435,010	392,115
39	Base FCR	2017	11,541,437	419,689	11,121,748	1,694,369	2,435,010	88,546	2,346,464	357,478
40	W Increased ROE	2017	11,541,437	419,689	11,121,748	1,806,220	2,435,010	88,546	2,346,464	381,076
41	Base FCR	2018	11,121,748	419,689	10,702,059	1,646,268	2,346,464	88,546	2,257,919	347,329
42	W Increased ROE	2018	11,121,748	419,689	10,702,059	1,753,898	2,346,464	88,546	2,257,919	370,037
43	Base FCR	2019	10,702,059	419,689	10,282,371	1,598,166	2,257,919	88,546	2,169,373	337,181
44	W Increased ROE	2019	10,702,059	419,689	10,282,371	1,701,576	2,257,919	88,546	2,169,373	358,998
45	Base FCR	2020	10,282,371	419,689	9,862,682	1,550,065	2,169,373	88,546	2,080,827	327,033
46	W Increased ROE	2020	10,282,371	419,689	9,862,682	1,649,254	2,169,373	88,546	2,080,827	347,959
47	Base FCR	2021	9,862,682	419,689	9,442,994	1,501,964	2,080,827	88,546	1,992,281	316,884
48	W Increased ROE	2021	9,862,682	419,689	9,442,994	1,596,932	2,080,827	88,546	1,992,281	336,920
49	Base FCR	2022	9,442,994	419,689	9,023,305	1,453,863	1,992,281	88,546	1,903,735	306,736
50	W Increased ROE	2022	9,442,994	419,689	9,023,305	1,544,610	1,992,281	88,546	1,903,735	325,882
51	Base FCR	2023	9,023,305	419,689	8,603,616	1,405,762	1,903,735	88,546	1,815,189	296,587
52	W Increased ROE	2023	9,023,305	419,689	8,603,616	1,492,288	1,903,735	88,546	1,815,189	314,843
53	Base FCR	2024	8,603,616	419,689	8,183,928	1,357,661	1,815,189	88,546	1,726,644	286,439
54	W Increased ROE	2024	8,603,616	419,689	8,183,928	1,439,966	1,815,189	88,546	1,726,644	303,804
55	Base FCR	2025	8,183,928	419,689	7,764,239	1,309,560	1,726,644	88,546	1,638,098	276,291
56	W Increased ROE	2025	8,183,928	419,689	7,764,239	1,387,644	1,726,644	88,546	1,638,098	292,765
57	Base FCR	2026	7,764,239	419,689	7,344,551	1,261,458	1,638,098	88,546	1,549,552	266,142
58	W Increased ROE	2026	7,764,239	419,689	7,344,551	1,335,322	1,638,098	88,546	1,549,552	281,726
59	Base FCR	2027	7,344,551	419,689	6,924,862	1,213,357	1,549,552	88,546	1,461,006	255,994
60	W Increased ROE	2027	7,344,551	419,689	6,924,862	1,283,001	1,549,552	88,546	1,461,006	270,687
61		....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

Line		Invest Yr	B0241.1-.2 Beginning	B0241.1-.2 Depreciation	B0241.1-.2 Ending	B0241.1-.2 Revenue	B0567 Beginning	B0567 Depreciation	B0567 Ending	B0567 Revenue
35	Base FCR	2015	2,038,633	69,106	1,969,527	294,837	5,589,973	183,278	5,406,695	802,947
36	W Increased ROE	2015	2,038,633	69,106	1,969,527	314,644	5,589,973	183,278	5,406,695	857,322
37	Base FCR	2016	1,969,527	69,106	1,900,421	286,916	5,406,695	183,278	5,223,417	781,941
38	W Increased ROE	2016	1,969,527	69,106	1,900,421	306,029	5,406,695	183,278	5,223,417	834,473
39	Base FCR	2017	1,900,421	69,106	1,831,314	278,996	5,223,417	183,278	5,040,140	760,936
40	W Increased ROE	2017	1,900,421	69,106	1,831,314	297,413	5,223,417	183,278	5,040,140	811,624
41	Base FCR	2018	1,831,314	69,106	1,762,208	271,076	5,040,140	183,278	4,856,862	739,930
42	W Increased ROE	2018	1,831,314	69,106	1,762,208	288,798	5,040,140	183,278	4,856,862	788,775
43	Base FCR	2019	1,762,208	69,106	1,693,102	263,155	4,856,862	183,278	4,673,584	718,924
44	W Increased ROE	2019	1,762,208	69,106	1,693,102	280,183	4,856,862	183,278	4,673,584	765,926
45	Base FCR	2020	1,693,102	69,106	1,623,996	255,235	4,673,584	183,278	4,490,306	697,918
46	W Increased ROE	2020	1,693,102	69,106	1,623,996	271,567	4,673,584	183,278	4,490,306	743,077
47	Base FCR	2021	1,623,996	69,106	1,554,890	247,314	4,490,306	183,278	4,307,028	676,913
48	W Increased ROE	2021	1,623,996	69,106	1,554,890	262,952	4,490,306	183,278	4,307,028	720,228
49	Base FCR	2022	1,554,890	69,106	1,485,783	239,394	4,307,028	183,278	4,123,751	655,907
50	W Increased ROE	2022	1,554,890	69,106	1,485,783	254,337	4,307,028	183,278	4,123,751	697,379
51	Base FCR	2023	1,485,783	69,106	1,416,677	231,474	4,123,751	183,278	3,940,473	634,901
52	W Increased ROE	2023	1,485,783	69,106	1,416,677	245,721	4,123,751	183,278	3,940,473	674,530
53	Base FCR	2024	1,416,677	69,106	1,347,571	223,553	3,940,473	183,278	3,757,195	613,896
54	W Increased ROE	2024	1,416,677	69,106	1,347,571	237,106	3,940,473	183,278	3,757,195	651,682
55	Base FCR	2025	1,347,571	69,106	1,278,465	215,633	3,757,195	183,278	3,573,917	592,890
56	W Increased ROE	2025	1,347,571	69,106	1,278,465	228,490	3,757,195	183,278	3,573,917	628,833
57	Base FCR	2026	1,278,465	69,106	1,209,359	207,713	3,573,917	183,278	3,390,639	571,884
58	W Increased ROE	2026	1,278,465	69,106	1,209,359	219,875	3,573,917	183,278	3,390,639	605,984
59	Base FCR	2027	1,209,359	69,106	1,140,252	199,792	3,390,639	183,278	3,207,362	550,878
60	W Increased ROE	2027	1,209,359	69,106	1,140,252	211,260	3,390,639	183,278	3,207,362	583,135
61		....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

ic 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 FERC to become effective June 1, 2008 and November 1, 2008 respectively.

	B0483.1-.3 Oak Hall-Wattsville	B0320 Cool Springs	BO568 3rd Indian River	BO272.1 Keeney 500kV Sub	BO751 Keeney - Additional Breakers on 500kV Bus
	No	No	No	Yes	Yes
	35	35	35	35	35
	No	No	No	No	No
	150	150	150	0	0
	11.4611%	11.4611%	11.4611%	11.4611%	11.4611%
	12.4668%	12.4668%	12.4668%	11.4611%	11.4611%
	8,379,558	14,504,530	6,681,345	217,662	5,055,041
	239,416	414,415	190,896	6,219	144,430
	12	9	8	6	6

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
7,421,894	239,416	7,182,478	1,062,610	12,743,266	414,415	12,328,851	1,827,443	6,045,026	190,896	5,854,131	861,846	202,115	6,219	195,896	28,671	4,693,967	144,430	4,549,537	665,859
7,421,894	239,416	7,182,478	1,134,844	12,743,266	414,415	12,328,851	1,951,434	6,045,026	190,896	5,854,131	920,721	202,115	6,219	195,896	28,671	4,693,967	144,430	4,549,537	665,859
7,182,478	239,416	6,943,062	1,035,171	12,328,851	414,415	11,914,435	1,779,946	5,854,131	190,896	5,663,235	839,967	195,896	6,219	189,677	27,958	4,549,537	144,430	4,405,107	649,306
7,182,478	239,416	6,943,062	1,104,997	12,328,851	414,415	11,914,435	1,899,770	5,854,131	190,896	5,663,235	896,922	195,896	6,219	189,677	27,958	4,549,537	144,430	4,405,107	649,306
6,943,062	239,416	6,703,646	1,007,731	11,914,435	414,415	11,500,020	1,732,450	5,663,235	190,896	5,472,340	818,089	189,677	6,219	183,458	27,245	4,405,107	144,430	4,260,677	632,752
6,943,062	239,416	6,703,646	1,075,149	11,914,435	414,415	11,500,020	1,848,105	5,663,235	190,896	5,472,340	873,124	189,677	6,219	183,458	27,245	4,405,107	144,430	4,260,677	632,752
6,703,646	239,416	6,464,230	980,291	11,500,020	414,415	11,085,605	1,684,953	5,472,340	190,896	5,281,444	796,210	183,458	6,219	177,239	26,533	4,260,677	144,430	4,116,248	616,199
6,703,646	239,416	6,464,230	1,045,302	11,500,020	414,415	11,085,605	1,796,441	5,472,340	190,896	5,281,444	849,325	183,458	6,219	177,239	26,533	4,260,677	144,430	4,116,248	616,199
6,464,230	239,416	6,224,815	952,851	11,085,605	414,415	10,671,190	1,637,456	5,281,444	190,896	5,090,549	774,331	177,239	6,219	171,020	25,820	4,116,248	144,430	3,971,818	599,646
6,464,230	239,416	6,224,815	1,015,454	11,085,605	414,415	10,671,190	1,744,776	5,281,444	190,896	5,090,549	825,526	177,239	6,219	171,020	25,820	4,116,248	144,430	3,971,818	599,646
6,224,815	239,416	5,985,399	925,411	10,671,190	414,415	10,256,775	1,589,959	5,090,549	190,896	4,899,653	752,452	171,020	6,219	164,801	25,107	3,971,818	144,430	3,827,388	583,092
6,224,815	239,416	5,985,399	985,606	10,671,190	414,415	10,256,775	1,693,112	5,090,549	190,896	4,899,653	801,728	171,020	6,219	164,801	25,107	3,971,818	144,430	3,827,388	583,092
5,985,399	239,416	5,745,983	897,972	10,256,775	414,415	9,842,360	1,542,463	4,899,653	190,896	4,708,757	730,573	164,801	6,219	158,582	24,394	3,827,388	144,430	3,682,958	566,539
5,985,399	239,416	5,745,983	955,759	10,256,775	414,415	9,842,360	1,641,447	4,899,653	190,896	4,708,757	777,929	164,801	6,219	158,582	24,394	3,827,388	144,430	3,682,958	566,539
5,745,983	239,416	5,506,567	870,532	9,842,360	414,415	9,427,944	1,494,966	4,708,757	190,896	4,517,862	708,694	158,582	6,219	152,363	23,682	3,682,958	144,430	3,538,529	549,986
5,745,983	239,416	5,506,567	925,911	9,842,360	414,415	9,427,944	1,589,783	4,708,757	190,896	4,517,862	754,130	158,582	6,219	152,363	23,682	3,682,958	144,430	3,538,529	549,986
5,506,567	239,416	5,267,151	843,092	9,427,944	414,415	9,013,529	1,447,469	4,517,862	190,896	4,326,966	686,816	152,363	6,219	146,144	22,969	3,538,529	144,430	3,394,099	533,432
5,506,567	239,416	5,267,151	896,064	9,427,944	414,415	9,013,529	1,538,118	4,517,862	190,896	4,326,966	730,332	152,363	6,219	146,144	22,969	3,538,529	144,430	3,394,099	533,432
5,267,151	239,416	5,027,735	815,652	9,013,529	414,415	8,599,114	1,399,972	4,326,966	190,896	4,136,071	664,937	146,144	6,219	139,926	22,256	3,394,099	144,430	3,249,669	516,879
5,267,151	239,416	5,027,735	866,216	9,013,529	414,415	8,599,114	1,486,454	4,326,966	190,896	4,136,071	706,533	146,144	6,219	139,926	22,256	3,394,099	144,430	3,249,669	516,879
5,027,735	239,416	4,788,319	788,212	8,599,114	414,415	8,184,699	1,352,476	4,136,071	190,896	3,945,175	643,058	139,926	6,219	133,707	21,543	3,249,669	144,430	3,105,239	500,326
5,027,735	239,416	4,788,319	836,368	8,599,114	414,415	8,184,699	1,434,789	4,136,071	190,896	3,945,175	682,735	139,926	6,219	133,707	21,543	3,249,669	144,430	3,105,239	500,326
4,788,319	239,416	4,548,903	760,772	8,184,699	414,415	7,770,284	1,304,979	3,945,175	190,896	3,754,280	621,179	133,707	6,219	127,488	20,830	3,105,239	144,430	2,960,810	483,773
4,788,319	239,416	4,548,903	806,521	8,184,699	414,415	7,770,284	1,383,125	3,945,175	190,896	3,754,280	658,936	133,707	6,219	127,488	20,830	3,105,239	144,430	2,960,810	483,773
4,548,903	239,416	4,309,487	733,333	7,770,284	414,415	7,355,869	1,257,482	3,754,280	190,896	3,563,384	599,300	127,488	6,219	121,269	20,118	2,960,810	144,430	2,816,380	467,219
4,548,903	239,416	4,309,487	776,673	7,770,284	414,415	7,355,869	1,331,460	3,754,280	190,896	3,563,384	635,137	127,488	6,219	121,269	20,118	2,960,810	144,430	2,816,380	467,219
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

BO566 Trappe Tap - Todd				BO733 Harmony Add 2nd 230/138 Auto Tr				B1247 Glasgow - Cecil 138 kV Circuit Rebuild						
No				No				No						
35				35				35						
No				No				No						
150				0				0						
11.4611%				11.4611%				11.4611%						
12.4668%				11.4611%				11.4611%						
16,372,433				10,567,349				6,694,564						
467,784				301,924				191,273						
12				4				5						
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
15,436,865	467,784	14,969,082	2,183,413	10,064,142	301,924	9,762,218	1,420,787	6,694,564	111,576	6,582,988	614,567	$ 11,931,325		$ 11,931,325
15,436,865	467,784	14,969,082	2,333,956	10,064,142	301,924	9,762,218	1,420,787	6,694,564	111,576	6,582,988	614,567	$ 12,556,823	$ 12,556,823	
14,969,082	467,784	14,501,298	2,129,799	9,762,218	301,924	9,460,293	1,386,183	6,582,988	191,273	6,391,715	923,837	$ 11,027,284		$ 11,027,284
14,969,082	467,784	14,501,298	2,275,638	9,762,218	301,924	9,460,293	1,386,183	6,582,988	191,273	6,391,715	923,837	$ 11,631,932	$ 11,631,932	
14,501,298	467,784	14,033,514	2,076,186	9,460,293	301,924	9,158,369	1,351,579	6,391,715	191,273	6,200,442	901,915	$ 10,737,809		$ 10,737,809
14,501,298	467,784	14,033,514	2,217,320	9,460,293	301,924	9,158,369	1,351,579	6,391,715	191,273	6,200,442	901,915	$ 11,321,608	$ 11,321,608	
14,033,514	467,784	13,565,730	2,022,572	9,158,369	301,924	8,856,445	1,316,975	6,200,442	191,273	6,009,169	879,993	$ 10,448,335		$ 10,448,335
14,033,514	467,784	13,565,730	2,159,003	9,158,369	301,924	8,856,445	1,316,975	6,200,442	191,273	6,009,169	879,993	$ 11,011,284	$ 11,011,284	
13,565,730	467,784	13,097,946	1,968,959	8,856,445	301,924	8,554,521	1,282,371	6,009,169	191,273	5,817,895	858,071	$ 10,158,860		$ 10,158,860
13,565,730	467,784	13,097,946	2,100,685	8,856,445	301,924	8,554,521	1,282,371	6,009,169	191,273	5,817,895	858,071	$ 10,700,960	$ 10,700,960	
13,097,946	467,784	12,630,163	1,915,346	8,554,521	301,924	8,252,596	1,247,767	5,817,895	191,273	5,626,622	836,149	$ 9,869,386		$ 9,869,386
13,097,946	467,784	12,630,163	2,042,367	8,554,521	301,924	8,252,596	1,247,767	5,817,895	191,273	5,626,622	836,149	$ 10,390,637	$ 10,390,637	
12,630,163	467,784	12,162,379	1,861,732	8,252,596	301,924	7,950,672	1,213,163	5,626,622	191,273	5,435,349	814,227	$ 9,579,911		$ 9,579,911
12,630,163	467,784	12,162,379	1,984,049	8,252,596	301,924	7,950,672	1,213,163	5,626,622	191,273	5,435,349	814,227	$ 10,080,313	$ 10,080,313	
12,162,379	467,784	11,694,595	1,808,119	7,950,672	301,924	7,648,748	1,178,559	5,435,349	191,273	5,244,075	792,305	$ 9,290,437		$ 9,290,437
12,162,379	467,784	11,694,595	1,925,731	7,950,672	301,924	7,648,748	1,178,559	5,435,349	191,273	5,244,075	792,305	$ 9,769,989	$ 9,769,989	
11,694,595	467,784	11,226,811	1,754,505	7,648,748	301,924	7,346,824	1,143,955	5,244,075	191,273	5,052,802	770,382	$ 9,000,962		$ 9,000,962
11,694,595	467,784	11,226,811	1,867,413	7,648,748	301,924	7,346,824	1,143,955	5,244,075	191,273	5,052,802	770,382	$ 9,459,665	$ 9,459,665	
11,226,811	467,784	10,759,027	1,700,892	7,346,824	301,924	7,044,899	1,109,351	5,052,802	191,273	4,861,529	748,460	$ 8,711,488		$ 8,711,488
11,226,811	467,784	10,759,027	1,809,095	7,346,824	301,924	7,044,899	1,109,351	5,052,802	191,273	4,861,529	748,460	$ 9,149,341	$ 9,149,341	
10,759,027	467,784	10,291,244	1,647,279	7,044,899	301,924	6,742,975	1,074,747	4,861,529	191,273	4,670,256	726,538	$ 8,422,013		$ 8,422,013
10,759,027	467,784	10,291,244	1,750,777	7,044,899	301,924	6,742,975	1,074,747	4,861,529	191,273	4,670,256	726,538	$ 8,839,017	$ 8,839,017	
10,291,244	467,784	9,823,460	1,593,665	6,742,975	301,924	6,441,051	1,040,143	4,670,256	191,273	4,478,982	704,616	$ 8,132,539		$ 8,132,539
10,291,244	467,784	9,823,460	1,692,459	6,742,975	301,924	6,441,051	1,040,143	4,670,256	191,273	4,478,982	704,616	$ 8,528,693	$ 8,528,693	
9,823,460	467,784	9,355,676	1,540,052	6,441,051	301,924	6,139,127	1,005,539	4,478,982	191,273	4,287,709	682,694	$ 7,843,065		$ 7,843,065
9,823,460	467,784	9,355,676	1,634,142	6,441,051	301,924	6,139,127	1,005,539	4,478,982	191,273	4,287,709	682,694	$ 8,218,370	$ 8,218,370	
....	....	.....	....	....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....		$ -	
													$ 231,782,679	$ 222,200,267

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

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

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May 15, 2015

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 2015 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 2015 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,

[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 2015 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

[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

Line	Description	Notes	FERC Form 1 Page # or Instruction	2014
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 2,239,982
2	Total Wages Expense		p354.28b	$ 27,471,315
3	Less A&G Wages Expense		p354.27b	$ 1,047,152
4	Total		(Line 2 - 3)	26,424,163
5	Wages & Salary Allocator		(Line 1 / 4)	8.4770%
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g (see Attachment 5)	$ 2,928,413,842
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	2,928,413,842
9	Accumulated Depreciation (Total Electric Plant)		p219.29c (see Attachment 5)	$ 739,384,650
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 16,702,099
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)	756,086,749
14	Net Plant		(Line 8 - 13)	2,172,327,093
15	Transmission Gross Plant		(Line 29 - Line 28)	877,312,310
16	Gross Plant Allocator		(Line 15 / 8)	29.9586%
17	Transmission Net Plant		(Line 39 - Line 28)	647,462,905
18	Net Plant Allocator		(Line 17 / 14)	29.8050%
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 838,506,779
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	26,153,337
22	Total Transmission Plant In Service		(Line 19 - 20 + 21)	864,660,116
23	General & Intangible		p205.5.g & p207.99.g (see Attachment 5)	$ 149,252,824
24	Common Plant (Electric Only)	(Notes A & B)	p356	$ -
25	Total General & Common		(Line 23 + 24)	149,252,824
26	Wage & Salary Allocation Factor		(Line 5)	8.47702%
27	General & Common Plant Allocated to Transmission		(Line 25 * 26)	12,652,194
28	Plant Held for Future Use (Including Land)	(Note C)	p214	782,029
29	TOTAL Plant In Service		(Line 22 + 27 + 28)	878,094,339
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 223,585,359
31	Accumulated General Depreciation		p219.28.c (see Attachment 5)	$ 57,192,317
32	Accumulated Intangible Amortization		(Line 10)	16,702,099
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)	73,894,416
36	Wage & Salary Allocation Factor		(Line 5)	8.47702%
37	General & Common Allocated to Transmission		(Line 35 * 36)	6,264,046
38	TOTAL Accumulated Depreciation		(Line 30 + 37)	229,849,405
39	TOTAL Net Property, Plant & Equipment		(Line 29 - 38)	648,244,934
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-181,596,841
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	29.81%
43	Accumulated Deferred Income Taxes Allocated To Transmission		(Line 41 * 42) + Line 40	-181,596,841
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	-2,470,750
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	8,392,275
46	Total Prepayments Allocated to Transmission		(Line 45)	8,392,275
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,260,277
48	Wage & Salary Allocation Factor		(Line 5)	8.48%
49	Total Transmission Allocated		(Line 47 * 48)	106,834
50	Transmission Materials & Supplies		p227.8c	$ 1,751,752
51	Total Materials & Supplies Allocated to Transmission		(Line 49 + 50)	1,858,586
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	18,077,392
53	1/8th Rule		x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission		(Line 52 * 53)	2,259,674
	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)	-171,557,055
59	Rate Base		(Line 39 + 58)	476,687,879

O&M

Line	Description		Note	Reference	Amount
	Transmission O&M				
60	Transmission O&M			p321.112.b (see Attachment 5)	$ 12,996,745
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)	12,996,745
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	$ -
68	Total A&G			p323.197.b (see Attachment 5)	$ 62,776,639
69	Less Property Insurance Account 924			p323.185b	$ 367,746
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$ 4,305,510
71	Less General Advertising Exp Account 930.1			p323.191b	$ 108,372
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$ -
73	Less EPRI Dues		(Note D)	p352-353	$ 135,371
74	General & Common Expenses			(Lines 67 + 68) - Sum (69 to 73)	57,859,640
75	Wage & Salary Allocation Factor			(Line 5)	8.4770%
76	General & Common Expenses Allocated to Transmission			(Line 74 * 75)	4,904,774
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	66,266
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	66,266
80	Property Insurance Account 924			p323.185b	$ 367,746
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	367,746
83	Net Plant Allocation Factor			(Line 18)	29.81%
84	A&G Directly Assigned to Transmission			(Line 82 * 83)	109,607
85	Total Transmission O&M			(Line 66 + 76 + 79 + 84)	18,077,392

Depreciation & Amortization Expense

Line	Description		Note	Reference	Amount
	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	19,681,563
87	General Depreciation			p336.10b&c	6,741,561
88	Intangible Amortization		(Note A)	p336.1d&e	49,728
89	Total			(Line 87 + 88)	6,791,289
90	Wage & Salary Allocation Factor			(Line 5)	8.4770%
91	General Depreciation Allocated to Transmission			(Line 89 * 90)	575,699
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)	8.4770%
96	Common Depreciation - Electric Only Allocated to Transmission			(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization			(Line 86 + 91 + 96)	20,257,262

Taxes Other than Income

Line	Description		Note	Reference	Amount
98	Taxes Other than Income			Attachment 2	1,011,390
99	Total Taxes Other than Income			(Line 98)	1,011,390

Return / Capitalization Calculations

Line	Description		Note	Reference	Amount
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	64,016,473
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	12,935,772
102	Long Term Interest			"(Line 100 - line 101)"	51,080,701
103	Preferred Dividends		enter positive	p118.29c	$ -
	Common Stock				
104	Proprietary Capital			p112.16c	$ 887,829,155
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)	887,829,155
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,053,163,351
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (7,698,729)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	-3,128,863
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-149,148,351
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	893,187,408
114	Preferred Stock			p112.3c	$ -
115	Common Stock			(Line 107)	887,829,155
116	Total Capitalization			(Sum Lines 113 to 115)	1,781,016,563
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)	0.0572
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)	0.0286
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)	0.0851
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	40,563,572

Composite Income Taxes

Line	Description		Note	Source	Amount
	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	$ (448,414)
134	T/(1-T)			(Line 132)	69.05%
135	Net Plant Allocation Factor			(Line 18)	29.8050%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-225,937
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	18,597,595
138	Total Income Taxes			(Line 136 + 137)	18,371,657

REVENUE REQUIREMENT

Line	Description	Note	Source	Amount
	Summary			
139	Net Property, Plant & Equipment		(Line 39)	648,244,934
140	Adjustment to Rate Base		(Line 58)	-171,557,055
141	Rate Base		(Line 59)	476,687,879
142	O&M		(Line 85)	18,077,392
143	Depreciation & Amortization		(Line 97)	20,257,262
144	Taxes Other than Income		(Line 99)	1,011,390
145	Investment Return		(Line 127)	40,563,572
146	Income Taxes		(Line 138)	18,371,657
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	98,281,274
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	838,506,779
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	838,506,779
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	98,281,274
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	98,281,274
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	2,894,356
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	95,386,918
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	95,386,918
158	Net Transmission Plant		(Line 19 - 30)	614,921,420
159	Net Plant Carrying Charge		(Line 157 / 158)	15.5121%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	12.3114%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	2.7272%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	36,451,689
163	Increased Return and Taxes		Attachment 4	62,964,473
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	99,416,162
165	Net Transmission Plant		(Line 19 - 30)	614,921,420
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	16.1673%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	12.9666%
168	Net Revenue Requirement		(Line 156)	95,386,918
169	True-up amount		Attachment 6	3,700,606
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	439,835
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)	99,527,358
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	2,444
174	Rate ($/MW-Year)		(Line 172 / 173)	40,731
175	Network Service Rate ($/MW/Year)		(Line 174)	40,731

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.

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	-	(613,363,777)	-	
ADIT-283	(791,062)	(18,447,587)	(41,924,151)	
ADIT-190	420,470	36,964,511	6,317,852	
Subtotal	(370,592)	(594,846,854)	(35,606,299)	
Wages & Salary Allocator			8.4770%	
Gross Plant Allocator		29.9586%		
ADIT	(370,592)	(178,207,895)	(3,018,354)	(181,596,841)

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 3,128,863

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 Total	C	D	E	F	G
ADIT-190			Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
190	1999 AMT	1,625,338			1,625,338		Plant related
190	Accrual Labor Related	5,890,325				5,890,325	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. For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are not deducted until paid.
190	Accrued Liab - Auto	233,978				233,978	Affects company personnel across all functions
190	Accrued Liab - Misc.	3,564,210			3,564,210		Related to T&D plant
190	Accrued Liability - General	788,577			788,577		Related to T&D plant
190	Accumulated Deferred Investment Tax Credit	1,616,098			1,616,098		Related to T&D plant
190	BAD DEBT RESERVE	3,696,951	3,696,951				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	BGS Deferred Related - Retail	16	16				Retail related
190	Charitable Contribution Limit	872,874	872,874				Related to gas, production or other
190	ENVIRONMENTAL EXPENSE	782,829	782,829				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	90,261	90,261				Relates to Above Market Energy Supply Contracts. All Generation related.
190	OPEB	14,824,880				14,824,880	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.
190	Reg Asset - FERC Formula Rate Adj. Trans. Svc	420,470		420,470			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
190	SECTION 461(H) - PREPAID INSURANCE	2,617,534			2,617,534		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	193,549				193,549	Affects company personnel across all functions.
190	Stranded Costs	3,337,529	3,337,529				All Generation related
190	Federal NOL	14,584,008			14,584,008		Related to both T & D plant
190	State NOL	13,784,845			13,784,845		Related to both T & D plant
190	FAS 109 Deferred Taxes - 190	1,282,671			1,282,671		Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the prior flow-through amounts. Related to all plant.
190	Subtotal - p234	70,206,942	8,780,460	420,470	39,863,280	21,142,732	
	Less FASB 109 Above if not separately removed	2,898,769			2,898,769		
190	Less FASB 106 Above if not separately removed	14,824,880				14,824,880	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.
190	Total	52,483,293	8,780,460	420,470	36,964,511	6,317,852	

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

	A	B	C	D	E	F	G
ADIT-282		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
282	Plant Related - APB 11 Deferred Taxes	(613,363,777)			(613,363,777)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	Plant Related - FAS109 Deferred Taxes	(24,889,799)			(24,889,799)		Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the deferred taxes on prior flow-through items. Related to all plant.
	Subtotal - p275	(638,253,576)	-	-	(638,253,576)	-	
	Less FASB 109 Above if not separately removed	(24,889,799)			(24,889,799)		
	Less FASB 106 Above if not separately removed	-					
282	Total	(613,363,777)	-	-	(613,363,777)	-	

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	Accrual Labor Related	(2,255,143)				(2,255,143)	Affects company personnel across all functions.
283	Amortization of OPEB	(2)				(2)	OPEB, labor related and relates to all functions
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	BGS Deferred Related - Retail	(21,699,776)	(21,699,776)				Retail related
283	Decommissioning & Decontamination	12,244	12,244				Related to gas, production or other
283	DEFERRED EXPENSE CLEARING	(752,834)			(752,834)		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	(118,040)	(118,040)				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	Interest on Contingent Taxes	(9,909,704)			(9,909,704)		Estimated book interest income on prior year taxes not included for tax purposes.
283	Loss on Reacquired Debt	3,128,863	3,128,863				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. Excluded here since included in Cost of Debt
283	Misc. Deferred Debits - Retail	(44,379)	(44,379)				Retail related
283	NUG BUYOUT	(14,291,857)	(14,291,857)				Generation related
283	PENSION PAYMENT RESERVE	(39,220,043)				(39,220,043)	Affects company personnel across all functions.
283	Reg Asset - FERC Formula Rate Adj. Trans. Svc	(791,062)		(791,062)			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	Reg Asset-NJ Rec-Base	(7,946,070)			(7,946,070)		Related to both T & D plant
283	Regulatory Asset - General	(448,962)				(448,962)	Regulatory liability for universal service fund
283	Regulatory Asset - NJ RGGI	(1,163,433)	(1,163,433)				Related to gas, production or other
283	Regulatory Asset - SREC Program	(3,615,820)	(3,615,820)				Generation related - Solar Renewable EnergyCertificate Program
283	Stranded Costs	(26,676,789)	(26,676,789)				All Generation related
283	Use Tax reserve	161,020			161,020		For book purposes, SFAS 5 reserves are established for potential prior year sales and use tax liabilities. For tax purposes, these liabilities can only be deducted when the amounts become fixed liabilities and are paid. Related to all plant.

283	Gross up on FAS 109 Deferred Taxes	(17,187,269)			(17,187,269)		Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the prior flow-through amounts. Related to all plant.
283	Subtotal - p277 (Form 1-F filer: see note 6, below)	(142,819,059)	(64,468,990)	(791,062)	(35,634,856)	(41,924,151)	
283	Less FASB 109 Above if not separately removed	(17,187,269)			(17,187,269)		
283	Less FASB 106 Above if not separately removed	-					
283	Total	(125,631,790)	(64,468,990)	(791,062)	(18,447,587)	(41,924,151)	

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

ADITC-255			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	4,858,878	448,414
5	Total		4,858,878	448,414
6	Form No. 1 balance (p.266) for amortization	Total Form No. 1 (p 266 & 267	4,858,878	448,414
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)	2,749,102		
2 Personal property	-		
3 City License	-		
4 Federal Excise	14,210		
Total Plant Related	2,763,312	29.9586%	827,850
Labor Related		***Wages & Salary Allocator***	
5 Federal FICA & Unemployment	1,860,922		
6 Unemployment	294,694		
Total Labor Related	2,155,616	8.4770%	182,732
Other Included		***Gross Plant Allocator***	
7 Miscellaneous	2,698		
Total Other Included	2,698	29.9586%	808
Total Included			1,011,390
Excluded			
8 State Franchise tax	-		
9 TEFA	(103,352)		
10 Use & Sales Tax	(595,385)		
11 Total "Other" Taxes (included on p. 263)	4,222,889		
12 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	4,222,889		
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)		894,990
2	Total Rent Revenues	(Sum Line 1)	894,990
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 867,192
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)		1,143,075
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)	3,524,637
12	Less line 17g		(630,281)
13	Total Revenue Credits		2,894,356
	<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.		894,990
17b	Costs associated with revenues in line 17a		365,572
17c	Net Revenues (17a - 17b)		529,418
17d	50% Share of Net Revenues (17c / 2)		264,709
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)		264,709
17g	Line 17f less line 17a		(630,281)
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.		10,284,670
19	Amount offset in line 4 above		88,320,039
20	Total Account 454, 456 and 456.1		102,129,346
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)	62,964,473
B	100 Basis Point increase in ROE				1.00%
Return Calculation					
59	Rate Base			(Line 39 + 58)	476,687,879
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	64,016,473
101	Less LTD Interest on Securitization B	(Note P)		Attachment 8	12,935,772
102	**Long Term Interest**			"(Line 100 - line 101)"	51,080,701
103	**Preferred Dividends**		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	887,829,155
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)	887,829,155
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,053,163,351
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	-7,698,729
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	-3,128,863
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	-149,148,351
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	893,187,408
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	887,829,155
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,781,016,563
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)	0.0572
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)	0.0286
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)**	**0.0901**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**42,947,011**
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	-448,414
134	T/(1-T)			(Line 132)	69.05%
135	Net Plant Allocation Factor			(Line 18)	29.8050%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-225,937**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			20,243,400
138	**Total Income Taxes**				**20,017,462**

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	16,702,099	16,702,099	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	4,858,878	4,858,878	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,260,277	1,260,277	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	49,728	49,728	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	13,292,544	782,029	12,510,515	Transmission Right of Way - Carll's Corner to Landis

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	2,928,510,397	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Servie without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	838,506,779	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	223,585,359	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	135,371	135,371	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	4,305,510	66,266	4,239,244	FERC Form 1 page 351 line 3 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,305,510	66,266	4,239,244	FERC Form 1 page 351 line 3 (h)

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	108,372	-	108,372	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)	8.9946%	9.00%	9.990%				Apportioned: NJ 8.8864%, PA 0.1082%

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	108,372	-	108,372	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 related	8,051,088	8.48%	682,492	
	Plant Related	5,969,091	29.96%	1,788,257	
	Other		0.00%	-	
	Total Transmission Related Reserves	14,020,179		2,470,750	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45 Prepayments						
5	Wages & Salary Allocator			8.477%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	8.477%	-	
	Prepayments	$	2,980,483	8.477%	252,656	
	Prepaid Pensions if not included in Prepayments	$	96,019,794	8.477%	8,139,619	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
			99,000,277		8,392,275	
						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	2,443.5	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						

Supporting documentation for FERC Form 1 reconciliation

Compliance with FERC Order on the Exelon Merger

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Merger Costs	Non Merger Related
60	Transmission O&M	p321.112.b	12,998,149	1,404	12,996,745
68	Total A&G	p323.197.b	63,969,747	1,193,108	62,776,639

ARO Exclusion - Cost Support

			Form 1 Amount	ARO's	Non-ARO's
	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	ARO's	Non-ARO's
6	Electric Plant in Service	p207.104g	2,928,510,397	96,555	2,928,413,842
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	739,424,882	40,232	739,384,650
23	General & Intangible	p205.5.g & p207.99.g	149,349,379	96,555	149,252,824
31	Accumulated General Depreciation	p219.28.c	57,232,549	40,232	57,192,317

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 13,882,162	$ 11,785,623	$ 24,382,713	$ 5,667,656	$ 55,718,155
Procurement & Administrative Services	7,001,366	4,598,470	10,475,398	343,584	22,418,818
Financial Services & Corporate Expenses	13,502,547	10,768,241	20,331,591	2,392,152	46,994,531
Insurance Coverage and Services	2,519,625	2,187,093	3,305,370	887,190	8,899,278
Human Resources	3,653,925	2,428,050	5,847,877	1,046,090	12,975,941
Legal Services	2,651,005	2,242,024	6,008,665	1,200,772	12,102,467
Audit Services	980,075	750,029	1,750,164	234,556	3,714,825
Customer Services	50,507,172	38,945,027	33,693,424	59,420	123,205,044
Utility Communication Services	56,240	-	87,358	-	143,598
Information Technology	15,350,317	11,421,231	34,068,152	334,163	61,173,863
External Affairs	3,329,577	2,605,534	5,487,511	670,032	12,092,654
Environmental Services	1,774,836	1,370,486	1,976,135	117,173	5,238,631
Safety Services	380,152	421,829	615,823	-	1,417,804
Regulated Electric & Gas T&D	33,672,104	25,702,737	45,555,831	330,416	105,261,089
Internal Consulting Services	699,514	376,268	1,019,829	1,904	2,097,515
Interns	208,653	118,776	144,867	180	472,476
Cost of Benefits	12,791,136	7,921,448	21,384,267	1,993,351	44,090,202
Building Services	4,513	110,543	4,224,537	-	4,339,592
Total	**$ 162,964,920**	**$ 123,753,411**	**$ 220,359,512**	**$ 15,278,638**	**$ 522,356,481**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2014

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	57,214,714	162,918,093	226,705	220,359,512
2	Delmarva Power & Light Company	39,247,411	123,549,735	167,774	162,964,920
3	Atlantic City Electric Company	24,854,235	98,773,234	125,942	123,753,411
4	Pepco Energy Services, Inc.	2,653,237	5,856,129	9,444	8,518,810
5	Conectiv, LLC	3,919	46,852	59	50,830
6	Potomac Capital Investment Corporation	146,353	120,086	661	267,100
7	Thermal Energy Limited Partnership	16,405	723,744	728	740,877
8	ATS Operating Services, Inc.	106	322,506	331	322,943
9	Atlantic Southern Properties, Inc.	7,201	184,696	197	192,094
10	Conectiv Energy Supply, Inc.	20,415	8,175	36	28,626
11	Pepco Holdings, Inc.	4,226,510	595,934	1,568	4,824,012
12	Conectiv Properties and Investments, Inc.	694	156,517	166	157,377
13	Conectiv Thermal Systems, Inc.	4,666	108,488	117	113,271
14	Conectiv Communications, Inc.	53	10,556	10	10,619
15	Atlantic City Electric Transition Funding LLC	31,698	5,736	35	37,469
16	Conectiv North East, LLC	253	4,677	5	4,935
17	Delaware Operating Services Company, LLC	177	118	8	303
18	ATE Investment, Inc.	773	1,097	3	1,873
19	Atlantic Generation, Inc.	80	13	1	94
20	Conectiv Services II, Inc.	33	7,227	7	7,267
21	Conectiv Solutions LLC	136	2		138
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	128,429,069	393,393,615	533,797	522,356,481

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2014
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	25,452,371	16,528,974	35,163,211	-	77,144,556	Not Included
182.3	Other Regulatory Assets	7,284,203	200,422	10,839,283	-	18,323,908	Not Included
184	Clearing Accounts - Other	(4,608)	(24,809)	126,528	(66,205)	30,906	Not Included
408.1	Taxes other than inc taxes, utility operating inc	1,811	15,040	1,849	-	18,699	Not Included
416-421	Other Income -Below the Line	266,750	465,608	570,194	15,344,844	16,647,396	Not Included
426.1-426.5	Other Income Deductions - Below the Line	3,271,318	2,695,830	5,494,225	-	11,461,373	Not Included
430	Interest-Debt to Associated Companies	346,840	260,349	468,738	-	1,075,927	Not Included
431	Interest-Short Term Debt	(179,066)	(134,408)	(242,033)	-	(555,506)	Not Included
556	System cont & load dispatch	2,177,755	1,891,923	1,705,407	-	5,775,084	Not Included
557	Other expenses	1,173,401	1,130,377	1,461,250	-	3,765,028	Not Included
560	Operation Supervision & Engineering	2,417,695	2,277,855	3,665,108	-	8,360,658	100% Included
561	Load dispatching	-	11	-	-	11	100% Included
561.1	Load Dispatching - Reliability	13,206	11,642	-	-	24,847	100% Included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	69,383	23,030	1,008,010	-	1,100,423	100% Included
561.3	Load Dispatch - Transmission Service & Scheduling	39,057	34,330	28,667	-	102,053	100% Included
561.5	Reliability, Planning and Standards	257,243	232,961	132,446	-	622,650	100% Included
563	Overhead line expenses			345	-	345	100% Included
562	Station expenses	-	-	8,533	-	8,533	100% Included
564	Underground Line Expenses - Transmission	-	-	6,641	-	6,641	100% Included
566	Miscellaneous transmission expenses	412,227	313,802	334,811	-	1,060,840	100% Included
568	Maintenance Supervision & Engineering	158,431	130,076	258,084	-	546,591	100% Included
569	Maint of structures	-	-	-	-	-	100% Included
569.2	Maintenance of Computer Software	571,924	291,641	454,366	-	1,317,931	100% Included
569.4	Maintenance of Transmission Plant	-	-	940	-	940	100% Included
570	Maintenance of station equipment	156,492	86,339	378,208	-	621,039	100% Included
571	Maintenance of overhead lines	146,461	170,076	249,124	-	565,660	100% Included
572	Maintenance of underground lines	35	272	9,974	-	10,281	100% Included
573	Maintenance of miscellaneous transmission plant	26,096	33,049	155,743	-	214,887	100% Included
580	Operation Supervision & Engineering	730,625	350,609	623,416	-	1,704,650	Not Included
581	Load dispatching	838,385	546,354	1,547,494	-	2,932,233	Not Included
582	Station expenses	837,194	-	115,333	-	952,527	Not Included
583	Overhead line expenses	77,312	125,967	29,852	-	233,131	Not Included
584	Underground line expenses	23,803	-	282,831	-	306,634	Not Included
585	Street lighting	11,177	-	41	-	11,218	Not Included
586	Meter expenses	786,669	575,817	1,622,146	-	2,984,632	Not Included
587	Customer installations expenses	69,822	341,159	487,591	-	898,572	Not Included
588	Miscellaneous distribution expenses	4,998,231	5,390,134	8,479,619	-	18,867,983	Not Included
589	Rents	30,570	6,315	20,959	-	57,844	Not Included
590	Maintenance Supervision & Engineering	865,163	720,247	338,570	-	1,923,980	Not Included
591	Maintain structures	-	-	1,937	-	1,937	Not Included
592	Maintain equipment	535,979	522,925	975,362	-	2,034,266	Not Included
593	Maintain overhead lines	1,107,894	653,471	1,798,778	-	3,560,142	Not Included
594	Maintain underground line	97,908	64,967	692,235	-	855,111	Not Included
595	Maintain line transformers	67	1,811	220,800	-	222,677	Not Included
596	Maintain street lighting & signal systems	44,641	37,249	8,246	-	90,136	Not Included
597	Maintain meters	27,120	31,452	41,070	-	99,642	Not Included
598	Maintain distribution plant	61,416	18,767	854,752	-	934,935	Not Included
800-894	Total Gas Accounts	2,210,101	-	-	-	2,210,101	Not Included
902	Meter reading expenses	188,544	49,162	49,142	-	286,847	Not Included
903	Customer records and collection expenses	41,899,731	39,033,339	33,166,986	-	114,100,056	Not Included
907	Supervision - Customer Svc & Information	82,458	10,418	108,745	-	201,620	Not Included
908	Customer assistance expenses	2,073,545	590,689	903,301	-	3,567,535	Not Included
909	Informational & instructional advertising	66,371	19,518	64,417	-	150,306	Not Included
912	Demonstrating and selling expense	7,962			-	7,962	Not Included
913	Advertising expense	30,520	-	-	-	30,520	Not Included
920	Administrative & General salaries	325,663	95,547	645,155	-	1,066,365	Wage & Salary Factor
921	Office supplies & expenses	14,314	12,513	24,279	-	51,106	Wage & Salary Factor
923	Outside services employed	48,702,231	40,630,932	84,352,816	-	173,685,978	Wage & Salary Factor
924	Property insurance	2,246	1,684	3,080	-	7,010	Net Plant Factor
925	Injuries & damages	2,046,510	1,624,059	3,293,661	-	6,964,230	Wage & Salary Factor
926	Employee pensions & benefits	6,990,629	3,656,906	11,806,837	-	22,454,372	Wage & Salary Factor
928	Regulatory commission expenses	1,280,938	532,794	1,787,129	-	3,600,860	Direct Transmission Only
929	Duplicate charges-Credit	240,484	131,613	1,078,264	-	1,450,360	Wage & Salary Factor
930.1	General ad expenses	273	-	13,789	-	14,062	Direct Transmission Only
930.2	Miscellaneous general expenses	1,268,142	1,121,501	2,354,056	-	4,743,699	Wage & Salary Factor
931	Rents	0	-	1	-	1	Wage & Salary Factor
935	Maintenance of general plant	331,262	221,104	287,172	-	839,538	Wage & Salary Factor
	Total	**162,964,920**	**123,753,411**	**220,359,512**	**15,278,638**	**522,356,481**	

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)

87,722,798 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					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	-	-	-	
								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!	

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

$ 655,709 Input to Formula Line 21

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

87,789,524 — 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)

$ 87,789,524

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

93,224,941 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 $ 61,561,236 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	2,888,866				11.5	33,221,958	-	-	-	2,768,497	-	-	-	
Feb	2,063,237				10.5	21,663,990	-	-	-	1,805,333	-	-	-	
Mar	4,898,887				9.5	46,539,430	-	-	-	3,878,286	-	-	-	
Apr	4,007,472				8.5	34,063,510	-	-	-	2,838,626	-	-	-	
May	12,233,757				7.5	91,753,178	-	-	-	7,646,098	-	-	-	
Jun	7,326,379				6.5	47,621,462	-	-	-	3,968,455	-	-	-	
Jul	(68,580)				5.5	(377,193)	-	-	-	(31,433)	-	-	-	
Aug	(358,011)				4.5	(1,611,048)	-	-	-	(134,254)	-	-	-	
Sep	886,897				3.5	3,104,139	-	-	-	258,678	-	-	-	
Oct	3,080,853				2.5	7,702,133	-	-	-	641,844	-	-	-	
Nov	14,549,088				1.5	21,823,632	-	-	-	1,818,636	-	-	-	
Dec	10,052,392				0.5	5,026,196	-	-	-	418,850	-	-	-	
Total	61,561,236	-	-	-		310,531,386	-	-	-	25,877,615	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										25,877,615	-	-	-	
								Input to Line 21 of Appendix A		25,877,615	-		-	25,877,615
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		6.96	#DIV/0!	#DIV/0!	#DIV/0!	

89,677,518 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	11,324,742				9.5	107,585,052	-	-	-	8,965,421	-	-	-	
Apr	1,075,666				8.5	9,143,160	-	-	-	761,930	-	-	-	
May	26,281,577				7.5	197,111,825	-	-	-	16,425,985	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	38,681,985	-	-	-		313,840,038	-	-	-	26,153,337	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										26,153,337	-	-	-	
95,826,753								Input to Line 21 of Appendix A		26,153,337	-		-	26,153,337
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		3.89	#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		
89,677,518	-	86,103,438	=	3,574,081

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	297,840	0.2800%	11.5	9,590	307,431
Jul	Year 1	297,840	0.2800%	10.5	8,756	306,597
Aug	Year 1	297,840	0.2800%	9.5	7,923	305,763
Sep	Year 1	297,840	0.2800%	8.5	7,089	304,929
Oct	Year 1	297,840	0.2800%	7.5	6,255	304,095
Nov	Year 1	297,840	0.2800%	6.5	5,421	303,261
Dec	Year 1	297,840	0.2800%	5.5	4,587	302,427
Jan	Year 2	297,840	0.2800%	4.5	3,753	301,593
Feb	Year 2	297,840	0.2800%	3.5	2,919	300,759
Mar	Year 2	297,840	0.2800%	2.5	2,085	299,925
Apr	Year 2	297,840	0.2800%	1.5	1,251	299,091
May	Year 2	297,840	0.2800%	0.5	417	298,257
Total		3,574,081				3,634,125

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	3,634,125	0.2800%	308,384	3,335,917
Jul	Year 2	3,335,917	0.2800%	308,384	3,036,874
Aug	Year 2	3,036,874	0.2800%	308,384	2,736,993
Sep	Year 2	2,736,993	0.2800%	308,384	2,436,273
Oct	Year 2	2,436,273	0.2800%	308,384	2,134,711
Nov	Year 2	2,134,711	0.2800%	308,384	1,832,304
Dec	Year 2	1,832,304	0.2800%	308,384	1,529,051
Jan	Year 3	1,529,051	0.2800%	308,384	1,224,949
Feb	Year 3	1,224,949	0.2800%	308,384	919,995
Mar	Year 3	919,995	0.2800%	308,384	614,187
Apr	Year 3	614,187	0.2800%	308,384	307,523
May	Year 3	307,523	0.2800%	308,384	0
Total with interest				3,700,606	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		3,700,606
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	95,826,753
Revenue Requirement for Year 3		99,527,358

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

$ 99,527,358 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)

$ 99,527,358

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
3			Formula Line		
4		A	160	Net Plant Carrying Charge without Depreciation	12.3114%
5		B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	12.9666%
6		C		Line B less Line A	0.6552%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.7272%

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 i**

Line		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		12.3114%		12.3114%	12.3114%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		13.2943%		12.3114%	12.3114%
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

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
35	Base FCR	2015	4,091,785	138,705	3,953,080	625,384	6,640,088	225,088	6,415,001	1,014,863	11,271,741	392,061	10,879,681	1,731,500
36	W Increased ROE	2015	4,091,785	138,705	3,953,080	664,237	6,640,088	225,088	6,415,001	1,014,863	11,271,741	392,061	10,879,681	1,731,500
37	Base FCR	2016	3,953,080	138,705	3,814,376	608,307	6,415,001	225,088	6,189,913	987,152	10,879,681	392,061	10,487,620	1,683,232
38	W Increased ROE	2016	3,953,080	138,705	3,814,376	645,797	6,415,001	225,088	6,189,913	987,152	10,879,681	392,061	10,487,620	1,683,232
39	Base FCR	2017	3,814,376	138,705	3,675,671	591,231	6,189,913	225,088	5,964,825	959,440	10,487,620	392,061	10,095,560	1,634,964
40	W Increased ROE	2017	3,814,376	138,705	3,675,671	627,358	6,189,913	225,088	5,964,825	959,440	10,487,620	392,061	10,095,560	1,634,964
41	Base FCR	2018	3,675,671	138,705	3,536,967	574,154	5,964,825	225,088	5,739,737	931,729	10,095,560	392,061	9,703,499	1,586,696
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	608,918	5,964,825	225,088	5,739,737	931,729	10,095,560	392,061	9,703,499	1,586,696
43	Base FCR	2019	3,536,967	138,705	3,398,262	557,078	5,739,737	225,088	5,514,650	904,018	9,703,499	392,061	9,311,439	1,538,428
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	590,478	5,739,737	225,088	5,514,650	904,018	9,703,499	392,061	9,311,439	1,538,428
45	Base FCR	2020	3,398,262	138,705	3,259,557	540,001	5,514,650	225,088	5,289,562	876,306	9,311,439	392,061	8,919,378	1,490,160
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	572,038	5,514,650	225,088	5,289,562	876,306	9,311,439	392,061	8,919,378	1,490,160
47	Base FCR	2021	3,259,557	138,705	3,120,853	522,925	5,289,562	225,088	5,064,474	848,595	8,919,378	392,061	8,527,317	1,441,892
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	553,599	5,289,562	225,088	5,064,474	848,595	8,919,378	392,061	8,527,317	1,441,892
49	Base FCR	2022	3,120,853	138,705	2,982,148	505,848	5,064,474	225,088	4,839,386	820,883	8,527,317	392,061	8,135,257	1,393,624
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	535,159	5,064,474	225,088	4,839,386	820,883	8,527,317	392,061	8,135,257	1,393,624
51	Base FCR	2023	2,982,148	138,705	2,843,444	488,772	4,839,386	225,088	4,614,299	793,172	8,135,257	392,061	7,743,196	1,345,355
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	516,719	4,839,386	225,088	4,614,299	793,172	8,135,257	392,061	7,743,196	1,345,355
53	Base FCR	2024	2,843,444	138,705	2,704,739	471,695	4,614,299	225,088	4,389,211	765,460	7,743,196	392,061	7,351,136	1,297,087
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	498,279	4,614,299	225,088	4,389,211	765,460	7,743,196	392,061	7,351,136	1,297,087
55	Base FCR	2025	2,704,739	138,705	2,566,035	454,619	4,389,211	225,088	4,164,123	737,749	7,351,136	392,061	6,959,075	1,248,819
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	479,840	4,389,211	225,088	4,164,123	737,749	7,351,136	392,061	6,959,075	1,248,819
57	Base FCR	2026	2,566,035	138,705	2,427,330	437,543	4,164,123	225,088	3,939,035	710,038	6,959,075	392,061	6,567,015	1,200,551
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	461,400	4,164,123	225,088	3,939,035	710,038	6,959,075	392,061	6,567,015	1,200,551
59	Base FCR	2027	2,427,330	138,705	2,288,625	420,466	3,939,035	225,088	3,713,948	682,326	6,567,015	392,061	6,174,954	1,152,283
60	W Increased ROE	2027		138,705	(138,705)	120,265	3,939,035	225,088	3,713,948	682,326	6,567,015	392,061	6,174,954	1,152,283
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

Column groups in the table above: Beginning–Revenue (first four) = B0265 Mickelton; next four = B0276 Monroe; last four = B0211 Union-Corson.

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 FERC to become effective June 1, 2008 and November

B0210 Orchard-500kV	B0210 Orchard-Below 500kV	B0277 Cumberland Sub:2nd Xfmr	B1398.5 Reconductor Mickleton - Depford - 230 Kv line	B1398.3.1 Mickleton Deptford 230kv term
Yes	Yes	Yes	Yes	Yes
35	35	35	35	35
No	No	No	No	No
150	150	150	0	0
12.3114%	12.3114%	12.3114%	12.3114%	12.3114%
13.2943%	13.2943%	13.2943%	12.3114%	12.3114%
26,046,638	18,572,212	6,759,777	4,127,104	12,794,561
744,190	530,635	193,136	117,917	365,559
7.00	7	2	5	5

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending
21,271,421	744,190	20,527,231	3,271,377	15,167,306	530,635	14,636,672	2,332,612	5,826,284	193,136	5,633,148	886,655	4,127,104	68,785	4,058,319	610,057	12,794,561	213,243	12,581,318
21,271,421	744,190	20,527,231	3,473,132	15,167,306	530,635	14,636,672	2,476,471	5,826,284	193,136	5,633,148	942,021	4,127,104	68,785	4,058,319	610,057	12,794,561	213,243	12,581,318
20,527,231	744,190	19,783,042	3,179,756	14,636,672	530,635	14,106,037	2,267,283	5,633,148	193,136	5,440,011	862,877	4,058,319	117,917	3,940,402	603,035	12,581,318	365,559	12,215,759
20,527,231	744,190	19,783,042	3,374,198	14,636,672	530,635	14,106,037	2,405,927	5,633,148	193,136	5,440,011	916,345	4,058,319	117,917	3,940,402	603,035	12,581,318	365,559	12,215,759
19,783,042	744,190	19,038,852	3,088,136	14,106,037	530,635	13,575,403	2,201,955	5,440,011	193,136	5,246,875	839,100	3,940,402	117,917	3,822,485	588,518	12,215,759	365,559	11,850,201
19,783,042	744,190	19,038,852	3,275,263	14,106,037	530,635	13,575,403	2,335,383	5,440,011	193,136	5,246,875	890,669	3,940,402	117,917	3,822,485	588,518	12,215,759	365,559	11,850,201
19,038,852	744,190	18,294,662	2,996,516	13,575,403	530,635	13,044,768	2,136,626	5,246,875	193,136	5,053,738	815,322	3,822,485	117,917	3,704,568	574,001	11,850,201	365,559	11,484,642
19,038,852	744,190	18,294,662	3,176,329	13,575,403	530,635	13,044,768	2,264,839	5,246,875	193,136	5,053,738	864,993	3,822,485	117,917	3,704,568	574,001	11,850,201	365,559	11,484,642
18,294,662	744,190	17,550,473	2,904,896	13,044,768	530,635	12,514,133	2,071,298	5,053,738	193,136	4,860,602	791,544	3,704,568	117,917	3,586,650	559,484	11,484,642	365,559	11,119,083
18,294,662	744,190	17,550,473	3,077,394	13,044,768	530,635	12,514,133	2,194,295	5,053,738	193,136	4,860,602	839,317	3,704,568	117,917	3,586,650	559,484	11,484,642	365,559	11,119,083
17,550,473	744,190	16,806,283	2,813,276	12,514,133	530,635	11,983,499	2,005,970	4,860,602	193,136	4,667,465	767,766	3,586,650	117,917	3,468,733	544,966	11,119,083	365,559	10,753,524
17,550,473	744,190	16,806,283	2,978,460	12,514,133	530,635	11,983,499	2,123,752	4,860,602	193,136	4,667,465	813,641	3,586,650	117,917	3,468,733	544,966	11,119,083	365,559	10,753,524
16,806,283	744,190	16,062,093	2,721,656	11,983,499	530,635	11,452,864	1,940,641	4,667,465	193,136	4,474,329	743,988	3,468,733	117,917	3,350,816	530,449	10,753,524	365,559	10,387,965
16,806,283	744,190	16,062,093	2,879,525	11,983,499	530,635	11,452,864	2,053,208	4,667,465	193,136	4,474,329	787,965	3,468,733	117,917	3,350,816	530,449	10,753,524	365,559	10,387,965
16,062,093	744,190	15,317,904	2,630,036	11,452,864	530,635	10,922,229	1,875,313	4,474,329	193,136	4,281,192	720,211	3,350,816	117,917	3,232,899	515,932	10,387,965	365,559	10,022,406
16,062,093	744,190	15,317,904	2,780,591	11,452,864	530,635	10,922,229	1,982,664	4,474,329	193,136	4,281,192	762,289	3,350,816	117,917	3,232,899	515,932	10,387,965	365,559	10,022,406
15,317,904	744,190	14,573,714	2,538,416	10,922,229	530,635	10,391,595	1,809,984	4,281,192	193,136	4,088,056	696,433	3,232,899	117,917	3,114,981	501,415	10,022,406	365,559	9,656,847
15,317,904	744,190	14,573,714	2,681,656	10,922,229	530,635	10,391,595	1,912,120	4,281,192	193,136	4,088,056	736,613	3,232,899	117,917	3,114,981	501,415	10,022,406	365,559	9,656,847
14,573,714	744,190	13,829,524	2,446,796	10,391,595	530,635	9,860,960	1,744,656	4,088,056	193,136	3,894,919	672,655	3,114,981	117,917	2,997,064	486,897	9,656,847	365,559	9,291,288
14,573,714	744,190	13,829,524	2,582,722	10,391,595	530,635	9,860,960	1,841,576	4,088,056	193,136	3,894,919	710,937	3,114,981	117,917	2,997,064	486,897	9,656,847	365,559	9,291,288
13,829,524	744,190	13,085,335	2,355,176	9,860,960	530,635	9,330,326	1,679,327	3,894,919	193,136	3,701,783	648,877	2,997,064	117,917	2,879,147	472,380	9,291,288	365,559	8,925,729
13,829,524	744,190	13,085,335	2,483,787	9,860,960	530,635	9,330,326	1,771,032	3,894,919	193,136	3,701,783	685,261	2,997,064	117,917	2,879,147	472,380	9,291,288	365,559	8,925,729
13,085,335	744,190	12,341,145	2,263,556	9,330,326	530,635	8,799,691	1,613,999	3,701,783	193,136	3,508,646	625,099	2,879,147	117,917	2,761,229	457,863	8,925,729	365,559	8,560,171
13,085,335	744,190	12,341,145	2,384,853	9,330,326	530,635	8,799,691	1,700,488	3,701,783	193,136	3,508,646	659,585	2,879,147	117,917	2,761,229	457,863	8,925,729	365,559	8,560,171
12,341,145	744,190	11,596,955	2,171,936	8,799,691	530,635	8,269,056	1,548,670	3,508,646	193,136	3,315,510	601,322	2,761,229	117,917	2,643,312	443,346	8,560,171	365,559	8,194,612
12,341,145	744,190	11,596,955	2,285,918	8,799,691	530,635	8,269,056	1,629,944	3,508,646	193,136	3,315,510	633,909	2,761,229	117,917	2,643,312	443,346	8,560,171	365,559	8,194,612
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....

1, 2008 respectively

inal

Revenue	Total	Incentive Charged	Revenue Credit
1,891,255	$ 12,363,703		$ 12,363,703
1,891,255	$ 12,803,537	$ 12,803,537	
1,869,488	$ 9,588,608		$ 9,588,608
1,869,488	$ 10,012,652	$ 10,012,652	
1,824,483	$ 9,314,826		$ 9,314,826
1,824,483	$ 9,723,078	$ 9,723,078	
1,779,478	$ 9,041,044		$ 9,041,044
1,779,478	$ 9,433,504	$ 9,433,504	
1,734,472	$ 8,767,261		$ 8,767,261
1,734,472	$ 9,143,931	$ 9,143,931	
1,689,467	$ 8,493,479		$ 8,493,479
1,689,467	$ 8,854,357	$ 8,854,357	
1,644,461	$ 8,219,697		$ 8,219,697
1,644,461	$ 8,564,783	$ 8,564,783	
1,599,456	$ 7,945,914		$ 7,945,914
1,599,456	$ 8,275,209	$ 8,275,209	
1,554,451	$ 7,672,132		$ 7,672,132
1,554,451	$ 7,985,636	$ 7,985,636	
1,509,445	$ 7,398,350		$ 7,398,350
1,509,445	$ 7,696,062	$ 7,696,062	
1,464,440	$ 7,124,568		$ 7,124,568
1,464,440	$ 7,406,488	$ 7,406,488	
1,419,435	$ 6,850,785		$ 6,850,785
1,419,435	$ 7,116,915	$ 7,116,915	
1,374,429	$ 6,577,003		$ 6,577,003
1,374,429	$ 6,504,645	$ 6,504,645	
....			$ -
....		$ -	
		$ 182,013,018	$ 174,772,640

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	12,935,772
	Capitalization	
112	**Less LTD on Securitization Bonds**	149,148,351

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2014 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

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

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May 15, 2015

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 2015 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 2015 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,

[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 2015 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

Line	Description	Notes	FERC Form 1 Page # or Instruction	2014
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21b	$ 6,784,867
2	Total Wages Expense		p354.28b	$ 73,784,124
3	Less A&G Wages Expense		p354.27b	$ 5,628,170
4	Total		(Line 2 - 3)	68,155,954
5	Wages & Salary Allocator		(Line 1 / 4)	9.9549%
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g (See attachment 5)	$ 7,159,426,045
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	7,159,426,045
9	Accumulated Depreciation (Total Electric Plant)		p219.29c See attachment 5)	$ 2,669,196,085
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 73,901,130
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)	2,743,097,215
14	Net Plant		(Line 8 - 13)	4,416,328,830
15	Transmission Gross Plant		(Line 29 - Line 28)	1,307,130,016
16	Gross Plant Allocator		(Line 15 / 8)	18.2575%
17	Transmission Net Plant		(Line 39 - Line 28)	869,543,562
18	Net Plant Allocator		(Line 17 / 14)	19.6893%
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 1,229,617,975
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	43,879,887
22	Total Transmission Plant In Service		(Line 19 - 20 + 21)	1,273,497,862
23	General & Intangible		p205.5.g & p207.99.g (see attachment 5)	337,844,729
24	Common Plant (Electric Only)	(Notes A & B)	p356	0
25	Total General & Common		(Line 23 + 24)	337,844,729
26	Wage & Salary Allocation Factor		(Line 5)	9.95491%
27	General & Common Plant Allocated to Transmission		(Line 25 * 26)	33,632,154
28	Plant Held for Future Use (Including Land)	(Note C)	p214	0
29	TOTAL Plant In Service		(Line 22 + 27 + 28)	1,307,130,016
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	416,723,571
31	Accumulated General Depreciation		p219.28.c (see attachment 5)	135,672,572
32	Accumulated Intangible Amortization		(Line 10)	73,901,130
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)	209,573,702
36	Wage & Salary Allocation Factor		(Line 5)	9.95491%
37	General & Common Allocated to Transmission		(Line 35 * 36)	20,862,883
38	TOTAL Accumulated Depreciation		(Line 30 + 37)	437,586,454
39	TOTAL Net Property, Plant & Equipment		(Line 29 - 38)	869,543,562
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-228,239,668
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	19.69%
43	Accumulated Deferred Income Taxes Allocated To Transmission		(Line 41 * 42) + Line 40	-228,239,668
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	-7,529,660
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	33,480,122
46	Total Prepayments Allocated to Transmission		(Line 45)	33,480,122
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	2,222,147
48	Wage & Salary Allocation Factor		(Line 5)	9.95%
49	Total Transmission Allocated		(Line 47 * 48)	221,213
50	Transmission Materials & Supplies		p227.8c	5,668,826
51	Total Materials & Supplies Allocated to Transmission		(Line 49 + 50)	5,890,039
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	41,156,492
53	1/8th Rule		x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission		(Line 52 * 53)	5,144,561
	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)	-191,254,606
59	Rate Base		(Line 39 + 58)	678,288,956

O&M

Line	Description	Note	Source	Amount
	Transmission O&M			
60	Transmission O&M		p321.112.b (see attachment 5)	28,496,500
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)	28,496,500
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	0
68	Total A&G		p323.197.b (see attachment 5)	129,601,920
69	Less Property Insurance Account 924		p323.185b	1,057,996
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	2,561,515
71	Less General Advertising Exp Account 930.1		p323.191b	1,910,540
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	0
73	Less EPRI Dues	(Note D)	p352-353	275,846
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)	123,796,023
75	Wage & Salary Allocation Factor		(Line 5)	9.9549%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)	12,323,788
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	127,892
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	127,892
80	Property Insurance Account 924		p323.185b	1,057,996
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
82	Total		(Line 80 + 81)	1,057,996
83	Net Plant Allocation Factor		(Line 18)	19.69%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)	208,312
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)	41,156,492

Depreciation & Amortization Expense

Line	Description	Note	Source	Amount
	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	26,757,876
86a	Amortization of Abandoned Transmission Plant		Attachment 5	0
87	General Depreciation		p336.10b&c	9,171,997
88	Intangible Amortization	(Note A)	p336.1d&e	1,353,007
89	Total		(Line 87 + 88)	10,525,004
90	Wage & Salary Allocation Factor		(Line 5)	9.9549%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)	1,047,755
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)	9.9549%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization		(Line 86 + 86a + 91 + 96)	27,805,631

Taxes Other than Income

Line	Description	Source	Amount
98	Taxes Other than Income	Attachment 2	9,870,628
99	Total Taxes Other than Income	(Line 98)	9,870,628

Return / Capitalization Calculations

Line	Description		Note	Source	Amount
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	116,829,335
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	Long Term Interest			"(Line 100 - line 101)"	116,829,335
103	Preferred Dividends		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	$ 2,087,549,365
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)	2,085,902,998
	Capitalization				
108	Long Term Debt			p112.17c through 21c	2,146,100,811
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-21,945,861
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	8,960,824
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	2,133,115,774
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	2,085,902,998
116	Total Capitalization			(Sum Lines 113 to 115)	4,219,018,772
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0%
119	Common %	Common Stock		(Line 115 / 116)	49%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0548
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)	0.0277
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0559
126	Total Return (R)			(Sum Lines 123 to 125)	0.0836
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	56,677,048

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)				69.01%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	-319,014
134	T/(1-T)			(Line 132)	69.01%
135	Net Plant Allocation Factor			(Line 18)	19.6893%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-106,157
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	26,150,589
138	Total Income Taxes			(Line 136 + 137)	26,044,431

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	869,543,562
140	Adjustment to Rate Base		(Line 58)	-191,254,606
141	Rate Base		(Line 59)	678,288,956
142	O&M		(Line 85)	41,156,492
143	Depreciation & Amortization		(Line 97)	27,805,631
144	Taxes Other than Income		(Line 99)	9,870,628
145	Investment Return		(Line 127)	56,677,048
146	Income Taxes		(Line 138)	26,044,431
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	161,554,230
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,229,617,975
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,229,617,975
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	161,554,230
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	161,554,230
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	6,220,764
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	155,333,467
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	155,333,467
158	Net Transmission Plant		(Line 19 - 30)	812,894,404
159	Net Plant Carrying Charge		(Line 157 / 158)	19.1087%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	15.8170%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	5.6408%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	72,611,987
163	Increased Return and Taxes		Attachment 4	88,389,184
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	161,001,171
165	Net Transmission Plant		(Line 19 - 30)	812,894,404
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	19.8059%
167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 163 - 86) / 165	16.5142%
168	Net Revenue Requirement		(Line 156)	155,333,467
169	True-up amount		Attachment 6	(3,096,305)
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	1,418,063
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	14,624,812
172	Net Zonal Revenue Requirement		(Line 168 - 169 + 171)	168,280,036
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	6,345
174	Rate ($/MW-Year)		(Line 172 / 173)	26,521
175	Network Service Rate ($/MW/Year)		(Line 174)	26,521

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. 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.

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	(1,307,213,107)	(10,390,208)	
ADIT-283	(4,683,528)	(121,838,345)	(97,958,654)	
ADIT-190	2,480,061	244,265,091	10,666,509	
Subtotal	(2,203,467)	(1,184,786,360)	(97,682,353)	
Wages & Salary Allocator			9.9549%	
Gross Plant Allocator		18.2575%		
ADIT	(2,203,467)	(216,312,007)	(9,724,195)	(228,239,668)

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 (8,960,824)

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)	2,412,330				2,412,330	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	6,751,178			6,751,178		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	2,885,550				2,885,550	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	1,014,952			1,014,952		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	1,652,297			1,652,297		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	1,093,339				1,093,339	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	2,908,883				2,908,883	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	1,366,408				1,366,408	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	7,776,968	7,776,968				For book purposes, environmental expenses are expensed when accrued. For tax purposes, they are deducted when paid.
Contribution Carryforward	4,581,843	4,581,843				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	90,482	90,482				Capital losses are limited to the amount of capital gains.
FAS 106 OPEB Adjustment	30,954,574				30,954,574	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	2,480,061		2,480,061			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	230,401,239			230,401,239		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	306,867	306,867				Estimated book interest expense on prior year taxes not deductible for tax purposes
Miscellaneous	5,958,178	(1,154,496)		7,112,674		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	307,190,733	16,157,249	2,480,061	246,932,340	41,621,083	
Less FASB 109 Above if not separately removed	2,667,249			2,667,249		
Less FASB 106 Above if not separately removed	30,954,574				30,954,574	
Total	273,568,910	16,157,249	2,480,061	244,265,091	10,666,509	

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 *ADIT- 282*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Accelerated Depreciation	(461,043,816)			(461,043,816)		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	(491,367,140)			(491,367,140)		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)	4,876,650			4,876,650		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	(96,116,641)			(96,116,641)		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	(104,084,192)			(104,084,192)		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	45,664,298			45,664,298		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	(11,077,273)			(11,077,273)		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	(49,716,646)			(49,716,646)		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	(328,272,213)			(328,272,213)		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	(21,077,814)			(21,077,814)		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	123,785,093			123,785,093		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	86,394,707			86,394,707		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	(3,622,884)	(3,622,884)				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	43,637	43,637				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	1,567,398			1,567,398		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	2,998,500			2,998,500		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	1,467,352			1,467,352		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	(173,282)			(173,282)		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	(81,648,520)			(81,648,520)		See the explanation for the control center transaction in Account 190.
FAS 109 - CCRF Equity	(15,743,143)	(15,743,143)				See the explanation for Account 190.
Capitalized Pension	19,765,896			19,765,896		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	(10,390,208)				(10,390,208)	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 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.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(1,395,443,069)	(28,123,109)	-	(1,356,929,753)	(10,390,208)	
Less FASB 109 Above if not separately removed	(65,459,789)	(15,743,143)	-	(49,716,646)	-	
Less FASB 106 Above if not separately removed	-					
Total	(1,329,983,280)	(12,379,965)	-	(1,307,213,107)	(10,390,208)	

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 *ADIT-283*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Amort Loss on Reacquisition	(8,960,824)	(8,960,824)				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. Excluded here since it is included in Cost of Debt.
FAS 109 - Flowthrough Items	(60,379,015)			(60,379,015)		See the explanation for Account 190.
Prepaid Interest	1,535,921				1,535,921	For book purposes, prepaid expenses, which related to a future period but are paid in the current period, must be capitalzied and amortized to the balance sheet as an asset. 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.
Pension Plan Contribution	(124,761,271)			(54,894,959)	(69,866,312)	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
Blueprint for the Future	(630,533)			(630,533)		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	(1,046,816)		(1,046,816)			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	(3,636,712)		(3,636,712)			This regulatory asset represents MAPP adbandonment cost with no potential future value other than through rate recovery; it is considered worthless for tax purposes and is deductible under IRC Section 165(a)as an abandonment loss.
Regulatory Assets	(185,009,855)	(96,878,687)		(58,502,904)	(29,628,264)	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	(7,809,949)			(7,809,949)		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	(6,571,438)	(6,571,438)				Estimated book interest income on prior year taxes not included for tax purposes
Subtotal - p277 (Form 1-F filer: see note 6, below)	(400,146,135)	(115,286,593)	(4,683,528)	(182,217,360)	(97,958,654)	
Less FASB 109 Above if not separately removed	(60,379,015)	-	-	(60,379,015)	-	
Less FASB 106 Above if not separately removed	-	-	-	-	-	
Total	(339,767,119)	(115,286,593)	(4,683,528)	(121,838,345)	(97,958,654)	

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	2,485,709	319,014
5	Total		2,485,709	319,014
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p	2,485,709	319,014
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)	$ 9,290,948	100%	$ 9,290,948
1a	Other Personal Property Tax (excluded)	$ 30,555,266	0%	$ -
2	Capital Stock Tax		18.2575%	$ -
3	Gross Premium (insurance) Tax		18.2575%	$ -
4	PURTA		18.2575%	$ -
5	Corp License		18.2575%	$ -
			18.2575%	$ -
	Total Plant Related	39,846,214		9,290,948
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & state unemployment	5,737,178		
	Total Labor Related	5,737,178	9.9549%	571,131
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous	46,823		
	Total Other Included	46,823	18.2575%	8,549
	Total Included			9,870,628

Currently Excluded

8	Franchise	22,397,793
9	kWhTax - State Gross Receipt (Excise Tax)	84,109,711
10	Electric environmental surcharge	2,107,593
11	Universal service fee	8,280,540
12	Montgomery County Fuel	143,017,665
13	PSC assessment	9,258,851
14	Real property (State, Municipal or Local)	6,611,440
15	DC Right of Way	22,801,869
16	Use & Sales Tax	4,552,933
17	FHUT	9,680
18	DC Ballpark	16,500
19	DC Reliable Energy Trust Fund	17,172,192
20	Misc. Other	115,998
21	Total "Other" Taxes (included on p. 263)	366,082,982
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	366,082,982
23	Difference	(0)

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, 2014

Assessable Plant

Transmission	$	874,060,381
Distribution	$	2,789,657,883
General	$	148,109,953
Total T,D&Genl	$	3,811,828,217

Plant ratios by Jurisdiction

Transmission Ratio	0.2293021435
Distribution ratio	0.7318424977
General Ratio	0.0388553588
	1.0000000000

Property Taxes	$	39,846,214
Transmission Property Tax	$	9,136,822
Distribution Property tax	$	29,161,153
General Property Tax	$	1,548,239
Total check	$	39,846,214
General Property Tax	$	1,548,239
Trans Labor Ratio		9.955%
Trans General		154,126

Total Transmission Property Taxes

Transmission	$	9,136,822
General	$	154,126
Total Transmission Property Taxes	$	9,290,948

Potomac Electric Power Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		11,641,767
2	Total Rent Revenues	(Sum Lines 1)	11,641,767
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 607,137
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)		2,169,500
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)	14,418,404
12	Less line 17g		(8,197,641)
13	Total Revenue Credits		6,220,764
	<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.		11,641,767
17b	Costs associated with revenues in line 17a		4,753,514
17c	Net Revenues (17a - 17b)		6,888,253
17d	50% Share of Net Revenues (17c / 2)		3,444,127
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)		3,444,127
17g	Line 17f less line 17a		(8,197,641)
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.		52,809,791
19	Amount offset in line 4 above		153,080,405
20	Total Account 454, 456 and 456.1		220,308,600
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)	88,389,184
B	100 Basis Point increase in ROE				1.00%
Return Calculation					
59	Rate Base			(Line 39 + 58)	678,288,956
	Long Term Interest				
100	**Long Term Interest**			p117.62c through 67c	116,829,335
101	Less LTD Interest on Securitization E	(Note P)		Attachment 8	0
102	Long Term Interest			"(Line 100 - line 101)"	116,829,335
103	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	2,087,549,365
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)	2,085,902,998
	Capitalization				
108	Long Term Debt			p112.17c through 21c	2,146,100,811
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-21,945,861
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	8,960,824
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	2,133,115,774
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	2,085,902,998
116	Total Capitalization			(Sum Lines 113 to 115)	4,219,018,772
117	Debt %		Total Long Term Debt	(Line 113 / 116)	51%
118	Preferred %		Preferred Stock	(Line 114 / 116)	0%
119	Common %		Common Stock	(Line 115 / 116)	49%
120	Debt Cost		Total Long Term Debt	(Line 102 / 113)	0.0548
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)	0.0277
124	Weighted Cost of Preferred		Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common		Common Stock	(Line 119 * 122)	0.0608
126	Total Return (R)			**(Sum Lines 123 to 125)**	**0.0885**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**60,030,541**
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)				69.01%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	p266.8f	(319,014)
134	T/(1-T)			(Line 132)	69%
135	Net Plant Allocation Factor			(Line 18)	19.6893%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-106,157**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			28,464,800
138	**Total Income Taxes**				**28,358,643**

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	$ 73,901,130	73,901,130	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	$ 2,485,709	2,485,709	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 2,222,147	2,222,147	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	$ 1,353,007	1,353,007	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	$ 58,346,977	0	58,346,977	Specific identification based on plant records: The following plant investments are included:
							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	$ 7,159,709,418	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Servie without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 1,229,617,975	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	$ 416,723,571	0	0	See Form 1

Potomac Electric Power Company

Attachment 5 - Cost Support

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	$ 275,846	275,846	See Form 1

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	$ 2,561,515	127,892	2,433,623	FERC Form 1 page 351.1 line 28, transmission related only.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	$ 2,561,515	127,892	2,433,623	FERC Form 1 page 351.1 line 28, transmission related portion only.

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	$ 1,910,540	-	1,910,540	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)	8.972%	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	$ 1,910,540	0	1,910,540	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

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	68,796,164	9.95%	6,848,599	
	Plant Related	3,730,311	18.26%	681,060	
	Other		0.00%	-	
	Total Transmission Related Reserves	72,526,475		7,529,660	

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		9.955%		
	Pension Liabilities, if any, in Account 242	-	9.955%	-	
	Prepayments	$ 20,675,181	9.955%	2,058,197	
	Prepaid Pensions if not included in Prepayments	$ 315,642,341	9.955%	31,421,925	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
		336,317,522	9.95%	33,480,122	

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	6,345.1	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

Brandywine Fly Ash Landfill Environmental Expenses

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
Step 9	Attachment 6 - Estimate and Reconciliation Worksheet - Footnote 1	$	(2,617,572)	Pepco shall make a negative adjustment to its transmission revenue requirement in its 2015 Annual Update in the amount of $2,617,572, to offset the $2,617,572 of Brandywine fly ash landfill environmental expenses included in Pepco's 2014 Annual Update ("2013 Brandywine Fly Ash Expenses"). Pepco shall not include the 2013 Brandywine Fly Ash Expenses in a future Annual Update while recovery of such expenses is being pursued from a party outside of the PJM Tariff, but once Pepco is no longer pursuing recovery of such expenses outside of the PJM Tariff, Pepco may include such costs in a future Annual Update to the extent such expenses have not been recovered outside of the PJM Tariff, subject to SMECO's right to challenge such inclusion at that time on any grounds permitted pursuant to Attachment H-9, including the Formula Rate Implementation Protocols, as though the costs had been included in the 2014 Annual Update. Any payments to Pepco for its 2013 Brandywine Fly Ash Expenses shall not be included in any Pepco Annual Update.

Supporting documentation for FERC Form 1 reconciliation

Compliance with FERC Order on the Exelon Merger					
Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Merger Costs	Non Merger Related
60	Transmission O&M	p321.112.b	28,499,784	3,284	28,496,500
68	Total A&G	p323.197.b	132,079,068	2,477,148	129,601,920

ARO Exclusion - Cost Support			Form 1 Amount	ARO's	Non-ARO's
Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	ARO's	Non-ARO's
6	Electric Plant in Service	p207.104g	7,159,709,418	283,373	7,159,426,045
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	2,669,328,195	132,110	2,669,196,085
23	General & Intangible	p205.5.g & p207.99.g	338,128,102	283,373	337,844,729
31	Accumulated General Depreciation	p219.28.c	135,804,682	132,110	135,672,572

Potomac Electric Power Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 13,882,162	$ 11,785,623	$ 24,382,713	$ 5,667,656	$ 55,718,155
Procurement & Administrative Services	7,001,366	4,598,470	10,475,398	343,584	22,418,818
Financial Services & Corporate Expenses	13,502,547	10,768,241	20,331,591	2,392,152	46,994,531
Insurance Coverage and Services	2,519,625	2,187,093	3,305,370	887,190	8,899,278
Human Resources	3,653,925	2,428,050	5,847,877	1,046,090	12,975,941
Legal Services	2,651,005	2,242,024	6,008,665	1,200,772	12,102,467
Audit Services	980,075	750,029	1,750,164	234,556	3,714,825
Customer Services	50,507,172	38,945,027	33,693,424	59,420	123,205,044
Utility Communication Services	56,240	-	87,358	-	143,598
Information Technology	15,350,317	11,421,231	34,068,152	334,163	61,173,863
External Affairs	3,329,577	2,605,534	5,487,511	670,032	12,092,654
Environmental Services	1,774,836	1,370,486	1,976,135	117,173	5,238,631
Safety Services	380,152	421,829	615,823	-	1,417,804
Regulated Electric & Gas T&D	33,672,104	25,702,737	45,555,831	330,416	105,261,089
Internal Consulting Services	699,514	376,268	1,019,829	1,904	2,097,515
Interns	208,653	118,776	144,867	180	472,476
Cost of Benefits	12,791,136	7,921,448	21,384,267	1,993,351	44,090,202
Building Services	4,513	110,543	4,224,537	-	4,339,592
Total	**$ 162,964,920**	**$ 123,753,411**	**$ 220,359,512**	**$ 15,278,638**	**$ 522,356,481**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2014

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	57,214,714	162,918,093	226,705	220,359,512
2	Delmarva Power & Light Company	39,247,411	123,549,735	167,774	162,964,920
3	Atlantic City Electric Company	24,854,235	98,773,234	125,942	123,753,411
4	Pepco Energy Services, Inc.	2,653,237	5,856,129	9,444	8,518,810
5	Conectiv, LLC	3,919	46,852	59	50,830
6	Potomac Capital Investment Corporation	146,353	120,086	661	267,100
7	Thermal Energy Limited Partnership	16,405	723,744	728	740,877
8	ATS Operating Services, Inc.	106	322,506	331	322,943
9	Atlantic Southern Properties, Inc.	7,201	184,696	197	192,094
10	Conectiv Energy Supply, Inc.	20,415	8,175	36	28,626
11	Pepco Holdings, Inc.	4,226,510	595,934	1,568	4,824,012
12	Conectiv Properties and Investments, Inc.	694	156,517	166	157,377
13	Conectiv Thermal Systems, Inc.	4,666	108,488	117	113,271
14	Conectiv Communications, Inc.	53	10,556	10	10,619
15	Atlantic City Electric Transition Funding LLC	31,698	5,736	35	37,469
16	Conectiv North East, LLC	253	4,677	5	4,935
17	Delaware Operating Services Company, LLC	177	118	8	303
18	ATE Investment, Inc.	773	1,097	3	1,873
19	Atlantic Generation, Inc.	80	13	1	94
20	Conectiv Services II, Inc.	33	7,227	7	7,267
21	Conectiv Solutions LLC	136	2		138
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	128,429,069	393,393,615	533,797	522,356,481

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2014
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	25,452,371	16,528,974	35,163,211	-	77,144,556	Not Included
182.3	Other Regulatory Assets	7,284,203	200,422	10,839,283	-	18,323,908	Not Included
184	Clearing Accounts - Other	(4,608)	(24,809)	126,528	(66,205)	30,906	Not Included
408.1	Taxes other than inc taxes, utility operating inc	1,811	15,040	1,849	-	18,699	Not Included
416-421	Other Income -Below the Line	266,750	465,608	570,194	15,344,844	16,647,396	Not Included
426.1-426.5	Other Income Deductions - Below the Line	3,271,318	2,695,830	5,494,225	-	11,461,373	Not Included
430	Interest-Debt to Associated Companies	346,840	260,349	468,738	-	1,075,927	Not Included
431	Interest-Short Term Debt	(179,066)	(134,408)	(242,033)	-	(555,506)	Not Included
556	System cont & load dispatch	2,177,755	1,891,923	1,705,407	-	5,775,084	Not Included
557	Other expenses	1,173,401	1,130,377	1,461,250	-	3,765,028	Not Included
560	Operation Supervision & Engineering	2,417,695	2,277,855	3,665,108	-	8,360,658	100% Included
561	Load dispatching	-	11	-	-	11	100% Included
561.1	Load Dispatching - Reliability	13,206	11,642	-	-	24,847	100% Included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	69,383	23,030	1,008,010	-	1,100,423	100% Included
561.3	Load Dispatch - Transmission Service & Scheduling	39,057	34,330	28,667	-	102,053	100% Included
561.5	Reliability, Planning and Standards	257,243	232,961	132,446	-	622,650	100% Included
563	Overhead line expenses			345	-	345	100% Included
562	Station expenses	-	-	8,533	-	8,533	100% Included
564	Underground Line Expenses - Transmission	-	-	6,641	-	6,641	100% Included
566	Miscellaneous transmission expenses	412,227	313,802	334,811	-	1,060,840	100% Included
568	Maintenance Supervision & Engineering	158,431	130,076	258,084	-	546,591	100% Included
569	Maint of structures	-	-	-	-	-	100% Included
569.2	Maintenance of Computer Software	571,924	291,641	454,366	-	1,317,931	100% Included
569.4	Maintenance of Transmission Plant	-	-	940	-	940	100% Included
570	Maintenance of station equipment	156,492	86,339	378,208	-	621,039	100% Included
571	Maintenance of overhead lines	146,461	170,076	249,124	-	565,660	100% Included
572	Maintenance of underground lines	35	272	9,974	-	10,281	100% Included
573	Maintenance of miscellaneous transmission plant	26,096	33,049	155,743	-	214,887	100% Included
580	Operation Supervision & Engineering	730,625	350,609	623,416	-	1,704,650	Not Included
581	Load dispatching	838,385	546,354	1,547,494	-	2,932,233	Not Included
582	Station expenses	837,194	-	115,333	-	952,527	Not Included
583	Overhead line expenses	77,312	125,967	29,852	-	233,131	Not Included
584	Underground line expenses	23,803	-	282,831	-	306,634	Not Included
585	Street lighting	11,177	-	41	-	11,218	Not Included
586	Meter expenses	786,669	575,817	1,622,146	-	2,984,632	Not Included
587	Customer installations expenses	69,822	341,159	487,591	-	898,572	Not Included
588	Miscellaneous distribution expenses	4,998,231	5,390,134	8,479,619	-	18,867,983	Not Included
589	Rents	30,570	6,315	20,959	-	57,844	Not Included
590	Maintenance Supervision & Engineering	865,163	720,247	338,570	-	1,923,980	Not Included
591	Maintain structures	-	-	1,937	-	1,937	Not Included
592	Maintain equipment	535,979	522,925	975,362	-	2,034,266	Not Included
593	Maintain overhead lines	1,107,894	653,471	1,798,778	-	3,560,142	Not Included
594	Maintain underground line	97,908	64,967	692,235	-	855,111	Not Included
595	Maintain line transformers	67	1,811	220,800	-	222,677	Not Included
596	Maintain street lighting & signal systems	44,641	37,249	8,246	-	90,136	Not Included
597	Maintain meters	27,120	31,452	41,070	-	99,642	Not Included
598	Maintain distribution plant	61,416	18,767	854,752	-	934,935	Not Included
800-894	Total Gas Accounts	2,210,101	-	-	-	2,210,101	Not Included
902	Meter reading expenses	188,544	49,162	49,142	-	286,847	Not Included
903	Customer records and collection expenses	41,899,731	39,033,339	33,166,986	-	114,100,056	Not Included
907	Supervision - Customer Svc & Information	82,458	10,418	108,745	-	201,620	Not Included
908	Customer assistance expenses	2,073,545	590,689	903,301	-	3,567,535	Not Included
909	Informational & instructional advertising	66,371	19,518	64,417	-	150,306	Not Included
912	Demonstrating and selling expense	7,962			-	7,962	Not Included
913	Advertising expense	30,520	-	-	-	30,520	Not Included
920	Administrative & General salaries	325,663	95,547	645,155	-	1,066,365	Wage & Salary Factor
921	Office supplies & expenses	14,314	12,513	24,279	-	51,106	Wage & Salary Factor
923	Outside services employed	48,702,231	40,630,932	84,352,816	-	173,685,978	Wage & Salary Factor
924	Property insurance	2,246	1,684	3,080	-	7,010	Net Plant Factor
925	Injuries & damages	2,046,510	1,624,059	3,293,661	-	6,964,230	Wage & Salary Factor
926	Employee pensions & benefits	6,990,629	3,656,906	11,806,837	-	22,454,372	Wage & Salary Factor
928	Regulatory commission expenses	1,280,938	532,794	1,787,129	-	3,600,860	Direct Transmission Only
929	Duplicate charges-Credit	240,484	131,613	1,078,264	-	1,450,360	Wage & Salary Factor
930.1	General ad expenses	273	-	13,789	-	14,062	Direct Transmission Only
930.2	Miscellaneous general expenses	1,268,142	1,121,501	2,354,056	-	4,743,699	Wage & Salary Factor
931	Rents	0	-	1	-	1	Wage & Salary Factor
935	Maintenance of general plant	331,262	221,104	287,172	-	839,538	Wage & Salary Factor
	Total	**162,964,920**	**123,753,411**	**220,359,512**	**15,278,638**	**522,356,481**	

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)

161,071,338 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	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)										17,950,913	-	-	-	
								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!	

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

$ 17,950,913 Input to Formula Line 21

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

163,004,917 — 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)

$ 163,004,917

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

168,842,716 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 $ 88,449,794 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	$937,940				11.5	10,786,310	-	-	-	898,859	-	-	-	
Feb	$1,355,632				10.5	14,234,140	-	-	-	1,186,178	-	-	-	
Mar	$7,117,473				9.5	67,615,993	-	-	-	5,634,666	-	-	-	
Apr	$35,918,085				8.5	305,303,723	-	-	-	25,441,977	-	-	-	
May	($14,279,483)				7.5	(107,096,126)	-	-	-	(8,924,677)	-	-	-	
Jun	$1,632,392				6.5	10,610,549	-	-	-	884,212	-	-	-	
Jul	($3,484,222)				5.5	(19,163,221)	-	-	-	(1,596,935)	-	-	-	
Aug	($107,169)				4.5	(482,262)	-	-	-	(40,189)	-	-	-	
Sep	$11,272,189				3.5	39,452,662	-	-	-	3,287,722	-	-	-	
Oct	$124,247				2.5	310,616	-	-	-	25,885	-	-	-	
Nov	$40,917,864				1.5	61,376,796	-	-	-	5,114,733	-	-	-	
Dec	$7,044,847				0.5	3,522,423	-	-	-	293,535	-	-	-	
Total	88,449,794	-	-	-		386,471,603	-	-	-	32,205,967	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										32,205,967	-	-	-	
								Input to Line 21 of Appendix A		32,205,967	-		-	32,205,967
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		7.63	#DIV/0!	#DIV/0!	#DIV/0!	

163,107,606 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	8,172,728				10.5	85,813,645	-	-	-	7,151,137	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr	51,852,352				8.5	440,744,994	-	-	-	36,728,749	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun					6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	60,025,080	-	-	-		526,558,638	-	-	-	43,879,887	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		43,879,887	-	-	-	
171,376,341								Input to Line 21 of Appendix A		43,879,887	-		-	43,879,887
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		3.23	#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)

Footnote 1: See Attachment 5 - Cost Support in regards to Brandywine Fly Ash Environmental Expenses

The Reconciliation in Step 7		The forecast in Prior Year			
163,107,606	-	166,098,047	=	(2,990,442)	See footnote 1 Attachment 5 - Cost Support 1

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	(249,203)	0.2800%	11.5	(8,024)	(257,228)
Jul	Year 1	(249,203)	0.2800%	10.5	(7,327)	(256,530)
Aug	Year 1	(249,203)	0.2800%	9.5	(6,629)	(255,832)
Sep	Year 1	(249,203)	0.2800%	8.5	(5,931)	(255,135)
Oct	Year 1	(249,203)	0.2800%	7.5	(5,233)	(254,437)
Nov	Year 1	(249,203)	0.2800%	6.5	(4,536)	(253,739)
Dec	Year 1	(249,203)	0.2800%	5.5	(3,838)	(253,041)
Jan	Year 2	(249,203)	0.2800%	4.5	(3,140)	(252,343)
Feb	Year 2	(249,203)	0.2800%	3.5	(2,442)	(251,646)
Mar	Year 2	(249,203)	0.2800%	2.5	(1,744)	(250,948)
Apr	Year 2	(249,203)	0.2800%	1.5	(1,047)	(250,250)
May	Year 2	(249,203)	0.2800%	0.5	(349)	(249,552)
Total		(2,990,442)				(3,040,681)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(3,040,681)	0.2800%	(258,025)	(2,791,170)
Jul	Year 2	(2,791,170)	0.2800%	(258,025)	(2,540,959)
Aug	Year 2	(2,540,959)	0.2800%	(258,025)	(2,290,049)
Sep	Year 2	(2,290,049)	0.2800%	(258,025)	(2,038,435)
Oct	Year 2	(2,038,435)	0.2800%	(258,025)	(1,786,118)
Nov	Year 2	(1,786,118)	0.2800%	(258,025)	(1,533,093)
Dec	Year 2	(1,533,093)	0.2800%	(258,025)	(1,279,361)
Jan	Year 3	(1,279,361)	0.2800%	(258,025)	(1,024,917)
Feb	Year 3	(1,024,917)	0.2800%	(258,025)	(769,762)
Mar	Year 3	(769,762)	0.2800%	(258,025)	(513,892)
Apr	Year 3	(513,892)	0.2800%	(258,025)	(257,305)
May	Year 3	(257,305)	0.2800%	(258,025)	-
Total with interest				(3,096,305)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	(3,096,305)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 171,376,341
Revenue Requirement for Year 3	168,280,036

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

$ 168,280,036 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)

$ 168,280,036

Potomac Electric Power Company

Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
3			Formula Line		
4		A	160	Net Plant Carrying Charge without Depreciation	15.8170%
5		B	167	Net Plant Carrying Charge per 100 Basis Point in ROE without Deprec	16.5142%
6		C		Line B less Line A	0.6972%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income T	5.6408%

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 D**

Line		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		15.8170%	15.8170%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		16.8628%	15.8170%
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

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
35	Base FCR	2015	28,324,871	958,811	27,366,060	5,287,303	6,080,269	199,626	5,880,643	1,129,768
36	W Increased ROE	2015	28,324,871	958,811	27,366,060	5,573,508	6,080,269	199,626	5,880,643	1,129,768
37	Base FCR	2016	27,366,060	958,811	26,407,249	5,135,648	5,880,643	199,626	5,681,018	1,098,193
38	W Increased ROE	2016	27,366,060	958,811	26,407,249	5,411,825	5,880,643	199,626	5,681,018	1,098,193
39	Base FCR	2017	26,407,249	958,811	25,448,438	4,983,993	5,681,018	199,626	5,481,392	1,066,618
40	W Increased ROE	2017	26,407,249	958,811	25,448,438	5,250,142	5,681,018	199,626	5,481,392	1,066,618
41	Base FCR	2018	25,448,438	958,811	24,489,627	4,832,338	5,481,392	199,626	5,281,766	1,035,043
42	W Increased ROE	2018	25,448,438	958,811	24,489,627	5,088,459	5,481,392	199,626	5,281,766	1,035,043
43	Base FCR	2019	24,489,627	958,811	23,530,816	4,680,682	5,281,766	199,626	5,082,140	1,003,468
44	W Increased ROE	2019	24,489,627	958,811	23,530,816	4,926,777	5,281,766	199,626	5,082,140	1,003,468
45	Base FCR	2020	23,530,816	958,811	22,572,006	4,529,027	5,082,140	199,626	4,882,514	971,894
46	W Increased ROE	2020	23,530,816	958,811	22,572,006	4,765,094	5,082,140	199,626	4,882,514	971,894
47	Base FCR	2021	22,572,006	958,811	21,613,195	4,377,372	4,882,514	199,626	4,682,889	940,319
48	W Increased ROE	2021	22,572,006	958,811	21,613,195	4,603,411	4,882,514	199,626	4,682,889	940,319
49	Base FCR	2022	21,613,195	958,811	20,654,384	4,225,717	4,682,889	199,626	4,483,263	908,744
50	W Increased ROE	2022	21,613,195	958,811	20,654,384	4,441,728	4,682,889	199,626	4,483,263	908,744
51	Base FCR	2023	20,654,384	958,811	19,695,573	4,074,062	4,483,263	199,626	4,283,637	877,169
52	W Increased ROE	2023	20,654,384	958,811	19,695,573	4,280,045	4,483,263	199,626	4,283,637	877,169
53	Base FCR	2024	19,695,573	958,811	18,736,762	3,922,406	4,283,637	199,626	4,084,011	845,594
54	W Increased ROE	2024	19,695,573	958,811	18,736,762	4,118,363	4,283,637	199,626	4,084,011	845,594
55	Base FCR	2025	18,736,762	958,811	17,777,951	3,770,751	4,084,011	199,626	3,884,385	814,019
56	W Increased ROE	2025	18,736,762	958,811	17,777,951	3,956,680	4,084,011	199,626	3,884,385	814,019
57	Base FCR	2026	17,777,951	958,811	16,819,140	3,619,096	3,884,385	199,626	3,684,760	782,445
58	W Increased ROE	2026	17,777,951	958,811	16,819,140	3,794,997	3,884,385	199,626	3,684,760	782,445
59	Base FCR	2027	16,819,140	958,811	15,860,330	3,467,441	3,684,760	199,626	3,485,134	750,870
60	W Increased ROE	2027	16,819,140	958,811	15,860,330	3,633,314	3,684,760	199,626	3,485,134	750,870
61		....		....	.....	....		....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

ecember 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 auth

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
15.8170%	15.8170%	15.8170%	15.8170%
15.8170%	16.8628%	16.8628%	15.8170%
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
4,362,648	143,233	4,219,415	810,619	33,204,762	1,048,571	32,156,190	6,134,719	18,095,238	571,429	17,523,810	3,343,171	1,809,524	57,143	1,752,381	334,317
4,362,648	143,233	4,219,415	810,619	33,204,762	1,048,571	32,156,190	6,471,021	18,095,238	571,429	17,523,810	3,526,442	1,809,524	57,143	1,752,381	334,317
4,219,415	143,233	4,076,181	787,963	32,156,190	1,048,571	31,107,619	5,968,867	17,523,810	571,429	16,952,381	3,252,788	1,752,381	57,143	1,695,238	325,279
4,219,415	143,233	4,076,181	787,963	32,156,190	1,048,571	31,107,619	6,294,202	17,523,810	571,429	16,952,381	3,430,083	1,752,381	57,143	1,695,238	325,279
4,076,181	143,233	3,932,948	765,308	31,107,619	1,048,571	30,059,048	5,803,014	16,952,381	571,429	16,380,952	3,162,405	1,695,238	57,143	1,638,095	316,241
4,076,181	143,233	3,932,948	765,308	31,107,619	1,048,571	30,059,048	6,117,383	16,952,381	571,429	16,380,952	3,333,724	1,695,238	57,143	1,638,095	316,241
3,932,948	143,233	3,789,715	742,653	30,059,048	1,048,571	29,010,476	5,637,161	16,380,952	571,429	15,809,524	3,072,023	1,638,095	57,143	1,580,952	307,202
3,932,948	143,233	3,789,715	742,653	30,059,048	1,048,571	29,010,476	5,940,564	16,380,952	571,429	15,809,524	3,237,365	1,638,095	57,143	1,580,952	307,202
3,789,715	143,233	3,646,481	719,998	29,010,476	1,048,571	27,961,905	5,471,309	15,809,524	571,429	15,238,095	2,981,640	1,580,952	57,143	1,523,810	298,164
3,789,715	143,233	3,646,481	719,998	29,010,476	1,048,571	27,961,905	5,763,745	15,809,524	571,429	15,238,095	3,141,005	1,580,952	57,143	1,523,810	298,164
3,646,481	143,233	3,503,248	697,342	27,961,905	1,048,571	26,913,333	5,305,456	15,238,095	571,429	14,666,667	2,891,257	1,523,810	57,143	1,466,667	289,126
3,646,481	143,233	3,503,248	697,342	27,961,905	1,048,571	26,913,333	5,586,926	15,238,095	571,429	14,666,667	3,044,646	1,523,810	57,143	1,466,667	289,126
3,503,248	143,233	3,360,015	674,687	26,913,333	1,048,571	25,864,762	5,139,603	14,666,667	571,429	14,095,238	2,800,874	1,466,667	57,143	1,409,524	280,087
3,503,248	143,233	3,360,015	674,687	26,913,333	1,048,571	25,864,762	5,410,107	14,666,667	571,429	14,095,238	2,948,287	1,466,667	57,143	1,409,524	280,087
3,360,015	143,233	3,216,782	652,032	25,864,762	1,048,571	24,816,190	4,973,751	14,095,238	571,429	13,523,810	2,710,491	1,409,524	57,143	1,352,381	271,049
3,360,015	143,233	3,216,782	652,032	25,864,762	1,048,571	24,816,190	5,233,288	14,095,238	571,429	13,523,810	2,851,928	1,409,524	57,143	1,352,381	271,049
3,216,782	143,233	3,073,548	629,377	24,816,190	1,048,571	23,767,619	4,807,898	13,523,810	571,429	12,952,381	2,620,108	1,352,381	57,143	1,295,238	262,011
3,216,782	143,233	3,073,548	629,377	24,816,190	1,048,571	23,767,619	5,056,469	13,523,810	571,429	12,952,381	2,755,569	1,352,381	57,143	1,295,238	262,011
3,073,548	143,233	2,930,315	606,722	23,767,619	1,048,571	22,719,048	4,642,046	12,952,381	571,429	12,380,952	2,529,725	1,295,238	57,143	1,238,095	252,973
3,073,548	143,233	2,930,315	606,722	23,767,619	1,048,571	22,719,048	4,879,650	12,952,381	571,429	12,380,952	2,659,210	1,295,238	57,143	1,238,095	252,973
2,930,315	143,233	2,787,082	584,066	22,719,048	1,048,571	21,670,476	4,476,193	12,380,952	571,429	11,809,524	2,439,342	1,238,095	57,143	1,180,952	243,934
2,930,315	143,233	2,787,082	584,066	22,719,048	1,048,571	21,670,476	4,702,831	12,380,952	571,429	11,809,524	2,562,851	1,238,095	57,143	1,180,952	243,934
2,787,082	143,233	2,643,848	561,411	21,670,476	1,048,571	20,621,905	4,310,340	11,809,524	571,429	11,238,095	2,348,959	1,180,952	57,143	1,123,810	234,896
2,787,082	143,233	2,643,848	561,411	21,670,476	1,048,571	20,621,905	4,526,012	11,809,524	571,429	11,238,095	2,466,491	1,180,952	57,143	1,123,810	234,896
2,643,848	143,233	2,500,615	538,756	20,621,905	1,048,571	19,573,333	4,144,488	11,238,095	571,429	10,666,667	2,258,576	1,123,810	57,143	1,066,667	225,858
2,643,848	143,233	2,500,615	538,756	20,621,905	1,048,571	19,573,333	4,349,193	11,238,095	571,429	10,666,667	2,370,132	1,123,810	57,143	1,066,667	225,858
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orized by 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
15.8170%	15.8170%	15.8170%	15.8170%
15.8170%	15.8170%	15.8170%	16.8628%
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
1,809,524	57,143	1,752,381	334,317	1,809,524	57,143	1,752,381	334,317	1,828,571	57,143	1,771,429	337,330	14,741,426	453,582	14,287,844	2,713,492
1,809,524	57,143	1,752,381	334,317	1,809,524	57,143	1,752,381	334,317	1,828,571	57,143	1,771,429	337,330	14,741,426	453,582	14,287,844	2,862,920
1,752,381	57,143	1,695,238	325,279	1,752,381	57,143	1,695,238	325,279	1,771,429	57,143	1,714,286	328,292	14,287,844	453,582	13,834,261	2,641,749
1,752,381	57,143	1,695,238	325,279	1,752,381	57,143	1,695,238	325,279	1,771,429	57,143	1,714,286	328,292	14,287,844	453,582	13,834,261	2,786,433
1,695,238	57,143	1,638,095	316,241	1,695,238	57,143	1,638,095	316,241	1,714,286	57,143	1,657,143	319,253	13,834,261	453,582	13,380,679	2,570,006
1,695,238	57,143	1,638,095	316,241	1,695,238	57,143	1,638,095	316,241	1,714,286	57,143	1,657,143	319,253	13,834,261	453,582	13,380,679	2,709,946
1,638,095	57,143	1,580,952	307,202	1,638,095	57,143	1,580,952	307,202	1,657,143	57,143	1,600,000	310,215	13,380,679	453,582	12,927,097	2,498,263
1,638,095	57,143	1,580,952	307,202	1,638,095	57,143	1,580,952	307,202	1,657,143	57,143	1,600,000	310,215	13,380,679	453,582	12,927,097	2,633,459
1,580,952	57,143	1,523,810	298,164	1,580,952	57,143	1,523,810	298,164	1,600,000	57,143	1,542,857	301,177	12,927,097	453,582	12,473,514	2,426,519
1,580,952	57,143	1,523,810	298,164	1,580,952	57,143	1,523,810	298,164	1,600,000	57,143	1,542,857	301,177	12,927,097	453,582	12,473,514	2,556,972
1,523,810	57,143	1,466,667	289,126	1,523,810	57,143	1,466,667	289,126	1,542,857	57,143	1,485,714	292,138	12,473,514	453,582	12,019,932	2,354,776
1,523,810	57,143	1,466,667	289,126	1,523,810	57,143	1,466,667	289,126	1,542,857	57,143	1,485,714	292,138	12,473,514	453,582	12,019,932	2,480,485
1,466,667	57,143	1,409,524	280,087	1,466,667	57,143	1,409,524	280,087	1,485,714	57,143	1,428,571	283,100	12,019,932	453,582	11,566,350	2,283,033
1,466,667	57,143	1,409,524	280,087	1,466,667	57,143	1,409,524	280,087	1,485,714	57,143	1,428,571	283,100	12,019,932	453,582	11,566,350	2,403,998
1,409,524	57,143	1,352,381	271,049	1,409,524	57,143	1,352,381	271,049	1,428,571	57,143	1,371,429	274,062	11,566,350	453,582	11,112,767	2,211,290
1,409,524	57,143	1,352,381	271,049	1,409,524	57,143	1,352,381	271,049	1,428,571	57,143	1,371,429	274,062	11,566,350	453,582	11,112,767	2,327,511
1,352,381	57,143	1,295,238	262,011	1,352,381	57,143	1,295,238	262,011	1,371,429	57,143	1,314,286	265,024	11,112,767	453,582	10,659,185	2,139,547
1,352,381	57,143	1,295,238	262,011	1,352,381	57,143	1,295,238	262,011	1,371,429	57,143	1,314,286	265,024	11,112,767	453,582	10,659,185	2,251,025
1,295,238	57,143	1,238,095	252,973	1,295,238	57,143	1,238,095	252,973	1,314,286	57,143	1,257,143	255,985	10,659,185	453,582	10,205,603	2,067,804
1,295,238	57,143	1,238,095	252,973	1,295,238	57,143	1,238,095	252,973	1,314,286	57,143	1,257,143	255,985	10,659,185	453,582	10,205,603	2,174,538
1,238,095	57,143	1,180,952	243,934	1,238,095	57,143	1,180,952	243,934	1,257,143	57,143	1,200,000	246,947	10,205,603	453,582	9,752,020	1,996,060
1,238,095	57,143	1,180,952	243,934	1,238,095	57,143	1,180,952	243,934	1,257,143	57,143	1,200,000	246,947	10,205,603	453,582	9,752,020	2,098,051
1,180,952	57,143	1,123,810	234,896	1,180,952	57,143	1,123,810	234,896	1,200,000	57,143	1,142,857	237,909	9,752,020	453,582	9,298,438	1,924,317
1,180,952	57,143	1,123,810	234,896	1,180,952	57,143	1,123,810	234,896	1,200,000	57,143	1,142,857	237,909	9,752,020	453,582	9,298,438	2,021,564
1,123,810	57,143	1,066,667	225,858	1,123,810	57,143	1,066,667	225,858	1,142,857	57,143	1,085,714	228,870	9,298,438	453,582	8,844,856	1,852,574
1,123,810	57,143	1,066,667	225,858	1,123,810	57,143	1,066,667	225,858	1,142,857	57,143	1,085,714	228,870	9,298,438	453,582	8,844,856	1,945,077
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

BO499 Burches Hill Sub: Add 3rd 500/230kV

Yes
35
No
150
15.8170%
16.8628%
29,544,357
844,124
6.00

Beginning	Depreciation	Ending	Revenue
27,434,046	844,124	26,589,921	5,049,855
27,434,046	844,124	26,589,921	5,327,942
26,589,921	844,124	25,745,797	4,916,340
26,589,921	844,124	25,745,797	5,185,599
25,745,797	844,124	24,901,672	4,782,825
25,745,797	844,124	24,901,672	5,043,256
24,901,672	844,124	24,057,548	4,649,309
24,901,672	844,124	24,057,548	4,900,912
24,057,548	844,124	23,213,423	4,515,794
24,057,548	844,124	23,213,423	4,758,569
23,213,423	844,124	22,369,299	4,382,279
23,213,423	844,124	22,369,299	4,616,225
22,369,299	844,124	21,525,174	4,248,764
22,369,299	844,124	21,525,174	4,473,882
21,525,174	844,124	20,681,050	4,115,248
21,525,174	844,124	20,681,050	4,331,538
20,681,050	844,124	19,836,925	3,981,733
20,681,050	844,124	19,836,925	4,189,195
19,836,925	844,124	18,992,801	3,848,218
19,836,925	844,124	18,992,801	4,046,852
18,992,801	844,124	18,148,676	3,714,702
18,992,801	844,124	18,148,676	3,904,508
18,148,676	844,124	17,304,552	3,581,187
18,148,676	844,124	17,304,552	3,762,165
17,304,552	844,124	16,460,427	3,447,672
17,304,552	844,124	16,460,427	3,619,821
....	....	.....	....
....	.....	.....	....

BO526 Ritchie-Benning: Install (2) 230kV Lines

Yes
35
No
0
15.8170%
15.8170%
58,581,170
1,673,748
6.00

Beginning	Depreciation	Ending	Revenue
54,396,801	1,673,748	52,723,053	10,012,958
54,396,801	1,673,748	52,723,053	10,012,958
52,723,053	1,673,748	51,049,305	9,748,222
52,723,053	1,673,748	51,049,305	9,748,222
51,049,305	1,673,748	49,375,558	9,483,485
51,049,305	1,673,748	49,375,558	9,483,485
49,375,558	1,673,748	47,701,810	9,218,748
49,375,558	1,673,748	47,701,810	9,218,748
47,701,810	1,673,748	46,028,062	8,954,011
47,701,810	1,673,748	46,028,062	8,954,011
46,028,062	1,673,748	44,354,314	8,689,274
46,028,062	1,673,748	44,354,314	8,689,274
44,354,314	1,673,748	42,680,567	8,424,537
44,354,314	1,673,748	42,680,567	8,424,537
42,680,567	1,673,748	41,006,819	8,159,800
42,680,567	1,673,748	41,006,819	8,159,800
41,006,819	1,673,748	39,333,071	7,895,064
41,006,819	1,673,748	39,333,071	7,895,064
39,333,071	1,673,748	37,659,324	7,630,327
39,333,071	1,673,748	37,659,324	7,630,327
37,659,324	1,673,748	35,985,576	7,365,590
37,659,324	1,673,748	35,985,576	7,365,590
35,985,576	1,673,748	34,311,828	7,100,853
35,985,576	1,673,748	34,311,828	7,100,853
34,311,828	1,673,748	32,638,080	6,836,116
34,311,828	1,673,748	32,638,080	6,836,116
....	....	.....	....
....	.....	.....	....

BO701.1 Benning Sub: Add 3rd 230/69kV, 250MVA

Yes
35
No
0
15.8170%
15.8170%
5,226,954
149,342
6.00

Beginning	Depreciation	Ending	Revenue
4,853,600	149,342	4,704,259	893,415
4,853,600	149,342	4,704,259	893,415
4,704,259	149,342	4,554,917	869,793
4,704,259	149,342	4,554,917	869,793
4,554,917	149,342	4,405,576	846,172
4,554,917	149,342	4,405,576	846,172
4,405,576	149,342	4,256,234	822,551
4,405,576	149,342	4,256,234	822,551
4,256,234	149,342	4,106,892	798,929
4,256,234	149,342	4,106,892	798,929
4,106,892	149,342	3,957,551	775,308
4,106,892	149,342	3,957,551	775,308
3,957,551	149,342	3,808,209	751,686
3,957,551	149,342	3,808,209	751,686
3,808,209	149,342	3,658,868	728,065
3,808,209	149,342	3,658,868	728,065
3,658,868	149,342	3,509,526	704,444
3,658,868	149,342	3,509,526	704,444
3,509,526	149,342	3,360,185	680,822
3,509,526	149,342	3,360,185	680,822
3,360,185	149,342	3,210,843	657,201
3,360,185	149,342	3,210,843	657,201
3,210,843	149,342	3,061,502	633,580
3,210,843	149,342	3,061,502	633,580
3,061,502	149,342	2,912,160	609,958
3,061,502	149,342	2,912,160	609,958
....	....	.....	....
....	.....	.....	....

BO496 Brighton Sub: Upgrade T1 500/230kv Transormer

Yes
35
No
150
15.8170%
16.8628%
19,021,804
543,480
2.00

Beginning	Depreciation	Ending	Revenue
18,210,725	543,480	17,667,244	3,337,910
18,210,725	543,480	17,667,244	3,522,681
17,667,244	543,480	17,123,764	3,251,948
17,667,244	543,480	17,123,764	3,431,034
17,123,764	543,480	16,580,284	3,165,985
17,123,764	543,480	16,580,284	3,339,388
16,580,284	543,480	16,036,804	3,080,023
16,580,284	543,480	16,036,804	3,247,742
16,036,804	543,480	15,493,324	2,994,061
16,036,804	543,480	15,493,324	3,156,096
15,493,324	543,480	14,949,844	2,908,098
15,493,324	543,480	14,949,844	3,064,450
14,949,844	543,480	14,406,364	2,822,136
14,949,844	543,480	14,406,364	2,972,803
14,406,364	543,480	13,862,884	2,736,174
14,406,364	543,480	13,862,884	2,881,157
13,862,884	543,480	13,319,404	2,650,212
13,862,884	543,480	13,319,404	2,789,511
13,319,404	543,480	12,775,923	2,564,249
13,319,404	543,480	12,775,923	2,697,865
12,775,923	543,480	12,232,443	2,478,287
12,775,923	543,480	12,232,443	2,606,218
12,232,443	543,480	11,688,963	2,392,325
12,232,443	543,480	11,688,963	2,514,572
11,688,963	543,480	11,145,483	2,306,362
11,688,963	543,480	11,145,483	2,422,926
....	....	.....	....
....	.....	.....	....

B1125 Convert Buzzard to Ritchie Line - 138kV to 230kV	b2008 Reconductor feeder Dickerson to Quince Orchard
Yes	Yes
35	35
No	No
0	0
15.8170%	15.8170%
15.8170%	15.8170%
51,852,352	8,172,728
1,481,496	233,507
10.00	2.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
51,571,154	1,481,496	50,089,658	9,404,182	8,172,728	194,589	7,978,139	1,456,492	$ 50,914,166		$ 50,914,166
51,571,154	1,481,496	50,089,658	9,404,182	8,172,728	194,589	7,978,139	1,456,492	$ 52,332,228	$ 52,332,228	
50,089,658	1,481,496	48,608,162	9,169,854	7,978,139	233,507	7,744,633	1,458,476	$ 49,603,968		$ 49,603,968
50,089,658	1,481,496	48,608,162	9,169,854	7,978,139	233,507	7,744,633	1,458,476	$ 50,975,805	$ 50,975,805	
48,608,162	1,481,496	47,126,667	8,935,525	7,744,633	233,507	7,511,126	1,421,542	$ 48,254,853		$ 48,254,853
48,608,162	1,481,496	47,126,667	8,935,525	7,744,633	233,507	7,511,126	1,421,542	$ 49,580,464	$ 49,580,464	
47,126,667	1,481,496	45,645,171	8,701,197	7,511,126	233,507	7,277,620	1,384,608	$ 46,905,738		$ 46,905,738
47,126,667	1,481,496	45,645,171	8,701,197	7,511,126	233,507	7,277,620	1,384,608	$ 48,185,123	$ 48,185,123	
45,645,171	1,481,496	44,163,675	8,466,869	7,277,620	233,507	7,044,113	1,347,675	$ 45,556,623		$ 45,556,623
45,645,171	1,481,496	44,163,675	8,466,869	7,277,620	233,507	7,044,113	1,347,675	$ 46,789,782	$ 46,789,782	
44,163,675	1,481,496	42,682,179	8,232,540	7,044,113	233,507	6,810,607	1,310,741	$ 44,207,508		$ 44,207,508
44,163,675	1,481,496	42,682,179	8,232,540	7,044,113	233,507	6,810,607	1,310,741	$ 45,394,441	$ 45,394,441	
42,682,179	1,481,496	41,200,683	7,998,212	6,810,607	233,507	6,577,100	1,273,807	$ 42,858,393		$ 42,858,393
42,682,179	1,481,496	41,200,683	7,998,212	6,810,607	233,507	6,577,100	1,273,807	$ 43,999,100	$ 43,999,100	
41,200,683	1,481,496	39,719,188	7,763,884	6,577,100	233,507	6,343,594	1,236,873	$ 41,509,278		$ 41,509,278
41,200,683	1,481,496	39,719,188	7,763,884	6,577,100	233,507	6,343,594	1,236,873	$ 42,603,759	$ 42,603,759	
39,719,188	1,481,496	38,237,692	7,529,555	6,343,594	233,507	6,110,087	1,199,940	$ 40,160,163		$ 40,160,163
39,719,188	1,481,496	38,237,692	7,529,555	6,343,594	233,507	6,110,087	1,199,940	$ 41,208,418	$ 41,208,418	
38,237,692	1,481,496	36,756,196	7,295,227	6,110,087	233,507	5,876,581	1,163,006	$ 38,811,048		$ 38,811,048
38,237,692	1,481,496	36,756,196	7,295,227	6,110,087	233,507	5,876,581	1,163,006	$ 39,813,077	$ 39,813,077	
36,756,196	1,481,496	35,274,700	7,060,899	5,876,581	233,507	5,643,074	1,126,072	$ 37,461,933		$ 37,461,933
36,756,196	1,481,496	35,274,700	7,060,899	5,876,581	233,507	5,643,074	1,126,072	$ 38,417,736	$ 38,417,736	
35,274,700	1,481,496	33,793,205	6,826,570	5,643,074	233,507	5,409,568	1,089,138	$ 36,112,818		$ 36,112,818
35,274,700	1,481,496	33,793,205	6,826,570	5,643,074	233,507	5,409,568	1,089,138	$ 37,022,395	$ 37,022,395	
33,793,205	1,481,496	32,311,709	6,592,242	5,409,568	233,507	5,176,061	1,052,205	$ 34,763,703		$ 34,763,703
33,793,205	1,481,496	32,311,709	6,592,242	5,409,568	233,507	5,176,061	1,052,205	$ 35,627,054	$ 35,627,054	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 775,850,650	$ 754,122,631

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		Notes	FERC Form 1 Page # or Instruction	2014 Data
Shaded cells are input cells				
Allocators				
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	8,815,908
2	Total Wages Expense		p354.28.b	90,980,746
3	Less A&G Wages Expense		p354.27.b	923,526
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	90,057,220
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**9.7892%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g	7,865,810,412
7	Accumulated Depreciation (Total Electric Plant)	(Note J)	p219.29.c	2,452,333,917
8	Accumulated Amortization	(Note A)	p200.21.c	56,047,108
9	Total Accumulated Depreciation		(Line 7 + 8)	2,508,381,025
10	Net Plant		(Line 6 - Line 9)	5,357,429,387
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 25 - Line 24)	2,897,800,742
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**36.8405%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 33 - Line 24)	2,347,417,200
14	**Net Plant Allocator**		(Line 13 / Line 10)	**43.8161%**
Plant Calculations				
	Plant In Service			
15	Transmission Plant In Service	(Note B)	p207.58.g	2,358,508,164
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	463,387,824
18	**Total Transmission Plant**		(Line 15 - Line 16 + Line 17)	**2,821,895,988**
19	General		p207.99.g	668,148,916
20	Intangible		p205.5.g	107,241,562
21	Total General and Intangible Plant		(Line 19 + Line 20)	775,390,478
22	Wage & Salary Allocator		(Line 5)	9.7892%
23	**Total General and Intangible Functionalized to Transmission**		(Line 21 * Line 22)	**75,904,754**
24	**Land Held for Future Use**	(Note C) (Note P)	Attachment 5	**45,055,773**
25	**Total Plant In Rate Base**		**(Line 18 + Line 23 + Line 24)**	**2,942,856,515**
	Accumulated Depreciation			
26	Transmission Accumulated Depreciation	(Note J)	p219.25.c	**522,273,974**
27	Accumulated General Depreciation	(Note J)	p219.28.c	231,100,809
28	Accumulated Amortization		(Line 8)	56,047,108
29	Total Accumulated Depreciation		(Line 27 + 28)	287,147,917
30	Wage & Salary Allocator		(Line 5)	9.7892%
31	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 29 * Line 30)	28,109,569
32	**Total Accumulated Depreciation**		**(Sum Lines 26 + 31)**	**550,383,543**
33	**Total Net Property, Plant & Equipment**		**(Line 25 - Line 32)**	**2,392,472,973**

Line	Description	Notes	Source	Amount
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
34	**ADIT net of FASB 106 and 109**		Attachment 1	**-254,573,497**
	CWIP for Incentive Transmission Projects			
35	CWIP Balances for Current Rate Year	(Note H)	Attachment 6	**226,463,298**
	Prepayments			
36	Prepayments	(Note A) (Note O)	Attachment 5	**688,517**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	p227.16.c	3,087,009
38	Wage & Salary Allocator		(Line 5)	9.7892%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	302,194
40	Transmission Materials & Supplies		p227.8.c	9,126,625
41	**Total Materials & Supplies Allocated to Transmission**		(Line 39 + Line 40)	**9,428,819**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 70)	55,820,719
43	1/8th Rule		1/8	12.5%
44	**Total Cash Working Capital Allocated to Transmission**		(Line 42 * Line 43)	**6,977,590**
45	**Total Adjustment to Rate Base**		(Lines 34 + 35 + 36 + 41 + 44)	**-11,015,273**
46	**Rate Base**		(Line 33 + Line 45)	**2,381,457,700**
	Operations & Maintenance Expense			
	Transmission O&M			
47	Transmission O&M		Attachment 5	121,522,011
48	Less Account 565		Attachment 5	80,276,320
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)	**41,245,691**
	Allocated Administrative & General Expenses			
51	Total A&G		323.197b	151,566,641
52	Less: Administrative & General Expenses on Securitization Bonds	(Note O)	Attachment 8	0
53	Plus: Fixed PBOP expense	(Note J)	Attachment 5	1,518,585
54	Less: Actual PBOP expense		Attachment 5	1,518,585
55	Less Property Insurance Account 924		p323.185.b	743,818
56	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	5,263,709
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)	145,559,114
60	Wage & Salary Allocator		(Line 5)	9.7892%
61	**Administrative & General Expenses Allocated to Transmission**		(Line 59 * Line 60)	**14,249,116**
	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	743,818
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 924 and 930.1 - General		(Line 65 + Line 66)	743,818
68	Net Plant Allocator		(Line 14)	43.8161%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**325,912**
70	**Total Transmission O&M**		**(Lines 50 + 61 + 64 + 69)**	**55,820,719**

	Depreciation & Amortization Expense				
	Depreciation Expense				
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	**36,526,694**
72	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	20,132,932
73	Intangible Amortization		(Note A)	p336.1.d&e	20,140,847
74	Total			(Line 72 + Line 73)	40,273,779
75	Wage & Salary Allocator			(Line 5)	9.7892%
76	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 74 * Line 75)	**3,942,493**
77	**Total Transmission Depreciation & Amortization**			**(Lines 71 + 76)**	**40,469,187**
	Taxes Other than Income Taxes				
78	**Taxes Other than Income Taxes**			Attachment 2	**3,134,513**
79	**Total Taxes Other than Income Taxes**			**(Line 78)**	**3,134,513**
	Return \ Capitalization Calculations				
	Long Term Interest				
80	Long Term Interest			p117.62.c through 66.c	123,860,728
81	Less LTD Interest on Securitization Bonds		(Note O)	Attachment 8	0
82	**Long Term Interest**			(Line 80 - Line 81)	**123,860,728**
83	**Preferred Dividends**		enter positive	p118.29.c	-
	Common Stock				
84	Proprietary Capital			p112.16.c	2,715,813,040
85	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	31,470
86	Less Preferred Stock			(Line 94)	0
87	Less Account 216.1			p112.12.c	10,261,435
88	**Common Stock**			(Line 84 - 85 - 86 - 87)	**2,705,520,135**
	Capitalization				
89	Long Term Debt			p112.18.c, 19.c & 21.c	2,613,750,000
90	Less Loss on Reacquired Debt			p111.81.c	49,403,653
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)	2,564,346,347
94	Preferred Stock			p112.3.c	0
95	Common Stock			(Line 88)	2,705,520,135
96	**Total Capitalization**			(Sum Lines 93 to 95)	**5,269,866,482**
97	Debt %	Total Long Term Debt		(Line 93 / Line 96)	48.7%
98	Preferred %	Preferred Stock		(Line 94 / Line 96)	0.0%
99	Common %	Common Stock		(Line 95 / Line 96)	51.3%
100	Debt Cost	Total Long Term Debt		(Line 82 / Line 93)	0.0483
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)	0.0235
104	Weighted Cost of Preferred	Preferred Stock		(Line 98 * Line 101)	0.0000
105	Weighted Cost of Common	Common Stock		(Line 99 * Line 102)	0.0600
106	**Rate of Return on Rate Base (ROR)**			(Sum Lines 103 to 105)	**0.0835**
107	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 106)**	**198,775,631**

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	-20,102
114	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 113 * (1 / (1 - Line 111))	**-34,359**
115	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 112 * Line 107 * (1- (Line 103 / Line 106))]	**101,277,465**
116	**Total Income Taxes**		**(Line 114 + Line 115)**	**101,243,107**

Revenue Requirement

	Summary			
117	Net Property, Plant & Equipment		(Line 33)	2,392,472,973
118	Total Adjustment to Rate Base		(Line 45)	-11,015,273
119	Rate Base		(Line 46)	2,381,457,700
120	Total Transmission O&M		(Line 70)	55,820,719
121	Total Transmission Depreciation & Amortization		(Line 77)	40,469,187
122	Taxes Other than Income		(Line 79)	3,134,513
123	Investment Return		(Line 107)	198,775,631
124	Income Taxes		(Line 116)	101,243,107
125	**Gross Revenue Requirement**		**(Sum Lines 120 to 124)**	**399,443,156**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Transmission Plant In Service		(Line 15)	2,358,508,164
127	Excluded Transmission Facilities	(Note M)	Attachment 5	0
128	Included Transmission Facilities		(Line 126 - Line 127)	2,358,508,164
129	Inclusion Ratio		(Line 128 / Line 126)	100.00%
130	Gross Revenue Requirement		(Line 125)	399,443,156
131	**Adjusted Gross Revenue Requirement**		(Line 129 * Line 130)	**399,443,156**
	Revenue Credits			
132	**Revenue Credits**		Attachment 3	**81,044,983**
133	**Net Revenue Requirement**		**(Line 131 - Line 132)**	**318,398,173**
	Net Plant Carrying Charge			
134	Gross Revenue Requirement		(Line 130)	**399,443,156**
135	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**2,526,085,312**
136	Net Plant Carrying Charge		(Line 134 / Line 135)	**15.8127%**
137	Net Plant Carrying Charge without Depreciation		(Line 134 - Line 71) / Line 135	**14.3668%**
138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 134 - Line 71 - Line 107 - Line 116) / Line 135	**2.4899%**
	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)	**99,424,418**
140	Increased Return and Taxes		Attachment 4	**320,916,025**
141	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 139 + Line 140)	**420,340,443**
142	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**2,526,085,312**
143	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 141 / Line 142)	**16.6400%**
144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 141 - Line 71) / Line 142	**15.1940%**
145	**Net Revenue Requirement**		(Line 133)	**318,398,173**
146	True-up amount		Attachment 6	**(53,949,038)**
147	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**-**
148	**Net Zonal Revenue Requirement**		(Line 145 + 146 + 147)	**264,449,135**
	Network Zonal Service Rate			
149	1 CP Peak	(Note L)	PJM Data	**8,038.0**
150	Rate ($/MW-Year)		(Line 148 / 149)	**$ 32,900**
151	**Network Service Rate ($/MW/Year)**		**(Line 150)**	**$ 32,900**

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	(286,260,355)	0	(60,949,782)		From Acct. 282 total, below
ADIT-283	0	(20,499,305)	(623,801)		From Acct. 283 total, below
ADIT-190	43,509,034	0	32,560,289		From Acct. 190 total, below
Subtotal	(242,751,321)	(20,499,305)	(29,013,294)		Sum lines 1 through 3
Wages & Salary Allocator			9.7892%		
Net Plant Allocator		43.8161%			
ADIT	(242,751,321)	(8,981,998)	(2,840,178)	(254,573,497)	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	B	C	D	E	F	G
ADIT-190	***Total***	***Gas, Prod, Dist Or Other Related***	***Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Account 190						
Accumulated Deferred Investment Tax Credits (Non-Transmission)	220,701	220,701				Basis difference between book plant and tax plant basis related to investment tax credits on distribution property.
Accumulated Deferred Investment Tax Credits (Transmission)	130,590		130,590			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)	156,527	156,527				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)	92,613		92,613			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)	87,986,538	87,986,538				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)	22,003,610		22,003,610			Transmission related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Pensions and Post-Retirement	7,315,807	7,315,807				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes.
FAS158 Regulatory Liability	154,465,716	154,465,716				Liability recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Bad Debts	9,071,640	9,071,640				Retail related book expense not deductible for tax return purposes.
Service Company Labor Related Costs	28,237,092				28,237,092	Book expense not deductible for tax return purposes - labor related to all functions.
Service Company Other Related Costs	(13,930,335)	(13,930,335)				Book expense not deductible for tax return purposes.
Vacation Pay	3,885,863				3,885,863	Book expense not deductible for tax return purposes - labor related to all functions.
Severance Pay	424,077	424,077				Book expense not deductible for tax return purposes - related to Talen transaction.
Deferred Compensation	437,334				437,334	Book expense not deductible for tax return purposes - labor related to all functions.
Taxes Other Than Income Taxes	9,119,938	9,119,938				Book expense not deductible for tax return purposes - retail related gross receipts and sales & use taxes.
AMT Tax Carryforward	706,647	706,647				Tax credits carryforward to a future period.
RAR Adjustments	(3,934,460)	(3,934,460)				Distribution related IRS audit adjustments.
Environmental Liability	2,240,658	2,240,658				Distribution related book expense for manufactured gas plants not deductible for tax return purposes.
Post Employment Liabilities	2,862,625	2,862,625				Book expense not deductible for tax return purposes.
State NOL Carryforwards	30,421,915	30,421,915				State net operating loss carryforward.
Tax Credit Carryforward	129,382	129,382				Tax credits carryforward to a future period.
Conservation Program Regulatory Asset	7,417,842	7,417,842				Distribution related expense deferred for book purposes and deducted for tax purposes.
Generation Service Charge over/undercollection	11,713,278	11,713,278				Distribution related expense deferred for book purposes and deducted for tax purposes.
Transmission Formula Rate over/undercollection	17,505,864		17,505,864			Transmission related expense deferred for book purposes and deducted for tax purposes.
Distribution System Improvement Charge over/undercollection	897,944	897,944				Distribution related expense deferred for book purposes and deducted for tax purposes.
Competitive Enhancement Rider over/undercollections	32,027	32,027				Distribution related expense deferred for book purposes and deducted for tax purposes.
Storm Damage over/undercollection	1,424,620	1,424,620				Distribution related expense deferred for book purposes and deducted for tax purposes.
Book Contingencies	563,315	563,315				Distribution related book expense not deductible for tax return purposes.
Charitable Contribution Carryforward	464,320	464,320				Distribution related tax deduction carryforward to a future period.
Federal NOL Carryforward	50,498,199	46,498,639	3,999,560			Federal net operating loss carryforward.
Deferred Intercompany Transactions	(1,614,015)	(1,614,015)				Retail related income recorded for book purposes not includable in taxable income - related to receivables factoring.
Subtotal - p234	430,947,872	354,655,346	43,732,237	0	32,560,289	
Less FASB 109 Above if not separately removed	600,431	377,228	223,203			
Less FASB 106 Above if not separately removed	6,015,505	6,015,505				
Total	424,331,936	348,262,613	43,509,034	0	32,560,289	

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.

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)	(614,724,640)	(614,724,640)				Deductions for distribution related tax depreciation in excess of book depreciation at federal rate.
ACRS/MACRS Property (General Plant)	(55,640,099)				(55,640,099)	Deductions for general plant related tax depreciation in excess of book depreciation at applicable federal and state rates.
ACRS/MACRS Property (Transmission)	(252,304,400)		(252,304,400)			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	(186,773,317)	(186,773,317)				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)	(325,347,998)	(325,347,998)				Basis difference between Distribution related book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (General Plant)	1,663,416				1,663,416	Basis difference between book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (Tx-related)	(33,910,545)		(33,910,545)			Basis difference between Transmission related plant and tax plant basis at federal & state rates.
RAR adjustments related to plant (Non-Transmission)	13,371,624	13,371,624				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	8,777,955	8,777,955				Agreed to IRS audit adjustments related to Distribution plant.
Non-Utility Property	(84,471)	(84,471)				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	(1,451,990,984)	(1,104,780,847)	(286,260,355)	0	(60,949,782)	
Less FASB 109 Above if not separately removed	(186,773,317)	(186,773,317)				
Less FASB 106 Above if not separately removed	0					
Total	(1,265,217,667)	(918,007,530)	(286,260,355)	0	(60,949,782)	

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	(20,499,305)			(20,499,305)		Plant related expense deferred for book purposes and deducted for tax purposes.
FAS 109 regulatory assets/liabilities	(132,461,848)	(132,461,848)				Asset recorded for regulatory purposes related to book and tax basis plant and non-plant differences.
Pension and post-retirement	(70,904,118)	(70,904,118)				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes.
FAS158 Regulatory Asset	(154,465,715)	(154,465,715)				Asset recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Storms Deferrals	(19,005,346)	(19,005,346)				Distribution related expense deferred for book purposes and deducted for tax purposes.
RAR Adjustments	(291,176)	(291,176)				Distribution related IRS audit adjustments.
Clearing accounts	(623,801)				(623,801)	Expense deferred for book purposes and deducted for tax purposes.
Receivables Factoring	(7,805,564)	(7,805,564)				Retail related income recorded for book purposes not includable in taxable income.
Prepaid Insurance	(1,464,034)	(1,464,034)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Universal Service Rider over/undercollection	(1,467,264)	(1,467,264)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Transmission Service Charge over/undercollections	(2,546,629)	(2,546,629)				Retail related book expense not deductible for tax return purposes.
Unrealized gains/losses	(22,320)	(22,320)				Equity adjustment for book purposes not includable in taxable income.
Deferred intercompany gain - trademark sale	(220,396)	(220,396)				Income recorded for book purposes not includable in taxable income.
Smart Meter Technology Regulatory Asset	(1,030,404)	(1,030,404)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Subtotal - p277	(412,807,920)	(391,684,814)	0	(20,499,305)	(623,801)	
Less FASB 109 Above if not separately removed	(132,461,848)	(132,461,848)				
Less FASB 106 Above if not separately removed	0	0				
Total	(280,346,072)	(259,222,966)	0	(20,499,305)	(623,801)	

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)	2,952,723		
2	PURTA	2,130,148		
3				
4				
5				
6				
7				
8	**Total Plant Related**	5,082,871	43.8161%	2,227,116
	Labor Related		**Wages & Salary Allocator**	
9	Federal FICA	6,614,493		
10	Federal Unemployment	41,875		
11	State Unemployment	339,765		
12				
13				
14	**Total Labor Related**	6,996,133	9.7892%	684,868
	Other Included		**Net Plant Allocator**	
15	PA Capital Stock Tax	507,870		
16				
17				
18				
19	**Total Other Included**	507,870	43.8161%	222,529
20	**Total Included (Lines 8 + 14 + 19)**	12,586,874		3,134,513
	Currently Excluded			
21	Gross Receipts	101,943,873		
22	Sales and Use	(28,591)		
23				
24				
25				
26				
27				
28	**Subtotal, Excluded**	101,915,282		
29	**Total, Included and Excluded (Line 20 + Line 28)**	114,502,156		
30	**Total Other Taxes from p114.14.c less Tax on Securitization Bonds**	114,502,156		
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.

PPL Electric Utilities Corporation

Attachment 3 - Revenue Credit Worksheet

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related		1,991,770
	Account 456 - Other Electric Revenues (Note 1)		
2	Transmission for Others (Note 3)		-
3	Schedule 12 Revenues (Note 3)		70,646,865
4	Schedule 1A		2,720,496
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)		3,654,297
7	Professional Services provided to others		1,384,911
8	Facilities Charges including Interconnection Agreements (Note 2)		646,644
9	Gross Revenue Credits	(Sum Lines 1-10)	81,044,983
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	320,916,025
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Attachment A Line 46)	2,381,457,700
	Long Term Interest			
2	Long Term Interest		(Attachment A Line 80)	123,860,728
3	Less LTD Interest on Securitization Bonds		Attachment 8	-
4	Long Term Interest		(Line 2 - Line 3)	123,860,728
5	**Preferred Dividends**	enter positive	p118.29.c	0
	Common Stock			
6	Proprietary Capital		p112.16.c	2,715,813,040
7	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	31,470
8	Less Preferred Stock		(Attachment A Line 86)	0
9	Less Account 216.1		p112.12.c	10,261,435
10	Common Stock		(Line 6 - 7 - 8 - 9)	2,705,520,135
	Capitalization			
11	Long Term Debt		p112.18.c, 19.c & 21.c	2,613,750,000
12	Less Loss on Reacquired Debt		p111.81.c	49,403,653
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)	2,564,346,347
16	Preferred Stock		p112.3.c	0
17	Common Stock		(Line 10)	2,705,520,135
18	Total Capitalization		(Sum Lines 15 to 17)	5,269,866,482
19	Debt %	Total Long Term Debt	(Line 15 / Line 18)	48.7%
20	Preferred %	Preferred Stock	(Line 16 / Line 18)	0.0%
21	Common %	Common Stock	(Line 17 / Line 18)	51.3%
22	Debt Cost	Total Long Term Debt	(Line 4 / Line 15)	0.0483
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)	0.0235
26	Weighted Cost of Preferred	Preferred Stock	(Line 20 * Line 23)	0.0000
27	Weighted Cost of Common	Common Stock	(Line 21 * Line 24)	0.0651
28	**Rate of Return on Rate Base (ROR)**		(Sum Lines 25 to 27)	**0.0886**
29	**Investment Return = Rate Base * Rate of Return**		**(Line 1 * Line 28)**	**211,001,902**

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	(20,102)
37	**ITC Adjust. Allocated to Trans. - Grossed Up**		(Line 36 * (1 / (1 - Line 33)	**-34,359**
38	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		109,948,481
39	**Total Income Taxes**			**109,914,123**

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	-1,434,969	-20,102	-1,414,867	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 &	47,962,529	40,351,104	4,704,669	2,906,756	
			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
					40,351,104	4,704,669		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	1,518,585			
54	Actual PBOP expense	Company Records	1,518,585			Current year actual PBOP expense
65	Property Insurance Account 924	p323.185.b	743,818	0	743,818	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	5,263,709	0	5,263,709	

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	-		-	-

Attachment 5 - Cost Support

Excluded Plant Cost Support

				Excluded Transmission Facilities	Description of the Facilities
	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				
	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	9,795,107	0	2,761,693	7,033,414	9.7892%	688,517	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	121,863,700	341,689	121,522,011	Adjustment for Ancillary Services p321.88b and p321.92b.
48	Less Account 565	p.321.96.b	80,276,320	0	80,276,320	**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	**8,038.0**	

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 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013	Total	5 - Year Amortization
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	33,149,776							
	Transmission Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	3,376,918	2,342,429	1,932,133	3,323,131	5,552,205	3,734,692	16,884,590	3,376,918
	Total Transmission Depreciation Expense Including Amortization of Limited Term	(Note J)	Company Records	36,526,694							
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	21,202,381							
	General Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	-1,069,449	-2,236,807	-1,205,818	-563,798	-956,740	-384,081	-5,347,244	-1,069,449
	Total General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	20,132,932							

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)

$ 220,796,523 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 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)
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		
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	3,360,353.94	11,489,610
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
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
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
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
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
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
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
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
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
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
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
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

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A	120,856,388
Input to Line 35 of Appendix A	
Month In Service or Month for CWIP	7.06

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

$ 304,139,489 — 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

$ 304,139,489 — 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)

$ 304,139,489

6 April Year 3 TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2008)

$ 232,000,664 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 $ 487,611,283 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 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
CWIP Balance Dec (prior yr.)		53,795,802	2,468,121		317,672,955		12
Jan	11,989,158	4,275,907	107,907	-	30,317,794	292,205	11.5
Feb	7,438,508	1,953,427	164,141	-	24,851,064	317,599	10.5
Mar	33,762,897	4,792,876	228,240	-	23,758,793	138,840	9.5
Apr	11,875,708	6,483,553	254,449	-	17,317,183	14,679,448	8.5
May	29,933,638	10,812,079	-164,737	562,966	13,208,833	727,623	7.5
Jun	60,877,332	-31,818,211	289,693	481,192	14,331,933	1,910,342	6.5
Jul	8,807,483	2,900,250	452,861	99,085	13,240,979	291,000	5.5
Aug	10,709,771	10,391,980	1,699,995	23,638	13,070,789	1,081,099	4.5
Sep	5,256,900	10,375,608	1,005,800	23,741	(139,182,887)	151,722,285	3.5
Oct	34,081,376	9,299,925	793,874	272,426	4,002,215	3,467,850	2.5
Nov	47,045,612	-2,517,939	499,906	10,371	7,140,888	1,643,198	1.5
Dec	40,775,621	6,324,735	-3,605,152	4,313,529	5,341,841	2,998,842	0.5
Total	302,554,004	87,069,991	4,195,098	5,786,948	345,072,380	179,270,331	

	(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)
CWIP Balance Dec (prior yr.)		645,549,624.00	29,617,453.56		3,812,075,463		
Jan	137,875,316	49,172,930	1,240,931	-	348,654,631	3,360,354	11,489,610
Feb	78,104,333	20,510,981	1,723,481	-	260,936,172	3,334,793	6,508,694
Mar	320,747,526	45,532,320	2,168,280	-	225,708,534	1,318,978.67	26,728,960
Apr	100,943,519	55,110,197	2,162,817	-	147,196,056	124,775,310	8,411,960
May	224,502,282	81,090,592	(1,235,528)	4,222,242	99,066,248	5,457,172	18,708,523
Jun	395,702,660	(206,818,369)	1,883,005	3,127,748	93,157,565	12,417,224	32,975,222
Jul	48,441,154	15,951,374	2,490,736	544,969	72,825,385	1,600,501	4,036,763
Aug	48,193,969	46,763,910	7,649,978	106,372	58,818,551	4,864,944	4,016,164
Sep	18,399,151	36,314,627	3,520,300	83,093	(487,140,105)	531,027,997	1,533,263
Oct	85,203,440	23,249,811	1,984,685	681,066	10,005,538	8,669,626	7,100,287
Nov	70,568,418	(3,776,908)	749,859	15,556	10,711,332	2,464,797	5,880,702
Dec	20,387,810	3,162,368	(1,802,576)	2,156,764	2,670,921	1,499,421	1,698,984
Total	1,549,069,578	811,813,457	52,153,419	10,937,811	4,654,686,287	700,791,118	129,089,132

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A 129,089,132
Input to Line 35 of Appendix A
Month In Service or Month for CWIP 6.88

$ 252,034,983 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		
252,034,983	-	304,139,489	=	(52,104,506)

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	(4,342,042)	0.2800%	11.5	(139,814)	(4,481,856)
Jul	Year 1	(4,342,042)	0.2800%	10.5	(127,656)	(4,469,698)
Aug	Year 1	(4,342,042)	0.2800%	9.5	(115,498)	(4,457,540)
Sep	Year 1	(4,342,042)	0.2800%	8.5	(103,341)	(4,445,383)
Oct	Year 1	(4,342,042)	0.2800%	7.5	(91,183)	(4,433,225)
Nov	Year 1	(4,342,042)	0.2800%	6.5	(79,025)	(4,421,067)
Dec	Year 1	(4,342,042)	0.2800%	5.5	(66,867)	(4,408,910)
Jan	Year 2	(4,342,042)	0.2800%	4.5	(54,710)	(4,396,752)
Feb	Year 2	(4,342,042)	0.2800%	3.5	(42,552)	(4,384,594)
Mar	Year 2	(4,342,042)	0.2800%	2.5	(30,394)	(4,372,436)
Apr	Year 2	(4,342,042)	0.2800%	1.5	(18,237)	(4,360,279)
May	Year 2	(4,342,042)	0.2800%	0.5	(6,079)	(4,348,121)
Total		(52,104,506)				(52,979,862)

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	(52,979,862)	0.2800%	(4,495,753)	(48,632,452)
Jul	Year 2	(48,632,452)	0.2800%	(4,495,753)	(44,272,870)
Aug	Year 2	(44,272,870)	0.2800%	(4,495,753)	(39,901,081)
Sep	Year 2	(39,901,081)	0.2800%	(4,495,753)	(35,517,051)
Oct	Year 2	(35,517,051)	0.2800%	(4,495,753)	(31,120,745)
Nov	Year 2	(31,120,745)	0.2800%	(4,495,753)	(26,712,130)
Dec	Year 2	(26,712,130)	0.2800%	(4,495,753)	(22,291,171)
Jan	Year 3	(22,291,171)	0.2800%	(4,495,753)	(17,857,833)
Feb	Year 3	(17,857,833)	0.2800%	(4,495,753)	(13,412,082)
Mar	Year 3	(13,412,082)	0.2800%	(4,495,753)	(8,953,882)
Apr	Year 3	(8,953,882)	0.2800%	(4,495,753)	(4,483,200)
May	Year 3	(4,483,200)	0.2800%	(4,495,753)	-
Total with interest				(53,949,038)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(53,949,038)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$	-
Revenue Requirement for Year 3		(53,949,038)

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
CWIP Balance Dec (prior yr.)		87,069,991	4,195,098		345,072,380		12
Jan	13,622,127	17,262,360	160,988	46,878	2,394,758	132,364	11.5
Feb	13,788,794	12,379,462	(254,463)	355,036	4,343,718	97,890	10.5
Mar	14,852,761	11,449,895	(2,845,179)	3,122,546	2,983,787	(16,013)	9.5
Apr	14,159,584	15,181,760	(17,218)	283,000	(650,991)	6,512,000	8.5
May	137,705,802	-57,311,891	(848,829)	883,829	(337,112,296)	341,755,913	7.5
Jun	28,383,208	2,223,269	(183,000)	208,000	(584,000)	3,799,673	6.5
Jul	76,372,660	-1,774,980	-	15,000	(5,000,000)	6,314,417	5.5
Aug	19,077,315	2,450,114	-	-	-	730,233	4.5
Sep	91,040,512	-53,705,101	-	-	-	626,357	3.5
Oct	43,647,636	7,903,844	-	-	-	631,748	2.5
Nov	34,846,159	4,795,214	-	-	(8,600,000)	8,816,060	1.5
Dec	98,871,207	4,916,804	-	-	-	167,420	0.5
Total	586,367,763	52,840,741	207,397	4,914,289	2,847,356	369,568,062	

	(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)
CWIP Balance Dec (prior yr.)		1,044,839,894	50,341,178		4,140,868,563		
Jan	156,654,455	198,517,140	1,851,362	539,097	27,539,717	1,522,186	13,054,538
Feb	144,782,339	129,984,349	(2,671,862)	3,727,882	45,609,039	1,027,845	12,065,195
Mar	141,101,227	108,774,000	(27,029,201)	29,664,187	28,345,977	(152,124)	11,758,436
Apr	120,356,465	129,044,963	(146,353)	2,405,500	(5,533,424)	55,352,000	10,029,705
May	1,032,793,513	(429,839,182)	(6,366,218)	6,628,718	(2,528,342,220)	2,563,169,348	86,066,126
Jun	184,490,850	14,451,250	(1,189,500)	1,352,000	(3,796,000)	24,697,875	15,374,238
Jul	420,049,632	(9,762,390)	-	82,500	(27,500,000)	34,729,294	35,004,136
Aug	85,847,916	11,025,511	-	-	-	3,286,049	7,153,993
Sep	318,641,790	(187,967,852)	-	-	-	2,192,250	26,553,483
Oct	109,119,090	19,759,610	-	-	-	1,579,370	9,093,257
Nov	52,269,238	7,192,821	-	-	(12,900,000)	13,224,090	4,355,770
Dec	49,435,603	2,458,402	-	-	-	83,710	4,119,634
Total	2,815,542,119	1,038,478,517	14,789,407	44,399,883	1,664,291,652	2,700,711,891	234,628,510

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A 234,628,510
Input to Line 35 of Appendix A
Month In Service or Month for CWIP 7.20

10 May Year 3 Post results of Step 9 on PJM web site
$ 264,449,135 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)
$ 264,449,135

(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
53,795,802	2,468,121		317,672,955		
4,112,340	103,411	-	29,054,553	280,029	
1,710,674	143,623	-	21,744,681	277,899	
3,795,610	180,690	-	18,809,044	109,915	
4,592,516	180,235	-	12,266,338	10,397,943	
6,776,083	(203,956)	328,956	9,682,394	402,434	
12,315,831	(67,957)	260,101	6,510,312	1,738,284	
4,258,254	211,364	-	4,647,689	347,800	
3,719,053	206,250	-	3,523,207	28,206	
1,746,098	204,167	-	(39,142,665)	43,315,928	
(4,395,185)	177,083	-	2,307,589	15,670	
556,741	96,364	-	1,150,429	9,402	
177,085	(105,722)	114,317	356,654	3,134	
93,160,901	3,593,673	703,374	388,583,180	56,926,645	-
		703,374		56,926,645	178,486,406
93,160,901	3,593,673		388,583,180		485,337,753
2.50	(0.09)	9.75	(1.11)	7.95	

(O)	(P)	(Q)	(R)	(S)	
NPR CWIP	Susq-Rose CWIP	Susq-Rose PIS	Susq-Rose CWIP	Susq-Rose PIS	Total
(I / 12)	(J / 12)	(K / 12)	(L / 12)	(M / 12)	
	< 500kV (b0487.1)	< 500kV (b0487.1)	>= 500kV (b0487)	>= 500kV (b0487)	
53,795,802	2,468,121		317,672,955		
4,097,744	103,411	-	29,054,553	280,029	
1,709,248	143,623	-	21,744,681	277,899	
3,794,360	180,690	-	18,809,044	109,915	
4,592,516	180,235	-	12,266,338	10,397,943	
6,757,549	(102,961)	351,854	8,255,521	454,764	
(17,234,864)	156,917	260,646	7,763,130	1,034,769	
1,329,281	207,561	45,414	6,068,782	133,375	
3,896,992	637,498	8,864	4,901,546	405,412	
3,026,219	293,358	6,924	(40,595,009)	44,252,333	
1,937,484	165,390	56,755	833,795	722,469	
(314,742)	62,488	1,296	892,611	205,400	
263,531	(150,215)	179,730	222,577	124,952	
67,651,121	4,346,118	911,484	387,890,524	58,399,260	
		911,484		58,399,260	188,399,876
67,651,121	4,346,118		387,890,524		459,887,764
2.68	(0.43)	10.11	(1.49)	8.09	

(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
87,069,991	4,195,098		345,072,380		
16,543,095	154,280	44,925	2,294,976	126,849	
10,832,029	(222,655)	310,657	3,800,753	85,654	
9,064,500	(2,252,433)	2,472,016	2,362,165	(12,677)	
10,753,747	(12,196)	200,458	(461,119)	4,612,667	
(35,819,932)	(530,518)	552,393	(210,695,185)	213,597,446	
1,204,271	(99,125)	112,667	(316,333)	2,058,156	
(813,532)	-	6,875	(2,291,667)	2,894,108	
918,793	-	-	-	273,837	
(15,663,988)	-	-	-	182,687	
1,646,634	-	-	-	131,614	
599,402	-	-	(1,075,000)	1,102,008	
204,867	-	-	-	6,976	
86,539,876	1,232,451	3,699,990	138,690,971	225,059,324	
		3,699,990		225,059,324	463,387,824
86,539,876	1,232,451		138,690,971		226,463,298
(7.65)	(59.31)	2.97	(572.50)	4.69	

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	14.3668%
4	B	144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	15.1940%
5	C		Line B less Line A	0.8273%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.4899%

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 Cooperstone Substation (b0468)
10		Details												
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		14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%	14.3668%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		15.4008%	15.4008%	15.4008%	14.3668%	14.3668%	14.3668%	15.4008%	15.4008%	15.4008%	14.3668%	14.3668%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified	Investment		138,690,971	229,916,081	369,568,062	86,626	62,067	123,504	1,232,451	9,021,866	4,914,289	3,733,895	22,735,783
18	Line 17 divided by line 12	Annual Depreciation Exp		-	5,474,192	8,799,240	2,063	1,478	2,941	-	214,806	117,007	88,902	541,328
19	Month in which project is placed in service (e.g. Jan=1)	Month In Service or Month for CWIP		-		4.69						2.97		

Line		Invest Yr	CWIP (b0487) Beginning	Depreciation	Ending	Revenue	Actual PIS (b0487) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	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	387,890,524	-	387,890,524	57,604,085	49,338,189	1,205,851	48,132,338	8,353,794
34	W Increased ROE	2014	387,890,524	-	387,890,524	61,557,021	49,338,189	1,205,851	48,132,338	8,844,304
35	W 11.68 % ROE	2015	138,690,971	-	138,690,971	19,925,391	225,656,515	5,474,192	220,182,322	37,107,245
36	W Increased ROE	2015	138,690,971	-	138,690,971	21,359,559	225,656,515	5,474,192	220,182,322	39,384,095
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		Invest Yr	Projected PIS (b0487) Beginning	Depreciation	Ending	Revenue	Hosensack (b0171.2) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	-	-	-	-	86,626	1,454	85,172	12,921
22	W Increased ROE	2008	-	-	-	-	86,626	1,454	85,172	12,921
23	W 11.68 % ROE	2009	-	-	-	-	85,172	2,063	83,109	19,836
24	W Increased ROE	2009	-	-	-	-	85,172	2,063	83,109	19,836
25	W 11.68 % ROE	2010	-	-	-	-	83,109	2,063	81,047	19,614
26	W Increased ROE	2010	-	-	-	-	83,109	2,063	81,047	19,614
27	W 11.68 % ROE	2011	-	-	-	-	81,047	2,063	78,984	17,668
28	W Increased ROE	2011	-	-	-	-	81,047	2,063	78,984	17,668
29	W 11.68 % ROE	2012	-	-	-	-	78,984	2,063	76,922	17,921
30	W Increased ROE	2012	-	-	-	-	78,984	2,063	76,922	17,921
31	W 11.68 % ROE	2013	-	-	-	-	76,922	2,063	74,859	14,779
32	W Increased ROE	2013	-	-	-	-	76,922	2,063	74,859	14,779
33	W 11.68 % ROE	2014	-	-	-	-	74,859	2,063	72,797	12,873
34	W Increased ROE	2014	-	-	-	-	74,859	2,063	72,797	12,873
35	W 11.68 % ROE	2015	369,568,062	6,091,825	363,476,237	42,244,212	72,797	2,063	70,734	12,225
36	W Increased ROE	2015	369,568,062	6,091,825	363,476,237	44,846,350	72,797	2,063	70,734	12,225
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		Invest Yr	Alburtis (b0172.1) Beginning	Depreciation	Ending	Revenue	Juniata (b0284.2) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	62,067	991	61,076	8,811	-	-	-	-
22	W Increased ROE	2008	62,067	991	61,076	8,811	-	-	-	-
23	W 11.68 % ROE	2009	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
24	W Increased ROE	2009	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
25	W 11.68 % ROE	2010	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
26	W Increased ROE	2010	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
27	W 11.68 % ROE	2011	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
28	W Increased ROE	2011	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
29	W 11.68 % ROE	2012	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
30	W Increased ROE	2012	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
31	W 11.68 % ROE	2013	55,165	1,478	53,687	10,598	111,742	2,941	108,801	21,423
32	W Increased ROE	2013	55,165	1,478	53,687	10,598	111,742	2,941	108,801	21,423
33	W 11.68 % ROE	2014	53,687	1,478	52,209	9,231	108,801	2,941	105,861	18,662
34	W Increased ROE	2014	53,687	1,478	52,209	9,231	108,801	2,941	105,861	18,662
35	W 11.68 % ROE	2015	52,209	1,478	50,732	8,766	105,861	2,941	102,920	17,727
36	W Increased ROE	2015	52,209	1,478	50,732	8,766	105,861	2,941	102,920	17,727
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		Invest Yr	CWIP (b0487.1) Beginning	Depreciation	Ending	Revenue	Actual PIS (b0487.1) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	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	4,346,118	-	4,346,118	645,425	3,018,143	77,022	2,941,121	513,796
34	W Increased ROE	2014	4,346,118	-	4,346,118	689,715	3,018,143	77,022	2,941,121	543,769
35	W 11.68 % ROE	2015	1,232,451	-	1,232,451	177,063	8,694,885	214,806	8,480,079	1,433,118
36	W Increased ROE	2015	1,232,451	-	1,232,451	189,808	8,694,885	214,806	8,480,079	1,520,809
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		Invest Yr	Projected PIS (b0487.1) Beginning	Depreciation	Ending	Revenue	Stanton 4th Transformer (b0791) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	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	-	-	-	-	-	-	-	-
24	W Increased ROE	2009	-	-	-	-	-	-	-	-
25	W 11.68 % ROE	2010	-	-	-	-	-	-	-	-
26	W Increased ROE	2010	-	-	-	-	-	-	-	-
27	W 11.68 % ROE	2011	-	-	-	-	3,733,895	25,673	3,708,222	237,250
28	W Increased ROE	2011	-	-	-	-	3,733,895	25,673	3,708,222	237,250
29	W 11.68 % ROE	2012	-	-	-	-	3,708,222	88,902	3,619,320	835,093
30	W Increased ROE	2012	-	-	-	-	3,708,222	88,902	3,619,320	835,093
31	W 11.68 % ROE	2013	-	-	-	-	3,619,320	88,902	3,530,418	688,638
32	W Increased ROE	2013	-	-	-	-	3,619,320	88,902	3,530,418	688,638
33	W 11.68 % ROE	2014	-	-	-	-	3,530,418	88,902	3,441,515	599,888
34	W Increased ROE	2014	-	-	-	-	3,530,418	88,902	3,441,515	599,888
35	W 11.68 % ROE	2015	4,914,289	97,846	4,816,444	676,494	3,441,515	88,902	3,352,613	570,564
36	W Increased ROE	2015	4,914,289	97,846	4,816,444	718,144	3,441,515	88,902	3,352,613	570,564
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		Invest Yr	Cooperstone (b0468) Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
20		Invest Yr	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	-	-	-	-	$ 7,975,048	$ 7,975,048	
27	W 11.68 % ROE	2011	918,555	11,846	906,709	108,883	$ 9,449,462		$ 9,449,462
28	W Increased ROE	2011	918,555	11,846	906,709	108,883	$ 9,911,193	$ 9,911,193	
29	W 11.68 % ROE	2012	906,709	21,670	884,838	204,296	$ 13,394,951		$ 13,394,951
30	W Increased ROE	2012	906,709	21,670	884,838	204,296	$ 14,016,520	$ 14,016,520	
31	W 11.68 % ROE	2013	22,244,731	539,606	21,705,126	4,226,803	$ 42,505,119		$ 42,505,119
32	W Increased ROE	2013	22,244,731	539,606	21,705,126	4,226,803	$ 44,881,943	$ 44,881,943	
33	W 11.68 % ROE	2014	21,776,090	541,328	21,234,762	3,694,818	$ 71,452,672		$ 71,452,672
34	W Increased ROE	2014	21,776,090	541,328	21,234,762	3,694,818	$ 75,870,381	$ 75,870,381	
35	W 11.68 % ROE	2015	21,234,762	541,328	20,693,433	3,514,303	$ 105,687,108		$ 105,687,108
36	W Increased ROE	2015	21,234,762	541,328	20,693,433	3,514,303	$ 112,142,348	$ 112,142,348	
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

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	75	S4	14.8	60.20	1.5848	161,558,411	41,797,728	119,760,683	1,898,007
352	Structures and Improvements	60	R4	15.1	44.90	2.0911	49,560,625	17,667,914	31,892,711	666,907
353	Station Equipment	48	R1	8.0	40.00	2.2896	783,543,578	182,704,232	600,839,346	13,756,985
354	Towers and Fixtures	70	R3	9.1	60.90	1.3810	724,202,117	143,690,938	580,511,179	8,016,775
354.2	Towers and Fixtures - Clearing Land and Rights of Way	75	R4	26.2	48.80	3.7374	12,581,592	7,118,922	5,462,670	204,163
355	Poles and Fixtures	55	R0.5	11.2	43.80	2.1679	119,727,108	41,125,520	78,601,588	1,704,034
355.2	Poles and Fixtures - Clearing Land and Rights of Way	75	R4	17.6	57.40	1.5772	10,399,529	4,073,108	6,326,421	99,781
356	Overhead Conductors and Devices	60	R3	12.4	47.60	1.8378	409,755,496	115,859,214	293,896,282	5,401,238
357	Underground Conduit	55	S4	4.7	50.30	1.5110	31,400,118	2,873,934	28,526,184	431,036
358	Underground Conductors and Devices	35	S4	11.4	23.60	4.0106	30,224,004	9,342,067	20,881,937	837,499
359	Roads and Trails	75	R4	19.8	55.20	2.0279	9,666,586	3,090,617	6,575,969	133,351
	General									
389.4	Land Rights	70	R4	42.0	28.00	3.1763	4,399	1,683	2,716	86
390.2	Structures and Improvements - Buildings	55	S0	38.6	16.40	2.8105	376,300,728	83,034,346	293,266,382	8,242,172
390.21	Structures and Improvements - Leaseholds	10	NA		4.50	-	741,658	450,415	291,243	0
390.4	Structures and Improvements - Air Conditioning	30	S1	8.2	21.80	4.6212	42,677,456	13,526,474	29,150,982	1,347,129
391.2	Office Furniture and Equipment - Furniture	20	NA		11.40	5.0738	22,511,853	8,731,355	13,780,498	1,142,209
391.4	Office Furniture and Equipment - Equipment	15	NA		8.60	6.6302	2,888,810	1,103,286	1,785,524	191,534
391.6	Office Furniture and Equipment - Computers	5	NA		3.00	12.7518	9,122,016	1,768,085	7,353,931	1,163,220
391.8	Office Furniture and Equipment - Power Mgmt. Sys.	7	NA		-	14.2800	38,155,394	38,155,394	0	0
392.1	Transportation Equipment - Automobiles	5	L4	2.4	2.60	49.9173	7,154,026	4,947,590	2,206,436	1,101,393
392.2	Transportation Equipment - Light Duty Trucks	8	R1	2.5	5.50	34.3034	19,721,789	13,820,652	5,901,137	2,024,293
392.3	Transportation Equipment - Heavy Duty Trucks	11	R4	5.1	5.90	8.1304	74,388,587	42,852,850	31,535,737	2,563,989
392.4	Transportation Equipment - Trailers	24	L1.5	5.4	18.60	5.6488	7,365,737	2,687,255	4,678,482	264,280
392.5	Transportation Equipment - Large Tankers/Tractors	16	L4	6.3	9.70	12.7985	3,585,083	1,631,834	1,953,249	249,986
392.6	Transportation Equipment - Large Crane Trucks	13	L3	8.2	4.80	19.3957	653,799	244,989	408,810	79,291
393	Stores Equipment	25	NA		9.70	4.7658	2,294,977	1,112,774	1,182,203	109,374
394	Tools and Work Equipment - L&S Line Crews	20	NA		9.40	5.6461	4,762,273	2,142,747	2,619,526	268,882
394.2	Tools and Work Equipment - Tools	20	NA		6.00	7.2110	285,256	149,508	135,748	20,570
394.4	Tools and Work Equipment - Construction Dept.	20	NA		10.00	5.0149	1,353,414	572,392	781,022	67,872
394.6	Tools and Work Equipment - Other	20	NA		12.70	4.8468	24,985,300	7,897,877	17,087,423	1,211,000
394.8	Tools and Work Equipment - Garage Equipment	20	NA		12.00	8.9310	1,993,101	603,920	1,389,181	178,004
395	Laboratory Equipment	20	NA		12.70	4.9135	4,717,745	1,682,766	3,034,979	231,806
396	Power Operated Equipment	13	S0	3.9	9.10	6.2967	2,238,835	1,296,454	942,381	140,973
397	Communication Equipment	15	NA		12.30	6.2438	7,106,551	4,580,590	2,525,961	443,719
398	Miscellaneous Equipment	20	NA		12.30	5.7881	2,774,711	713,811	2,060,900	160,602
	Intangible									
303.2	Miscellaneous Intangible Plant - Software	5	NA		2.70	20.00	101,544,998	53,705,856	47,839,142	19,380,608
303.4	Miscellaneous Intangible Plant - Fiber Optic	15	NA		-	-	1,035,137	1,035,137	-	-
303.5	Smart Meter Software	5	NA		-	-	4,038,092	1,142,865	2,895,227	760,238

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, 303.4 and 303.5 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	450,415	291,243	0
391.2	Office Furniture and Equipment - Furniture - Gross Method	20	4.8627	19,616,131	6,378,913	13,237,218	953,868
391.2	Office Furniture and Equipment - Furniture - Net Method	20	34.6674	2,895,722	2,352,442	543,280	188,341
				22,511,853	8,731,355	13,780,498	1,142,209
391.4	Office Furniture and Equipment - Equipment - Gross Method	15	6.6290	2,883,895	1,100,307	1,783,588	191,174
391.4	Office Furniture and Equipment - Equipment - Net Method	15	18.5798	4,915	2,979	1,936	360
				2,888,810	1,103,286	1,785,524	191,534
391.6	Office Furniture and Equipment - Computers - Gross Method	5	12.7518	9,122,016	1,768,085	7,353,931	1,163,220
391.8	Office Furniture and Equipment - Power Mgmt. Sys. - Gross Method	7	14.2800	38,155,394	38,155,394	0	0
393	Store Equipment - Gross Method	25	4.2756	1,277,335	523,745	753,590	54,614
393	Store Equipment - Net Method	25	12.7761	1,017,642	589,029	428,613	54,760
				2,294,977	1,112,774	1,182,203	109,374
394	Tools and Work Equipment - L&S Line Crews - Gross Method	20	5.0000	2,371,042	945,920	1,425,122	118,552
394	Tools and Work Equipment - L&S Line Crews - Net Method	20	12.5862	2,391,231	1,196,827	1,194,404	150,330
				4,762,273	2,142,747	2,619,526	268,882
394.2	Tools and Work Equipment - Tools - Gross Method	20	5.0000	133,692	41,943	91,749	6,685
394.2	Tools and Work Equipment - Tools - Net Method	20	31.5579	151,564	107,565	43,999	13,885
				285,256	149,508	135,748	20,570
394.4	Tools and Work Equipment - Construction Dept. - Gross Method	20	5.0000	1,345,463	567,434	778,029	67,273
394.4	Tools and Work Equipment - Construction Dept. - Net Method	20	20.0000	7,951	4,958	2,993	599
				1,353,414	572,392	781,022	67,872
394.6	Tools and Work Equipment - Other - Gross Method	20	4.7114	22,568,424	5,610,528	16,957,896	1,063,278
394.6	Tools and Work Equipment - Other - Net Method	20	114.0467	2,416,876	2,287,349	129,527	147,721
				24,985,300	7,897,877	17,087,423	1,211,000
394.8	Tools and Work Equipment - Garage Equipment - Gross Method	20	4.7153	1,614,625	309,046	1,305,579	76,134
394.8	Tools and Work Equipment - Garage Equipment - Net Method	20	121.8504	378,476	294,874	83,602	101,869
				1,993,101	603,920	1,389,181	178,004
395	Laboratory Equipment - Gross Method	20	4.8991	3,139,600	852,801	2,286,799	153,811
395	Laboratory Equipment - Net Method	20	10.4247	1,578,145	829,965	748,180	77,995
				4,717,745	1,682,766	3,034,979	231,806
397	Communication Equipment - Gross Method	15	5.8473	6,425,972	4,047,607	2,378,365	375,749
397	Communication Equipment - Net Method	15	46.0513	680,579	532,983	147,596	67,970
				7,106,551	4,580,590	2,525,961	443,719
398	Miscellaneous Equipment - Gross Method	20	5.0452	2,007,380	359,347	1,648,033	101,276
398	Miscellaneous Equipment - Net Method	20	14.3693	767,331	354,464	412,867	59,326
				2,774,711	713,811	2,060,900	160,602

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

Formula Rate Update for AEP East subsidiaries in PJM

To be Effective July 1, 2015 through June 30, 2016
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, 2015 through June 30, 2016. 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, 2015 from $30,513.51 per MW per year to $32,113.77 per MW per year with the AEP annual revenue requirement increasing from $697,120,761 to $783,836,137.

The AEP Schedule 1A rate decreased from $.1267 per MWh to $.0949 per MWh.

An annual revenue requirement of $19,114,738 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) $1,344,668
2. b0318 (Amos 765/138 kV Transformer) $1,803,726
3. b0504 (Hanging Rock) $1,080,039
4. b0570 (East Side Lima) $256,815
5. b1034.1 (Torrey-West Canton) $1,190,102
6. b1034.6 (138kV circuit South Canton Station) $372,396
7. b1231 (West Moulton Station) $1,394,076
8. b1465.2 (Rockport Jefferson 300 MVAR bank) $87,935
9. b1465.3 (Rockport Jefferson 765 kV line) $5,091,283
10. b1712.2 (Altavista-Leesville 138kV line) $(79,033)
11. b1864.1 (OPCo Kammer 345/138 kV transformers) $(98,636)
12. b1864.2 (West Bellaire-Brues 138 kV circuit) of $72,360
13. b2020 (Rebuild Amos-Kanawha River) $1,675,943
14. b2021 (APCo Kanawha River Gen Retirement Upgrades) $501,532
15. b2017 (APCo Rebuild Sporn-Waterford Muskingum River 345kV line) $2,647,738
16. b1659.14 (Ft. Wayne Relocate) $(124,488)
17. b2048 (Tanners Creek-Transformer Replacement) $204,798
18. b1818 (Expand the Allen Station) $248,467
19. b1819 (Rebuild Robinson Park 138kV line corridor) $35,564
20. b1465.4 (Switching imp at Sullivan Jefferson 765kV station) $169,845
21. b2021 (OPCo 345/138kV Transformer) $(3,083,468)
22. b2032 (Rebuild 138kV Elliott Tap-Poston) $24,172
23. b1034.2 (Loop South Canton-Wayview) $316,199

24. b1034.7 (Replace circuit breakers Torrey/Wagenhals) $686,228
25. b1970 (Reconductor Kammer-West Bellaire) $302,421
26. b2018 (Loop Conesville-Bixby 345kV) $198,854
27. b1032.4 (Loop the existing South Canton-Wayview 138kV circuit) $247,850
28. b1666 (Build an 8 breaker 138kV station Fosteria-East Lima) $559,098
29. b1957 (Terminate transformer #2 SW Lima) $265,269
30. b1962 (Add four 765kV breakers Kammer) $63,382
31. b2019 (Burger 345/138kV Station) $1,039,339
32. b2017 (OPCo Reconductor Sporn-Waterford-Muskingum River) $805,154
33. b1864.1 (WPCo 345/138kV transformer Kammer) $(184,891)

During the 2014 Annual Update Review Period, it was determined that certain costs associated with the corporate separation of AEP Ohio's generating assets were inadvertently recorded to accounts that were reflected in the AEP East Operating Companies' 2013 and 2014 Annual Updates. The AEP East Operating Companies' total Annual Transmission Revenue Requirement was overstated by $17,078 and $98,328 in 2012 and 2013, respectively. The appropriate amounts have been credited (with interest) in the 2015 Annual Update.

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, 2015
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, 2015 through June 30, 2016. 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, 2015 from $7,083.07 per MW per year or $19.41/MW Day to $9,323.87 per MW per year or $25.54/MW Day with the AEP annual revenue requirement increasing from $161,821,872 to $227,577,878.

The AEP Transmission Companies' Schedule 1A rates are not applicable because they are handled via AEP Operating Companies.

An annual revenue requirement of $87,259,618 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 $1,400,283
2. b1465.2 (Rockport Jefferson-MVAR Bank) $2,105,019
3. b2048 (Tanners Creek 345/138 kV transformer) $873,939
4. b1818 (Expand the Allen station) $3,313,394
5. b1819 (Rebuild Robinson Park) $3,630,294
6. b0570 (Lima-Sterling) $1,343,234
7. b1231 (Wapakoneta-West Moulton) $499,989
8. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $1,135,924
9. b1034.8 (South Canton Wagenhals Station) $788,422
10. b1864.2 (West Bellaire-Brues 138 kV Circuit) $165,512
11. b1870 (Ohio Central Transformer) $1,157,364
12. b1032.2 (Two 138kV outlets to Delano/Camp Sherman) $794,740
13. b1034.2 (Loop existing South Canton-Wayview 138kV) $1,309,614
14. b1034.3 (345/138kV 450 MVA transformer Canton Central) $2,711,173

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, 2015
Docket No ER10-355

15. b1970 (Reconductor Kammer-West Bellaire) $2,727,692
16. b2018 (Loop Conesville-Bixby 345 kV) $1,947,610
17. b2021 (OHTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $4,482,976
18. b2032 (Rebuild 138kV Elliott Tap Poston line) $(432,386)
19. b1032.1 (Construct new 345/138kV station Marquis-Bixby) $3,457,342
20. b1032.4 (Install 138/69kV transformer Ross Highland) $643,594
21. b1666 (Build 8 breaker 138kV station Fostoria-East Lima) $1,528,116
22. b1819 (Rebuild Robinson Park 345kV double circuit) $4,010,942
23. b1957 (Terminate Transformer #2 SW Lima) $714,472
24. b2019 (Establish Burger 345/138kV station) $6,416,043
25. b2017 (OHTCo Rebuild Sporn-Waterford-Muskingum River) $7,243,003
26. b1661 (765kV circuit breaker Wyoming station) $769,141
27. b1864.1 (Add 2 345/138kV transformers at Kammer) $18,429,787
28. b2021 (WVTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $3,427,461
29. b1948 (New 765/345 interconnection Sporn) $6,946,099
30. b1962 (Add four 765kV breakers Kammer) $2,348,715
31. b2017 (WVTCo Rebuild Sporn-Waterford-Muskingum River) $231,097
32. b2020 (Rebuild Amos-Kanawha River 138 kV corridor) $772,367
33. b2022 (Tristate-Kyger Creek 345kV line at Sporn) $366,645