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VIA ELECTRONIC MAIL & REGULAR MAIL

June 5, 2009

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, 2007
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2008
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2009

Docket Nos. EO03050394, EO06020119, ER07060379, ER08050310
+++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No. _______________

Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Izzo:

This letter (original and 10 copies) is filed with the Board of Public Utilities (the "Board") 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"). Enclosed please find copies of tariff sheets proposed by each of the EDCs and revised to reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to (i) formula rate filings made by PPL Electric Utilities Corporation ("PPL") in Federal Energy Regulatory Commission ("FERC") Docket No. ER08-1457 and by American Electric Power Service Corporation ("AEP") in FERC Docket No. ER08-1329, (ii) the annual formula rate update filings made by Trans-Allegheny Interstate Line Company ("TrAILCo") in FERC Docket No. ER07-562, and (iii) the modified formula rate filing for the Mid-Atlantic Power Pathway ("MAPP") project 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) thought (iii) above are collectively referred to as the "Filings").

Background

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), the 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"). In the most recent Board Order (BPU Docket No. ER08050310), the Board discussed this issue and concluded that this process for FERC-approved transmission rate changes was in the best interests of BGS customers.

In compliance with a directive from Board Staff, the EDCs have made this filing with the expectation that the Board will assign a tracking docket number for administrative purposes. However, the EDCs note that the Board has approved the pass-through of changes to FERC-approved transmission rates in the BGS dockets listed above, and therefore the noticing and hearing requirements for this compliance filing are subsumed by the Board's prior approvals in the BGS dockets.

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.

This is the fourth filing the EDCs have made with the Board to recover costs associated with TECs from BGS customers 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] On August 3, 2007, ACE, JCP&L, PSE&G and RECO filed to collect the TECs associated with the FERC-approved TrAILCo project. The Board approved this filing by Order dated January 18, 2008, and authorized the EDCs to recover the FERC-approved transmission charges for the TrAILCo project.

On June 16, 2008, ACE, JCP&L, PSE&G and RECO filed with the Board to recover the FERC-approved TECs associated with the Potomac Appalachian Transmission Highline ("PATH") project, for certain projects of the Virginia Electric Power Company ("VEPCo"), and for an update to the enhancement charges found in Schedule 12 of the OATT for the TrAILCo

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

project. By Order dated September 15, 2008, the Board approved and authorized ACE, JCP&L, PSE&G and RECO to recover the FERC-approved transmission charges for these projects.

On November 14, 2008, PSE&G filed with the Board for an increase in Basic Generation Service-Fixed Price ("BGS-FP") and Basic Generation Service-Commercial and Industrial Energy Price ("BGS-CIEP") rates to recover the formula rate approved by FERC for PSE&G in FERC Docket No. ER08-1233, and in response to the annual formula rate update filings made by PATH and VEPCo. ACE, JCP&L and RECO also filed on the same day for the TECs associated with the PSE&G formula rate applicable to load in their respective service territories as well as for the TECs associated with the PATH and VEPCo projects.

By Orders dated December 18, 2008, in response to the November 14, 2008 filings, the Board approved and authorized ACE, JCP&L and RECO to recover, and separately authorized PSE&G to recover, the FERC-approved TECs found in Schedule 12 of the OATT to reflect the revised formula rate filings for the PATH and VEPCo projects, as well as the formula rate filing made by PSE&G in FERC Docket No. ER08-1233.

On February 4, 2009, ACE, JCP&L, PSE&G and RECO filed a notice with the Board that PJM had approved a formula rate for PPL, but that the amounts PJM was billing for the period were too small to warrant an increase in BGS supplier payments at the time. It was noted in that filing that the EDCs would file for the PPL TEC costs when the PPL TEC rate was reset on June 1, 2009.

Request for Board Approval

JCP&L, PSE&G and RECO request Board approval to implement revised BGS-FP and BGS-CIEP tariff rates as shown in Attachment 1. The attached pro-forma tariff sheets have an effective date of July 1, 2009 and will remain in effect until changed. The BGS-FP and BGS-CIEP rates included in the amended tariff sheets are revised to reflect costs effective on June 1, 2009 for TECs resulting from all of the FERC-approved Filings, applicable to customers in each EDC's service territory. Attachment 2 shows the cost impact for the 2009/2010 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 July 1, 2009 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, 2009. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs.

Any differences between payments to BGS-FP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges. This treatment is consistent with the previously-approved mechanisms.

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

We thank the Board for all courtesies extended.

Respectfully submitted,

Original Signed by
Frances I. Sundheim, Esq.

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Stacy Peterson
Stefanie Brand, Division of Rate Counsel
Service List (via Electronic Mail Server)

BGS TRANSMISSION CHARGES
BPU DOCKET NO. EO05040368, EO05040317, EO06020119 AND ER07060379

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Attachment 1a
Jersey Central Power and Light Tariff Sheets
Attachment 1b
Public Service Electric and Gas Company Tariff Sheets
Attachment 1c
Rockland Electric Company Tariff Sheets

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

1) BGS Energy Charge per KWH: (Continued)

(Note 1) Summer Peak Surcharge (SPS): A SPS of an additional **$0.090400** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be applicable to RS customers KWH usage above 2500 (or above 3500 KWH if participating in the Company's Life Support program) for June through September. A SPS of an additional **$0.180024** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be applicable to RT customer on-peak KWH usage above 1000 (or above 1400 KWH if participating in the Company's Life Support program) for June through September.

(Note 2) Retail Margin: A Retail Margin of **$0.005350** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Energy Charges stated above applicable to all KWH usage by any GS and GST customers that the Company has identified with loads of 750 KW or greater (but less than 1000 KW) as of November 1, 2008 and that the Company has notified that the Retail Margin would be added to the BGS Energy Charges applicable to their KWH usage beginning June 1, 2009.

(Note 3) Summer Peak Demand Charge - Pilot (SPDC-P): A SPDC-P of $29.69 per KW Demand-P (includes Sales and Use Tax as provide in Rider SUT) during June through September will be applicable to Pilot customers that the Company has identified with lower than class average load factor and are located in certain circuit congestive areas. The Company has notified the Pilot customers that the SPDC-P will be applicable to KW Demand-P to be determined as follows: monthly maximum KW demand above 10 KW in excess of 80% of the prior year's monthly maximum KW demand above 10 KW, adjusted for KWH usage increases compared to the prior year. The Pilot customers will not be billed the SPDC as other non-Pilot customers; all other charges for GS under this Rider will still apply to the Pilot customers.

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, 2009, a RMR surcharge of **$0.000058** 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 January 1, 2009 through December 31, 2009, a PATH2-TEC surcharge of **$0.000070** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO2-TEC surcharge of **$0.000001** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG1-TEC surcharge of **$0.001252** 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 July 1, 2009, a TRAILCO3-TEC surcharge of **$0.000128** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO-TEC surcharge of **$0.000026** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE-TEC surcharge of **$0.000114** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva-TEC surcharge of **$0.000003** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East-TEC surcharge of **$0.000002** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL-TEC surcharge of **$0.000009** 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: ($0.004675) (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.

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

Issued by Donald M. Lynch, President
300 Madison Avenue, Morristown, NJ 07962-1911

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

3) BGS Transmission Charge per KWH: (Continued)

Effective January 1, 2009 through December 31, 2009, a PATH2-TEC surcharge, a VEPCO2-TEC surcharge and a PSEG1-TEC surcharge 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):

	PATH2-TEC	VEPCO2-TEC	PSEG1-TEC
GT – High Tension Service	**$0.000011**	**$0.000000**	**$0.000198**
GT	**$0.000041**	**$0.000001**	**$0.000739**
GP	**$0.000043**	**$0.000001**	**$0.000762**
GS and GST	**$0.000070**	**$0.000001**	**$0.001252**

Effective July 1, 2009, 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):

	TRAILCO3-TEC	PEPCO-TEC	ACE-TEC
GT – High Tension Service	**$0.000025**	**$0.000005**	**$0.000021**
GT	**$0.000082**	**$0.000016**	**$0.000073**
GP	**$0.000080**	**$0.000016**	**$0.000071**
GS and GST	**$0.000128**	**$0.000026**	**$0.000114**

	Delmarva-TEC	AEP-East-TEC	PPL-TEC
GT – High Tension Service	**$0.000001**	**$0.000000**	**$0.000002**
GT	**$0.000002**	**$0.000001**	**$0.000005**
GP	**$0.000002**	**$0.000001**	**$0.000005**
GS and GST	**$0.000003**	**$0.000002**	**$0.000009**

4) BGS Reconciliation Charge per KWH: ($0.000225) (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.

Attachment 1b

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

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,000 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	11.1800 ¢	11.9626 ¢	11.9263 ¢	12.7611 ¢
RS – in excess of 600 kWh	11.1800 ¢	11.9626 ¢	12.8273 ¢	13.7252 ¢
RHS – first 600 kWh	10.2512 ¢	10.9688 ¢	11.7948 ¢	12.6204 ¢
RHS – in excess of 600 kWh	10.2512 ¢	10.9688 ¢	12.9995 ¢	13.9095 ¢
RLM On-Peak	14.4193 ¢	15.4287 ¢	15.8236 ¢	16.9313 ¢
RLM Off-Peak	7.6261 ¢	8.1599 ¢	8.0514 ¢	8.6150 ¢
WH	8.6773 ¢	9.2847 ¢	9.7344 ¢	10.4158 ¢
WHS	8.6875 ¢	9.2956 ¢	9.7888 ¢	10.4740 ¢
HS	10.2402 ¢	10.9570 ¢	13.5201 ¢	14.4665 ¢
BPL	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢
BPL-POF	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢
PSAL	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September...$ 4.8077
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.1442

Charge applicable in the months of October through May...$ 4.7880
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.1232

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 stated in the
FERC Electric Tariff of the PJM Interconnection, LLC ....$ 18,054.72 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 .... $ 25.09 per MW per month
Virginia Electric and Power Company ....$ 0.36 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ 17.46 per MW per month
PPL Electric Utilities Corporation ....$ 2.11 per MW per month
American Electric Power Service Corporation ....$ 0.53 per MW per month
Atlantic City Electric Company. ....$ 7.26 per MW per month
Delmarva Power and Light Company...$ 0.84 per MW per month
Potomac Electric Power Company. ....$ 5.89 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months..$ 1.5642
Charge including New Jersey Sales and Use Tax (SUT) ....$ 1.6737

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 stated in the
FERC Electric Tariff of the PJM Interconnection, LLC ....$ 18,054.72 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....................................$ 25.09 per MW per month
Virginia Electric and Power Company...$ 0.36 per MW per month
Potomac-Appalachian Transmission Highline L.L.C......................$ 17.46 per MW per month
PPL Electric Utilities Corporation ....$ 2.11 per MW per month
American Electric Power Service Corporation ....$ 0.53 per MW per month
Atlantic City Electric Company. ....$ 7.26 per MW per month
Delmarva Power and Light Company...$ 0.84 per MW per month
Potomac Electric Power Company...$ 5.89 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months...$ 1.5642
Charge including New Jersey Sales and Use Tax (SUT) ....$ 1.6737

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.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – SIX PART – 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	0.135 ¢ per kWh	0.135 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

* Definition of Summer Billing Months
June through September

(Continued)

Draft

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – SIX PART – MONTHLY: (Continued)

	Summer Months*	Other Months
(2) Distribution Charges (Continued)		
Primary Voltage Service Only Over 60,000 kWh or 300 hours use of demand, whichever is greater....................................@	1.348 ¢ per kWh	1.348 ¢ per kWh

(3) Transmission Charges

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
Demand Charge		
First 5 kW or less…………..@	No Charge	No Charge
Over 5 kW…………………..@	$1.38 per kW	$1.19 per kW
Usage Charge		
First 4,920 kWh…………….@	0.552 ¢ per kWh	0.552 ¢ per kWh
Over 4,920 kWh…………..@	0.552 ¢ per kWh	0.552 ¢ per kWh
Primary Voltage Service Only Over 60,000 kWh or 300 hours use of demand, whichever is greater ……………………...@	0.552 ¢ per kWh	0.552 ¢ 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.

	Summer Months*	Other Months
Secondary Voltage Service Only All kWh	0.087 ¢ per kWh	0.087 ¢ per kWh
Primary Voltage Service Only All kWh	0.056 ¢ per kWh	0.056 ¢ per kWh

(Continued)

ISSUED: EFFECTIVE:

ISSUED BY: William Longhi, President
Saddle River, New Jersey 07458

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

RATE – SIX PART – MONTHLY: (Continued)

(3) Transmission Charge (Continued)
A. (Continued)

	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..................................@	0.116	¢ per kWh	0.116	¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

* Definition of Summer Billing Months
June through September

(Continued)

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

RATE – SIX PART – 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 ....@	0.071	¢ per kWh	0.071	¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

* Definition of Summer Billing Months
June through September

(Continued)

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

RATE – SEVEN PART – 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.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.094 ¢ per kWh	0.094 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) CIEP Standby Fee

In accordance with General Information Section 28A, a CIEP Standby Fee shall be assessed on all kWh delivered hereunder.

(7) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

(Continued)

Attachment 2a
Cost Allocation of 2009/2010 TrailCo Schedule 12 Charges

Attachment 2b
Cost Allocation of 2009/2010 Delmarva Schedule 12 Charges

Attachment 2c
Cost Allocation of 2009/2010 ACE Schedule 12 Charges

Attachment 2d
Cost Allocation of 2009/2010 PEPCo Schedule 12 Charges

Attachment 2e
Cost Allocation of 2009/2010 PPL Schedule 12 Charges

Attachment 2f
Cost Allocation of 2009/2010 AEP-East Schedule 12 Charges

Attachment 2a

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
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 2009- May 2010 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**
Prexy - 502 Junction (<500kV) - CWIP	b0321.2; b0321.3	$ 823,160.84	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Prexy - 502 Junction (>=500kV) - CWIP[1]	b0321.1	$ 575,637.10	1.89%	4.50%	7.61%	0.31%	$10,880	$25,904	$43,806	$1,784	$82,374
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 31,308,738.36	1.89%	4.50%	7.61%	0.31%	$591,735	$1,408,893	$2,382,595	$97,057	$4,480,280
Wylie Ridge	b0218	$ 2,327,876.21	11.83%	15.56%	0.00%	0.00%	$275,388	$362,218	$0	$0	$637,605
Black Oak	b0216	$ 9,089,137.18	1.89%	4.50%	7.61%	0.31%	$171,785	$409,011	$691,683	$28,176	$1,300,656
N Shenandoah Txfmr	b0323	$ 227,993.61	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook Txfmr	b0230	$ 1,003,886.47	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook 200 MVAR capacitor	b0559	$ 77,998.22	1.89%	4.50%	7.61%	0.31%	$1,474	$3,510	$5,936	$242	$11,162
Bedington 500/138 KV TXfmr	b0229	$ 720,577.68	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Kammer 765/500 kV TXfmr	b0495	$ 1,107,040.49	1.89%	4.50%	7.61%	0.31%	$20,923	$49,817	$84,246	$3,432	$158,417
Totals							**$1,072,184**	**$2,259,352**	**$3,208,266**	**$130,692**	**$6,670,494**
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 08/09**	**2008 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2009 Impact (7 months)**	**2010 Impact (5 months)**	**2009-2010 Impact (12 months)**
PSE&G	$ 267,355.48	10,654.0	$ 25.09	$ 1,871,488	$ 1,336,777	$ 3,208,266
JCP&L	$ 188,279.36	6,298.6	$ 29.89	$ 1,317,956	$ 941,397	$ 2,259,352
ACE	$ 89,348.70	2,638.4	$ 33.86	$ 625,441	$ 446,743	$ 1,072,184
RE	$ 10,890.96	439.9	$ 24.76	$ 76,237	$ 54,455	$ 130,692
Total Impact on NJ Zones	**$ 555,874.50**			**$ 3,891,121**	**$ 2,779,372**	**$ 6,670,494**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns b-e) from PJM OATT Sheets 270F-270F.01i
2) PJM Settlement for "Below 500kV" filed in September 2007 FERC and still pending.
3) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present and future).

(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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.83%) / DPL (19.39%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.41%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.83%) / DPL (19.39%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.41%)
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%)
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)†
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

* 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 (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

*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.)

b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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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)
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%)
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)†
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)††

* Neptune Regional Transmission System, LLC
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†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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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%)

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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)
b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

* 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 (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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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.)

b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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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.)

b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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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)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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%)

* 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)
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)
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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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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** 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)
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 – Bedington 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.89%*) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (*1.89%*) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
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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**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.)

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 (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
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.)

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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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%)

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

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%)
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%)
b0677	Reconductor Double Toll Gate – Riverton 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 (72.14%) / JCPL (4.18%) / ME (6.81%) / NEPTUNE* (0.19%) / PECO (4.06%) / PENELEC (5.89%) / ECP** (0.09%) / PSEG (6.39%) / RE (0.25%)
b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)

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

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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

(15) Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0164	Reconductor Wolfs - Oswego 138kV with 636 ACSS		ComEd (100%)
b0236.1	Build new West Loop 138 kV substation		ComEd (100%)
b0236.2	Install two new 345 kV circuits from Crawford and Taylor to West Loop and two new 345/138 kV auto-transformers at West Loop.		ComEd (100%)
b0299	Upgrade line 0108 – LaSalle County – Mazon 138 kV with 3.4 miles of 664.8 ACSS		ComEd (100%)
b0301	Increase capacity of Wolfs – Oswego 138 kV line 14304		ComEd (100%)
b0302	Dixon – McGirr 138kV – Replace small piece of conductor on line 10714 and install 138 kV CB at Sandwich		ComEd (100%)
b0303	Install 345 kV CB and change Elwood 345 kV BT to normally closed		ComEd (100%)
b0304	Reconductor line 11106 Electric Junction – North Aurora tap 4 miles		ComEd (100%)
b0305	Normally open East Frankfort 138 kV red-blue bus tie		ComEd (100%)
b0306	Reconductor line Electric Junction – North Aurora (11104 0.3 miles)		ComEd (100%)
b0377	Install a second Byron – Wempletown 345 kV circuit		AEC (0.60%) / BGE (1.32%) / ComEd (85.95%) / Dayton (0.73%) / DL (1.01%) / DPL (0.87%) / Dominion (2.45%) / JCPL (1.41%) / Neptune* (0.14%) / PECO (1.79%) / PEPCO (1.20%) / PSEG (2.37%) / RE (0.09%) / ECP** (0.07%)

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

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc. (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0379	Reconductor 10301 & 10302 Lisle – Lombard 138 kV circuits		ComEd (100%)
b0380	Reconductor 17713 from Burnham – Wildwood and 7611 from Wildwood to the Beverly tap		ComEd (100%)
b0394	Reconductor 2.8 miles of Wolfs – Frontenac 138 kV line 14310		ComEd (100%)
b0461	Install a 115.2 MVAR capacitor at Will County 138 kV		ComEd (100%)
b0462	Install a 57.6 MVAR capacitor at Joliet 138 kV		ComEd (100%)
b0463	Install a 115.2 MVAR capacitor at East Frankfort 138 kV		ComEd (100%)
b0464	Increase capacity of 138 kV line 14304 between Oswego TDC 592 to Montgomery TSS 106		ComEd (100%)
b0465	Install a 115.2 MVAR capacitor at Libertyville 138 kV		ComEd (100%)
b0466	Install a 115.2 MVAR capacitor at Prospect Heights 138 kV		ComEd (100%)
b0510	Install two 115.3 MVAR capacitors at Elmhurst 138 kV		ComEd (100%)
b0511	Reconductor the Pleasant Valley – Woodstock 138 kV line		ComEd (100%)
b0546	Install a 20 MVAR capacitor at Shorewood substation		ComEd (100%)
b0547	Install a 15 MVAR capacitor at Wilmington substation		ComEd (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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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 – Bedington 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.89%*) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (*1.89%*) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
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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**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.)

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 (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
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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**East Coast Power, L.L.C.

Attachment 2b

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
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 2009- May 2010 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	$ 1,418,277.00	1.89%	4.50%	7.61%	0.31%	$26,805	$63,822	$107,931	$4,397	$202,955
Red Lion Sub Reconfiguration	b0241.3	$ 2,170,869.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$26,805**	**$63,822**	**$107,931**	**$4,397**	**$202,955**
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 08/09**	**2008 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2009 Impact (7 months)**	**2010 Impact (5 months)**	**2009-2010 Impact (12 months)**
PSE&G	$ 8,994.24	10,654.0	$ 0.84	$ 62,960	$ 44,971	$ 107,931
JCP&L	$ 5,318.54	6,298.6	$ 0.84	$ 37,230	$ 26,593	$ 63,822
ACE	$ 2,233.79	2,638.4	$ 0.85	$ 15,637	$ 11,169	$ 26,805
RE	$ 366.39	439.9	$ 0.83	$ 2,565	$ 1,832	$ 4,397
Total Impact on NJ Zones	**$ 16,912.95**			**$ 118,391**	**$ 84,565**	**$ 202,955**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns b-e) are from PJM OATT sheets 270E.09
2) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present an

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 to Salem		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

Attachment 2c

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
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 2009- May 2010 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Upgrade AE portion of Delco Tap	b0265	$ 654,014.00	89.87%	9.48%	0.00%	0.00%	$587,762	$62,001	$0	$0	$0
Replace Monroe 230/69 kV TXfmrs	b0276	$ 980,848.00	91.28%	0.00%	8.29%	0.29%	$895,318	$0	$81,312	$2,844	$979,475
Reconductor Union - Corson 138 kV	b0211	$ 2,477,413.00	65.23%	25.87%	6.35%	0.00%	$1,616,016	$640,907	$157,316	$0	$2,414,239
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210	$ 5,680,025.00	1.89%	4.50%	7.61%	0.31%	$107,352	$255,601	$432,250	$17,608	$812,812
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion	b0210.1	$ 4,050,067.00	65.23%	25.87%	6.35%	0.00%	$2,641,859	$1,047,752	$257,179	$0	$3,946,790
Totals							**$5,848,308**	**$2,006,261**	**$928,057**	**$20,453**	**$8,153,316**
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 08/09**	**2008 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2009 Impact (7 months)**	**2010 Impact (5 months)**	**2009-2010 Impact (12 months)**
PSE&G	$ 77,338.10	10,654.0	$ 7.26	$ 541,367	$ 386,690	$ 928,057
JCP&L	$ 167,188.39	6,298.6	$ 26.54	$ 1,170,319	$ 835,942	$ 2,006,261
ACE	$ 487,359.01	2,638.4	$ 184.72	$ 3,411,513	$ 2,436,795	$ 5,848,308
RE	$ 1,704.38	439.9	$ 3.87	$ 11,931	$ 8,522	$ 20,453
Total Impact on NJ Zones	**$ 733,589.88**			**$ 5,135,129**	**$ 3,667,949**	**$ 8,803,079**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns e,f) are from PJM OATT sheets 270E.08-270E.08c
2) Allocation share pending FERC approval
3) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present and future).

(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 (89.87%) / JCPL (9.48%) / Neptune* (0.65%)
b0276	Replace both Monroe 230/69 kV transformers		AEC (91.28%) / PSEG (8.29%) / RE (0.23%) / ECP** (0.20%)
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%)

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

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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)†

* 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

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)
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 (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)††
b0211	Reconductor Union - Corson 138kV circuit		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0212	Substation upgrades at Union and Corson 138kV		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0214	Install 50 MVAR capacitor at Cardiff 230kV substation		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)

* Neptune Regional Transmission System, LLC

††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.

Attachment 2d

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
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 2009- May 2010 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 - PEPCO portion	b0512	$ 9,898,240.00	1.89%	4.50%	7.61%	0.31%	$187,077	$445,421	$753,256	$30,685	$1,416,438
Totals							**$187,077**	**$445,421**	**$753,256**	**$30,685**	**$1,416,438**
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 08/09**	**2008 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2009 Impact (7 months)**	**2010 Impact (5 months)**	**2009-2010 Impact (12 months)**
PSE&G	$ 62,771.34	10,654.0	$ 5.89	$ 439,399	$ 313,857	$ 753,256
JCP&L	$ 37,118.40	6,298.6	$ 5.89	$ 259,829	$ 185,592	$ 445,421
ACE	$ 15,589.73	2,638.4	$ 5.91	$ 109,128	$ 77,949	$ 187,077
RE	$ 2,557.05	439.9	$ 5.81	$ 17,899	$ 12,785	$ 30,685
Total Impact on NJ Zones	**$ 118,036.51**			**$ 826,256**	**$ 590,183**	**$ 1,416,438**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns b-e) are from PJM OATT sheets 270F.20a
2) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present an

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 (1.76%) / APS (19.70%) / BGE (22.14%) / DPL (3.69%) / JCPL (0.72%) / ME (2.48%) / Neptune* (0.03%) / PECO (5.54%) / PEPCO (41.87%) / PPL (2.07%)
b0478	Reconductor the four circuits from Burchess 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 to Salem		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

*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.

Attachment 2e

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for PPL Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2009- May 20010 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
New 500 KV Susquehana-Roseland Line	b0487	$ 3,446,167.00	1.89%	4.50%	7.61%	0.31%	$65,133	$155,078	$262,253	$10,683	$0
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 17,289.00	1.89%	4.50%	7.61%	0.31%	$327	$778	$1,316	$54	$2,474
Replace wavetrap at Hosensack 500KV Sub	b0171.1	$ 12,397.00	1.89%	4.50%	7.61%	0.31%	$234	$558	$943	$38	$1,774
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 15,719.00	1.89%	4.50%	7.61%	0.31%	$297	$707	$1,196	$49	$2,249
New S-R additions < 500kV[2]	b0487.1	$ 91,338.00	0.00%	0.00%	5.13%	0.19%	$0	$0	$4,686	$174	$4,859
Totals							**$65,991**	**$157,121**	**$270,394**	**$10,997**	**$11,357**
	b0495	$ 1,107,040									
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 08/09	(l) 2008 TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2009 Impact (7 months)	(o) 2010 Impact (5 months)	(p) 2009-2010 Impact (12 months)
PSE&G	$ 22,532.86	10,654.0	$ 2.11	$ 157,730	$ 112,664	$ 270,394
JCP&L	$ 13,093.40	6,298.6	$ 2.08	$ 91,654	$ 65,467	$ 157,121
ACE	$ 5,499.23	2,638.4	$ 2.08	$ 38,495	$ 27,496	$ 65,991
RE	$ 916.45	439.9	$ 2.08	$ 6,415	$ 4,582	$ 10,997
Total Impact on NJ Zones	**$ 42,041.93**			**$ 294,293**	**$ 210,210**	**$ 504,503**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns e,f) are from PJM OATT sheets 270E.08-270E.08c
2) Allocations pending FERC approval
3) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present and

(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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

* 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 (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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%)
b0378	Install a 3000 A disconnect switch at Alburtis 230 kV bus		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 (4.56%) / Neptune* (0.19%) / PECO (1.79%) / PENELEC (0.33%) / PPL (86.87%) / ECP** (0.09%) / PSEG (5.95%) / RE (0.22%)
b0469	Install 130 MVAR capacitor at West Shore 230 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)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
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 (6.33%) / DPL (8.74%) / JCPL (14.68%) / ME (10.69%) / Neptune* (0.69%) / PECO (15.81%) / PPL (21.23%) / ECP** (0.29%) / PSEG (20.76%) / RE (0.78%)

*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)
b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (*1.89*%) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
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.

Attachment 2f

PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
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*	June 2009- May 2010 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	JCP&L Zone Share[1]	PSE&G Zone Share[1]	RE Zone Share[1]	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 895,456.00	1.89%	4.50%	7.61%	0.31%	$16,924	$40,296	$68,144	$2,776	$0
Totals							**$16,924**	**$40,296**	**$68,144**	**$2,776**	**$0**
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 08/09	(l) 2008 TX Peak Load *per PJM website*	(m) Rate in \$/MW-mo.	(n) 2009 Impact (7 months)	(o) 2010 Impact (5 months)	(p) 2009-2010 Impact (12 months)
PSE&G	$ 5,678.68	10,654.0	$ 0.53	$ 39,751	$ 28,393	$ 68,144
JCP&L	$ 3,357.96	6,298.6	$ 0.53	$ 23,506	$ 16,790	$ 40,296
ACE	$ 1,410.34	2,638.4	$ 0.53	$ 9,872	$ 7,052	$ 16,924
RE	$ 231.33	439.9	$ 0.53	$ 1,619	$ 1,157	$ 2,776
Total Impact on NJ Zones	**$ 10,678.31**			**$ 74,748**	**$ 53,392**	**$ 128,140**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2009 allocation share percentages (columns b-e) are from PJM OATT sheets 270F.20a
2) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-e above - past, present an

(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) (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 (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
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%)

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

Attachment 3a
Translation of 2009/2010 Schedule 12 Charges into Rates – JCP&L

Attachment 3b
Translation of 2009/2010 Schedule 12 Charges into Rates – PSE&G

Attachment 3c
Translation of 2009/2010 Schedule 12 Charges into Rates - RECO

Attachment 3a - JCP&L Rate Translation

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly PPL-TEC Costs Allocated to JCP&L Zone	$	13,093.40	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
PPL-Transmission Enhancement Rate ($/MW-month)	$	2.08	

				Effective July 1, 2009:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL-TEC Surcharge ($/kWh)	PPL-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	138,069	16,530,397,205	$ 0.000008	$ 0.000009
Primary	378.4	9,439	1,818,130,448	$ 0.000005	$ 0.000005
Transmission @ 34.5 kV	364.5	9,092	1,700,004,880	$ 0.000005	$ 0.000005
Transmission @ 230 kV	20.9	521	326,210,273	$ 0.000002	$ 0.000002
Total	6299.0	157,121	20,374,742,806		

(1) Attachment 5 Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months PPL Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	PPL-Transmission Enhancement Costs to FP Suppliers	$	121,757	= Line 3 x $2.08 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	3,357.96	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	0.53	

				Effective July 1, 2009:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	AEP-East-TEC Surcharge ($/kWh)	AEP-East-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	35,409	16,530,397,205	$ 0.000002	$ 0.000002
Primary	378.4	2,421	1,818,130,448	$ 0.000001	$ 0.000001
Transmission @ 34.5 kV	364.5	2,332	1,700,004,880	$ 0.000001	$ 0.000001
Transmission @ 230 kV	20.9	134	326,210,273	$ -	$ -
Total	6299.0	40,296	20,374,742,806		

(1) Attachment 5 Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months AEP-East Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	AEP-East-Transmission Enhancement Costs to FP Suppliers	$	31,226	= Line 3 x $0.53 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Attachment 3

Jersey Central Power & Light Company
Proposed Delmarva Project Transmission Enhancement Charge (Delmarva-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved Delmarva Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly Delmarva-TEC Costs Allocated to JCP&L Zone	$	5,318.54	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
Delmarva-Transmission Enhancement Rate ($/MW-month)	$	0.84	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective July 1, 2009: Delmarva-TEC Surcharge ($/kWh)	Effective July 1, 2009: Delmarva-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	56,084	16,530,397,205	$ 0.000003	$ 0.000003
Primary	378.4	3,834	1,818,130,448	$ 0.000002	$ 0.000002
Transmission @ 34.5 kV	364.5	3,693	1,700,004,880	$ 0.000002	$ 0.000002
Transmission @ 230 kV	20.9	212	326,210,273	$ 0.000001	$ 0.000001
Total	6299.0	63,822	20,374,742,806		

(1) Attachment 5 Cost Allocation of Delmarva Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months Delmarva Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	Delmarva-Transmission Enhancement Costs to FP Suppliers	$	49,458	= Line 3 x $0.84 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Attachment 3

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	167,188.39	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
ACE-Transmission Enhancement Rate ($/MW-month)	$	26.54	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective July 1, 2009: ACE-TEC Surcharge ($/kWh)	ACE-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	1,762,987	16,530,397,205	$ 0.000107	$ 0.000114
Primary	378.4	120,522	1,818,130,448	$ 0.000066	$ 0.000071
Transmission @ 34.5 kV	364.5	116,095	1,700,004,880	$ 0.000068	$ 0.000073
Transmission @ 230 kV	20.9	6,657	326,210,273	$ 0.000020	$ 0.000021
Total	6299.0	2,006,261	20,374,742,806		

(1) Attachment 5 Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months ACE Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

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

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	ACE-Transmission Enhancement Costs to FP Suppliers	$	1,554,701	= Line 3 x $26.54 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.09	= Line 4 / Line 2

Attachment 3

Jersey Central Power & Light Company

Proposed PEPCO Project Transmission Enhancement Charge (PEPCO-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly PEPCO-TEC Costs Allocated to JCP&L Zone	$	37,118.40	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
PEPCO-Transmission Enhancement Rate ($/MW-month)	$	5.89	

				Effective July 1, 2009:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PEPCO-TEC Surcharge ($/kWh)	PEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	391,410	16,530,397,205	$ 0.000024	$ 0.000026
Primary	378.4	26,758	1,818,130,448	$ 0.000015	$ 0.000016
Transmission @ 34.5 kV	364.5	25,775	1,700,004,880	$ 0.000015	$ 0.000016
Transmission @ 230 kV	20.9	1,478	326,210,273	$ 0.000005	$ 0.000005
Total	6299.0	445,421	20,374,742,806		

(1) Attachment 5 Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months PEPCO Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	PEPCO-Transmission Enhancement Costs to FP Suppliers	$	345,168	= Line 3 x $5.89 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.02	= Line 4 / Line 2

Attachment 3

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO3-TEC Surcharge) effective July 1, 2009
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2009 - May 2010

2009/2010 Average Monthly TRAILCO3-TEC Costs Allocated to JCP&L Zone	$	188,279.36	(1)
2008 JCP&L Zone Transmission Peak Load (MW)		6299	
TRAILCO3-Transmission Enhancement Rate ($/MW-month)	$	29.89	

				Effective July 1, 2009:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	TRAILCO3-TEC Surcharge ($/kWh)	TRAILCO3-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5535.2	1,985,389	16,530,397,205	$ 0.000120	$ 0.000128
Primary	378.4	135,726	1,818,130,448	$ 0.000075	$ 0.000080
Transmission @ 34.5 kV	364.5	130,740	1,700,004,880	$ 0.000077	$ 0.000082
Transmission @ 230 kV	20.9	7,497	326,210,273	$ 0.000023	$ 0.000025
Total	6299.0	2,259,352	20,374,742,806		

(1) Attachment 5 Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2009/2010
(2) Based on 12 months TRAILCO Project costs from June 2009 through May 2010
(3) July 2009 through May 2010

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

Line No.				
1	BGS-FP Eligible Sales July through May @ Customer		16,092,283	MWH
2	BGS-FP Eligible Sales July through May @ Transmission Node		17,702,799	MWH
3	BGS-FP Eligible Transmission Obligation		5,325	MW
4	TRAILCO3-Transmission Enhancement Costs to FP Suppliers	$	1,750,828	= Line 3 x $29.89 x 11
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.10	= Line 4 / Line 2

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for Trans-Allegheny Interstate Line Company - TrAILCo Projects 2009 Annual Update

TEC Charges for June 2009 - May 2010	$ 3,208,265.76		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,654.00		
Term (Months)	12		
OATT rate	$ 25.09	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 301.08	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.1009	$ 0.0684	$ 0.0749	$ -	$ -	$ 0.0662	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0101**	**0.0068**	**0.0075**	**0**	**0**	**0.0066**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0251**	**$ 0.0251**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 2,645,861		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0746	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 2,483,641		unrounded	= (6) * (3)
8	Difference due to rounding	$ (162,220)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for Delmarva Power and Light Company Projects 2009 Annual Update

TEC Charges for June 2009 - May 2010	$ 107,930.88	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,654.00	
Term (Months)	12	
OATT rate	$ 0.84	/MW/month
converted to $/MW/yr =	$ 10.08	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0034	$ 0.0023	$ 0.0025	$ -	$ -	$ 0.0022	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0003**	**0.0002**	**0.0003**	**0**	**0**	**0.0002**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0008**	**$ 0.0008**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 88,582		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0025	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ -	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ -		unrounded	= (6) * (3)
8	Difference due to rounding	$ (88,582)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for Atlantic City Electric Projects 2009 Annual Update

TEC Charges for June 2009 - May 2010	$ 928,057.18		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,654.00		
Term (Months)	12		
OATT rate	$ 7.26	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 87.12	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0292	$ 0.0198	$ 0.0217	$ -	$ -	$ 0.0192	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0029**	**0.002**	**0.0022**	**0**	**0**	**0.0019**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0073**	**$ 0.0073**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 765,602		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0216	/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	$ 709,612		unrounded	= (6) * (3)
8	Difference due to rounding	$ (55,990)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for Potomac Electric Power Company Projects 2009 Annual Update

TEC Charges for June 2009 - May 2010	$ 753,256.06		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,654.00		
Term (Months)	12		
OATT rate	$ 5.89	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 70.68	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0237	$ 0.0161	$ 0.0176	$ -	$ -	$ 0.0156	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0024**	**0.0016**	**0.0018**	**0**	**0**	**0.0016**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0059**	**$ 0.0059**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 621,129		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0175	/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	$ 709,612		unrounded	= (6) * (3)
8	Difference due to rounding	$ 88,483		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for PPL Electric Utilities Corporation Projects 2009 Annual Update

TEC Charges for June 2009 - May 2010	$ 270,394.27		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,654.00		
Term (Months)	12		
OATT rate	$ 2.11	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 25.32	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0085	$ 0.0058	$ 0.0063	$ -	$ -	$ 0.0056	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0008**	**0.0006**	**0.0006**	**0**	**0**	**0.0006**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0021**	**$ 0.0021**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 222,510		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0063	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.01	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 354,806		unrounded	= (6) * (3)
8	Difference due to rounding	$ 132,296		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2009 - May 2010
Calculation of costs and monthly PJM charges for American Electric Power Service Corporation

TEC Charges for June 2009 - May 2010	$	68,144.20	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,654.00	
Term (Months)		12	
OATT rate	$	0.53	/MW/month
converted to $/MW/yr =	$	6.36	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4522.9	42.1	74.9	0.0	0.0	6.2	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0021	$ 0.0014	$ 0.0016	$ -	$ -	$ 0.0014	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0002**	**0.0001**	**0.0002**	**0**	**0**	**0.0001**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0005**	**$ 0.0005**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8787.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 55,891		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0016	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ -	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ -		unrounded	= (6) * (3)
8	Difference due to rounding	$ (55,891)		unrounded	= (7) - (4)

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective July 1, 2009

To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly ACE-TEC Costs Allocated to RECO	$	1,704	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	3.85	

	Col. 1	Col. 2	Col.3=Col.2 x $1,704 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$ 12,751	701,602,000	$ 0.00002	$ 0.00002
SC2 Secondary	132.5	29.90%	$ 6,115	538,938,000	$ 0.00001	$ 0.00001
SC2 Primary	19.0	4.29%	$ 877	111,861,000	$ 0.00001	$ 0.00001
SC3	0.1	0.02%	$ 5	271,000	$ 0.00002	$ 0.00002
SC4	0.0	0.00%	$ -	6,463,000	$ -	$ -
SC5	3.8	0.86%	$ 175	18,539,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,049,000	$ -	$ -
SC7	11.5	2.59%	$ 531	42,835,000	$ 0.00001	$ 0.00001
Total	443.2 (2)	100.00%	$ 20,454	1,425,558,000		

(1) Attachment 5 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2009 through May 2010

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	17,223.40	= Line 3 x $3.85 * 11
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP-East) effective July 1, 2009
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	231	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.52	

	Col. 1	Col. 2	Col.3=Col.2 x $231 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$ 1,731	701,602,000	$ -	$ -
SC2 Secondary	132.5	29.90%	$ 830	538,938,000	$ -	$ -
SC2 Primary	19.0	4.29%	$ 119	111,861,000	$ -	$ -
SC3	0.1	0.02%	$ 1	271,000	$ -	$ -
SC4	0.0	0.00%	$ -	6,463,000	$ -	$ -
SC5	3.8	0.86%	$ 24	18,539,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,049,000	$ -	$ -
SC7	11.5	2.59%	$ 72	42,835,000	$ -	$ -
Total	443.2 (2)	100.00%	$ 2,777	1,425,558,000		

(1) Attachment 5 - Cost Allocation of AEP-East Schedule 12 Charges to RECO Zone for June 2009 through May 2010
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	2,326.28	= Line 3 x $0.52 * 11
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Delmarva) effective July 1, 2009

To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	366	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.83	

	Col. 1	Col. 2	Col.3=Col.2 x $366 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$	2,741	701,602,000	$	-	$	-
SC2 Secondary	132.5	29.90%	$	1,314	538,938,000	$	-	$	-
SC2 Primary	19.0	4.29%	$	188	111,861,000	$	-	$	-
SC3	0.1	0.02%	$	1	271,000	$	-	$	-
SC4	0.0	0.00%	$	-	6,463,000	$	-	$	-
SC5	3.8	0.86%	$	38	18,539,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,049,000	$	-	$	-
SC7	11.5	2.59%	$	114	42,835,000	$	-	$	-
Total	443.2 (2)	100.00%	$	4,396	1,425,558,000				

(1) Attachment 5 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2009 through May 2010

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	3,713.10	= Line 3 x $0.83 * 11
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective July 1, 2009
To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	2,557	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	5.77	

	Col. 1	Col. 2	Col.3=Col.2 x $2,557 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$ 19,129	701,602,000	$ 0.00003	$ 0.00003
SC2 Secondary	132.5	29.90%	$ 9,174	538,938,000	$ 0.00002	$ 0.00002
SC2 Primary	19.0	4.29%	$ 1,315	111,861,000	$ 0.00001	$ 0.00001
SC3	0.1	0.02%	$ 7	271,000	$ 0.00003	$ 0.00003
SC4	0.0	0.00%	$ -	6,463,000	$ -	$ -
SC5	3.8	0.86%	$ 263	18,539,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,049,000	$ -	$ -
SC7	11.5	2.59%	$ 796	42,835,000	$ 0.00002	$ 0.00002
Total	443.2 (2)	100.00%	$ 30,684	1,425,558,000		

(1) Attachment 5 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2009 through May 2010
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	25,812.73	= Line 3 x $5.77 * 11
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 (PPL) effective July 1, 2009
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly PPL-TEC Costs Allocated to RECO	$	916	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.07	

Rate Class	Col. 1 Full Service Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)		Col.3=Col.2 x $916 x 12 Allocated Cost Recovery (1)	Col. 4 Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)		Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)		Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$	6,856	701,602,000	$	0.00001	$	0.00001
SC2 Secondary	132.5	29.90%	$	3,288	538,938,000	$	0.00001	$	0.00001
SC2 Primary	19.0	4.29%	$	471	111,861,000	$	-	$	-
SC3	0.1	0.02%	$	2	271,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,463,000	$	-	$	-
SC5	3.8	0.86%	$	94	18,539,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,049,000	$	-	$	-
SC7	11.5	2.59%	$	285	42,835,000	$	0.00001	$	0.00001
Total	443.2 (2)	100.00%	$	10,996	1,425,558,000				

(1) Attachment 5 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2009 through May 2010
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	9,260.37	= Line 3 x $2.07 * 11
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective July 1, 2009

To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2009 to May 2010

2009/2010 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	10,891	(1)
2008 RECO Zone Transmission Peak Load (MW)		443.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	24.57	

Rate Class	Col. 1 Full Service Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)		Col.3=Col.2 x $10,891 x 12 Allocated Cost Recovery (1)	Col. 4 Full Service BGS Eligible Sales Jul 2009 - May 2010 (kWh)		Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)		Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	276.3	62.34%	$	81,476	701,602,000	$	0.00012	$	0.00013
SC2 Secondary	132.5	29.90%	$	39,072	538,938,000	$	0.00007	$	0.00007
SC2 Primary	19.0	4.29%	$	5,603	111,861,000	$	0.00005	$	0.00005
SC3	0.1	0.02%	$	29	271,000	$	0.00011	$	0.00012
SC4	0.0	0.00%	$	-	6,463,000	$	-	$	-
SC5	3.8	0.86%	$	1,121	18,539,000	$	0.00006	$	0.00006
SC6	0.0	0.00%	$	-	5,049,000	$	-	$	-
SC7	11.5	2.59%	$	3,391	42,835,000	$	0.00008	$	0.00009
Total	443.2 (2)	100.00%	$	130,692	1,425,558,000				

(1) Attachment 5 - Cost Allocation of TrailCo Schedule 12 Charges to RECO Zone for June 2009 through May 2010

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Oct - December @ cust (RECO Eastern Division)		1,236,841	MWH
2	BGS-FP Eligible Sales Oct - December @ trans node (RECO Eastern Division)		1,325,636	MWH
3	BGS-FP Eligible Transmission Obligation		407	MW
4	Transmission Enhancement Costs to FP Suppliers	$	109,916.60	= Line 3 x $24.57 * 11
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.08	= Line 4/Line 2

Attachment 3

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes effective July 1, 2009

To reflect: RMR Costs

FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009
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 2009
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009 currently in RECO's rates
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2009 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	$0.00000
ACE - TEC	(2)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00007	0.00005	0.00003	0.00006	0.00000	0.00004	0.00000	0.00005
PEPCO - TEC	(6)	0.00003	0.00002	0.00001	0.00003	0.00000	0.00001	0.00000	0.00002
PPL - TEC	(7)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PSE&G - TEC	(8)	0.00102	0.00066	0.00043	0.00086	0.00000	0.00054	0.00000	0.00071
TrAILCo - TEC	(9)	0.00012	0.00007	0.00005	0.00011	0.00000	0.00006	0.00000	0.00008
VEPCo - TEC	(10)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total ($/kWh and excl SUT)		$0.00127	$0.00082	$0.00053	$0.00109	$0.00000	$0.00067	$0.00000	$0.00088
Total (¢/kWh and excl SUT)		0.127 ¢	0.082 ¢	0.053 ¢	0.109 ¢	0.000 ¢	0.067 ¢	0.000 ¢	0.088 ¢

(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	$0.00000
ACE - TEC	(2)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00007	0.00005	0.00003	0.00006	0.00000	0.00004	0.00000	0.00005
PEPCO - TEC	(6)	0.00003	0.00002	0.00001	0.00003	0.00000	0.00001	0.00000	0.00002
PPL - TEC	(7)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PSE&G - TEC	(8)	0.00109	0.00071	0.00046	0.00092	0.00000	0.00058	0.00000	0.00076
TrAILCo - TEC	(9)	0.00013	0.00007	0.00005	0.00012	0.00000	0.00006	0.00000	0.00009
VEPCo - TEC	(10)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total ($/kWh and incl SUT)		$0.00135	$0.00087	$0.00056	$0.00116	$0.00000	$0.00071	$0.00000	$0.00094
Total (¢/kWh and incl SUT)		0.135 ¢	0.087 ¢	0.056 ¢	0.116 ¢	0.000 ¢	0.071 ¢	0.000 ¢	0.094 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2009.
(2) ACE-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(3) AEP-East-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(4) Delmarva-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(5) Current PATH-TEC rates pursuant to the Board's Order dated December 18, 2008 in Docket Nos. EO03050394, EO05040317, EO06020119, and ER07060379.
(6) PEPCO-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(7) PPL-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(8) Current PSE&G-TEC rates pursuant to the Board's Order dated December 18, 2008 in Docket Nos. EO03050394, EO05040317, EO06020119, and ER07060379.
(9) TrAILCo-TEC rates calculated in Attachment 6 (based on Attachment 5 of the joint EDC filing)
(10) Current VEPCo-TEC rates pursuant to the Board's Order dated December 18, 2008 in Docket Nos. EO03050394, EO05040317, EO06020119, and ER07060379.

Attachment 4a
TrAILCo Formula Rate Update Compliance Filing

Attachment 4b
Delmarva Formula Rate Update Compliance Filing

Attachment 4c
ACE Formula Rate Update Compliance Filing

Attachment 4d
PEPCo Formula Rate Update Compliance Filing

Attachment 4e
PPL Formula Rate Update Compliance Filing

Attachment 4f
AEP-East Formula Rate Update Compliance Filing

Attachment 4a

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 2009 Forecast
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	478,204
2	Total Wages Expense		p354.28.b	2,144,989
3	Less A&G Wages Expense		p354.27.b	1,666,785
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	478,204
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	77,935,050
7	Total Plant In Service		(Line 6)	77,935,050
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	1,649,800
9	Total Accumulated Depreciation		(Line 8)	1,649,800
10	Net Plant		(Line 7 - Line 9)	76,285,250
11	Transmission Gross Plant		(Line 15 + Line 21)	77,935,050
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	76,285,250
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	74,486,606
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	13,674,751
17	**Total Transmission Plant**		(Line 15 + Line 16)	**88,161,357**
18	General & Intangible		Attachment 5	3,448,444
19	Total General & Intangible		(Line 18)	3,448,444
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**3,448,444**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**91,609,801**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	1,649,800
24	Accumulated General Depreciation		Attachment 5	0
25	Accumulated Intangible Amortization		Attachment 5	0
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	0
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**0**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**1,649,800**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**89,960,001**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109 Enter Negative		Attachment 1	-912,642
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**-912,642**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**256,380,609**
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	**851,529**
	Prepayments			
36	**Transmission Related Prepayments**	(Note A)	Attachment 5	**49,017**
	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)	5,680,086
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**710,011**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**257,078,523**
46	**Rate Base**		(Line 30 + Line 45)	**347,038,524**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	897,460
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	689,344
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)	**208,116**
	A&G Expenses			
53	Total A&G		p323.197.b	4,779,281
54	Less Property Insurance Account 924		p323.185.b	12,517
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	0
56	Less General Advertising Exp Account 930.1		p323.191.b	399,596
57	Less PBOP Adjustment		Attachment 5	-3,345
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	4,370,513
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**4,370,513**
	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	399,596
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**399,596**
65	Property Insurance Account 924		p323.185.b	12,517
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	12,517
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**12,517**
	Account 566 Miscellaneous Transmission Expense			
70	Amortization Expense on Pre-Commercial Cost	Account 566	Attachment 5	567,686
71	Pre-Commercial Expense	Account 566	Attachment 5	99,015
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	22,643
73	Total Account 566		Sum (Lines 70 to 72)	**689,344**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**5,680,086**

	Depreciation & Amortization Expense				
	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	1,649,698
76	General Depreciation			Attachment 5	0
77	Intangible Amortization		(Note A)	Attachment 5	0
78	Total			(Line 76 + Line 77)	0
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**0**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**1,649,698**
	Taxes Other than Income				
82	**Transmission Related Taxes Other than Income**			Attachment 2	**600,701**
83	**Total Taxes Other than Income**			**(Line 82)**	**600,701**
	Return / Capitalization Calculations				
84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	134,379,588
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	-69
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	134,379,657
	Capitalization				
90	Long Term Debt		(Note N)		90,000,000
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)	90,000,000
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	134,379,657
97	**Total Capitalization**			(Sum Lines 94 to 96)	224,379,657
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	50.0%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	50.0%
101	Debt Cost	Total Long Term Debt			0.048
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)	0.02417
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0585
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.08267**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**28,688,980**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			9.06%
111	p	(percent of federal income tax deductible for state purpo	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.89%
113	T/ (1-T)			69.17%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**14,041,872**
115	**Total Income Taxes**		**(Line 114)**	**14,041,872**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	89,960,001
117	Total Adjustment to Rate Base		(Line 45)	257,078,523
118	**Rate Base**		(Line 46)	**347,038,524**
119	Total Transmission O&M		(Line 74)	5,680,086
120	Total Transmission Depreciation & Amortization		(Line 81)	1,649,698
121	Taxes Other than Income		(Line 83)	600,701
122	Investment Return		(Line 108)	28,688,980
123	Income Taxes		(Line 115)	14,041,872
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**50,661,337**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	91,609,801
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	91,609,801
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	50,661,337
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**50,661,337**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	561,914
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**50,099,423**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**50,099,423**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**342,892,165**
135	FCR		(Line 133 / Line 134)	**14.6108%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**14.1297%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**13.9353%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**1.6678%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**7,368,571**
140	Increased Return and Taxes		Attachment 4	**45,666,205**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**53,034,776**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**342,892,165**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**15.4669%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**14.9858%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**14.7913%**
146	**Net Revenue Requirement**		(Line 132)	**50,099,423**
147	Reconciliation amount		Attachment 6	**-5,460,000**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**2,622,623**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**47,262,046**
	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

	Trans-Allegheny Interstate Company								
	B1	**B2**	**B3**	**C**	**D**	**E**	**F**	**G**	
	Beg of Year Total	***End of Year Total***	**End of Year for Est. Average for Final *Total***	**Retail Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**Total ADIT**	
ADIT- 282 From Account Total Below	366,313	4,971,980	4,971,980	[redacted]	4,971,980	-	-	4,971,980	
ADIT-283 From Account Total Below	778,287	140	140	[redacted]	140	-	-	140	
ADIT-190 From Account Total Below	(1,965,117)	(4,059,478)	(4,059,478)	[redacted]	(4,059,478)	-	-	(4,059,478)	Enter Negative
Subtotal					912,642	-	-	912,642	
Wages & Salary Allocator							100.0000%		
Gross Plant Allocator						100.0000%			
ADIT					912,642	-	-	912,642	

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
Tax Interest Capitalized	1,042,269	3,304,578	3,304,578			3,304,578	-		Actual amount of tax interest capitalized
Depreciation	42	662,231	662,231			662,231			Book depreciation
Intercompany Charges	102,289	21,843	21,843			21,843			Intercompany charges from the AP service company
Worker's Compensation	42,230	68,830	68,830			68,830			Actual amount of reserve for workers' compensation
Deferred Tax Reclassification	778,287	1,950	1,950			1,950			Deferred tax reclassification
Excess Over/Under Pr Service	-	46	46			46			Excess over under prior service cost
Subtotal	1,965,117	4,059,478	4,059,478	-	-	4,059,478	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	1,965,117	4,059,478	4,059,478	-	-	4,059,478	-	-	

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	366,313	552,983	552,983			552,983			Allowance for borrowed funds used during construction (ABFUDC)
Property Related - Tax Depreciation	-	4,418,997	4,418,997			4,418,997			Tax depreciation
FASB 109	-	540,106	540,106			540,106			FASB 109 fixed asset adjustment
Subtotal	366,313	5,512,086	5,512,086	-	-	5,512,086	-	-	
Less FASB 109 included above	-	540,106	540,106	-	-	-	-	-	
Less FASB 106 included above	-	-	-	-	-	-	-	-	
Total	366,313	4,971,980	4,971,980		-	5,512,086	-	-	

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**							
Deferred Tax Reclassification	778,287	-	-	-	-	-	-	-	ADIT balance sheet reclassification
Regulated Asset Prexy LT	-	540,486	540,486	-	-	540,486	-	-	Regulatory asset for Prexy reclassification Non-property related
Regulated Asset Prexy LT	-	(540,486)	(540,486)	-	-	(540,486)	-	-	Exclude regulatory asset for Prexy reclassification Non-property related
WV Rate Change Consol Benefit	-	140	140	-	-	140	-	-	Temporary difference due to change in state tax rate in West Virginia
Reg Asset PJM Receivable	-	3,279,376	3,279,376	-	-	3,279,376	-	-	Comparison of actual to forecast revenues - Non-property related
Reg Asset PJM Receivable	-	(3,279,376)	(3,279,376)	-	-	(3,279,376)	-	-	Exclude comparison of actual to forecast revenues Non-property related
Subtotal	778,287	140	140		-	140	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	778,287	140	140		-	140	-	-	

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	Local Property WV	p263.1.15(i)	460	100.0000%	$ 460
2	Local Property VA	p263.1.20(i)	6,121	100.0000%	6,121
3	Local Property PA	p263.1.28(i)	1,985	100.0000%	1,985
4	Local Property MD	p263.1.31(i)	245,173	100.0000%	245,173
5	2007 Capital Stock Tax/Franchise MD	p263.20(i)	300	100.0000%	300
6	2008 Capital Stock Tax/Franchise MD	p263.21(i)	300	100.0000%	300
7	2008 Capital Stock Tax/Franchise PA	p263.32(i)	79,850	100.0000%	79,850
8	2008 Franchise Tax Billed PA	p263.33(i)	11	100.0000%	11
9	State Corp License Tax	p263.1.8(i)	30	100.0000%	30
10					
11					
12					
13					
14					
15	**Total Plant Related**		334,230	100.0000%	334,230
	Labor Related			**Wages & Salary Allocator**	
16	Accrued Federal FICA	p263.3(i)	235,559		
17	Accrued Federal Unemployment	p263.4(i)	2,516		
18	State Unemployment	p263.1.11(i)	8,840		
19					
20					
21	**Total Labor Related**		246,915	100.0000%	246,915
	Other Included			**Gross Plant Allocator**	
22	State Use Tax Billed PA	p263.31(i)	19,556		
23					
24					
25					
26	**Total Other Included**		19,556	100.0000%	19,556
27	**Total Included (Lines 8 + 14 + 19)**		600,701		**600,701** Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded				
28	Federal Income Tax	p263.2(i)	798,372		
29	Corporate Net Income Tax MD	p263.17(i)	407,405		
30	Corporate Net Income Tax PA	p263.28(i)	163,903		
31	Corporate Net Income Tax VA	p263.37(i)	159,962		
32	Corporate Net Income Tax WV	p263.1.4(i)	-263,165		
33					
34					
35					
36					
37					
38	**Subtotal, Excluded**		1,266,477		
39	**Total, Included and Excluded (Line 20 + Line 28)**		1,867,178		
40	**Total Other Taxes from p114.14.c**		600,700		
41	Difference (Line 39 - Line 40)		1,266,478		

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

Line	Description	Reference	Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		-	
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		561,914	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)	561,914	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	561,914	Input to Appendix A, Line 131
	Revenue Adjustment to determine Revenue Credit			
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			

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.

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)		45,666,205	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		347,038,524
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		134,379,588
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		-69
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		134,379,657
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		90,000,000
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		90,000,000
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		134,379,657
15	Total Capitalization		Appendix A, Line 97		224,379,657
16	Debt %	Total Long Term Debt	Appendix A, Line 98		50%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0%
18	Common %	Common Stock	Appendix A, Line 100		50%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0483
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)		0.0242
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0635
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.0877**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**30,424,173**

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	9.06%
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	40.89%
31	T/ (1-T)		Appendix A, Line 113	69.17%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		15,242,032
33	**Total Income Taxes**		**(Line 32)**	**15,242,032**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Source		13 Month Balance for Reconciliation Total	EOY Balance for Estimate Total
	Calculation of Transmission Plant In Service	Source			
		Prior year FERC Form 1			
	December	p207.58.g (and notes)	For 2007	59,282,298	
	January	company records	For 2008	60,438,302	
	February	company records	For 2008	60,914,266	
	March	company records	For 2008	61,073,786	
	April	company records	For 2008	61,167,755	
	May	company records	For 2008	63,852,352	
	June	company records	For 2008	71,824,173	
	July	company records	For 2008	71,871,507	
	August	company records	For 2008	71,890,804	
	September	company records	For 2008	71,921,358	
	October	company records	For 2008	71,936,674	
	November	company records	For 2008	72,472,837	
	December	p207.58.g	For 2008	74,486,606	74,486,606
15	**Transmission Plant In Service**			**67,164,055**	**74,486,606**
				Link to Appendix A, line 15	**Link to Appendix A, line 15**
	Calculation of Distribution Plant In Service	Source			
	December	p206.75.b	For 2007	-	
	January	company records	For 2008	-	
	February	company records	For 2008	-	
	March	company records	For 2008	-	
	April	company records	For 2008	-	
	May	company records	For 2008	-	
	June	company records	For 2008	-	
	July	company records	For 2008	-	
	August	company records	For 2008	-	
	September	company records	For 2008	-	
	October	company records	For 2008	-	
	November	company records	For 2008	-	
	December	p207.75.g	For 2008	-	-
	Distribution Plant In Service			-	-
	Calculation of Intangible Plant In Service	Source			
	December	p204.5.b	For 2007	-	
	December	p205.5.g	For 2008	-	-
18	**Intangible Plant In Service**			-	-
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of General Plant In Service	Source			
	December	p206.99.b	For 2007	-	-
	December	p207.99.g	For 2008	3,448,444	3,448,444
18	**General Plant In Service**			1,724,222	3,448,444
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of Production Plant In Service	Source			
	December	p204.46b	For 2007	-	
	January	company records	For 2008	-	
	February	company records	For 2008	-	
	March	company records	For 2008	-	
	April	company records	For 2008	-	
	May	company records	For 2008	-	
	June	company records	For 2008	-	
	July	company records	For 2008	-	
	August	company records	For 2008	-	
	September	company records	For 2008	-	
	October	company records	For 2008	-	
	November	company records	For 2008	-	
	December	p205.46.g	For 2008	-	-
	Production Plant In Service			-	-
6	**Total Plant In Service**	Sum of averages above		68,888,277	77,935,050
				Link to Appendix A, line 6	**Link to Appendix A, line 6**

Details

13 Month Plant Balance For Reconciliation

Month	Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	**Meadowbrook Transformer**	North Shenandoah	**Total**
December	44,367,279	12,763,316	2,151,702	-	-	-	-	59,282,298
January	44,344,577	13,224,242	2,869,483	-	-	-	-	60,438,302
February	44,468,849	13,327,865	2,869,640	2,928	244,984	-	-	60,914,266
March	44,613,199	13,343,036	2,869,640	2,928	244,984	-	-	61,073,786
April	44,666,979	13,375,150	2,877,715	2,928	244,984	-	-	61,167,755
May	44,802,736	13,376,964	3,428,134	2,928	244,984	-	1,996,606	63,852,352
June	44,824,947	13,374,708	3,427,968	2,928	244,984	7,936,609	2,012,030	71,824,173
July	44,853,853	13,376,567	3,428,029	2,928	244,984	7,956,828	2,008,319	71,871,507
August	44,869,644	13,372,225	3,428,145	2,928	244,984	7,962,790	2,010,090	71,890,804
September	44,899,870	13,372,225	3,428,064	2,928	244,984	7,963,102	2,010,186	71,921,358
October	44,995,937	13,376,130	3,428,064	2,928	244,984	7,967,168	1,921,464	71,936,674
November	45,625,266	13,291,705	3,419,013	2,928	244,984	7,967,477	1,921,464	72,472,837
December	45,842,798	13,291,705	5,213,431	2,928	244,984	7,973,203	1,917,557	74,486,606
Transmission Plant In Service	**44,859,687**	**13,297,372**	**3,295,310**	**2,477**	**207,294**	**4,286,706**	**1,215,209**	**67,164,055**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			13 Month Balance for Reconciliation	EOY Balance for Estimate
	Calculation of Transmission Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.25.b	For 2007	102	
	January	company records	For 2008	173,647	
	February	company records	For 2008	264,406	
	March	company records	For 2008	397,430	
	April	company records	For 2008	530,609	
	May	company records	For 2008	663,977	
	June	company records	For 2008	797,683	
	July	company records	For 2008	939,218	
	August	company records	For 2008	1,080,828	
	September	company records	For 2008	1,222,566	
	October	company records	For 2008	1,364,380	
	November	company records	For 2008	1,506,436	
	December	p219.25.b	For 2008	1,649,800	1,649,800
23	**Transmission Accumulated Depreciation**			**814,699**	**1,649,800**
				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 2007	-	
	January	company records	For 2008	-	
	February	company records	For 2008	-	
	March	company records	For 2008	-	
	April	company records	For 2008	-	
	May	company records	For 2008	-	
	June	company records	For 2008	-	
	July	company records	For 2008	-	
	August	company records	For 2008	-	
	September	company records	For 2008	-	
	October	company records	For 2008	-	
	November	company records	For 2008	-	
	December	p219.26.b	For 2008	-	-
	Distribution Accumulated Depreciation			-	-
	Calculation of Intangible Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p200.21.b	For 2007	-	
	December	p200.21b	For 2008	-	-
25	**Accumulated Intangible Depreciation**			-	-
				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 2007	-	
	December	p219.28.b	For 2008	-	-
24	**Accumulated General Depreciation**			-	-
				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-	For 2007	-	
	January	company records	For 2008	-	
	February	company records	For 2008	-	
	March	company records	For 2008	-	
	April	company records	For 2008	-	
	May	company records	For 2008	-	
	June	company records	For 2008	-	
	July	company records	For 2008	-	
	August	company records	For 2008	-	
	September	company records	For 2008	-	
	October	company records	For 2008	-	
	November	company records	For 2008	-	
	December	p219.20.b thru 219.24.b	For 2008	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**814,698.74**	**1,649,800.04**
				Link to Appendix A, line 8	**Link to Appendix A, line 8**

Details — **13 Month Balance For Reconciliation**

	Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	**Meadowbrook Transformer**	North Shenandoah	**Total**
December	-	-	102	-	-	-	-	102
January	151,179	22,314	153	-	-	-	-	173,647
February	218,766	45,436	204	-	-	-	-	264,406
March	328,428	68,738	256	5	4	-	-	397,430
April	438,196	92,088	307	10	8	-	-	530,609
May	548,097	115,495	358	15	12	-	-	663,977
June	658,333	138,904	410	20	16	-	-	797,683
July	768,624	162,310	461	26	20	7,778	-	939,218
August	878,986	185,719	513	31	24	15,556	-	1,080,828
September	989,485	209,121	564	36	28	23,334	-	1,222,566
October	1,100,058	232,522	615	41	32	31,111	-	1,364,380
November	1,210,868	255,930	667	46	36	38,889	-	1,506,436
December	1,323,133	279,191	718	51	40	46,667	-	1,649,800
Transmission Accumulated Depreciation	**662,627**	**139,059**	**410**	**22**	**17**	**12,564**	**-**	**814,699**

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	59,282,298	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	59,282,298	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	102	-	-	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

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	$ 1,135,372	$ 567,686	$ 567,686	$ 851,529

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			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	399,596	-	-	Link to Appendix A, line 66	Enter Details Here

MultiState Workpaper

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates		MD 8.25%	WV 8.75%	PA 9.99%			
			Composite	Composite is calculated based on sales, payroll and property for each jurisdiction				
110	SIT=State Income Tax Rate or Composite	(Note H)	9.06%					

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	399,596	399,596	-	Enter Details Here

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Excluded Plant Cost Support

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

Prepayments

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average of Beginning and Ending Balances	Allocation	Transmission Related	Details
36	Prepayments				Enter $		Amount	
	Prepayments	Prepaid Insurance	35,363	62,670	49,017	100%	49,017	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		35,363	62,670	49,017		49,017	

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		$ 567,686	
71	Pre-Commercial Expense		99,015	
72	Miscellaneous Transmission Expense		22,643	
	Total Account 566 Miscellaneous Transmission Expenses	p.321	$ 689,344	

Summary of Pre-Commercial Expenses

Cost Element Name	Total
Labor & Overhead (1)	95,937
Miscellaneous (2)	947
Outside Services Legal (3)	
Outside Services Other (4)	
Outside Services Rates (5)	
Advertising (6)	
Travel, Lodging and Meals (7)	2,131
Total	99,015

(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	Annual Depreciation Expense: Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Meadowbrook Transformer	North Shenandoah	Total
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43	227	-	-	-	-	-	-	227
352	Structures & Improvements	50	-	R3	(10)	2.20	-	-	-	-	-	-	-	-
	SVC	35	-			2.86	-	-	-	-	-	-	-	-
353	Station Equipment													-
	Other	50	-	R2	(5)	2.10	-	279,191	616	51	40	46,667	-	326,565
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96	1,322,839	-	-	-	-	-	-	1,322,839
	SCADA	15	-	S3	0	6.67	-	-	-	-	-	-	-	-
354	Towers & Fixtures	65	-	R4	(25)	1.92	-	-	-	-	-	-	-	-
355	Poles & Fixtures	55	-	R2.5	(20)	2.18	-	-	-	-	-	-	-	-
356	Overhead Conductors & Devices													
	Other	55	-	R2.5	(40)	2.80	-	-	-	-	-	-	-	-
	Clearing	70	-	R4	0	1.43	67	-	-	-	-	-	-	67
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							1,323,133	279,191	616	51	40	46,667	-	1,649,698
Total Transmission Depreciation Expense (must tie to p336.7.f)	1,649,698.26													

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

GENERAL PLANT		Life	Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	Total
390	Structures & Improvements	50	R1	0	2.00	-
391	Office Furniture & Equipment	20	SQ	0	5.00	-
	Information Systems	10	SQ	0	10.00	-
	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	-
	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	-
398	Miscellaneous Equipment	15	SQ	0	6.67	-
Total General Plant						-
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	-					

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

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

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

PBOP Expenses

	1	Total PBOP expenses	22,856,433
	2	Amount relating to retired personnel	8,786,372
	3	Amount allocated on FTEs	14,070,061
	4	Number of FTEs for Allegheny	4,408
	5	Cost per FTE	3,192
	6	TrAILCo FTEs (labor not capitalized) current year	14.09
	7	TrAILCo PBOP Expense for base year	44,965
	8	TrAILCo PBOP Expense in Account 926 for current year	41,620
57	9	PBOP Adjustment for Appendix A, Line 57	3,345
		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	Column D		Column E	Column F	Column G
				Pre-Commercial Costs			CWIP		
			Expensed (Estimated)	Deferred	Amount of Deferred Amortized in Year		Average of 13 Monthly Balances		
Step 1	**For Estimate:**					**Estimate Step 2**			
	Prexy - 502 Junction 138 kV (CWIP)		10,629		60,937		12,455,579		
	Prexy - 502 Junction 500 kV (CWIP)		13,690		78,492		9,930,390		
	502 Junction - Territorial Line	(CWIP)	74,696		428,257		233,994,640		
	Total		99,015	1,135,372	567,686		256,380,609		

				Pre-Commercial Costs					AFUDC (If
Step 3	**For Reconciliation:**		Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year	**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	CWIP was not in Rate Base)
	Prexy - 502 Junction 138 kV (CWIP)								
	1		10,629	121,874	60,937				
	2		-		-				
	3		-		-				
	4		-		-				
	…								
	Total		10,629	121,874	60,937				
	Prexy - 502 Junction 500 kV (CWIP)								
	1		13,690	156,984	78,492				
	2		-		-				
	3		-		-				
	4		-		-				
	…								
	Total		13,690	156,984	78,492				
	502 Junction - Territorial Line	(CWIP)							
	1		74,696	856,513	428,257				
	2		-		-				
	3		-		-				
	4		-		-				
	…								
	Total		74,696	856,513	428,257				

Total Additions to Plant In Service (sum of the above for each project)	Refer to Attachment 5 - Cost Support Plant in Service Worksheet
Total Additions to Plant in Service reported on pages 204-207 of the Form No.	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) Other Projects PIS (monthly additions)	(B) Meadowbrook Transformer (monthly additions) (in service)	(C) North Shenandoah (monthly additions) (in service)	(D) Black Oak (monthly additions) (in service)	(E) Wylie Ridge (monthly additions) (in service)	(F) 502 Junction - Territorial Line (monthly additions) CWIP	(G) 500 kV Prexy - 502 Junction (monthly additions) CWIP	(H) 138 kV Prexy - 502 Junction (monthly additions) CWIP
Dec (Prior Year CWIP) p216.b.43					197,754	20,651,884	5,244,579	4,808,804
Jan 2008				(22,702)	263,171	4,293,957	840,954	206,229
Feb				124,272	103,624	2,558,667	106,363	646,181
Mar				144,349	15,171	3,694,409	691,038	561,300
Apr				53,780	32,114	3,027,346	452,945	583,461
May		8,376,439	2,309,887	60,000	1,000	3,723,096	1,107,046	652,025
Jun		200,000	-	-	1,000	4,845,848	1,131,268	1,640,887
Jul		100,000	-	-	1,000	8,657,237	3,138,696	2,190,571
Aug		40,000	-	-	-	19,123,669	2,203,356	2,767,924
Sep		15,000	-	-	-	26,501,863	2,280,989	5,702,856
Oct		5,000	-	640,000	-	21,369,973	2,131,446	2,058,061
Nov		-	-	-	-	36,472,126	5,216,999	6,641,396
Dec		-	-	-	-	18,242,867	5,336,228	6,122,254
Total	-	8,736,439	2,309,887	999,699	614,834	173,162,941	29,881,907	34,581,949

New Transmission Plant Additions for Year 2 (13 month average balance)

Month End Balances

	Other Projects PIS (Monthly additions)	Meadowbrook Transformer (monthly balance) (in service)	North Shenandoah (monthly balance) (in service)	Black Oak (monthly balance) (in service)	Wylie Ridge (monthly balance) (in service)	502 Junction - Territorial Line (monthly balance) CWIP	500 kV Prexy - 502 Junction (monthly balance) CWIP	138 kV Prexy - 502 Junction (monthly balance) CWIP
Dec (Prior Year CWIP) p216.b.43		-	-	-	197,754	20,651,884	5,244,579	4,808,804
Jan 2008		-	-	(22,702)	460,926	24,945,841	6,085,533	5,015,033
Feb		-	-	101,570	564,549	27,504,508	6,191,896	5,661,214
Mar		-	-	245,919	579,720	31,198,916	6,882,934	6,222,515
Apr		-	-	299,699	611,834	34,226,262	7,335,879	6,805,975
May		8,376,439	2,309,887	359,699	612,834	37,949,358	8,442,925	7,458,000
Jun		8,576,439	2,309,887	359,699	613,834	42,795,206	9,574,193	9,098,887
Jul		8,676,439	2,309,887	359,699	614,834	51,452,443	12,712,889	11,289,458
Aug		8,716,439	2,309,887	359,699	614,834	70,576,112	14,916,245	14,057,382
Sep		8,731,439	2,309,887	359,699	614,834	97,077,975	17,197,234	19,760,238
Oct		8,736,439	2,309,887	999,699	614,834	118,447,948	19,328,680	21,818,299
Nov		8,736,439	2,309,887	999,699	614,834	154,920,074	24,545,679	28,459,695
Dec		8,736,439	2,309,887	999,699	614,834	173,162,941	29,881,907	34,581,949
		69,286,514	18,479,097	5,422,080	7,330,452	884,909,470	168,340,573	175,037,451
Average 13 Month Balance		5,329,732	1,421,469	417,083	563,881	68,069,959	12,949,275	13,464,419
		(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 33)	(Appendix A, Line 33)	(Appendix A, Line 33)

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

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

Total Revenue Requirement	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly Additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	500 kV Prexy - 502 Junction (Monthly additions)	138 kV Prexy - 502 Junction (Monthly additions)
$ 29,743,638.96	898,323	239,588	7,935,132	2,246,291	13,424,438	2,474,425	2,525,443

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)	(J)	(K)
		Meadow Brook SS Capacitor (monthly additions)	Bedington Transformer (monthly additions)	Kammer Transformers (monthly additions)	Meadowbrook Transformer (monthly additions)	North Shenandoah (monthly additions)	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual								94,947,300	9,677,269	11,774,984
Jan 2009	Actual								16,462,989	8,209	16,158
Feb	Actual								15,756,860	(667)	5,117
Mar	Actual								23,616,986	2,744	337,218
Apr	Actual		7,390,667						27,801,175	15,822	(22,120)
May	Budget		86,965						43,283,026	150,006	106,332
Jun	Budget		219						25,112,454	82,381	205,951
Jul	Budget		1,371						26,367,587	62,381	155,952
Aug	Budget								19,580,901	62,381	155,953
Sep	Budget								18,288,188	62,381	155,952
Oct	Budget								15,090,492	52,857	132,143
Nov	Budget			51,636,975					16,641,875	52,857	132,143
Dec	Budget	7,276,323							20,484,265	52,857	132,143
Total		7,276,323	7,479,222.12	51,636,975	-	-	-	-	363,434,098.38	10,281,477.40	13,287,925.31

New Transmission Plant Additions for Year 3 (13 month average balance)

Month End Balances

	Other Projects PIS (Monthly additions)	Meadow Brook SS Capacitor (monthly balance)	Bedington Transformer (monthly balance)	Kammer Transformers (monthly balance)	Meadowbrook Transformer (monthly balance)	North Shenandoah (monthly balance)	Black Oak (monthly balance)	Wylie Ridge (monthly balance)	502 Junction - Territorial Line (monthly balance)	500 kV Prexy - 502 Junction (monthly balance)	138 kV Prexy - 502 Junction (monthly balance)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP)		-	-	-	-	-	-	-	94,947,300	9,677,269	11,774,984
Jan 2009		-	-	-	-	-	-	-	111,410,289	9,685,477	11,791,142
Feb		-	-	-	-	-	-	-	127,167,149	9,684,810	11,796,259
Mar		-	-	-	-	-	-	-	150,784,135	9,687,554	12,133,476
Apr		-	7,390,667	-	-	-	-	-	178,585,310	9,703,376	12,111,356
May		-	7,477,632	-	-	-	-	-	221,868,336	9,853,382	12,217,688
Jun		-	7,477,851	-	-	-	-	-	246,980,790	9,935,763	12,423,639
Jul		-	7,479,222	-	-	-	-	-	273,348,377	9,998,144	12,579,591
Aug		-	7,479,222	-	-	-	-	-	292,929,278	10,060,525	12,735,544
Sep		-	7,479,222	-	-	-	-	-	311,217,466	10,122,906	12,891,496
Oct		-	7,479,222	-	-	-	-	-	326,307,958	10,175,763	13,023,639
Nov		-	7,479,222	51,636,975	-	-	-	-	342,949,833	10,228,620	13,155,782
Dec		7,276,323	7,479,222	51,636,975	-	-	-	-	363,434,098	10,281,477	13,287,925
Total		**7,276,323**	**67,221,483**	**103,273,951**	**-**	**-**	**-**	**-**	**3,041,930,322**	**129,095,070**	**161,922,524**
New Transmission Plant Additions for Year 3 (13 month average balance)		559,717	5,170,883	7,944,150	-	-	-	-	233,994,640	9,930,390	12,455,579

Total Revenue Requirement	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Kammer Transformers (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	500 kV Prexy - 502 Junction (Monthly additions)	138 kV Prexy - 502 Junction (Monthly additions)
$ 52,722,046.53	77,998	720,578	1,107,040	1,151,253	267,217	7,908,192	2,092,522	35,885,563	1,561,498	1,950,184

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)
	Meadowbrook Transformer (monthly additions)	North Shenandoah (monthly additions)	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
				197,754	20,651,884	5,244,579	4,808,804
Jan 2008			-	(197,754)	3,576,176	838,026	(38,754)
Feb			-	-	2,558,510	106,363	646,181
Mar			-	-	3,694,409	691,038	561,300
Apr			-	-	3,019,271	452,945	583,461
May	-	-	-	-	3,400,394	568,078	796,098
Jun	-	-	-	-	3,147,324	617,637	461,193
Jul	-	-	-	-	3,948,936	728,685	596,644
Aug	-	-	-	-	4,524,442	610,998	636,290
Sep	-	-	-	-	5,279,750	623,487	382,816
Oct	.	-	-	-	10,415,770	(555,597)	(262,765)
Nov	-	-	513	-	10,071,475	(248,876)	(51,516)
Dec	-	-	44,440	-	20,658,960	(96)	2,655,231
Total	-	-	44,953	-	94,947,300	9,677,269	11,774,984

Month End Balances

	Other Projects PIS (Monthly additions)	Meadowbrook Transformer (Monthly balance)	North Shenandoah (Monthly balance)	Black Oak (monthly balance)	Wylie Ridge (monthly balance)	502 Junction - Territorial Line (monthly balance)	500 kV Prexy - 502 Junction (monthly balance)	138 kV Prexy - 502 Junction (monthly balance)	
		(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP	
		-	-	-	197,754	20,651,884	5,244,579	4,808,804	
Jan 2008		-	-	-	-	24,228,060	6,082,605	4,770,050	
Feb		-	-	-	-	26,786,569	6,188,968	5,416,231	
Mar		-	-	-	-	30,480,978	6,880,006	5,977,531	
Apr		-	-	-	-	33,500,249	7,332,951	6,560,992	
May		-	-	-	-	36,900,643	7,901,030	7,357,090	
Jun		-	-	-	-	40,047,967	8,518,666	7,818,283	
Jul		-	-	-	-	43,996,903	9,247,352	8,414,927	
Aug		-	-	-	-	48,521,345	9,858,350	9,051,217	
Sep		-	-	-	-	53,801,095	10,481,837	9,434,033	
Oct		-	-	-	-	64,216,865	9,926,240	9,171,268	
Nov		-	-	513	-	74,288,339	9,677,365	9,119,753	
Dec		-	-	44,953	-	94,947,300	9,677,269	11,774,984	
Total		**-**	**-**	**45,466**	**197,754**	**592,368,197**	**107,017,217**	**99,675,161**	
Average 13 Month Balance		-	-	3,497	15,212	45,566,784	8,232,094	7,667,320	61,484,907

Result of Formula for Reconciliation

Total Revenue Requirement	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	500 kV Prexy - 502 Junction (Monthly additions)	138 kV Prexy - 502 Junction (Monthly additions)
$ 24,534,901.92	757,738	202,169	9,061,731	2,470,814	9,058,233	1,533,932	1,450,284

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		
24,534,902	-	29,743,639	=	(5,208,737)

<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 0.3800%

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(434,061)	0.3800%	11.5	(18,968)	(453,030)
Jul	Year 1	(434,061)	0.3800%	10.5	(17,319)	(451,380)
Aug	Year 1	(434,061)	0.3800%	9.5	(15,670)	(449,731)
Sep	Year 1	(434,061)	0.3800%	8.5	(14,020)	(448,082)
Oct	Year 1	(434,061)	0.3800%	7.5	(12,371)	(446,432)
Nov	Year 1	(434,061)	0.3800%	6.5	(10,721)	(444,783)
Dec	Year 1	(434,061)	0.3800%	5.5	(9,072)	(443,133)
Jan	Year 2	(434,061)	0.3800%	4.5	(7,422)	(441,484)
Feb	Year 2	(434,061)	0.3800%	3.5	(5,773)	(439,834)
Mar	Year 2	(434,061)	0.3800%	2.5	(4,124)	(438,185)
Apr	Year 2	(434,061)	0.3800%	1.5	(2,474)	(436,536)
May	Year 2	(434,061)	0.3800%	0.5	(825)	(434,886)
Total		(5,208,737)				(5,327,496)

		Balance	Interest	Amort	Balance
Jun	Year 2	(5,327,496)	0.3800%	(455,000)	(4,892,741)
Jul	Year 2	(4,892,741)	0.3800%	(455,000)	(4,456,333)
Aug	Year 2	(4,456,333)	0.3800%	(455,000)	(4,018,267)
Sep	Year 2	(4,018,267)	0.3800%	(455,000)	(3,578,537)
Oct	Year 2	(3,578,537)	0.3800%	(455,000)	(3,137,135)
Nov	Year 2	(3,137,135)	0.3800%	(455,000)	(2,694,056)
Dec	Year 2	(2,694,056)	0.3800%	(455,000)	(2,249,293)
Jan	Year 3	(2,249,293)	0.3800%	(455,000)	(1,802,841)
Feb	Year 3	(1,802,841)	0.3800%	(455,000)	(1,354,691)
Mar	Year 3	(1,354,691)	0.3800%	(455,000)	(904,839)
Apr	Year 3	(904,839)	0.3800%	(455,000)	(453,278)
May	Year 3	(453,278)	0.3800%	(455,000)	(0)
Total with interest				(5,460,000)	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest		(5,460,000)	Input to Appendix A, Line 143
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$	52,722,047	
Revenue Requirement for Year 3		47,262,046	

Reconciliation Amount by Project							
Total Revenue Requirement	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)	500 kV Prexy - 502 Junction (Monthly additions)	138 kV Prexy - 502 Junction (Monthly additions)
$ (5,460,000)	$ (147,367)	$ (39,224)	$ 1,180,945	$ 235,354	$ (4,576,825)	$ (985,861)	$ (1,127,023)

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

$ 47,262,046

10 June Year 3 Results of Step 8 go into effect

$ 47,262,046

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	13.9353%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	14.7913%
5	C		Line B less Line A	0.8561%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxe	1.6678%

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 yea**

Line		Details		PJM Upgrade ID: b0321.2; b0321.3	PJM Upgrade ID: b0321.1
10		Details		Prexy - 502 Junction 138 kV (CWIP + Plant In Service)	Prexy - 502 Junction 500 kV (CWIP+ Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No
13	Input the allowed ROE	Allowed ROE		12.70%	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		13.9353%	13.9353%
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		14.7913%	14.7913%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	Investment		12,700,523	9,933,267
17	Annual Depreciation Exp from Attachment 5			40	51

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation Amount**	Revenue	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue
18													
19	See Calculations for each item below	Wo Incentive ROE	2009	1,769,855	40	71,566	(1,127,023)	714,437.12	1,384,230	51	92,183	(985,861)	490,602.66
20	See Calculations for each item below	W Incentive ROE	2009	1,878,579	40	71,566	(1,127,023)	823,160.84	1,469,264	51	92,183	(985,861)	575,637.10

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.

Line	Description	PJM Upgrade ID: b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	PJM Upgrade ID: b0218	PJM Upgrade ID: b0216
1				
2				
3				
4				
5				
6				
7				
8				
9				
10		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"	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	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	13.9353%	13.9353%	13.9353%
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	14.7913%	13.9353%	14.7913%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	239,207,353	13,012,514	44,519,664
17	Annual Depreciation Exp from Attachment 5	616	279,191	1,323,133

Line	Description	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	33,334,243	616	502,953	(4,576,825)	29,260,986.89	1,813,332	279,191	235,354	2,327,876.21	6,203,945	1,323,133	1,180,945	8,708,023.44
20	See Calculations for each item below	35,381,994	616	502,953	(4,576,825)	31,308,738.36	1,813,332	279,191	235,354	2,327,876.21	6,585,059	1,323,133	1,180,945	9,089,137.18

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 At

Line	Description	PJM Upgrade ID: b0323				PJM Upgrade ID: b0230				PJM Upgrade ID: b0559			
1													
2													
3													
4													
5													
6													
7													
8													
9													
10		North Shenandoah Transformer (Plant In Service)				Meadowbrook Transformer (Plant In Service)				Meadow Brook SS Capacitor (Plant In Service)			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.9353%				13.9353%				13.9353%			
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	13.9353%				13.9353%				13.9353%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,917,557				7,926,536				559,717.15			
17	Annual Depreciation Exp from Attachment 5	0				46,667				-			
18		Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue
19	See Calculations for each item below	267,217	0	(39,224)	227,993.61	1,104,586	46,667	(147,367)	1,003,886.47	77,998.22	0.00	0.00	77,998.22
20	See Calculations for each item below	267,217	0	(39,224)	227,993.61	1,104,586	46,667	(147,367)	1,003,886.47	77,998.22	0.00	0.00	77,998.22

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

1

2

3
4
5

6

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9

Line	Description	PJM Upgrade ID: b0229				PJM Upgrade ID: b0495							
10		Bedington Transformer (Plant In Service)				Kammer Transformers (Plant In Service)							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes							
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No							
13	Input the allowed ROE	11.70%				11.70%							
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.9353%				13.9353%							
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	13.9353%				13.9353%							
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	5,170,883.32				7,944,150.04							
17	Annual Depreciation Exp from Attachment 5	-				-							
18		Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Total	Incentive Charged	Revenue Credit	$2,622,623.36
19	See Calculations for each item below	720,577.68	0.00	0.00	720,577.68	1,107,040.49	0.00	0.00	1,107,040.49	44,639,422.79		44,639,422.79	**Ax A Line 148**
20	See Calculations for each item below	720,577.68	0.00	0.00	720,577.68	1,107,040.49	0.00	0.00	1,107,040.49	47,262,046.15	47,262,046.15		

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 At

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

	t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE	(d) Net Proceeds At Issuance	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z*	(h) Weighted Outstanding Ratios	(i) Effective Cost Rate (Tables 2 and 3)	(j) Weighted Debt Cost at t = N (h) * (i)	
Long Term Debt Cost at Year Ended:	12/31/2014											
First Mortgage Bonds:												
(1) 7.09%, Debenture Description, Series, Name of Issuer		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, Name of Issuer		1/1/2014	6/30/2025									
Other Long Term Debt:												
(3) 6.6%, Medium Term Notes, Series, Name of Issuer		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 Drawdown, 6.59% (2014 Interest Rate), 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

Long Term Debt Issuances	Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT (Attachment 1)	(hh) Net Proceeds	(ii) Net Proceeds Ratio	(jj) Coupon Rate	(kk) Annual Interest	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
First Mortgage Bonds													
(1) 7.09%, Debenture Description, Series, Name of Issuer	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, Name of Issuer		xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxxx	xxx	xxxx	xx.xxxx
Other Long Term Debt:												-	
(3) 6.6%, Medium Term Notes, Series, Name of Issuer	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_0 equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Trans-Allegheny Interstate Line Company
Attachment 8, page 2, Table 3

TABLE 3: Project Financing Costs for Long Term Debt Credit Line Drawdowns using the Internal Rate of Return Methodology

Hypothetical Example: Construction project financing will be a 7 year loan, where by Company pays Origination Fees of $5.2 million; Commitments Fee of 0.3% on the undrawn principal and interest on amounts drawn.
Consistent with GAAP, Company will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return ("IRR") formula below.
The IRR is the fluctuating effective yield to maturity of the construction project financing loan at a given time "t".

Each year, Company will reconcile the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment. Company anticipates entering into permanent financing at the end of the term of the project financing, when the project is in-service. At such time, Company will reconcile amounts borrowed, issuance cost, issuance discount or premium, interest paid, etc., on Table 2.

IRR= Internal Rate of Return; NPV = Net Present Value; C = Net Cashflows (Column I below); t = time period; pwr = exponential power.

Total Loan Amount	**$**	**550,000,000**

Internal Rate of Return[1] **4.83360%**
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
Revolving Credit Commitment Fee	0.0050
Revolving Credit Commitment Fee	0.0037

	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%	4.34%	4.34%	4.34%	4.34%	4.34%	4.34%	4.34%

(A) Year	(B)	(C) Capital Expenditures	(D) Principle Drawn In Quarter ($000's)	(E) Principle Drawn To Date	Outstanding Debt Balance	(F) Interest Expense	(G) Origination Fees	(H) Commitment	(I) 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				10,000,000	-	-
3/24/2008	Q1	25,543,000		10,000,000	10,000,000	155,048			(155,048)	118,382	(36,665)
6/23/2008	Q2	20,509,000		10,000,000	9,963,335	97,477			(97,477)	117,948	20,471
8/15/2008	Q3	-	55,000,000	65,000,000	9,983,805	59,689	7,780,954	-	47,159,357	68,667	8,978
8/25/2008	Q3	-		65,000,000	57,211,829	-	15,125	-	(15,125)	74,038	74,038
9/15/2008	Q3	-	(20,000,000)	45,000,000	57,270,742	243,025	-	-	(20,243,025)	155,750	(87,274)
9/30/2008	Q3	24,995,000	-	45,000,000	37,183,468	-	-	235,521	(235,521)	72,202	72,202
10/15/2008	Q3	-	20,000,000	65,000,000	37,020,149	-	-	-	20,000,000	71,885	71,885
12/15/2008	Q4	-	25,000,000	90,000,000	57,092,034	718,999		-	24,281,001	452,175	(266,824)
(1) 1/6/2009	Q1	42,068,000	-	90,000,000	81,825,210	-		618,334	(618,334)	233,139	233,139
3/15/2009	Q1	75,475,000	60,791,000	150,791,000	81,440,015	963,123		575,000	59,252,877	719,358	(243,765)
6/15/2009	Q2	66,048,000	78,284,000	229,075,000	141,412,250	1,649,530		499,011	76,135,459	1,692,576	43,047
9/15/2009	Q3	61,175,000	53,475,000	282,550,000	219,240,286	2,505,892		401,156	50,567,952	2,624,107	118,215
12/15/2009	Q4	73,715,000	54,288,000	336,838,000	272,432,345	3,057,268		334,313	50,896,419	3,225,116	167,848
3/15/2010	Q1	168,370,000	92,260,000	429,098,000	326,553,880	3,604,628		266,453	88,388,919	3,823,090	218,462
6/15/2010	Q2	83,172,000	80,476,000	509,574,000	418,765,889	4,693,979		151,128	75,630,893	5,012,248	318,269
9/15/2010	Q3	70,980,000	40,426,000	550,000,000	499,409,031	5,574,321		50,533	34,801,147	5,977,473	403,153
12/15/2010	Q4	56,349,000	-	550,000,000	540,187,651	5,951,151			(5,951,151)	6,394,864	443,714
3/15/2011	Q1	58,293,000	-	550,000,000	540,631,364	5,885,753			(5,885,753)	6,329,376	443,623
6/15/2011	Q2	59,524,000	-	550,000,000	541,074,987	6,016,548			(6,016,548)	6,476,177	459,629
9/15/2011	Q3	42,228,000	-	550,000,000	541,534,616	6,016,548			(6,016,548)	6,481,678	465,130
12/15/2011	Q4	39,701,000	-	550,000,000	541,999,746	5,951,151			(5,951,151)	6,416,316	465,166
3/15/2012	Q1	42,672,000	-	550,000,000	542,464,912	5,951,151			(5,951,151)	6,421,823	470,672
6/15/2012	Q2		-	550,000,000	542,935,584	6,016,548			(6,016,548)	6,498,447	481,899
9/15/2012	Q3		-	550,000,000	543,417,483	6,016,548			(6,016,548)	6,504,215	487,667
12/15/2012	Q4		-	550,000,000	543,905,150	5,951,151			(5,951,151)	6,438,873	487,722
3/15/2013	Q1		-	550,000,000	544,392,872	5,885,753			(5,885,753)	6,373,413	487,660
6/15/2013	Q2	-	-	550,000,000	544,880,532	6,016,548			(6,016,548)	6,521,726	505,178
9/15/2013	Q3	-	-	550,000,000	545,385,710	6,016,548			(6,016,548)	6,527,772	511,225
12/15/2013	Q4	-	-	550,000,000	545,896,934	5,951,151			(5,951,151)	6,462,452	511,301
3/15/2014	Q1	-	-	550,000,000	546,408,236	5,885,753			(5,885,753)	6,397,008	511,255
6/15/2014	Q2	-	-	550,000,000	546,919,490	6,016,548			(6,016,548)	6,546,130	529,582
9/15/2014	Q3		-	550,000,000	547,449,073	6,016,548			(6,016,548)	6,552,469	535,921
12/15/2014	Q4		-	550,000,000	547,984,994	5,951,151			(5,951,151)	6,487,171	536,020
3/15/2015	Q1		-	550,000,000	548,521,014	5,885,753			(5,885,753)	6,421,743	535,990
6/15/2015	Q2	-	-	550,000,000	549,057,004	6,016,548			(6,016,548)	6,571,715	555,167
9/15/2015	Q3	-	-	550,000,000	549,612,171	6,016,548			(6,016,548)	6,578,359	561,811
8/15/2015	Q3		-	550,000,000	550,173,982	(2,027,315)			(547,972,685)	(2,201,297)	(173,982)

(1) Commitment fees for 4th quarter 2008

[1] The IRR is the Debt Cost shown on Long Term Debt Cost Tables 1 and 2 of Attachment 8. (note in Excel, the Analysis Tool Pack Add-in must be loaded for the cacluation). 7.9% will be used until the construction project debt financing is executed.
[2] The IRR is a discount rate that makes the net present value ("NPV") of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e. XIRR function in a spreadsheet program).

Attachment 4b

ATTACHMENT H-3D

	Delmarva Power & Light Company Formula Rate - Appendix A	Notes	FERC Form 1 Page # or Instruction	2008
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 2,247,047
2	Total Wages Expense		p354.28b	$ 30,225,895
3	Less A&G Wages Expense		p354.27b	$ 2,553,786
4	Total		(Line 2 - 3)	27,672,109
5	**Wages & Salary Allocator**		(Line 1 / 4)	**8.1203%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,097,683,993
7	Common Plant In Service - Electric		(Line 24)	74,730,016
8	Total Plant In Service		(Sum Lines 6 & 7)	2,172,414,009
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 810,491,470
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 25,847,304
11	Accumulated Common Amortization - Electric	(Note A)	p356	17,196,214
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	$ 37,798,490
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	891,333,478
14	Net Plant		(Line 8 - 13)	1,281,080,531
15	Transmission Gross Plant		(Line 29 - Line 28)	667,417,533
16	**Gross Plant Allocator**		(Line 15 / 8)	**30.7224%**
17	Transmission Net Plant		(Line 39 - Line 28)	404,019,002
18	**Net Plant Allocator**		(Line 17 / 14)	**31.5374%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 641,302,061
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	12,059,758
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**653,361,819**
23	General & Intangible		p205.5.g & p207.99.g	98,364,376
24	Common Plant (Electric Only)	(Notes A & B)	p356	74,730,016
25	Total General & Common		(Line 23 + 24)	173,094,392
26	Wage & Salary Allocation Factor		(Line 5)	8.12026%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**14,055,713**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**667,417,533**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 254,178,010
31	Accumulated General Depreciation		p219.28.c	$ 32,707,577
32	Accumulated Intangible Amortization		(Line 10)	25,847,304
33	Accumulated Common Amortization - Electric		(Line 11)	17,196,214
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	37,798,490
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	113,549,585
36	Wage & Salary Allocation Factor		(Line 5)	8.12026%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**9,220,521**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**263,398,531**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**404,019,002**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-115,124,961
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	-6,204,252
42	Net Plant Allocation Factor		(Line 18)	31.54%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-117,081,618**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**	(Note B)	p216.43.b as Shown on Attachment 6	**5,283,249**
	Transmission O&M Reserves			
44	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**-2,000,920**
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	15,495,543
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**15,495,543**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 1,612,994
48	Wage & Salary Allocation Factor		(Line 5)	8.12%
49	Total Transmission Allocated		(Line 47 * 48)	130,979
50	Transmission Materials & Supplies		p227.8c	4,028,772
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**4,159,751**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	13,976,762
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**1,747,095**
	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)	**-92,396,899**
59	**Rate Base**		(Line 39 + 58)	**311,622,103**

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b	$ 10,585,013
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)	**10,585,013**
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	0
68	Total A&G			p323.197.b	$ 50,758,048
69	Less Property Insurance Account 924			p323.185b	352,274
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	3,299,506
71	Less General Advertising Exp Account 930.1			p323.191b	88,557
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	6,582,874
73	Less EPRI Dues		(Note D)	p352-353	34,018
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)	40,400,819
75	Wage & Salary Allocation Factor			(Line 5)	8.1203%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)	**3,280,651**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	**0**
80	Property Insurance Account 924			p323.185b	352,274
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	352,274
83	Net Plant Allocation Factor			(Line 18)	31.54%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)	**111,098**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**	**13,976,762**

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	**15,396,422**
87	General Depreciation			p336.10b&c	3,465,919
88	Intangible Amortization		(Note A)	p336.1d&e	142,676
89	Total			(Line 87 + 88)	3,608,595
90	Wage & Salary Allocation Factor			(Line 5)	8.1203%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)	**293,027**
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	3,473,129
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	3,473,129
95	Wage & Salary Allocation Factor			(Line 5)	8.1203%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)	**282,027**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**	**15,971,476**

Taxes Other than Income

98	**Taxes Other than Income**			Attachment 2	**5,766,874**
99	**Total Taxes Other than Income**			**(Line 98)**	**5,766,874**

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	$ 36,278,572
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	36,278,572
103	**Preferred Dividends**		enter positive	p118.29c	40,403
	Common Stock				
104	Proprietary Capital			p112.16c	734,680,191
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)	732,502,412
	Capitalization				
108	Long Term Debt			p112.17c through 21c	782,570,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-19,190,253
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,596,405
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	765,976,152
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	732,502,412
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,498,478,564
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51.12%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	48.88%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0474
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)	0.0242
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0552
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0794**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**24,757,798**

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		8.39%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.45%
132	T/ (1-T)				67.94%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	Attachment 1	-232,486
134	T/(1-T)			(Line 132)	67.94%
135	Net Plant Allocation Factor			(Line 18)	31.5374%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-123,132**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**11,694,432**
138	**Total Income Taxes**			**(Line 136 + 137)**	**11,571,300**

REVENUE REQUIREMENT

	Summary				
139	Net Property, Plant & Equipment			(Line 39)	404,019,002
140	Adjustment to Rate Base			(Line 58)	-92,396,899
141	**Rate Base**			(Line 59)	**311,622,103**
142	O&M			(Line 85)	13,976,762
143	Depreciation & Amortization			(Line 97)	15,971,476
144	Taxes Other than Income			(Line 99)	5,766,874
145	Investment Return			(Line 127)	24,757,798
146	Income Taxes			(Line 138)	11,571,300
147	**Gross Revenue Requirement**			**(Sum Lines 142 to 146)**	**72,044,212**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	641,302,061
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	641,302,061
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	72,044,212
153	**Adjusted Gross Revenue Requirement**			(Line 151 * 152)	**72,044,212**
	Revenue Credits & Interest on Network Credits				
154	**Revenue Credits**			Attachment 3	8,054,237
155	**Interest on Network Credits**		(Note N)	PJM Data	-
156	**Net Revenue Requirement**			**(Line 153 - 154 + 155)**	**63,989,975**
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	**63,989,975**
158	Net Transmission Plant			(Line 19 - 30)	**387,124,051**
159	Net Plant Carrying Charge			(Line 157 / 158)	**16.5296%**
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	**12.5524%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	**3.1681%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	**27,660,876**
163	Increased Return and Taxes			Attachment 4	**38,887,309**
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	**66,548,185**
165	Net Transmission Plant			(Line 19 - 30)	**387,124,051**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	**17.1904%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation			(Line 163 - 86) / 165	**13.2133%**
168	**Net Revenue Requirement**			(Line 156)	**63,989,975**
169	True-up amount			Attachment 6	**(6,645,698)**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	**299,490**
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515			Attachment 5	**-**
172	**Net Zonal Revenue Requirement**			(Line 168 - 169 + 171)	**57,643,767**
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	**3,991**
174	Rate ($/MW-Year)			(Line 172 / 173)	**14,444**
175	**Network Service Rate ($/MW/Year)**			**(Line 174)**	**14,444**

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.

END

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	0	(345,173,966)	0	
ADIT-283	0	(19,428,353)	(71,672,056)	
ADIT-190	0	9,464,666	(2,441,108)	
Subtotal	0	(355,137,653)	(74,113,164)	(429,250,817)
Wages & Salary Allocator			8.1203%	
Gross Plant Allocator		30.7224%		
ADIT	0	(109,106,780)	(6,018,181)	(115,124,961)

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 (2,596,405)

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 Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Merrill Creek Excess Capacity	6,072,741	6,072,741				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 ar
Above Market Sales Contracts	3,031,920	3,031,920				This represents deferred tax generated as a result of a book expense related to Energy Trading. For tax purposes, this item did not give rise to a tax deduction. Deductions for tax will be amortized over future periods. Generation related.
Below Market Sales Contracts	(391,896)	(391,896)				This represents deferred tax generated as a result of a book reserve related to Energy Trading. For tax purposes, this item did not give rise to a tax deduction as it did not meet the "all events" test. Generation related.
Deferred Restructuring Costs	(199,144)	(199,144)				These deferred taxes are the result of books deferring costs associated with the deregulation of the Energy Business. For tax, these costs were deducted as ordinary and necessary expenses under IRC section 162. Retail related.
Allowance for Doubtful Accounts	4,714,669	4,714,669				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 pe
Excess Property Reserve	(7,023)	(7,023)				This represents deferred tax generated as a result of a book reserve related to deregulation of the Energy Business. For tax purposes, this item did not give rise to a tax deduction as it did not meet the "all events" test. Generation related.
Environmental Expense	(56,259)	(56,259)				aside a reserve for environmental site clean-up expenses. For tax no deduction is
Merger Costs	(6,068,791)	(6,068,791)				Reflects deferred taxes generated on Delmarva Power & Light Company /Atlantic
Claims Reserve	2,280,868			2,280,868		These deferred taxes are the result of a deduction taken for book purposes to se
Emissions Allowances	(50,559)	(50,559)				Proceeds from the sale of emissions allowances are deferred, pending future rate
Preliminary Survey & Investigation Costs	(670)	(670)				immaterial
Building Maintenance Accrual	88,495	88,495				Acct 242650 immaterial
Merrill Creek - Rent	4,041,091	4,041,091				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
Wilmington Coal Gas Site Cleanup	(723,292)	(723,292)				Timing differences related to Gas operations.
Merger Costs	458,232				458,232	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.
Performance Based Restr.Stck	(938,766)				(938,766)	Relates to Executive compensation that tax can not deduct until all restriction lapse
Capital Loss over Capital Gain	(18,302)			(18,302)		This relates to a capital loss carry forward, tax can not deduct loss in excess of capital gain.
PJM Member Defaults	16,062			16,062		December 2007 two members of PJM were declared in default on their obligations
Blueprint for the Future	(686,745)			(686,745)		is designed to help customers, both residential and business, manage their energy
Merger/ERO Paid Out of Pension	(576,381)				(576,381)	This relates to ACE/DPL merger seperation payments paid out of pension fund ;this is deductible when pension is fully funded.
Miscellaneous	(1,036,828)	(1,036,828)				Timing differences related to Gas operations.
Deferred Fuel	7,715,087	7,715,087				To help utilities cope with price fluctuations, many regulators have approved rate tariffs that allow rates to be adjusted through fuel adjustment clauses that pass through actual fuel expense increases/decreases to rate payers by means of surcharges or r
Summit Land Transfer	42	42				transaction was disregarded resulting in deferred taxes. Tax liability is recognized
Venture Capital Invest/Partnership Inc	359,976	359,976				Investment attributable to non-utility operations
Gain on Sale of Microwave Systems	(234,579)			(234,579)		The deferred tax balance reflects the difference between the book gain and tax gain on the disposition assets. Involves both T & D facilities.
MD DSM Deferred Interest	(344,100)	(344,100)				deferred costs balance. For tax these costs are expensed when paid. These
Deferred ITC	6,103,655			6,103,655		encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior
Plant Related	77,922,895	77,922,895				Life and method differences related to all plant
Pension And Other Labor Related	(1,384,192)				(1,384,192)	Affects company personnel across all functions.
OPEB	3,078,796				3,078,796	OPEB contributions are made to the trust. These deferred taxes are the result of
	-					

Other Adjustment	(2,656,272)	(2,656,272)				Adjustment relatied to other plant
Subtotal - p234	100,510,730	92,412,083	0	7,460,959	637,688	
Less FASB 109 Above if not separately removed	(2,003,707)			(2,003,707)	-	
Less FASB 106 Above if not separately removed	3,078,796				3,078,796	
Total	99,435,641	92,412,083	-	9,464,666	(2,441,108)	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water,
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

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

hment 1- Accumulated 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*
Recoverable Income Tax	(62,550,021)			(62,550,021)		FASB 109 gross up, removed below
Plant Related	(405,789,619)	(60,615,653)		(345,173,966)		Plant
Subtotal - p275	(468,339,640)	(60,615,653)	0	(407,723,987)	0	
Less FASB 109 Above if not separately removed	(62,550,021)			(62,550,021)		
Less FASB 106 Above if not separately removed						
Total	(405,789,619)	(60,615,653)	0	(345,173,966)	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water,
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

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

hment 1- Accumulated 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*
Merger Costs	(365,431)				(365,431)	Reflects deferred taxes generated on Delmarva Power & Light Company /Atlantic City Electric Company merger costs deducted for tax purposes. For books these costs were capitalized. Pension related and therefore labor related.
Materials Reserve	(719,064)	(719,064)				This represents deferred tax generated as a result of a deduction taken for amounts set aside in a reserve for book purposes. For tax, no deduction is permitted until economic performance takes place. These reserves are related to deregulation of Energy
Charitable Contributions	(22,209)			(22,209)		PHI's consolidated return is in an NOL situation, therefore, DPL'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. Involves all functio
DSM Costs	81	81				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
Deferred Fuel	(10,086,103)	(10,086,103)				To help utilities cope with price fluctuations, many regulators have approved rate tariffs that allow rates to be adjusted through fuel adjustment clauses that pass through actual fuel expense increases or decreases to rate payers by means of surcharges o
Deferred Fuel Interest	(292,513)	(292,513)				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. Re
Reacquired Debt	(2,596,405)	(2,596,405)				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. The reacquired debt item is re

Mark to Market Adj	(268,887)	(268,887)				For tax, DPL elected to be a dealer in securities and marks their section 475 trade receivables to market value by means of schedule m adjustments. For book purposes, the change in market value of securities is generally not recognized. These are the de
Property Taxes	782,416	782,416				For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Unregulated related
Copco Deferred Fuel	(892,292)	(892,292)				Deferred tax relates to fuel costs for retail customers
Reg Liab - MD SOS Energy	(6,677,651)	(6,677,651)				Retail SOS, Other
Reg Liab - MD SOS Transmission	(438,251)	(438,251)				Retail SOS, Other
Reg Liab - DE SOS Energy	(2,109,604)	(2,109,604)				Retail SOS, Other
Reg Liab - DE SOS Transmission	504,203	504,203				Retail SOS, Other
Gas Environmental surcharge	216,255	216,255				Gas related
Miscellaneous	(500,904)	(500,904)				Miscellaneous temporary differences that are less than $100,000 for each item.
Copco Carrying Charge	(1,487,420)	(1,487,420)				These deferred taxes are the result of fuel associated costs that are amortized for book purposes . For tax these cost were deducted when paid. Retail related.
Copco DSM Costs	41,769	41,769				For books, Demand Side Management Costs are deferred. Interest accrues on the deferred costs balance. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature.
MD DSM Deferred Interest	346,833	346,833				For books, Demand Side Management Costs are deferred. Interest accrues on the deferred costs balance. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature.
Capitalized Interest	393,048			393,048		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
AFUDC Debt	(248,914)			(248,914)		For book purposes, AFUDC is capitalized and depreciated. For tax purposes, AFUDC is not recognized. Related to all plant.
Repair Allowance	(3,970,730)			(3,970,730)		Deferred tax represents the difference between tax deductible repairs and book capitalization of repair costs related to all plant
Reserve Adjustment	(167,000)			(167,000)		Depreciation adjustment related to all plant
Plant Related	(347,853)			(347,853)		Life and method differences related to all plant
Pension/OPEB AND Other Labor Related	(71,306,626)				(71,306,626)	Affects company personnel across all functions.
	-					
Other	(54,313)	(54,313)				
Subtotal - p277 (Form 1-F filer: see note 6, below)	(100,267,564)	(24,231,850)	-	(4,363,658)	(71,672,056)	
Less FASB 109 Above if not separately removed	15,064,695			15,064,695		
Less FASB 106 Above if not separately removed	0				-	
Total	(115,332,259)	(24,231,850)	-	(19,428,353)	(71,672,056)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water,
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 included in taxable

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

hment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

	Item		Balance	Amortization	
Rate Base Treatment					
Balance to line 41 of Appendix A	Total		6,204,252	527,042	
Amortization					
Amortization to line 133 of Appendix A	Total		1,320,569	232,486	Excludes $56,643 related to gas function amortization
					Excludes $759,528related to gas function balance
Total			7,524,821	759,528	
Total Form No. 1 (p 266 & 267)			7,524,821	759,528	
Difference /1			(0)	0	

/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)	**17,837,972**		
2 Personal property			
3 Federal/State Excise			
4			
5			
6			
Total Plant Related	17,837,972	30.7224%	5,480,252
Labor Related		***Wages & Salary Allocator***	
7 Federal FICA & Unemployment	**3,369,658**		
8 Unemployment	**40,932**		
9			
10			
11			
Total Labor Related	3,410,590	8.1203%	276,949
Other Included		***Gross Plant Allocator***	
12 Miscellaneous	31,489		
13			
14			
Total Other Included	31,489	30.7224%	9,674
Total Included	21,280,051		5,766,874
Excluded			
15 State Franchise Tax	**5,795,404**		
16 Gross Receipts	**-**		
17 Sales and Use	**296,253**		
18 Utility Tax for Delmarva	**11,409,469**		
19 City License	**3,996**		
20			
21 Total "Other" Taxes (included on p. 263)	38,785,173		
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	38,785,173		
23 Difference	-		

Criteria for Allocation:

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

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

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

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

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

Delmarva Power & Light Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		1,177,703
2	Total Rent Revenues	(Sum Line 1)	1,177,703
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 1,452,219
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)		1,810,885
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)		4,440,497
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	8,881,304
12	Less line 17g		(827,067)
13	Total Revenue Credits		8,054,237

Revenue Adjustment to determine Revenue Credit

14

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

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

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

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	1,177,703
17b	Costs associated with revenues in line 17a	476,431
17c	Net Revenues (17a - 17b)	701,272
17d	50% Share of Net Revenues (17c / 2)	350,636
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)	350,636
17g	Line 17f less line 17a	(827,067)
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.	14,356,296
19	Amount offset in line 4 above	66,495,907
20	Total Account 454, 456 and 456.1	89,733,507
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)	38,887,309
B		100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	311,622,103
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	36,278,572
101	Less LTD Interest on Securitization Bonds			Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	36,278,572
103	**Preferred Dividends**		enter positive	p118.29c	40,403
	Common Stock				
104	Proprietary Capital			p112.16c	734,680,191
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)	732,502,412
	Capitalization				
108	Long Term Debt			p112.17c through 21c	782,570,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-19,190,253
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,596,405
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	765,976,152
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	732,502,412
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,498,478,564
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51.12%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	48.88%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0474
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)	0.0242
124	Weighted Cost o	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost o	Common Stock		(Line 119 * 122)	0.0601
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0843**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**26,281,103**

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	(232,486)
134	T/(1-T)			(Line 132)	68%
135	Net Plant Allocation Factor			(Line 18)	31.5374%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-123,132**
137	**Income Tax Component =**		CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		**12,729,338**
138	**Total Income Taxes**			**(Line 136 + 137)**	**12,606,206**

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	49,783,347	25,847,304	23,936,043	See Form 1
11	Accumulated Common Amortization - Electric	(Note A)	p356	20,471,683	17,196,213	3,275,470	See Form 1
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	44,998,201	37,798,490	7,199,711	See Form 1
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	88,964,305	74,730,016	14,234,289	See Form 1
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	8,240,442	7,524,821	715,621	See Form 1
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 1,685,822	1,612,994	72,828	95.68% Electric, 4.32% 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	151,147	142,676	8,471	See FERC Form 2, Page 337, Line 1, Column h for non-electric portion.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	$ 3,473,129	3,473,129	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	397,133	0	397,133	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	Enter	Enter	Enter	Enter Details
							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	$ 2,097,683,993	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 641,302,061	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	74,730,016	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	254,178,010	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	34018	34018	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	$ 3,299,506	0	3,299,506	FERC related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	3,299,506	0	3,299,506	FERC related

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	88,557	0	88,557	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 0.00089%, VA 0.1757%, DE 5.8801%, MD 2.33%, OH 0.0014%, NY 0.0

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	88,557	0	88,557	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

Delmarva Power & Light 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	7,565,712	8.12%	614,355	
	Plant Related	4,513,205	30.72%	1,386,565	
	Other		0.00%	-	
	Total Transmission Related Reserves	12,078,917		2,000,920	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
				Allocator	To Line 45	
	Pension Liabilities, if any, in Account 242		-	6.821%	-	
	Prepayments	$	43,074,001	6.821%	2,938,085	
	Prepaid Pensions if not included in Prepayments	$	184,099,468	6.821%	12,557,457	
			227,173,469	6.82%	15,495,543	
5	Wages & Salary Allocator		8.120%			
	Electric vs Gas		84%	Based on Modified Wisconsin Method		
	Modified Wages & Salaries Allocator		6.821%			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	$ -	$ -

Delmarva Power & Light 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	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	3,991	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 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 6,088,669	$ 4,685,228	$ 13,055,598	$ 11,843,832	$ 35,673,327
Security Services Administration	448,463	281,895	1,103,634	215,476	2,049,468
Purchasing, Storeroom & Materials Mgt	764,668	401,128	2,292,990	162,133	3,620,919
Vehicle Resource Management	823,131	510,583	667,782	23,980	2,025,476
General Services	2,499,014	1,185,490	1,992,218	833,669	6,510,391
Building Services	845,609	719,336	2,002,356	650,304	4,217,605
Real Estate	1,062,693	914,165	168,676	123,622	2,269,156
Corporate Insurance Administration	161,286	107,288	243,862	132,157	644,593
Claims Administration	554,166	522,344	1,258,298	-	2,334,808
Regulatory Affairs	3,557,440	2,525,542	5,206,817	51,787	11,341,586
Accounts Payable Accounting Services	480,561	369,796	415,968	175,455	1,441,780
Payroll Services	345,067	197,596	527,080	82,924	1,152,667
Asset & Project Accounting Services	465,891	441,261	1,235,701	396,926	2,539,779
Investor Relations	163,900	137,954	391,953	232,342	926,149
Shareholder Services	239,252	200,704	573,491	340,459	1,353,906
Financial Reporting	714,616	611,787	1,710,178	1,032,682	4,069,263
Sarbanes-Oxley Compliance	170,005	155,738	406,322	240,877	972,942
Investment Financial Management	162,452	144,408	324,998	227,000	858,858
Other Financial Services	4,822,102	4,016,397	7,066,305	5,585,377	21,490,181
Insurance Premiums & Claims	2,183,779	1,532,480	3,622,824	2,853,195	10,192,278
Cost of Benefits	9,645,396	5,280,286	14,835,121	4,851,358	34,612,161
Executive Compensation Services	1,304,179	1,102,347	3,098,578	1,836,230	7,341,334
Other Human Resources Services	6,003,234	3,552,335	7,295,156	4,221,881	21,072,606
Legal Services	3,295,848	2,149,716	4,685,334	1,193,530	11,324,428
Audit Services	901,281	937,556	1,344,601	725,695	3,909,133
Special Billing	596,177	523,426	1,032,596	23,547	2,175,746
Other Customer Care	32,330,273	33,228,289	9,939,300	-	75,497,862
Marketing Services	1,337,414	901,584	2,152,837	71,686	4,463,521
Information Technology	6,446,316	4,108,253	28,658,896	2,414,853	41,628,318
PHI Corporate Contributions	4,413	3,760	10,600	6,249	25,022
Federal Government Affairs	236,465	199,898	565,539	334,717	1,336,619
Other Corporate Communications	965,371	576,380	1,674,735	591,134	3,807,620
Environmental Management Services	1,356,946	891,749	2,094,110	594,133	4,936,938
System Operations Shared	2,441,554	1,611,650	5,351,445	186,866	9,591,515
Electric Maintenance Meter Shop	1,353,932	767,471	-	-	2,121,403
Other Delivery Services	23,228,812	16,373,165	29,935,926	40,567	69,578,470
Power Procurement	1,691,047	1,405,532	2,847,431	-	5,944,010
Management & Administration	112,436	21,520	-	10,169,677	10,303,633
Merchant Functions	907,522	-	-	21,600,003	22,507,525
Engineering Administration	254,758	117,831	-	10,043,444	10,416,033
Internal Consulting Services	104,095	70,196	157,910	-	332,201
IT Voice Support	-	-	2,430	-	2,430
Interns	159,834	109,390	144,916	342	414,482
Total	$ 121,230,067	$ 93,593,454	$ 160,094,512	$ 84,110,109	$ 459,028,142

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, 2008

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	70,313,952	90,411,393	(630,833)	160,094,512
2	Delmarva Power & Light Company	37,169,665	84,325,788	(265,386)	121,230,067
3	Atlantic City Electric	22,993,733	70,823,730	(224,009)	93,593,454
4	Conectiv Energy Supply, Inc.	19,820,277	10,843,609	(37,598)	30,626,288
5	Conectiv Delmarva Generation, Inc.	5,683,137	11,664,701	(56,877)	17,290,961
6	Pepco Energy Services, Inc.	4,018,268	9,426,518	(70,597)	13,374,189
7	Conectiv Atlantic Generation, LLC	3,189,892	4,706,247	(26,309)	7,869,830
8	Conectiv Bethlehem, LLC	1,945,436	1,766,615	(31,160)	3,680,891
9	Pepco Holdings, Inc.	219,543	3,138,792	(86,688)	3,271,647
10	Potomac Capital Investment Corporation	1,300,935	1,086,853	(22,585)	2,365,203
11	PHI Operating Services Company	703,267	1,216,914	(951)	1,919,230
12	Thermal Energy Limited Partnership	108,347	684,357	(7,865)	784,839
13	Conectiv Mid-Merit, LLC	940,099	179,868	(902)	1,119,065
14	Conectiv Thermal Systems	138,656	160,340	(1,033)	297,963
15	Atlantic Southern Properties	53,082	90,180	(572)	142,690
16	Conectiv Communications, Inc.	732	37,058	(813)	36,977
17	ATE Investments, Inc.	1,310	26,026	(695)	26,641
18	Atlantic City Electric Transition Funding, LLC	51,570	670,171	(21,846)	699,895
19	Delaware Operating Services Company	2,006			2,006
20	Conectiv Properties and Investments, Inc.	9,125	62,047		71,172
21	Conectiv Pennsylvania Generation, LLC	14	6,175	(45)	6,144
22	Conectiv Solutions LLC	8,461	5,117		13,578
23	Conectiv North East, LLC	80,417	3,130	(37)	83,510
24	Atlantic Generation, Inc.	7,221	1,169	(8)	8,382
25	DCTC-Burney, Inc.	782	348		1,130
26	Conectiv Services II, Inc.	37,593	12,763		50,356
27	Vineland General, Inc.	12,660	150	(1)	12,809
28	Vineland Limited, Inc.		6		6
29	ACE REIT, Inc.	13	21	(1)	33
30	Conectiv	7,625	11,091	(334)	18,382
31	Atlantic Thermal Operating Company	49	119,384		119,433
32	Conectiv Energy Holding Company	424	223,071	(6,983)	216,512
33	Delta, LLC	347			347
34					
35					
36					
37					
38					
39					
40	**Total**	**168,818,638**	**291,703,632**	**(1,494,128)**	**459,028,142**

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)

$ 71,063,227 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	772,841				10.5	8,114,831	-	-	-	676,236	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	13,343,290				6.5	86,731,385	-	-	-	7,227,615	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	14,116,131	-	-	-		94,846,216	-	-	-	7,903,851	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										7,903,851	-	-	-	
								Input to Line 21 of Appendix A		7,903,851	-		-	7,903,851
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.28	#DIV/0!	#DIV/0!	#DIV/0!	

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

$ 7,903,851 Input to Formula Line 21

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

$ 71,955,591 — 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)

$ 71,955,591

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

62,104,415 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 $ 24,655,022 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	-				11.5	-	-	-	-	-	-	-	-	
Feb	70,200				10.5	737,100	-	-	-	61,425	-	-	-	
Mar	2,152				9.5	20,444	-	-	-	1,704	-	-	-	
Apr	85,452				8.5	726,342	-	-	-	60,529	-	-	-	
May	3,680,563				7.5	27,604,223	-	-	-	2,300,352	-	-	-	
Jun	7,446,117				6.5	48,399,761	-	-	-	4,033,313	-	-	-	
Jul	5,254,923				5.5	28,902,077	-	-	-	2,408,506	-	-	-	
Aug	229,406				4.5	1,032,327	-	-	-	86,027	-	-	-	
Sep	1,175,371				3.5	4,113,799	-	-	-	342,817	-	-	-	
Oct	4,084,690				2.5	10,211,725	-	-	-	850,977	-	-	-	
Nov	743,213		152883.13		1.5	1,114,820	-	229,325	-	92,902	-	19,110	-	
Dec	1,882,935		142681.4		0.5	941,468	-	71,341	-	78,456	-	5,945	-	
Total	24,655,022	-	295,565	-		123,804,083	-	-	-	10,317,007	-	25,055	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										10,317,007	-	25,055	-	
								Input to Line 21 of Appendix A		10,317,007	-		-	10,317,007
								Input to Line 43a of Appendix A				25,055		25,055
								Month In Service or Month for CWIP		6.98	#DIV/0!	10.98	#DIV/0!	

60,598,298.70 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			1128898		11.5	-	-	12,982,325	-	-	-	1,081,860	-	
Feb			833333		10.5	-	-	8,750,000	-	-	-	729,167	-	
Mar			833333		9.5	-	-	7,916,667	-	-	-	659,722	-	
Apr			833333		8.5	-	-	7,083,333	-	-	-	590,278	-	
May			833333		7.5	-	-	6,250,000	-	-	-	520,833	-	
Jun	22,264,169		833333		6.5	144,717,099	-	5,416,667	-	12,059,758	-	451,389	-	
Jul			833333		5.5	-	-	4,583,333	-	-	-	381,944	-	
Aug			833333		4.5	-	-	3,750,000	-	-	-	312,500	-	
Sep			833333		3.5	-	-	2,916,667	-	-	-	243,056	-	
Oct			833333		2.5	-	-	2,083,333	-	-	-	173,611	-	
Nov			833333		1.5	-	-	1,250,000	-	-	-	104,167	-	
Dec			833333		0.5	-	-	416,667	-	-	-	34,722	-	
Total	22,264,169	-	10,295,565	-		144,717,099	-	-	-	12,059,758	-	5,283,249	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										12,059,758	-	5,283,249	-	
64,289,465								Input to Line 21 of Appendix A		12,059,758	-		-	12,059,758
								Input to Line 43a of Appendix A				5,283,249		5,283,249
								Month In Service or Month for CWIP		5.50	#DIV/0!	5.84	#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		
60,598,299	-	66,938,169	=	(6,339,870)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.3800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(528,322)	0.3800%	11.5	(23,088)	(551,410)
Jul	Year 1	(528,322)	0.3800%	10.5	(21,080)	(549,403)
Aug	Year 1	(528,322)	0.3800%	9.5	(19,072)	(547,395)
Sep	Year 1	(528,322)	0.3800%	8.5	(17,065)	(545,387)
Oct	Year 1	(528,322)	0.3800%	7.5	(15,057)	(543,380)
Nov	Year 1	(528,322)	0.3800%	6.5	(13,050)	(541,372)
Dec	Year 1	(528,322)	0.3800%	5.5	(11,042)	(539,364)
Jan	Year 2	(528,322)	0.3800%	4.5	(9,034)	(537,357)
Feb	Year 2	(528,322)	0.3800%	3.5	(7,027)	(535,349)
Mar	Year 2	(528,322)	0.3800%	2.5	(5,019)	(533,342)
Apr	Year 2	(528,322)	0.3800%	1.5	(3,011)	(531,334)
May	Year 2	(528,322)	0.3800%	0.5	(1,004)	(529,326)
Total		(6,339,870)				(6,484,419)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(6,484,419)	0.3800%	(553,808)	(5,955,252)
Jul	Year 2	(5,955,252)	0.3800%	(553,808)	(5,424,073)
Aug	Year 2	(5,424,073)	0.3800%	(553,808)	(4,890,877)
Sep	Year 2	(4,890,877)	0.3800%	(553,808)	(4,355,654)
Oct	Year 2	(4,355,654)	0.3800%	(553,808)	(3,818,397)
Nov	Year 2	(3,818,397)	0.3800%	(553,808)	(3,279,099)
Dec	Year 2	(3,279,099)	0.3800%	(553,808)	(2,737,751)
Jan	Year 3	(2,737,751)	0.3800%	(553,808)	(2,194,347)
Feb	Year 3	(2,194,347)	0.3800%	(553,808)	(1,648,877)
Mar	Year 3	(1,648,877)	0.3800%	(553,808)	(1,101,335)
Apr	Year 3	(1,101,335)	0.3800%	(553,808)	(551,712)
May	Year 3	(551,712)	0.3800%	(553,808)	(0)
Total with interest				(6,645,698)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(6,645,698)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	64,289,465
Revenue Requirement for Year 3		57,643,767

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

$ 57,643,767 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)

$ 57,643,767

Delmarva Power & Light 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	12.552%
5		B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	13.213%
6		C		Line B less Line A	0.6608%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	3.1681%

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 be identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by FER**

Line		Details		B0512 MAPP		B0241.3 Red Lion sub reconfiguration
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		150
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		12.5524%		12.5524%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		13.5437%		13.5437%
18	Columns A, B or C from Attachment 6	Investment		10,295,565	may be weighted average of small projects	14,689,101
19	Line 18 divided by line 13	Annual Depreciation Exp		294,159		419,689
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		5.84		6.00

Line	Details	Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	Base FCR	2008	295,565	-	295,565	22,130			-	-
22	W Increased ROE	2008	295,565	-	295,565	23,878			-	-
23	Base FCR	2009	10,295,565	-	10,295,565	1,292,346	14,689,101	209,844	14,479,257	2,027,346
24	W Increased ROE	2009	10,295,565	-	10,295,565	1,394,399	14,689,101	209,844	14,479,257	2,170,869
25	Base FCR	2010	10,295,565	-	10,295,565	1,292,346	14,479,257	419,689	14,059,568	2,184,509
26	W Increased ROE	2010	10,295,565	-	10,295,565	1,394,399	14,479,257	419,689	14,059,568	2,323,872
27	Base FCR	2011	10,295,565	-	10,295,565	1,292,346	14,059,568	419,689	13,639,880	2,131,828
28	W Increased ROE	2011	10,295,565	-	10,295,565	1,394,399	14,059,568	419,689	13,639,880	2,267,031
29	Base FCR	2012	10,295,565	-	10,295,565	1,292,346	13,639,880	419,689	13,220,191	2,079,146
30	W Increased ROE	2012	10,295,565	-	10,295,565	1,394,399	13,639,880	419,689	13,220,191	2,210,190
31	Base FCR	2013	10,295,565	-	10,295,565	1,292,346	13,220,191	419,689	12,800,502	2,026,465
32	W Increased ROE	2013	10,295,565	-	10,295,565	1,394,399	13,220,191	419,689	12,800,502	2,153,349
33	Base FCR	2014	10,295,565	-	10,295,565	1,292,346	12,800,502	419,689	12,380,814	1,973,784
34	W Increased ROE	2014	10,295,565	-	10,295,565	1,394,399	12,800,502	419,689	12,380,814	2,096,507
35	Base FCR	2015	10,295,565	-	10,295,565	1,292,346	12,380,814	419,689	11,961,125	1,921,103
36	W Increased ROE	2015	10,295,565	-	10,295,565	1,394,399	12,380,814	419,689	11,961,125	2,039,666
37	Base FCR	2016	10,295,565	-	10,295,565	1,292,346	11,961,125	419,689	11,541,437	1,868,422
38	W Increased ROE	2016	10,295,565	-	10,295,565	1,394,399	11,961,125	419,689	11,541,437	1,982,825
39	Base FCR	2017	10,295,565	-	10,295,565	1,292,346	11,541,437	419,689	11,121,748	1,815,740
40	W Increased ROE	2017	10,295,565	-	10,295,565	1,394,399	11,541,437	419,689	11,121,748	1,925,983
41	Base FCR	2018	10,295,565	-	10,295,565	1,292,346	11,121,748	419,689	10,702,059	1,763,059
42	W Increased ROE	2018	10,295,565	-	10,295,565	1,394,399	11,121,748	419,689	10,702,059	1,869,142
43	Base FCR	2019	10,295,565	-	10,295,565	1,292,346	10,702,059	419,689	10,282,371	1,710,378
44	W Increased ROE	2019	10,295,565	-	10,295,565	1,394,399	10,702,059	419,689	10,282,371	1,812,301
45	Base FCR	2020	10,295,565	-	10,295,565	1,292,346	10,282,371	419,689	9,862,682	1,657,697
46	W Increased ROE	2020	10,295,565	-	10,295,565	1,394,399	10,282,371	419,689	9,862,682	1,755,459
47	Base FCR	2021	10,295,565	-	10,295,565	1,292,346	9,862,682	419,689	9,442,994	1,605,016
48	W Increased ROE	2021	10,295,565	-	10,295,565	1,394,399	9,862,682	419,689	9,442,994	1,698,618
49	Base FCR	2022	10,295,565	-	10,295,565	1,292,346	9,442,994	419,689	9,023,305	1,552,334
50	W Increased ROE	2022	10,295,565	-	10,295,565	1,394,399	9,442,994	419,689	9,023,305	1,641,777
51	Base FCR	2023	10,295,565	-	10,295,565	1,292,346	9,023,305	419,689	8,603,616	1,499,653
52	W Increased ROE	2023	10,295,565	-	10,295,565	1,394,399	9,023,305	419,689	8,603,616	1,584,935
53	Base FCR	2024	10,295,565	-	10,295,565	1,292,346	8,603,616	419,689	8,183,928	1,446,972
54	W Increased ROE	2024	10,295,565	-	10,295,565	1,394,399	8,603,616	419,689	8,183,928	1,528,094
55	Base FCR	2025	10,295,565	-	10,295,565	1,292,346	8,183,928	419,689	7,764,239	1,394,291
56	W Increased ROE	2025	10,295,565	-	10,295,565	1,394,399	8,183,928	419,689	7,764,239	1,471,253
57	Base FCR	2026	10,295,565	-	10,295,565	1,292,346	7,764,239	419,689	7,344,551	1,341,610
58	W Increased ROE	2026	10,295,565	-	10,295,565	1,394,399	7,764,239	419,689	7,344,551	1,414,411
59	Base FCR	2027	10,295,565	-	10,295,565	1,292,346	7,344,551	419,689	6,924,862	1,288,928
60	W Increased ROE	2027		-	-	-	7,344,551	419,689	6,924,862	1,357,570
61		....		....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

come effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects
RC to become effective June 1, 2008 and November 1, 2008 respectively

B0494.1-4 Red Lion-Keeney				B0241.1-.2 Red Lion-Keeney						
No				No						
35				35						
No				No						
150				150						
12.5524%				12.5524%						
13.5437%				13.5437%						
3,099,104				2,418,717						
88,546				69,106						
6.00				6.00						
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
		-	-			-	-	$ 22,130		$ 22,130
		-	-			-	-	$ 23,878	$ 23,878	
3,099,104	44,273	3,054,831	427,729	2,418,717	34,553	2,384,164	333,824	$ 4,081,244		$ 4,081,244
3,099,104	44,273	3,054,831	458,010	2,418,717	34,553	2,384,164	357,457	$ 4,380,735	$ 4,380,735	
3,054,831	88,546	2,966,285	460,887	2,384,164	69,106	2,315,058	359,703	$ 4,297,444		$ 4,297,444
3,054,831	88,546	2,966,285	490,290	2,384,164	69,106	2,315,058	382,650	$ 4,591,212	$ 4,591,212	
2,966,285	88,546	2,877,739	449,773	2,315,058	69,106	2,245,952	351,028	$ 4,224,974		$ 4,224,974
2,966,285	88,546	2,877,739	478,298	2,315,058	69,106	2,245,952	373,291	$ 4,513,019	$ 4,513,019	
2,877,739	88,546	2,789,194	438,658	2,245,952	69,106	2,176,845	342,354	$ 4,152,504		$ 4,152,504
2,877,739	88,546	2,789,194	466,305	2,245,952	69,106	2,176,845	363,931	$ 4,434,826	$ 4,434,826	
2,789,194	88,546	2,700,648	427,543	2,176,845	69,106	2,107,739	333,679	$ 4,080,033		$ 4,080,033
2,789,194	88,546	2,700,648	454,313	2,176,845	69,106	2,107,739	354,572	$ 4,356,632	$ 4,356,632	
2,700,648	88,546	2,612,102	416,429	2,107,739	69,106	2,038,633	325,005	$ 4,007,563		$ 4,007,563
2,700,648	88,546	2,612,102	442,321	2,107,739	69,106	2,038,633	345,212	$ 4,278,439	$ 4,278,439	
2,612,102	88,546	2,523,556	405,314	2,038,633	69,106	1,969,527	316,330	$ 3,935,092		$ 3,935,092
2,612,102	88,546	2,523,556	430,328	2,038,633	69,106	1,969,527	335,853	$ 4,200,246	$ 4,200,246	
2,523,556	88,546	2,435,010	394,199	1,969,527	69,106	1,900,421	307,656	$ 3,862,622		$ 3,862,622
2,523,556	88,546	2,435,010	418,336	1,969,527	69,106	1,900,421	326,493	$ 4,122,053	$ 4,122,053	
2,435,010	88,546	2,346,464	383,085	1,900,421	69,106	1,831,314	298,981	$ 3,790,152		$ 3,790,152
2,435,010	88,546	2,346,464	406,344	1,900,421	69,106	1,831,314	317,134	$ 4,043,860	$ 4,043,860	
2,346,464	88,546	2,257,919	371,970	1,831,314	69,106	1,762,208	290,306	$ 3,717,681		$ 3,717,681
2,346,464	88,546	2,257,919	394,351	1,831,314	69,106	1,762,208	307,774	$ 3,965,666	$ 3,965,666	
2,257,919	88,546	2,169,373	360,855	1,762,208	69,106	1,693,102	281,632	$ 3,645,211		$ 3,645,211
2,257,919	88,546	2,169,373	382,359	1,762,208	69,106	1,693,102	298,415	$ 3,887,473	$ 3,887,473	
2,169,373	88,546	2,080,827	349,741	1,693,102	69,106	1,623,996	272,957	$ 3,572,740		$ 3,572,740
2,169,373	88,546	2,080,827	370,367	1,693,102	69,106	1,623,996	289,055	$ 3,809,280	$ 3,809,280	
2,080,827	88,546	1,992,281	338,626	1,623,996	69,106	1,554,890	264,283	$ 3,500,270		$ 3,500,270
2,080,827	88,546	1,992,281	358,374	1,623,996	69,106	1,554,890	279,696	$ 3,731,087	$ 3,731,087	
1,992,281	88,546	1,903,735	327,511	1,554,890	69,106	1,485,783	255,608	$ 3,427,800		$ 3,427,800
1,992,281	88,546	1,903,735	346,382	1,554,890	69,106	1,485,783	270,336	$ 3,652,894	$ 3,652,894	
1,903,735	88,546	1,815,189	316,397	1,485,783	69,106	1,416,677	246,934	$ 3,355,329		$ 3,355,329
1,903,735	88,546	1,815,189	334,389	1,485,783	69,106	1,416,677	260,977	$ 3,574,700	$ 3,574,700	
1,815,189	88,546	1,726,644	305,282	1,416,677	69,106	1,347,571	238,259	$ 3,282,859		$ 3,282,859
1,815,189	88,546	1,726,644	322,397	1,416,677	69,106	1,347,571	251,617	$ 3,496,507	$ 3,496,507	
1,726,644	88,546	1,638,098	294,167	1,347,571	69,106	1,278,465	229,585	$ 3,210,388		$ 3,210,388
1,726,644	88,546	1,638,098	310,405	1,347,571	69,106	1,278,465	242,257	$ 3,418,314	$ 3,418,314	
1,638,098	88,546	1,549,552	283,053	1,278,465	69,106	1,209,359	220,910	$ 3,137,918		$ 3,137,918
1,638,098	88,546	1,549,552	298,412	1,278,465	69,106	1,209,359	232,898	$ 3,340,121	$ 3,340,121	
1,549,552	88,546	1,461,006	271,938	1,209,359	69,106	1,140,252	212,236	$ 3,065,448		$ 3,065,448
1,549,552	88,546	1,461,006	286,420	1,209,359	69,106	1,140,252	223,538	$ 1,867,529	$ 1,867,529	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 73,688,469	$ 70,369,404

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

ATTACHMENT H-1A

Atlantic City Electric Company

	Formula Rate - Appendix A		Notes	FERC Form 1 Page # or Instruction	2008
	Shaded cells are input cells				
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 1,662,426
2	Total Wages Expense			p354.28b	$ 20,474,113
3	Less A&G Wages Expense			p354.27b	$ 595,694
4	Total			(Line 2 - 3)	19,878,419
5	**Wages & Salary Allocator**			(Line 1 / 4)	**8.3630%**
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g	$ 2,138,714,296
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	2,138,714,296
9	Accumulated Depreciation (Total Electric Plant)			p219.29c	$ 626,776,018
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 39,453,724
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)	666,229,742
14	Net Plant			(Line 8 - 13)	1,472,484,554
15	Transmission Gross Plant			(Line 29 - Line 28)	683,727,618
16	**Gross Plant Allocator**			(Line 15 / 8)	**31.9691%**
17	Transmission Net Plant			(Line 39 - Line 28)	486,142,961
18	**Net Plant Allocator**			(Line 17 / 14)	**33.0151%**
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 658,126,150
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	12,676,170
22	**Total Transmission Plant In Service**			(Line 19 - 20 + 21)	**670,802,320**
23	General & Intangible			p205.5.g & p207.99.g	$ 154,553,934
24	Common Plant (Electric Only)		(Notes A & B)	p356	$ -
25	Total General & Common			(Line 23 + 24)	154,553,934
26	Wage & Salary Allocation Factor			(Line 5)	8.36297%
27	**General & Common Plant Allocated to Transmission**			(Line 25 * 26)	**12,925,297**
28	**Plant Held for Future Use (Including Land)**		(Note C)	p214	**1,350,288**
29	**TOTAL Plant In Service**			**(Line 22 + 27 + 28)**	**685,077,906**
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 190,199,742
31	Accumulated General Depreciation			p219.28.c	$ 48,851,218
32	Accumulated Intangible Amortization			(Line 10)	39,453,724
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)	88,304,942
36	Wage & Salary Allocation Factor			(Line 5)	8.36297%
37	**General & Common Allocated to Transmission**			(Line 35 * 36)	**7,384,915**
38	**TOTAL Accumulated Depreciation**			**(Line 30 + 37)**	**197,584,657**
39	**TOTAL Net Property, Plant & Equipment**			**(Line 29 - 38)**	**487,493,249**
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-113,687,402
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	33.02%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**			(Line 41 * 42) + Line 40	**-113,687,402**
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	**-1,273,787**
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	5,470,404
46	**Total Prepayments Allocated to Transmission**			(Line 45)	**5,470,404**
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	850,542
48	Wage & Salary Allocation Factor			(Line 5)	8.36%
49	Total Transmission Allocated			(Line 47 * 48)	71,131
50	Transmission Materials & Supplies			p227.8c	$ 2,770,421
51	**Total Materials & Supplies Allocated to Transmission**			(Line 49 + 50)	**2,841,552**
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	12,980,467
53	1/8th Rule			x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**			(Line 52 * 53)	**1,622,558**
	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)	**-105,026,675**
59	**Rate Base**			(Line 39 + 58)	**382,466,574**

O&M

	Transmission O&M					
60	Transmission O&M			p321.112.b	$	9,126,554
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		0
65	Plus Transmission Lease Payments		(Note A)	p200.3c	$	-
66	**Transmission O&M**			(Lines 60 - 63 + 64 + 65)		**9,126,554**
	Allocated General & Common Expenses					
67	Common Plant O&M		(Note A)	p356	$	-
68	Total A&G			p323.197.b	$	48,602,729
69	Less Property Insurance Account 924			p323.185b	$	350,369
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$	3,463,479
71	Less General Advertising Exp Account 930.1			p323.191b	$	54,971
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$	-
73	Less EPRI Dues		(Note D)	p352-353	$	34,018
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)		44,699,892
75	Wage & Salary Allocation Factor			(Line 5)		8.3630%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)		**3,738,238**
	Directly Assigned A&G					
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b		0
78	General Advertising Exp Account 930.1		(Note K)	p323.191b		0
79	Subtotal - Transmission Related			(Line 77 + 78)		**0**
80	Property Insurance Account 924			p323.185b	$	350,369
81	General Advertising Exp Account 930.1		(Note F)	p323.191b		0
82	Total			(Line 80 + 81)		350,369
83	Net Plant Allocation Factor			(Line 18)		33.02%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)		**115,675**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**		**12,980,467**

Depreciation & Amortization Expense

	Depreciation Expense					
86	Transmission Depreciation Expense			p336.7b&c		**14,201,744**
87	General Depreciation			p336.10b&c		5,063,134
88	Intangible Amortization		(Note A)	p336.1d&e		146,372
89	Total			(Line 87 + 88)		5,209,506
90	Wage & Salary Allocation Factor			(Line 5)		8.3630%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)		**435,669**
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)		8.3630%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)		**0**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**		**14,637,413**

Taxes Other than Income

98	**Taxes Other than Income**			Attachment 2		**893,839**
99	**Total Taxes Other than Income**			**(Line 98)**		**893,839**

Return / Capitalization Calculations

	Long Term Interest					
100	Long Term Interest			p117.62c through 67c		54,956,753
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		23,518,887
102	**Long Term Interest**			"(Line 100 - line 101)"		31,437,866
103	**Preferred Dividends**		enter positive	p118.29c	$	262,842
	Common Stock					
104	Proprietary Capital			p112.16c	$	543,339,680
105	Less Preferred Stock		enter negative	(Line 114)		-6,214,500
106	Less Account 216.1		enter negative	p112.12c	$	-
107	**Common Stock**			(Sum Lines 104 to 106)		537,125,180
	Capitalization					
108	Long Term Debt			p112.17c through 21c	$	1,056,272,762
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$	14,103,726
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$	-
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1		2,087,030
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8		-422,207,762
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)		650,255,756
114	Preferred Stock			p112.3c	$	6,214,500
115	Common Stock			(Line 107)		537,125,180
116	**Total Capitalization**			(Sum Lines 113 to 115)		1,193,595,436
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)		0.0483
121	Preferred Cost	Preferred Stock		(Line 103 / 114)		0.0423
122	Common Cost	Common Stock	(Note J)	Fixed		0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)		0.0242
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)		**0.0807**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**		**30,854,903**

Composite Income Taxes

Line	Description	Formula / Note	Reference	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	$ (1,021,567)
134	T/(1-T)		(Line 132)	69.05%
135	Net Plant Allocation Factor		(Line 18)	33.0151%
136	**ITC Adjustment Allocated to Transmission**		(Line 133 * (1 + 134) * 135)	**-570,164**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 132 * 127 * (1-(123 / 126))]	**14,921,626**
138	**Total Income Taxes**		**(Line 136 + 137)**	**14,351,462**

REVENUE REQUIREMENT

Line	Description	Note	Reference	Amount
	Summary			
139	Net Property, Plant & Equipment		(Line 39)	487,493,249
140	Adjustment to Rate Base		(Line 58)	-105,026,675
141	**Rate Base**		(Line 59)	**382,466,574**
142	O&M		(Line 85)	12,980,467
143	Depreciation & Amortization		(Line 97)	14,637,413
144	Taxes Other than Income		(Line 99)	893,839
145	Investment Return		(Line 127)	30,854,903
146	Income Taxes		(Line 138)	14,351,462
147	**Gross Revenue Requirement**		**(Sum Lines 142 to 146)**	**73,718,084**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	658,126,150
149	Excluded Transmission Facilities	(Note M)	Attachment 5	27,526,011
150	Included Transmission Facilities		(Line 148 - 149)	630,600,139
151	Inclusion Ratio		(Line 150 / 148)	95.82%
152	Gross Revenue Requirement		(Line 147)	73,718,084
153	**Adjusted Gross Revenue Requirement**		(Line 151 * 152)	**70,634,838**
	Revenue Credits & Interest on Network Credits			
154	**Revenue Credits**		Attachment 3	4,111,805
155	**Interest on Network Credits**	(Note N)	PJM Data	-
156	**Net Revenue Requirement**		**(Line 153 - 154 + 155)**	**66,523,034**
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	**66,523,034**
158	Net Transmission Plant		(Line 19 - 30)	**467,926,408**
159	Net Plant Carrying Charge		(Line 157 / 158)	**14.2166%**
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	**11.1815%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	**2.1411%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	**21,316,669**
163	Increased Return and Taxes		Attachment 4	**48,439,196**
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	**69,755,865**
165	Net Transmission Plant		(Line 19 - 30)	**467,926,408**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	**14.9074%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	**11.8724%**
168	**Net Revenue Requirement**		(Line 156)	**66,523,034**
169	True-up amount		Attachment 6	**(1,667,410)**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	**493,272**
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	**450,000**
172	**Net Zonal Revenue Requirement**		(Line 168 - 169 + 171)	**65,798,896**
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	**2,638**
174	Rate ($/MW-Year)		(Line 172 / 173)	**24,939**
175	**Network Service Rate ($/MW/Year)**		**(Line 174)**	**24,939**

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.

END

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	0	(353,005,117)	0	
ADIT-283	0	6,781,561	(36,201,763)	
ADIT-190	0	(7,351,796)	28,398,801	
Subtotal	0	(353,575,352)	(7,802,962)	
Wages & Salary Allocator			8.3630%	
Gross Plant Allocator		31.9691%		
ADIT	0	(113,034,842)	(652,559)	(113,687,402)

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 (2,087,030)

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 Related	D Only Transmission Related	E Plant	F Labor	G Justifications
190 BAD DEBT RESERVE		5,917,061	5,917,061	-	-	-	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 FASB 112-ACCTING FOR POST RETIRE		1,058,203	-	-	-	1,058,203	The book records accrual for post employment benefits. Tax deduction is taken at the time a payment is made. Affects company personnel across all functions.
190 LEGAL REGULATORY FEES		1,597,109	1,597,109	-	-	-	Legal fees incurred and paid for regulatory issues were deferred for book purposes. For tax purposes, the fees were deductible in full as paid. Retail related.
190 LEAC DISALLOWANCE		(111,388)	(111,388)	-	-	-	For tax purposes, LEAC (Levelized Energy Adjustment Clause) disallowance costs were deductible as incurred. For book purposes, a reserve for the disallowance costs was recorded. Retail related.
190 UNCOLLECTIBLE ACCOUNTS		(252,724)	(252,724)	-	-	-	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 deduction for tax purposes. Retail related.
190 FEBRUARY 98 SPECIAL RESERVES		144,186	144,186	-	-	-	For book purposes, the loan value position for Portland Station was written off as a loss. For tax purposes, the loss was not deductible. Generation related.
190 ACCRUAL SEVERANCE		(174,251)				(174,251)	adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual.
190 CLAIMS RESERVE		902,210				902,210	For book purposes, a deduction is taken for amounts set aside as a reserve for possible health, injury, and damages claims against ACE. For tax purposes, these amounts are not deductible until paid out as claims. Affects company personnel across all functions.
190 PLANT ABANDONMENT - SFAS 90		6,834,488	6,834,488			-	Plant Abandonment Amount represents deferred tax asset resulting from the disallowances of plant costs associated with ACE's investment in Unit No. 1 of the Hope Creek Generation Station upon adoption of FAS 90 in 1986. [The FAS90 requires that a loss be recognized if disallowance costs provide no return on investment of any portion of a plant.] Generator related.
190 MERGER RELATED ENTRIES		4,840,658				4,840,658	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.
190 Misc Deferred Debits - Retail		(334,160)	(334,160)				Retail related
190 Stores Clearing Accounts		204,113			204,113		Stores relates to all functions
190 Nuclear Fuel		249,176	249,176				Generation related
190 Hope Creek O&M		189,982	189,982				Generation related
190 Amortization of OPEB		920,894				920,894	OPEB, labor related and relates to all functions
190 MISCELLANEOUS		625,941			625,941	-	Miscellaneous temporary differences that are less than $100,000 for each item. Related to all functions
190 OFFICER'S/MANAGERS DEFERRED COMP		432,683	-	-	-	432,683	For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are not deducted until paid. Affects company personnel across all functions.
190 HYDROGEN WATER CHEMISTRY W/O		6,033	6,033	-	-	-	Amortization of book costs on generation project study which was an add-back for tax purposes. Generation related.
190 DSM COSTS		3,323,872	3,323,872	-	-	-	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.
190 DEFERRED FUEL		1,230,175	1,230,175	-	-	-	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.
190 ENVIRONMENTAL SITE EXPENSE		1,320,480	1,320,480	-	-	-	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		(382,112)			(382,112)	-	Pursuant to IRC Sec 475, the company is taking deduction to mark-to-market its accounts receivable. For book purposes, the receivables remained valued at their original amounts. Reflects unbilled revenues and customer accounts receivables. Applies to all functions.
190 NJ EXCISE TAX		8,512	8,512	-	-	-	Gross receipts and franchise tax catch up and go current payment. Fully deducted when paid on the tax return. Book amortized over 10 years. Retail related.
190 PEACH BOTTOM MASTER LEASE		15,668	15,668	-	-	-	Leased hardware is being tax depreciated. The portion of the lease payments charged to expense on the books must be added back to income for tax purposes. Retail related.

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

190	DEFERRED PURCHASED POWER		2,818,011	2,818,011	-	-	-	Book records amortization on Susquehanna deferred capitalized costs . For tax purposes, the amortization is added back to taxable income. Retail related.
190	PENSION PAYMENT RESERVE		26,950,783	-	-	-	26,950,783	Book records a deduction for actual SFAS 87 pension expense. A tax deduction is only allowed for actual payments into the pension trust. Affects company personnel across all functions.
190	SECTION 461(H) - PREPAID INSURANCE		4,124,337			4,124,337	-	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	SECTION 461(H) - PREPAID OTHER		51,960	51,960	-	-	-	Book records a deduction for accrual liability of Public Utility Assessment. A tax deduction is only allowed for actual payments made. Retail Related
190	SEVERANCE PACKAGE		(4,751,596)				(4,751,596)	individual. For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. Affects company personnel across all
190	AMORTIZATION (LEGAL)		-					year incurred. For tax purposes, these costs are capital in nature and are amortized over a 30 year period. Generation related.
	LOSS ON REACQ DEBT		(1,754,672)	(1,754,672)				over the life of the new bond issue for book purposes. Excluded here since included in Cost of Debt
	ASBESTOS REMOVAL		1	1				as paid . These costs were deferred and amortized for book purposes. Generation related.
	SERP		798,575				798,575	Affects company personnel across all functions.
	NUG BUYOUT		55,145,910	55,145,910				Generation related
	AMORT of OPEB		(10,769,125)			(10,769,125)		OPEB, labor related and relates to all functions
	NOL		(2,782,606)			(2,782,606)		Related to both T & D plant
	AMA		2,315			2,315		Related to both T & D plant
	Miscell Diff		(113,554)				(113,554)	This deferred tax balance relates to plant and results from life and method differences. Related to both T & D plant
	Stranded Costs		(40,224,769)	(40,224,769)				All Generation related
	Deregulation/Stranded Cost Generation Assets		(6,646,284)	(6,646,284)				This deferred tax balance relates to our plant and results from life and method differences. Generation related
	PLANT RELATED		(1,747,518)	(1,747,518)				This deferred tax balance relates to plant and results from life and method differences. Related to both T & D plant
	Reclass		3,811,947	3,811,947				Related to generation
	1999 AMT		1,625,341			1,625,341		Plant related
	De-regulated Deferred		80,685,095	80,685,095				Related to generation and retail
190	**Subtotal - p234**		135,790,959	112,278,151	-	(7,351,796)	30,864,604	
	Less FASB 109 Above if not separately removed							
190	**Less FASB 106 Above if not separately removed**		2,465,803				2,465,803	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**		133,325,156	112,278,151	-	(7,351,796)	28,398,801	

Instructions for Account 190:

1.
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
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	Deregulation/Stranded Cost Generation Assets		(108,418,163)	(108,418,163)	-	-	-	This deferred tax balance relates to our plant and results from life and method differences. Generation related
282	Plant Related		(421,298,425)	(68,293,308)		(353,005,117)	-	This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
	Subtotal - p275		(529,716,588)	(176,711,471)	-	(353,005,117)	-	
	Less FASB 109 Above if not separately removed							
	Less FASB 106 Above if not separately removed							
282	Total		(529,716,588)	(176,711,471)	-	(353,005,117)	-	

Instructions for Account 282:

1.
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	DUPONT RECEIVABLE		(6,498)	(6,498)	-	-	-	Tax deduction was taken for direct write off of receivable from Dupont project. For book purposes, reserve was recorded. Generation related.
283	BOARD OF DIRECTORS DEFERRED COMP		(15,390)	-	-	-	(15,390)	For tax purposes, payments for deferred compensation are deducted when paid. Affects company personnel across all functions.
283	SEVERANCE PACKAGE		(2,035)	-	-	-	(2,035)	For tax purposes, the severance costs are deductible when they are paid to the severed individual. For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. Affects company personnel across all functions.
283	REGULATORY ISSUES		(1,912,208)	(1,912,208)	-	-	-	Costs incurred and paid for regulatory issues are deferred and amortized for book purposes. These costs were tax deductible in full as paid . Retail related

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

283	AMORTIZATION (LEGAL)		(6,211)	(6,211)	-	-	-	Legal costs related to Deepwater emergency facility were expensed on the books in the year incurred. For tax purposes, these costs are capital in nature and are amortized over a 30 year period. Generation related.
283	LOSS ON REACQ DEBT		(332,358)	(332,358)	-	-	-	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	ASBESTOS REMOVAL		(2,277,818)	(2,277,818)	-	-	-	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	DEFERRED EXPENSE CLEARING		(1,087,778)			(1,087,778)	-	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	PROPERTY LOSS AMORTIZATION		(1,554,677)	(1,554,677)	-	-	-	Reflects the deferred taxes as a result of the tax deductions taken on various generation related studies, such as Atlantic Generation Study, Hydrogen Water Chemistry, Baseline Configuration and Nuclear Fuel Contract Costs. Generation related.
283	SAVINGS & THRIFT GUARANTEE 401(k)		(927,567)	-	-	-	(927,567)	Labor related. Affects company personnel across all functions.
283	ACE REGULATORY RESTRUCTURING CHARGES		355,615	355,615	-	-	-	Costs incurred and paid for customer care enhancement program associated with de-regulation are deferred and amortized for book purposes. Amortization of these costs were non-tax deductible. Retail related.
283	GATX Terminal Agreement for Atlantic CT's		113,767	113,767	-	-	-	Generation related
283	Reserve for Future Stranded Cost Disallowances		4,148,440	4,148,440	-	-	-	For book purposes, a loss due to future disallowance of stranded generation assets was set up as a reserve. For tax purposes, the loss is not deductible until the generation assets are disposed of. Retail related.
283	DUP-CL PROP R		(192,037)	(192,037)				Generation related
283	DUP-CL REM CO		(205,157)	(205,157)				Generation related
283	Less FASB 109 Above if not separately removed		(420,954)			(420,954)		FAS 109 Plant related, related to all functions.
283	Misc De-Regulation		196,783	196,783				Various items related to deregulation
283	Market to Market		321,554	321,554				Accounts Receivable, Other
283	Miscell Diff		3,371,827		-	-	3,371,827	This deferred tax balance relates to plant and results from life and method differences. Related to both T & D plant
283	DEFERRED REVENUE		615,928	615,928				Reflects the deferred taxes generated as a result of revenue included as taxable income. For book purposes this amount was deferred in FERC account 254000. Retail related
	Stranded Costs		147,735,394	147,735,394				All Generation related
	MISCELL RESERVE		124,443	124,443				Generation related, Environmental Reserve for BL England site,
	PENSION PAYMENT RESERVE		(36,973,296)				(36,973,296)	Affects company personnel across all functions.
	SERP		(823,558)				(823,558)	Affects company personnel across all functions.
	SECTION 461(H) Prepaid		(651,031)			(651,031)		Related to both T & D plant
	NUG BUYOUT		7,588,588	7,588,588				Generation related
	AMORT of OPEB		4,082,031			4,082,031		OPEB, labor related and relates to all functions
	BGS Deferred Related - Retail		26,572,632	26,572,632				Retail related
	MISC DEFERRED DEBITS		31,581	31,581				Deferred Costs for Universal Service Fund, Retail related
	NOL		2,922,347			2,922,347		Related to both T & D plant
	AMA		1,936,946			1,936,946		Related to both T & D plant
283	Plant Related		(194,127,961)	(75,708,827)		(118,419,134)		
	Reclass		(3,811,947)	-3811947				Related to generation
283	Subtotal - p277 (Form 1-F filer: see note 6, below)		(45,210,604)	101,796,988	-	(111,637,573)	(35,370,018)	
283	Less FASB 109 Above if not separately removed		(118,419,134)			(118,419,134)		
	Less FASB 106 Above if not separately removed		831,745				831,745	
283	Total		72,376,785	101,796,988	-	6,781,561	(36,201,763)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

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		10,037,587	1,021,567
5	Total			10,037,587	1,021,567
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.266) for a		10,037,587	1,021,567
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)	2,282,742		
2	Personal property			
3	City License	-		
4	State Excise	-		
Total Plant Related		2,282,742	31.9691%	729,772
Labor Related			***Wages & Salary Allocator***	
5	Federal FICA & Unemployment	1,843,860		
6	Unemployment	75,842		
Total Labor Related		1,919,702	8.3630%	160,544
Other Included			***Gross Plant Allocator***	
7	Miscellaneous	11,019		
Total Other Included		11,019	31.9691%	3,523
Total Included				893,839
	Excluded			
8	State Franchise tax	66,941		
9	TEFA	20,282,662		
10	Use & Sales Tax	1,226,567		
11	Total "Other" Taxes (included on p. 263)	25,789,633		
12	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	25,789,633		
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

Atlantic City Electric Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		782,127
2	Total Rent Revenues	(Sum Line 1)	782,127
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 920,406
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)		1,674,866
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)		1,275,599
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		32,477
11	Gross Revenue Credits	(Sum Lines 2-10)	4,685,475
12	Less line 17g		(573,671)
13	Total Revenue Credits		4,111,805

<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.	814,604
17b	Costs associated with revenues in line 17a	332,737
17c	Net Revenues (17a - 17b)	481,867
17d	50% Share of Net Revenues (17c / 2)	240,934
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)	240,934
17g	Line 17f less line 17a	(573,671)
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.	9,575,364
19	Amount offset in line 4 above	60,383,695
20	Total Account 454, 456 and 456.1	74,644,534
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)	48,439,196
B	100 Basis Point increase in ROE				1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	382,466,574
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	54,956,753
101	Less LTD Interest on Securitization B	(Note P)		Attachment 8	23,518,887
102	**Long Term Interest**			"(Line 100 - line 101)"	31,437,866
103	**Preferred Dividends**		enter positive	p118.29c	262,842
	Common Stock				
104	Proprietary Capital			p112.16c	543,339,680
105	Less Preferred Stock		enter negative	(Line 114)	-6,214,500
106	Less Account 216.1		enter negative	p112.12c	0
107	**Common Stock**			(Sum Lines 104 to 106)	537,125,180
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,056,272,762
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	14,103,726
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,087,030
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	-422,207,762
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	650,255,756
114	Preferred Stock			p112.3c	6,214,500
115	Common Stock			(Line 107)	537,125,180
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,193,595,436
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)	0.0483
121	Preferred Cost		Preferred Stock	(Line 103 / 114)	0.0423
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)	0.0242
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)**	**0.0857**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**32,767,236**

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	-1,021,567
134	T/(1-T)			(Line 132)	69.05%
135	Net Plant Allocation Factor			(Line 18)	33.0151%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-570,164**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			16,242,124
138	**Total Income Taxes**				**15,671,960**

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	$ 39,453,724	39,453,724	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	10,037,587	10,037,587	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	850,542	850,542	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	146,372	146,372	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	5,553,713	1,350,288	4,203,425	"Transmission R/W - Carll's Corner" and "Future Conversion of Cumberland-Corcon 138 KV" are transmission.
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	Enter	Enter	Enter	

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	2,138,714,296	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	658,126,150	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	190,199,742	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	34018	34018	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	3,463,479	0	3,463,479	Transmission related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	3,463,479	0	3,463,479	Transmission related.

Safety Related Advertising Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	54,971	-	54,971	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)	9%	9.00%	9.900%				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	54,971	-	54,971	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	27,526,011	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	8,695,443	8.36%	727,197	
	Plant Related	1,709,744	31.97%	546,590	
	Other		0.00%	-	
	Total Transmission Related Reserves	10,405,187		1,273,787	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			8.363%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	8.363%	-	
	Prepayments	$	59,350,245	8.363%	4,963,443	
	Prepaid Pensions if not included in Prepayments	$	6,061,976	8.363%	506,961	
			65,412,221		5,470,404	
						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)	450,000	Settelement agreement. $15k/mo Jan-Apr 18 + $37.5/mo Apr 19-Dec.

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	2,638.4	See Form 1

Statements BG/BH (Present and Proposed Revenues)

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

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 6,088,669	$ 4,685,228	$ 13,055,598	$ 11,843,832	$ 35,673,327
Security Services Administration	448,463	281,895	1,103,634	215,476	2,049,468
Purchasing, Storeroom & Materials Mgt	764,668	401,128	2,292,990	162,133	3,620,919
Vehicle Resource Management	823,131	510,583	667,782	23,980	2,025,476
General Services	2,499,014	1,185,490	1,992,218	833,669	6,510,391
Building Services	845,609	719,336	2,002,356	650,304	4,217,605
Real Estate	1,062,693	914,165	168,676	123,622	2,269,156
Corporate Insurance Administration	161,286	107,288	243,862	132,157	644,593
Claims Administration	554,166	522,344	1,258,298	-	2,334,808
Regulatory Affairs	3,557,440	2,525,542	5,206,817	51,787	11,341,586
Accounts Payable Accounting Services	480,561	369,796	415,968	175,455	1,441,780
Payroll Services	345,067	197,596	527,080	82,924	1,152,667
Asset & Project Accounting Services	465,891	441,261	1,235,701	396,926	2,539,779
Investor Relations	163,900	137,954	391,953	232,342	926,149
Shareholder Services	239,252	200,704	573,491	340,459	1,353,906
Financial Reporting	714,616	611,787	1,710,178	1,032,682	4,069,263
Sarbanes-Oxley Compliance	170,005	155,738	406,322	240,877	972,942
Investment Financial Management	162,452	144,408	324,998	227,000	858,858
Other Financial Services	4,822,102	4,016,397	7,066,305	5,585,377	21,490,181
Insurance Premiums & Claims	2,183,779	1,532,480	3,622,824	2,853,195	10,192,278
Cost of Benefits	9,645,396	5,280,286	14,835,121	4,851,358	34,612,161
Executive Compensation Services	1,304,179	1,102,347	3,098,578	1,836,230	7,341,334
Other Human Resources Services	6,003,234	3,552,335	7,295,156	4,221,881	21,072,606
Legal Services	3,295,848	2,149,716	4,685,334	1,193,530	11,324,428
Audit Services	901,281	937,556	1,344,601	725,695	3,909,133
Special Billing	596,177	523,426	1,032,596	23,547	2,175,746
Other Customer Care	32,330,273	33,228,289	9,939,300	-	75,497,862
Marketing Services	1,337,414	901,584	2,152,837	71,686	4,463,521
Information Technology	6,446,316	4,108,253	28,658,896	2,414,853	41,628,318
PHI Corporate Contributions	4,413	3,760	10,600	6,249	25,022
Federal Government Affairs	236,465	199,898	565,539	334,717	1,336,619
Other Corporate Communications	965,371	576,380	1,674,735	591,134	3,807,620
Environmental Management Services	1,356,946	891,749	2,094,110	594,133	4,936,938
System Operations Shared	2,441,554	1,611,650	5,351,445	186,866	9,591,515
Electric Maintenance Meter Shop	1,353,932	767,471	-	-	2,121,403
Other Delivery Services	23,228,812	16,373,165	29,935,926	40,567	69,578,470
Power Procurement	1,691,047	1,405,532	2,847,431	-	5,944,010
Management & Administration	112,436	21,520	-	10,169,677	10,303,633
Merchant Functions	907,522	-	-	21,600,003	22,507,525
Engineering Administration	254,758	117,831	-	10,043,444	10,416,033
Internal Consulting Services	104,095	70,196	157,910	-	332,201
IT Voice Support	-	-	2,430	-	2,430
Interns	159,834	109,390	144,916	342	414,482
Total	$ 121,230,067	$ 93,593,454	$ 160,094,512	$ 84,110,109	$ 459,028,142

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, 2008

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	70,313,952	90,411,393	(630,833)	160,094,512
2	Delmarva Power & Light Company	37,169,665	84,325,788	(265,386)	121,230,067
3	Atlantic City Electric	22,993,733	70,823,730	(224,009)	93,593,454
4	Conectiv Energy Supply, Inc.	19,820,277	10,843,609	(37,598)	30,626,288
5	Conectiv Delmarva Generation, Inc.	5,683,137	11,664,701	(56,877)	17,290,961
6	Pepco Energy Services, Inc.	4,018,268	9,426,518	(70,597)	13,374,189
7	Conectiv Atlantic Generation, LLC	3,189,892	4,706,247	(26,309)	7,869,830
8	Conectiv Bethlehem, LLC	1,945,436	1,766,615	(31,160)	3,680,891
9	Pepco Holdings, Inc.	219,543	3,138,792	(86,688)	3,271,647
10	Potomac Capital Investment Corporation	1,300,935	1,086,853	(22,585)	2,365,203
11	PHI Operating Services Company	703,267	1,216,914	(951)	1,919,230
12	Thermal Energy Limited Partnership	108,347	684,357	(7,865)	784,839
13	Conectiv Mid-Merit, LLC	940,099	179,868	(902)	1,119,065
14	Conectiv Thermal Systems	138,656	160,340	(1,033)	297,963
15	Atlantic Southern Properties	53,082	90,180	(572)	142,690
16	Conectiv Communications, Inc.	732	37,058	(813)	36,977
17	ATE Investments, Inc.	1,310	26,026	(695)	26,641
18	Atlantic City Electric Transition Funding, LLC	51,570	670,171	(21,846)	699,895
19	Delaware Operating Services Company	2,006			2,006
20	Conectiv Properties and Investments, Inc.	9,125	62,047		71,172
21	Conectiv Pennsylvania Generation, LLC	14	6,175	(45)	6,144
22	Conectiv Solutions LLC	8,461	5,117		13,578
23	Conectiv North East, LLC	80,417	3,130	(37)	83,510
24	Atlantic Generation, Inc.	7,221	1,169	(8)	8,382
25	DCTC-Burney, Inc.	782	348		1,130
26	Conectiv Services II, Inc.	37,593	12,763		50,356
27	Vineland General, Inc.	12,660	150	(1)	12,809
28	Vineland Limited, Inc.		6		6
29	ACE REIT, Inc.	13	21	(1)	33
30	Conectiv	7,625	11,091	(334)	18,382
31	Atlantic Thermal Operating Company	49	119,384		119,433
32	Conectiv Energy Holding Company	424	223,071	(6,983)	216,512
33	Delta, LLC	347			347
34					
35					
36					
37					
38					
39					
40	**Total**	**168,818,638**	**291,703,632**	**(1,494,128)**	**459,028,142**

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)

$ 57,783,364 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	806,851				8.5	6,858,234	-	-	-	571,519	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	63,328,641				6.5	411,636,167	-	-	-	34,303,014	-	-	-	
Jul	1,159,601				5.5	6,377,806	-	-	-	531,484	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov	552,748				1.5	829,122	-	-	-	69,094	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	65,847,841	-	-	-		425,701,328	-	-	-	35,475,111	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										35,475,111	-	-	-	
								Input to Line 21 of Appendix A		35,475,111	-		-	35,475,111
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.54	#DIV/0!	#DIV/0!	#DIV/0!	

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

$ 35,475,111 Input to Formula Line 21

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

$ 61,419,620 — 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)

$ 61,419,620

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

$ 65,981,220 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 $ 119,833,058 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	$0				11.5	-	-	-	-	-	-	-	-	
Feb	$0				10.5	-	-	-	-	-	-	-	-	
Mar	$20,839				9.5	197,971	-	-	-	16,498	-	-	-	
Apr	$208,469				8.5	1,771,987	-	-	-	147,666	-	-	-	
May	$0				7.5	-	-	-	-	-	-	-	-	
Jun	$43,652,717				6.5	283,742,661	-	-	-	23,645,222	-	-	-	
Jul	$56,241,409				5.5	309,327,750	-	-	-	25,777,312	-	-	-	
Aug	$124,958				4.5	562,311	-	-	-	46,859	-	-	-	
Sep	$825,988				3.5	2,890,958	-	-	-	240,913	-	-	-	
Oct	$9,146,424				2.5	22,866,060	-	-	-	1,905,505	-	-	-	
Nov	$309,405				1.5	464,108	-	-	-	38,676	-	-	-	
Dec	$9,302,849				0.5	4,651,425	-	-	-	387,619	-	-	-	
Total	119,833,058	-	-	-		626,475,228	-	-	-	52,206,269	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										52,206,269	-	-	-	
								Input to Line 21 of Appendix A		52,206,269	-		-	52,206,269
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		6.77	#DIV/0!	#DIV/0!	#DIV/0!	

59,471,190.50 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	2,185,873				9.5	20,765,794	-	-	-	1,730,483	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	20,207,423				6.5	131,348,250	-	-	-	10,945,687	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	22,393,296	-	-	-		152,114,043	-	-	-	12,676,170	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										12,676,170	-	-	-	
67466306.15								Input to Line 21 of Appendix A		12,676,170	-		-	12,676,170
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.21	#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		
59,471,190	-	61,061,868	=	(1,590,678)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.3800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(132,556)	0.3800%	11.5	(5,793)	(138,349)
Jul	Year 1	(132,556)	0.3800%	10.5	(5,289)	(137,845)
Aug	Year 1	(132,556)	0.3800%	9.5	(4,785)	(137,342)
Sep	Year 1	(132,556)	0.3800%	8.5	(4,282)	(136,838)
Oct	Year 1	(132,556)	0.3800%	7.5	(3,778)	(136,334)
Nov	Year 1	(132,556)	0.3800%	6.5	(3,274)	(135,831)
Dec	Year 1	(132,556)	0.3800%	5.5	(2,770)	(135,327)
Jan	Year 2	(132,556)	0.3800%	4.5	(2,267)	(134,823)
Feb	Year 2	(132,556)	0.3800%	3.5	(1,763)	(134,319)
Mar	Year 2	(132,556)	0.3800%	2.5	(1,259)	(133,816)
Apr	Year 2	(132,556)	0.3800%	1.5	(756)	(133,312)
May	Year 2	(132,556)	0.3800%	0.5	(252)	(132,808)
Total		(1,590,678)				(1,626,945)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(1,626,945)	0.3800%	(138,951)	(1,494,177)
Jul	Year 2	(1,494,177)	0.3800%	(138,951)	(1,360,904)
Aug	Year 2	(1,360,904)	0.3800%	(138,951)	(1,227,124)
Sep	Year 2	(1,227,124)	0.3800%	(138,951)	(1,092,836)
Oct	Year 2	(1,092,836)	0.3800%	(138,951)	(958,038)
Nov	Year 2	(958,038)	0.3800%	(138,951)	(822,728)
Dec	Year 2	(822,728)	0.3800%	(138,951)	(686,904)
Jan	Year 3	(686,904)	0.3800%	(138,951)	(550,563)
Feb	Year 3	(550,563)	0.3800%	(138,951)	(413,704)
Mar	Year 3	(413,704)	0.3800%	(138,951)	(276,326)
Apr	Year 3	(276,326)	0.3800%	(138,951)	(138,425)
May	Year 3	(138,425)	0.3800%	(138,951)	(0)
Total with interest				(1,667,410)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(1,667,410)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	67,466,306
Revenue Requirement for Year 3		65,798,896

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

$ 65,798,896 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)

$ 65,798,896

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	11.1815%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	11.8724%
6	C		Line B less Line A	0.6909%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.1411%

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**

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 FER

11 **12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and**

Line	Description	Details		B0265 Mickelton		B0276 Monroe	
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		11.1815%		11.1815%	
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		12.2178%		11.1815%	
18	Columns A, B or C from Attachment 6	Investment		4,854,660	may be weighted average of small projects	7,878,071	
19	Line 18 divided by line 13	Annual Depreciation Exp		138,705		225,088	
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00		6.00	

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	Base FCR	2008			-	-			-	-
22	W Increased ROE	2008			-	-			-	-
23	Base FCR	2009	4,854,660	69,352	4,785,308	604,422	7,878,071	112,544	7,765,527	980,848
24	W Increased ROE	2009	4,854,660	69,352	4,785,308	654,014	7,878,071	112,544	7,765,527	980,848
25	Base FCR	2010	4,785,308	138,705	4,646,603	658,265	7,765,527	225,088	7,540,439	1,068,224
26	W Increased ROE	2010	4,785,308	138,705	4,646,603	706,419	7,765,527	225,088	7,540,439	1,068,224
27	Base FCR	2011	4,646,603	138,705	4,507,899	642,756	7,540,439	225,088	7,315,352	1,043,055
28	W Increased ROE	2011	4,646,603	138,705	4,507,899	689,473	7,540,439	225,088	7,315,352	1,043,055
29	Base FCR	2012	4,507,899	138,705	4,369,194	627,247	7,315,352	225,088	7,090,264	1,017,887
30	W Increased ROE	2012	4,507,899	138,705	4,369,194	672,526	7,315,352	225,088	7,090,264	1,017,887
31	Base FCR	2013	4,369,194	138,705	4,230,489	611,738	7,090,264	225,088	6,865,176	992,719
32	W Increased ROE	2013	4,369,194	138,705	4,230,489	655,579	7,090,264	225,088	6,865,176	992,719
33	Base FCR	2014	4,230,489	138,705	4,091,785	596,228	6,865,176	225,088	6,640,088	967,551
34	W Increased ROE	2014	4,230,489	138,705	4,091,785	638,633	6,865,176	225,088	6,640,088	967,551
35	Base FCR	2015	4,091,785	138,705	3,953,080	580,719	6,640,088	225,088	6,415,001	942,382
36	W Increased ROE	2015	4,091,785	138,705	3,953,080	621,686	6,640,088	225,088	6,415,001	942,382
37	Base FCR	2016	3,953,080	138,705	3,814,376	565,210	6,415,001	225,088	6,189,913	917,214
38	W Increased ROE	2016	3,953,080	138,705	3,814,376	604,739	6,415,001	225,088	6,189,913	917,214
39	Base FCR	2017	3,814,376	138,705	3,675,671	549,701	6,189,913	225,088	5,964,825	892,046
40	W Increased ROE	2017	3,814,376	138,705	3,675,671	587,792	6,189,913	225,088	5,964,825	892,046
41	Base FCR	2018	3,675,671	138,705	3,536,967	534,191	5,964,825	225,088	5,739,737	866,878
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	570,846	5,964,825	225,088	5,739,737	866,878
43	Base FCR	2019	3,536,967	138,705	3,398,262	518,682	5,739,737	225,088	5,514,650	841,709
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	553,899	5,739,737	225,088	5,514,650	841,709
45	Base FCR	2020	3,398,262	138,705	3,259,557	503,173	5,514,650	225,088	5,289,562	816,541
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	536,952	5,514,650	225,088	5,289,562	816,541
47	Base FCR	2021	3,259,557	138,705	3,120,853	487,663	5,289,562	225,088	5,064,474	791,373
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	520,006	5,289,562	225,088	5,064,474	791,373
49	Base FCR	2022	3,120,853	138,705	2,982,148	472,154	5,064,474	225,088	4,839,386	766,205
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	503,059	5,064,474	225,088	4,839,386	766,205
51	Base FCR	2023	2,982,148	138,705	2,843,444	456,645	4,839,386	225,088	4,614,299	741,037
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	486,112	4,839,386	225,088	4,614,299	741,037
53	Base FCR	2024	2,843,444	138,705	2,704,739	441,136	4,614,299	225,088	4,389,211	715,868
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	469,165	4,614,299	225,088	4,389,211	715,868
55	Base FCR	2025	2,704,739	138,705	2,566,035	425,626	4,389,211	225,088	4,164,123	690,700
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	452,219	4,389,211	225,088	4,164,123	690,700
57	Base FCR	2026	2,566,035	138,705	2,427,330	410,117	4,164,123	225,088	3,939,035	665,532
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	435,272	4,164,123	225,088	3,939,035	665,532
59	Base FCR	2027	2,427,330	138,705	2,288,625	394,608	3,939,035	225,088	3,713,948	640,364
60	W Increased ROE	2027		138,705	(138,705)	121,758	3,939,035	225,088	3,713,948	640,364
61		....		....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

C to become effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for
November 1, 2008 respectively

B0211 Union-Corson	B0210 Orchard-500kV
Yes	Yes
35	35
No	No
0	150
11.1815%	11.1815%
11.1815%	12.2178%
13,722,120	26,046,638
392,061	744,190
9.00	7.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
13,722,120	98,015	13,624,105	605,809	26,046,638	310,079	25,736,559	1,748,948
13,722,120	98,015	13,624,105	605,809	26,046,638	310,079	25,736,559	1,882,306
13,624,105	392,061	13,232,044	1,871,604	25,736,559	744,190	24,992,369	3,538,717
13,624,105	392,061	13,232,044	1,871,604	25,736,559	744,190	24,992,369	3,797,719
13,232,044	392,061	12,839,984	1,827,766	24,992,369	744,190	24,248,180	3,455,505
13,232,044	392,061	12,839,984	1,827,766	24,992,369	744,190	24,248,180	3,706,795
12,839,984	392,061	12,447,923	1,783,928	24,248,180	744,190	23,503,990	3,372,293
12,839,984	392,061	12,447,923	1,783,928	24,248,180	744,190	23,503,990	3,615,871
12,447,923	392,061	12,055,863	1,740,089	23,503,990	744,190	22,759,800	3,289,082
12,447,923	392,061	12,055,863	1,740,089	23,503,990	744,190	22,759,800	3,524,947
12,055,863	392,061	11,663,802	1,696,251	22,759,800	744,190	22,015,611	3,205,870
12,055,863	392,061	11,663,802	1,696,251	22,759,800	744,190	22,015,611	3,434,023
11,663,802	392,061	11,271,741	1,652,413	22,015,611	744,190	21,271,421	3,122,658
11,663,802	392,061	11,271,741	1,652,413	22,015,611	744,190	21,271,421	3,343,099
11,271,741	392,061	10,879,681	1,608,574	21,271,421	744,190	20,527,231	3,039,446
11,271,741	392,061	10,879,681	1,608,574	21,271,421	744,190	20,527,231	3,252,176
10,879,681	392,061	10,487,620	1,564,736	20,527,231	744,190	19,783,042	2,956,235
10,879,681	392,061	10,487,620	1,564,736	20,527,231	744,190	19,783,042	3,161,252
10,487,620	392,061	10,095,560	1,520,898	19,783,042	744,190	19,038,852	2,873,023
10,487,620	392,061	10,095,560	1,520,898	19,783,042	744,190	19,038,852	3,070,328
10,095,560	392,061	9,703,499	1,477,059	19,038,852	744,190	18,294,662	2,789,811
10,095,560	392,061	9,703,499	1,477,059	19,038,852	744,190	18,294,662	2,979,404
9,703,499	392,061	9,311,439	1,433,221	18,294,662	744,190	17,550,473	2,706,599
9,703,499	392,061	9,311,439	1,433,221	18,294,662	744,190	17,550,473	2,888,480
9,311,439	392,061	8,919,378	1,389,383	17,550,473	744,190	16,806,283	2,623,388
9,311,439	392,061	8,919,378	1,389,383	17,550,473	744,190	16,806,283	2,797,556
8,919,378	392,061	8,527,317	1,345,544	16,806,283	744,190	16,062,093	2,540,176
8,919,378	392,061	8,527,317	1,345,544	16,806,283	744,190	16,062,093	2,706,632
8,527,317	392,061	8,135,257	1,301,706	16,062,093	744,190	15,317,904	2,456,964
8,527,317	392,061	8,135,257	1,301,706	16,062,093	744,190	15,317,904	2,615,708
8,135,257	392,061	7,743,196	1,257,868	15,317,904	744,190	14,573,714	2,373,753
8,135,257	392,061	7,743,196	1,257,868	15,317,904	744,190	14,573,714	2,524,784
7,743,196	392,061	7,351,136	1,214,029	14,573,714	744,190	13,829,524	2,290,541
7,743,196	392,061	7,351,136	1,214,029	14,573,714	744,190	13,829,524	2,433,860
7,351,136	392,061	6,959,075	1,170,191	13,829,524	744,190	13,085,335	2,207,329
7,351,136	392,061	6,959,075	1,170,191	13,829,524	744,190	13,085,335	2,342,936
6,959,075	392,061	6,567,015	1,126,353	13,085,335	744,190	12,341,145	2,124,117
6,959,075	392,061	6,567,015	1,126,353	13,085,335	744,190	12,341,145	2,252,012
6,567,015	392,061	6,174,954	1,082,514	12,341,145	744,190	11,596,955	2,040,906
6,567,015	392,061	6,174,954	1,082,514	12,341,145	744,190	11,596,955	2,161,088
....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....

r specific projects identified or to be indentified in Attachment 7 is

B0210 Orchard-Below 500kV

Yes
35

No

150

0.11181521

0.122178477

18,572,212
530,635

7

Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
18,572,212	221,098	18,351,114	1,247,065	$ 3,601,822		$ 3,601,822
18,572,212	221,098	18,351,114	1,342,153	$ 3,830,268	$ 3,830,268	
18,351,114	530,635	17,820,480	2,523,235	$ 9,518,827		$ 9,518,827
18,351,114	530,635	17,820,480	2,707,914	$ 10,012,099	$ 10,012,099	
17,820,480	530,635	17,289,845	2,463,902	$ 9,473,662		$ 9,473,662
17,820,480	530,635	17,289,845	2,643,082	$ 9,952,286	$ 9,952,286	
17,289,845	530,635	16,759,210	2,404,569	$ 9,246,602		$ 9,246,602
17,289,845	530,635	16,759,210	2,578,249	$ 9,710,577	$ 9,710,577	
16,759,210	530,635	16,228,576	2,345,236	$ 9,019,541		$ 9,019,541
16,759,210	530,635	16,228,576	2,513,417	$ 9,468,867	$ 9,468,867	
16,228,576	530,635	15,697,941	2,285,903	$ 8,792,481		$ 8,792,481
16,228,576	530,635	15,697,941	2,448,585	$ 9,227,158	$ 9,227,158	
15,697,941	530,635	15,167,306	2,226,570	$ 8,565,420		$ 8,565,420
15,697,941	530,635	15,167,306	2,383,753	$ 8,985,448	$ 8,985,448	
15,167,306	530,635	14,636,672	2,167,237	$ 8,338,359		$ 8,338,359
15,167,306	530,635	14,636,672	2,318,921	$ 8,743,739	$ 8,743,739	
14,636,672	530,635	14,106,037	2,107,904	$ 8,111,299		$ 8,111,299
14,636,672	530,635	14,106,037	2,254,089	$ 8,502,030	$ 8,502,030	
14,106,037	530,635	13,575,403	2,048,571	$ 7,884,238		$ 7,884,238
14,106,037	530,635	13,575,403	2,189,257	$ 8,260,320	$ 8,260,320	
13,575,403	530,635	13,044,768	1,989,238	$ 7,657,178		$ 7,657,178
13,575,403	530,635	13,044,768	2,124,425	$ 8,018,611	$ 8,018,611	
13,044,768	530,635	12,514,133	1,929,905	$ 7,430,117		$ 7,430,117
13,044,768	530,635	12,514,133	2,059,592	$ 7,776,902	$ 7,776,902	
12,514,133	530,635	11,983,499	1,870,572	$ 7,203,056		$ 7,203,056
12,514,133	530,635	11,983,499	1,994,760	$ 7,535,192	$ 7,535,192	
11,983,499	530,635	11,452,864	1,811,239	$ 6,975,996		$ 6,975,996
11,983,499	530,635	11,452,864	1,929,928	$ 7,293,483	$ 7,293,483	
11,452,864	530,635	10,922,229	1,751,906	$ 6,748,935		$ 6,748,935
11,452,864	530,635	10,922,229	1,865,096	$ 7,051,773	$ 7,051,773	
10,922,229	530,635	10,391,595	1,692,573	$ 6,521,875		$ 6,521,875
10,922,229	530,635	10,391,595	1,800,264	$ 6,810,064	$ 6,810,064	
10,391,595	530,635	9,860,960	1,633,240	$ 6,294,814		$ 6,294,814
10,391,595	530,635	9,860,960	1,735,432	$ 6,568,355	$ 6,568,355	
9,860,960	530,635	9,330,326	1,573,907	$ 6,067,753		$ 6,067,753
9,860,960	530,635	9,330,326	1,670,600	$ 6,326,645	$ 6,326,645	
9,330,326	530,635	8,799,691	1,514,574	$ 5,840,693		$ 5,840,693
9,330,326	530,635	8,799,691	1,605,767	$ 6,084,936	$ 6,084,936	
8,799,691	530,635	8,269,056	1,455,241	$ 5,613,632		$ 5,613,632
8,799,691	530,635	8,269,056	1,540,935	$ 5,546,659	$ 5,546,659	
....	....	.....	....			$ -
....	.....	.....	....		$ -	
					$ 155,705,413	$ 148,906,300

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	23,518,887
	Capitalization	
112	**Less LTD on Securitization Bonds**	422,207,762

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2007 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 31 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Attachment 4d

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	2008
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21b	$ 4,207,079
2	Total Wages Expense			p354.28b	$ 53,083,661
3	Less A&G Wages Expense			p354.27b	$ 4,492,531
4	Total			(Line 2 - 3)	48,591,130
5	**Wages & Salary Allocator**			(Line 1 / 4)	**8.6581%**
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g	$ 5,207,636,430
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	5,207,636,430
9	Accumulated Depreciation (Total Electric Plant)			p219.29c	$ 2,285,551,295
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 79,117,838
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)	2,364,669,133
14	Net Plant			(Line 8 - 13)	2,842,967,297
15	Transmission Gross Plant			(Line 29 - Line 28)	771,697,485
16	**Gross Plant Allocator**			(Line 15 / 8)	**14.8186%**
17	Transmission Net Plant			(Line 39 - Line 28)	421,400,675
18	**Net Plant Allocator**			(Line 17 / 14)	**14.8226%**
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 725,351,802
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	15,380,924
22	**Total Transmission Plant In Service**			(Line 19 - 20 + 21)	**740,732,726**
23	General & Intangible			p205.5.g & p207.99.g	357,638,304
24	Common Plant (Electric Only)		(Notes A & B)	p356	0
25	Total General & Common			(Line 23 + 24)	357,638,304
26	Wage & Salary Allocation Factor			(Line 5)	8.65812%
27	**General & Common Plant Allocated to Transmission**			(Line 25 * 26)	**30,964,758**
28	**Plant Held for Future Use (Including Land)**		(Note C)	p214	**0**
29	**TOTAL Plant In Service**			**(Line 22 + 27 + 28)**	**771,697,485**
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	329,956,613
31	Accumulated General Depreciation			p219.28.c	155,808,372
32	Accumulated Intangible Amortization			(Line 10)	79,117,838
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)	234,926,210
36	Wage & Salary Allocation Factor			(Line 5)	8.65812%
37	**General & Common Allocated to Transmission**			(Line 35 * 36)	**20,340,196**
38	**TOTAL Accumulated Depreciation**			**(Line 30 + 37)**	**350,296,809**
39	**TOTAL Net Property, Plant & Equipment**			**(Line 29 - 38)**	**421,400,675**
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-107,161,913
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	14.82%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**			(Line 41 * 42) + Line 40	**-107,161,913**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**		(Note B)	p216.43.b as Shown on Attachment 6	24,097,545
	Transmission O&M Reserves				
44	**Total Balance Transmission Related Account 242 Reserves**		Enter Negative	Attachment 5	**-3,555,989**
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	26,570,669
46	**Total Prepayments Allocated to Transmission**			(Line 45)	**26,570,669**
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	2,874,523
48	Wage & Salary Allocation Factor			(Line 5)	8.66%
49	Total Transmission Allocated			(Line 47 * 48)	248,880
50	Transmission Materials & Supplies			p227.8c	3,926,742
51	**Total Materials & Supplies Allocated to Transmission**			(Line 49 + 50)	**4,175,622**
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	32,013,042
53	1/8th Rule			x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**			(Line 52 * 53)	**4,001,630**
	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)	**-51,872,436**
59	**Rate Base**			(Line 39 + 58)	**369,528,239**

O&M

Line	Description	Note	Source	Amount
	Transmission O&M			
60	Transmission O&M		p321.112.b	23,755,048
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)	**23,755,048**
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	0
68	Total A&G		p323.197.b	96,622,624
69	Less Property Insurance Account 924		p323.185b	817,168
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	1,630,238
71	Less General Advertising Exp Account 930.1		p323.191b	101,657
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	0
73	Less EPRI Dues	(Note D)	p352-353	93,955
74	**General & Common Expenses**		(Lines 67 + 68) - Sum (69 to 73)	93,979,606
75	Wage & Salary Allocation Factor		(Line 5)	8.6581%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**8,136,868**
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	**0**
80	Property Insurance Account 924		p323.185b	817,168
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
82	Total		(Line 80 + 81)	817,168
83	Net Plant Allocation Factor		(Line 18)	14.82%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**121,125**
85	**Total Transmission O&M**		**(Line 66 + 76 + 79 + 84)**	**32,013,042**

Depreciation & Amortization Expense

Line	Description	Note	Source	Amount
	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	**15,543,180**
87	General Depreciation		p336.10b&c	13,769,680
88	Intangible Amortization	(Note A)	p336.1d&e	7,282,131
89	Total		(Line 87 + 88)	21,051,811
90	Wage & Salary Allocation Factor		(Line 5)	8.6581%
91	**General Depreciation Allocated to Transmission**		(Line 89 * 90)	**1,822,691**
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)	8.6581%
96	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 94 * 95)	**0**
97	**Total Transmission Depreciation & Amortization**		**(Line 86 + 91 + 96)**	**17,365,871**

Taxes Other than Income

Line	Description	Note	Source	Amount
98	**Taxes Other than Income**		Attachment 2	**7,015,262**
99	**Total Taxes Other than Income**		**(Line 98)**	**7,015,262**

Return / Capitalization Calculations

Line	Description		Note	Source	Amount
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	80,019,744
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	80,019,744
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,235,731,612
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	-1,646,367
107	**Common Stock**			(Sum Lines 104 to 106)	1,234,085,245
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,504,300,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-38,887,461
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	368,747
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	1,465,781,286
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,234,085,245
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,699,866,531
117	Debt %	Total Long Term Debt		(Line 113 / 116)	54%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0%
119	Common %	Common Stock		(Line 115 / 116)	46%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0546
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)	0.0296
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0517
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0813**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**30,038,845**

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		8.23%
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)} =			40.35%
132	T/ (1-T)				67.63%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	-2,034,384
134	T/(1-T)			(Line 132)	67.63%
135	Net Plant Allocation Factor			(Line 18)	14.8226%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-505,500**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**12,909,227**
138	**Total Income Taxes**			**(Line 136 + 137)**	**12,403,727**

REVENUE REQUIREMENT

	Summary				
139	Net Property, Plant & Equipment			(Line 39)	421,400,675
140	Adjustment to Rate Base			(Line 58)	-51,872,436
141	**Rate Base**			(Line 59)	**369,528,239**
142	O&M			(Line 85)	32,013,042
143	Depreciation & Amortization			(Line 97)	17,365,871
144	Taxes Other than Income			(Line 99)	7,015,262
145	Investment Return			(Line 127)	30,038,845
146	Income Taxes			(Line 138)	12,403,727
147	**Gross Revenue Requirement**			**(Sum Lines 142 to 146)**	**98,836,746**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	725,351,802
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	725,351,802
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	98,836,746
153	**Adjusted Gross Revenue Requirement**			(Line 151 * 152)	**98,836,746**
	Revenue Credits & Interest on Network Credits				
154	**Revenue Credits**			Attachment 3	5,708,546
155	**Interest on Network Credits**		(Note N)	PJM Data	-
156	**Net Revenue Requirement**			**(Line 153 - 154 + 155)**	**93,128,200**
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	**93,128,200**
158	Net Transmission Plant			(Line 19 - 30)	**395,395,189**
159	Net Plant Carrying Charge			(Line 157 / 158)	**23.5532%**
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	**19.6221%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	**8.8879%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	**50,685,628**
163	Increased Return and Taxes			Attachment 4	**45,274,062**
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	**95,959,691**
165	Net Transmission Plant			(Line 19 - 30)	**395,395,189**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	**24.2693%**
167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 163 - 86) / 165	**20.3383%**
168	**Net Revenue Requirement**			(Line 156)	**93,128,200**
169	True-up amount			Attachment 6	**(4,679,645)**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	**862,178**
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515			Attachment 5	**-**
172	**Net Zonal Revenue Requirement**			(Line 168 - 169 + 171)	**89,310,733**
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	**6,751**
174	Rate ($/MW-Year)			(Line 172 / 173)	**13,229**
175	**Network Service Rate ($/MW/Year)**			**(Line 174)**	**13,229**

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.

END

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	0	(762,478,041)	8,589,132	
ADIT-283	0	(114,612,040)	(63,635,705)	
ADIT-190	0	178,344,215	13,262,265	
Subtotal	0	(698,745,866)	(41,784,308)	
Wages & Salary Allocator			8.6581%	
Gross Plant Allocator		14.8186%		
ADIT	0	(103,544,177)	(3,617,736)	(107,161,913)

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 (368,747)

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*
Fuel Supply Sale	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant
Fuel Rights Sale	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant
Enrichment Contract Sale	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant
Fuel Excise Tax Write-off	0	0				Deferred taxes related Generation
Deferred Payments	0				0	For book purposes, deferred executive compensation and deferred payments are expensed when accrued. For tax purposes, they are deducted when paid. Affects company personnel across all functions.
Deferred Compensation(stk)	10,808,920				10,808,920	purposes, they are deducted when paid. Affects company personnel across all functions.
Additional Rental Income	0				0	Rental of General Plant and therefore allocated on labor.
D. C. Gross Receipts Tax	0	0				Retail related
Control Center - Lease Payment	86,194,377			86,194,377		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.
Avg. Payment Plan	0	0				monthly payments based on this average. For tax purposes, payments are included in income upon receipt whereas for book purposes, income is based on the meters read basis. The debit to deferred tax arises
Customer Deposits	0	0				Customer deposits are treated as deferred liabilities for book purposes; for tax purposes deposits held over two years are included in taxable income. Retail related
Normalization Adjustment	0			0		This adjustment reflects the flowback to the customer for the difference resulting from taxes deferred at the 46% federal tax rate and the lower 34% corporate tax rate in accordance with the Tax Reform Act of 1986. Involves all plant and is not limited to retail.
Normalization-MD Case 8162	0			0		This adjustment reflects the flowback to the customer for the difference resulting from taxes deferred at the 46% federal tax rate and the lower 34% corporate tax rate in accordance with the Tax Reform Act of 1986.Involves all plant and is not limited to retail.
CIAC	84,829,319			84,829,319		Notice 87-51, if CIAC are not grossed up, the deferred taxes must be included in rate base in order for the
Normalization - Unbilled Revenues	0			0		Relates to all revenues
Unbilled Revenues(1989 & TRA 1986)	0			0		Relates to all revenues
Unbilled Revenue Adj. DC Order #10387	0			0		Relates to all revenues
NPDES Permits (Net)	0	0				The cost of discharge permits for the Company's generating stations are expensed currently for book purposes and are required to be amortized over a 5 year period for tax purposes. Generation related
Cap. Construct Period Taxes	0			0		Pursuant to IRC Section 189, these taxes are capitalized and amortized over ten years for tax purposes whereas for book purposes, they are deducted currently. Related to all plant.
Bad Debt Reserve Amort	6,295,854			6,295,854		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.
Bad Debt Expense/Adjustment	0			0		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	2,456,452				2,456,452	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.
Connection Fees	(722,756)	(722,756)				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.
Service - Conn Fee Income	0	0				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
Dep - Conn Fee Income	0	0				capitalized and depreciated for tax purposes. For book purposes, connection fees are excluded from
Mine Closing Costs/Conemaugh Adj	0	0				Generation related
Consl.Audit Adj.	0			0		This deferred tax balance relate to prior Internal Revenue Service audits of the Company
FAS 109 - Deferred Taxes on ITC	4,082,080			4,082,080		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	5,147,314			5,147,314		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 - Flowthrough Items	0			0		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 - Normalization	0			0		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 - Earnings Effect	0			0		differences regardless of whether the difference is normalized or flowed-through. These balances primarily
Current Portion of Deferred Tax Liability	0			0		Represents the portion of the deferred taxes that have been identified as current. Related to all plant.
SMECO Contract Termination/Interest	0	0				For book purposes, the gain was recorded when the termination contract was entered into. For tax purposes, the gain is recognized when the terms of the contract are met. Generation related.
94/95 Audit-Human Resource Initiatives/Gude Capacity Pymt	0	0				Relates to prior IRS audit adjustments. The tax amortization period is longer than the book s which currently expensed these costs. Gude is generation related
Customer Sharing	(3,143,338)	(3,143,338)				expensed when the gain on the sale was recorded. For tax purposes, gain to be shared is deducted when paid. Generation related
Pension Curtailment	4,311,753	4,311,753				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.
Transition Costs	1,287,846	1,287,846				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. Generation related.
Severance Payments/Other	0				0	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 individuals. Affects company personnel across all functions.
Empowerment Zone Credit	0				0	PHI's consolidated return is in an NOL situation, therefore, Pepco's Empowerment Zone credit is carried forward until such time as PHI is in a taxable income position. Affects company personnel across all functions.
PG County Right of Way	404,166	404,166				Council. Since Maryland counties are prohibited from enacting any tax without the authority of the state
MD Adjustment	744,160	744,160				This deferred tax balance relates to a Maryland refund that was received in 2007 relating to the sale of Pepco generation.
Mirant Settlement	26,296,840	26,296,840				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.
Accrued Retired Executive Compensation	(3,107)				(3,107)	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.

Contribution Carryforward	748,833			748,833		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.
Leased Vehicles	275,831			275,831		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.
Subtotal - p234	230,014,544	29,178,671	0	187,573,608	13,262,265	
Less FASB 109 Above if not separately removed	9,229,394		0	9,229,394		
Less FASB 106 Above if not separately removed	0		0		0	
Total	220,785,150	29,178,671	0	178,344,215	13,262,265	

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
included in taxable income in different periods than
they are included in rates, therefore if the item giving

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

)eferred 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	(519,143,936)			(519,143,936)		computed pursuant to the Internal Revenue Code and the book depreciation associated with all assets.
Depreciation (BG&E)/Gain On Sale Conemaugh	0	0				Generation related
Repair Allowance	(25,174,154)			(25,174,154)		Deferred tax represents the difference between tax deductible repairs and book capitalization of repair costs Affects company personnel across all functions.
Repair Allowance Proceeds	0			0		previously expensed repair allowance property and is included in taxable income. For book purposes, proceeds are charged to the depreciation reserve. Affects company personnel across all functions.
Disc on Bond Redemption	0			0		For book purposes, the discount is amortized over the life of the replacement bond issuance. For tax purposes, the discount is deducted currently. Related to all functions.
Adj. Tax Gain - TDR's	325,526			325,526		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.
Adj. Tax Gain - FAR's	0			0		This adjustment reflects the disposition or salvage relating to FARs. 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)	2,989,896			2,989,896		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.
Disp of ACRS Mass Property	0			0		be currently recognized as taxable income or loss. For book purposes the proceeds from the disposition or
Control Center - Depreciation/Amort	(51,838,371)			(51,838,371)		See the explanation for Account 190.
Removal Cost Adjustment	(22,687,853)			(22,687,853)		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.
Removal Cost Adj - MD	0	0				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. Retail related
Removal Cost Adj - DC	0	0				for book purposes. Removal costs relating to post-1980 assets are required to be normalized under the Internal Revenue Code. Retail related.
Book Deprec-Reloc Proceeds	0			0		For book purposes, the relocation proceeds are credited to the book depreciation reserve. For tax purposes relocation proceeds are included in income upon receipt. Related to all plant.
Proceeds ACRS Mass Property	0			0		For tax purposes, any disposition or salvage related to post-1980 accelerated cost recovery property must be currently recognized as taxable income or loss. For book purposes the proceeds from the disposition or salvage of post-1980 property is credited to the depreciation reserve. Related to all plant.
Disp of ACRS Non Mass Prop	0			0		be currently recognized as taxable income or loss. For book purposes the proceeds from the disposition or
Normalization Adjustment	0			0		See the explanation for Account 190
Normalization-MD Case 8162	0			0		See the explanation for Account 191
Capitalized Interest	19,458,987			19,458,987		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
AFUDC Debt	(2,127,698)			(2,127,698)		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		purposes, AFUDC is used. Related to all plant.
FAS 109 Earnings Benefit 34/35%	0			0		See the explanation for Account 190.
FAS 109 - Flowthrough Items	(45,505,845)			(45,505,845)		See the explanation for Account 190.
FAS 109 - Normalization	0			0		See the explanation for Account 190.
FAS 109 - CCRF/AFUDC Equity	(34,395,809)			(34,395,809)		See the explanation for Account 190.
FAS 109 Earnings Effect - Nonoperating	0			0		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	(162,790,239)			(162,790,239)		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				Energy Use Mgt. assets. Retail related
Reduction State Taxes	0			0		Related to all plant.
MD Subtraction (Adj Gain or Loss)	0			0		the imposition of MD income tax on assets placed in service prior to the commencement of MD income taxes on operating income in 2000. Related to all assets.
Spare Parts	0			0		to be depreciated for tax purposes. Related to all spare parts.
DC Consolidated Adjustment	7,696,161			7,696,161		See the explanation for Account 190.
Casualty Losses	(9,442,883)			(9,442,883)		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.
Capitalized Pension	10,911,584				10,911,584	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	(2,322,451)				(2,322,451)	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)	(835,622,148)	(1,831,585)	0	(842,379,695)	8,589,132	
Less FASB 109 Above if not separately removed	(79,901,654)			(79,901,654)		
Less FASB 106 Above if not separately removed	0					
Total	(755,720,494)	(1,831,585)	0	(762,478,041)	8,589,132	

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

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

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)eferred 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*
Capitalized A&G	445,268			445,268		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	851,817			851,817		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	500,788			500,788		but capitalized and depreciated for book purposes. Related to all plant.
Doug Pt Term Costs - G.E.	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant. Generation related.
G E Term Costs - Non-Jur	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant. Generation related.

Plant Abandonment	0	0				Deferred taxes related to the termination of Pepco's planned nuclear plant. Generation related.
Invol Conv - Derwood Sub	0	0				For book purposes a loss from an involuntary conversion is deductible. For tax purposes, a loss from an involuntary conversion is deductible only if the converted property is used in a business or for the production of income. Distribution related.
Invol Conv - Md Prop MG016	0			0		For book purposes a loss from an involuntary conversion is deductible. For tax purposes, a loss from an involuntary conversion is deductible only if the converted property is used in a business or for the production of income.
Invol Conv - Civic Center	0			0		involuntary conversion is deductible only if the converted property is used in a business or for the production of income.
D.C. Adjustment	0	0				This represents the reversal of deferred taxes accrued at 48% that reversed at 46% to DC customers. Retail related.
MD Adjustment	0	0				This represents the reversal of deferred taxes accrued at 48% that reversed at 46% to MD customers. Retai related.
Excess Book Over Tax Gain	0	0				The deferred tax balance reflects the difference between the book gain and tax gain on the disposition/salvage of assets. Related to all assets
FAS 106 OPEB Adjustment	26,411,023				26,411,023	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.
OPEB Adj DC Order #10387	0				0	manner in which the DC Commission ordered these costs to be recovered from customers. Retail related.
Bk Depr on Poll Bond Int	(115,774)	(115,774)				Generation related.
Book Deprec on AFUDC	0			0		Related to all assets.
Environtech Investment	0	0				Unregulated business.
D.C. Street Lighting	0	0				The difference between the book gain and tax gain related to the non-operating sale of the DC street lights. Retail related.
Exp - Redemp. Pref. Stk.	0			0		The deferred tax balance represents the difference between the book and tax treatment for the redemption of preferred stock. Related to all functions.
PSI Cost-Cauph Proj	0	0				Pumped Hydro (CAUPH) project. These costs are being amortized for book purposes over a different period than for tax purposes. Generation related.
Amort Loss on Reacquisition	(368,747)	(368,747)				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.
D.C. Street Lighting Gain	0	0				The difference between the book gain and tax gain related to the non-operating sale of the DC street lights. Retail related.
Health Care Plans	1,160,249			1,160,249		deducted for tax purposes when they are paid. Affects company personnel across all functions.
Control Center - Interest Expense	(62,854,831)			(62,854,831)		See the explanation for the control center transaction in Account 190.
Loss on Marketable Securities	(13,078,620)	(13,078,620)				The deferred tax balance reflects the difference between the book gain and tax gain on the disposition/salvage of marketable securities.
Ordinary Gains/Losses	0			0		The difference between the book gain and tax gain on the disposition/salvage of assets. Related to all assets.
Capital Gains/Losses-D.C.	0			0		The difference between the book gain and tax gain on the disposition/salvage of assets. Related to all assets.
Legal Fees	0			0		tax purposes, these costs are capital in nature and are amortized over a 30 year period. Related to all
Amort of Unit Train Costs	0	0				Generation related.
Dividend Income Not Rec'd/Other Rental Income	0	0				
Normalization Adjust	0			0		See the explanation for Account 190
ESOP Deduction over ESOP ITC	0				0	Affects company personnel across all functions.
Other Exp - Non Oper(PCI)	0	0				Unregulated business.
Normalization-MD Case 8162	0			0		See the explanation for Account 190
Int Income - Basis Adj	0			0		Related to all functions.
NPDES Permits, 1981-83	0	0				purposes and are required to be amortized over a 5 year period for tax purposes. Generation related.
Compensation	0				0	Deferred employee comp. Related to all functions
Contributions	0			0		Charitable contributions. Related to all functions.
SFAS 121 Impairment Loss	859,870	859,870				book purposes. For tax purposes, an asset can not be written down for the loss. Generation related.
FAS 109 - Flowthrough Items	0			0		See the explanation for Account 190.
FAS 109 - Normalization	0			0		See the explanation for Account 190.
FAS 109 - Regulatory Receivable/Liability	22,750,159			22,750,159		See the explanation for Account 190.
FAS 109 - Earnings Effect - Nonoperating/Other	0	0				See the explanation for Account 190.
FAS 109 - CCRF Equity	(15,743,143)	(15,743,143)				See the explanation for Account 190.
CCRF - Operating/DSM 2000	0	0				DSM related. Retail related.
CCRF - Common Facility Costs	0	0				DSM related. Retail related.
CCRF Adj DC Order #10387	0	0				DSM related. Retail related.
Gain/Loss on Disposal of Allowances	0	0				Generation related.
Human Resource Initiatives	0				0	Payments are deducted when accrued for book purposes and when paid for tax. Affects company personnel across all functions.
Severance Pay/Other Comp/Incentive Bonus	3,721,424				3,721,424	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.
Pension Plan Contribution	(122,086,297)			(53,717,971)	(68,368,325)	per ERISA. For book purposes pension plan contributions are governed by FAS 106. This timing difference
VA GRT Adj	0	0				Retail related.
SMECO Contract Termination	0	0				purposes, the gain is recognized when the terms of the contract are met. Generation related.
Conservation Costs (DSM)	(11,733,934)	(11,733,934)				DSM related. Retail related.
Merger Costs - Software	0			0		Related to BG&E/PEPCO merger. Related to all functions.
Gainsharing / '94-'95 IRS Audit Adjustment	0				0	
Amortization-DSM Debt (DC)	0	0				DSM related. Retail related.
Empowerment Zone	0				0	See the explanation for Account 190.
Miscellaneous	310,214	310,214				See the explanation for Account 190.
Gude Landfill	0	0				See the explanation for Account 190.
Other Comprehensive Income	0				0	SERPA . Affects company personnel across all functions.
Blueprint for the Future	(997,361)			(997,361)		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.
DC Consolidated Adjustment	0			0		See the explanation for Account 190.
Prepaid Interest	(3,297,326)				(3,297,326)	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 assset. For tax purposes, there is "12-mnth 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 and is labor related.
SERP	4,308,522				4,308,522	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.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(168,956,697)	(39,870,134)	0	(91,861,881)	(37,224,683)	
Less FASB 109 Above if not separately removed	22,750,159			22,750,159		
Less FASB 106 Above if not separately removed	26,411,023				26,411,023	
Total	(218,117,879)	(39,870,134)	-	(114,612,040)	(63,635,705)	

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

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

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	12,491,863	2,034,384
5	Total		12,491,863	2,034,384
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (	12,491,863	2,034,384
7	Difference /1		-	-

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)	$ 6,614,159	100%	$ 6,614,159
1a	Other Personal Property Tax (excluded)	$ 24,163,039	0%	$ -
2	Capital Stock Tax		14.8186%	$ -
3	Gross Premium (insurance) Tax		14.8186%	$ -
4	PURTA		14.8186%	$ -
5	Corp License		14.8186%	$ -
			14.8186%	$ -
Total Plant Related		30,777,198		6,614,159
Labor Related			***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & state unemployment	4,632,674		
Total Labor Related		4,632,674	8.6581%	401,103
Other Included			***Gross Plant Allocator***	
7	Miscellaneous	0		
Total Other Included		0	14.8186%	0
Total Included				7,015,262

Currently Excluded

8	Franchise	0
9	kWhTax - State Gross Receipt (Excise Tax)	106,397,360
10	Electric environmental surcharge	2,143,816
11	Universal service fee	8,109,220
12	Montgomery County Fuel	89,500,539
13	PSC assessment	6,077,655
14	Real property (State, Municipal or Local)	7,532,069
15	DC Right of Way	20,262,132
16	Use & Sales Tax	3,606,927
17	FHUT	17,512
18	DC Ballpark	16,500
19	DC Reliable Energy Trust Fund	13,560,500
20	Misc. Other	0
21	Total "Other" Taxes (included on p. 263)	292,634,102
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	292,634,102
23	Difference	-

Criteria for Allocation:

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

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

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

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

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

Pepco
Allocation of Property taxes to Transmission Function
Year Ended December 31, 2008

Assessable Plant		**Maryland**
Transmission	$	564,585,796
Distribution	$	1,972,320,736
General	$	151,126,860
Total T,D&Genl	$	2,688,033,392
Plant ratios by Jurisdiction		
Transmission Ratio		0.21003675
Distribution ratio		0.73374116
General Ratio		0.05622209
		1.00000000
Property Taxes	$	30,777,198
Transmission Property Tax	$	6,464,343
Distribution Property tax	$	22,582,497
General Property Tax	$	1,730,358
Total check	$	30,777,198
Allocation of General to Transmission		
General Property Tax	$	1,730,358
Trans Labor Ratio		0.086581213
Trans General		149,817

Total Transmission Property Taxes		
Transmission	$	6,464,343
General	$	149,817
Total Transmission Property Taxes	$	6,614,159

Potomac Electric Power Company

Attachment 3 - Revenue Credit Workpaper

Line	Description	Reference	Amount
	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		8,910,666
2	Total Rent Revenues	(Sum Lines 1)	8,910,666
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 610,672
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)		2,440,116
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)	11,961,454
12	Less line 17g		(6,252,908)
13	Total Revenue Credits		5,708,546

Revenue Adjustment to determine Revenue Credit

Line	Description	Amount
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.	8,910,666
17b	Costs associated with revenues in line 17a	3,595,149
17c	Net Revenues (17a - 17b)	5,315,517
17d	50% Share of Net Revenues (17c / 2)	2,657,759
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)	2,657,759
17g	Line 17f less line 17a	(6,252,908)
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.	29,621,369
19	Amount offset in line 4 above	91,008,446
20	Total Account 454, 456 and 456.1	132,591,269
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)	45,274,062
B	100 Basis Point increase in ROE				1.00%
Return Calculation					
59	Rate Base			(Line 39 + 58)	369,528,239
	Long Term Interest				
100	**Long Term Interest**			p117.62c through 67c	80,019,744
101	Less LTD Interest on Securitization E	(Note P)		Attachment 8	0
102	Long Term Interest			"(Line 100 - line 101)"	80,019,744
103	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	1,235,731,612
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	-1,646,367
107	Common Stock			(Sum Lines 104 to 106)	1,234,085,245
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,504,300,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-38,887,461
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	368,747
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	1,465,781,286
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,234,085,245
116	Total Capitalization			(Sum Lines 113 to 115)	2,699,866,531
117	Debt %		Total Long Term Debt	(Line 113 / 116)	54%
118	Preferred %		Preferred Stock	(Line 114 / 116)	0%
119	Common %		Common Stock	(Line 115 / 116)	46%
120	Debt Cost		Total Long Term Debt	(Line 102 / 113)	0.0546
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)	0.0296
124	Weighted Cost of Preferred		Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common		Common Stock	(Line 119 * 122)	0.0562
126	Total Return (R)			**(Sum Lines 123 to 125)**	**0.0859**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**31,727,926**
Composite Income Taxes					
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite				8.23%
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)} =			40.35%
132	T/ (1-T)				67.63%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	p266.8f	(2,034,384)
134	T/(1-T)			(Line 132)	68%
135	Net Plant Allocation Factor			(Line 18)	14.8226%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-505,500**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			14,051,636
138	**Total Income Taxes**				**13,546,137**

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	$ 79,117,838	79,117,838	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	10,030,596	10,030,596	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 2,874,523	2,874,523	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	$ 7,282,131	7,282,131	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	986,410	0	986,410	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	Enter	Enter	Enter	Enter Details
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	$ 5,207,636,430	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 725,351,802	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	329,956,613	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	93955	93955	See Form 1

Potomac Electric Power Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 1,630,238	0	1,630,238	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	1,630,238	0	1,630,238	FERC

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	101,657	-	101,657	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)	8.2255%	8.25%	9.975%	Enter %	Enter %	Enter %	Apportioned: MD 4.39%, DC 3.8349

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	101,657	0	101,657	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	38,918,152	8.66%	3,369,581	
	Plant Related	1,257,933	14.82%	186,408	
	Other		0.00%	-	
	Total Transmission Related Reserves	40,176,085		3,555,989	

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		8.658%		
	Pension Liabilities, if any, in Account 242	-	8.658%	-	
	Prepayments	$ 164,726,444	8.658%	14,262,215	
	Prepaid Pensions if not included in Prepayments	$ 142,160,791	8.658%	12,308,454	
		306,887,235	8.66%	26,570,669	

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	6,751.0	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
Pepco zone				-	-	-
Total				-	-	-

Potomac Electric Power Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 6,088,669	$ 4,685,228	$ 13,055,598	$ 11,843,832	$ 35,673,327
Security Services Administration	448,463	281,895	1,103,634	215,476	2,049,468
Purchasing, Storeroom & Materials Mgt	764,668	401,128	2,292,990	162,133	3,620,919
Vehicle Resource Management	823,131	510,583	667,782	23,980	2,025,476
General Services	2,499,014	1,185,490	1,992,218	833,669	6,510,391
Building Services	845,609	719,336	2,002,356	650,304	4,217,605
Real Estate	1,062,693	914,165	168,676	123,622	2,269,156
Corporate Insurance Administration	161,286	107,288	243,862	132,157	644,593
Claims Administration	554,166	522,344	1,258,298	-	2,334,808
Regulatory Affairs	3,557,440	2,525,542	5,206,817	51,787	11,341,586
Accounts Payable Accounting Services	480,561	369,796	415,968	175,455	1,441,780
Payroll Services	345,067	197,596	527,080	82,924	1,152,667
Asset & Project Accounting Services	465,891	441,261	1,235,701	396,926	2,539,779
Investor Relations	163,900	137,954	391,953	232,342	926,149
Shareholder Services	239,252	200,704	573,491	340,459	1,353,906
Financial Reporting	714,616	611,787	1,710,178	1,032,682	4,069,263
Sarbanes-Oxley Compliance	170,005	155,738	406,322	240,877	972,942
Investment Financial Management	162,452	144,408	324,998	227,000	858,858
Other Financial Services	4,822,102	4,016,397	7,066,305	5,585,377	21,490,181
Insurance Premiums & Claims	2,183,779	1,532,480	3,622,824	2,853,195	10,192,278
Cost of Benefits	9,645,396	5,280,286	14,835,121	4,851,358	34,612,161
Executive Compensation Services	1,304,179	1,102,347	3,098,578	1,836,230	7,341,334
Other Human Resources Services	6,003,234	3,552,335	7,295,156	4,221,881	21,072,606
Legal Services	3,295,848	2,149,716	4,685,334	1,193,530	11,324,428
Audit Services	901,281	937,556	1,344,601	725,695	3,909,133
Special Billing	596,177	523,426	1,032,596	23,547	2,175,746
Other Customer Care	32,330,273	33,228,289	9,939,300	-	75,497,862
Marketing Services	1,337,414	901,584	2,152,837	71,686	4,463,521
Information Technology	6,446,316	4,108,253	28,658,896	2,414,853	41,628,318
PHI Corporate Contributions	4,413	3,760	10,600	6,249	25,022
Federal Government Affairs	236,465	199,898	565,539	334,717	1,336,619
Other Corporate Communications	965,371	576,380	1,674,735	591,134	3,807,620
Environmental Management Services	1,356,946	891,749	2,094,110	594,133	4,936,938
System Operations Shared	2,441,554	1,611,650	5,351,445	186,866	9,591,515
Electric Maintenance Meter Shop	1,353,932	767,471	-	-	2,121,403
Other Delivery Services	23,228,812	16,373,165	29,935,926	40,567	69,578,470
Power Procurement	1,691,047	1,405,532	2,847,431	-	5,944,010
Management & Administration	112,436	21,520	-	10,169,677	10,303,633
Merchant Functions	907,522	-	-	21,600,003	22,507,525
Engineering Administration	254,758	117,831	-	10,043,444	10,416,033
Internal Consulting Services	104,095	70,196	157,910	-	332,201
IT Voice Support	-	-	2,430	-	2,430
Interns	159,834	109,390	144,916	342	414,482
Total	$ 121,230,067	$ 93,593,454	$ 160,094,512	$ 84,110,109	$ 459,028,142

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, 2008

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	70,313,952	90,411,393	(630,833)	160,094,512
2	Delmarva Power & Light Company	37,169,665	84,325,788	(265,386)	121,230,067
3	Atlantic City Electric	22,993,733	70,823,730	(224,009)	93,593,454
4	Conectiv Energy Supply, Inc.	19,820,277	10,843,609	(37,598)	30,626,288
5	Conectiv Delmarva Generation, Inc.	5,683,137	11,664,701	(56,877)	17,290,961
6	Pepco Energy Services, Inc.	4,018,268	9,426,518	(70,597)	13,374,189
7	Conectiv Atlantic Generation, LLC	3,189,892	4,706,247	(26,309)	7,869,830
8	Conectiv Bethlehem, LLC	1,945,436	1,766,615	(31,160)	3,680,891
9	Pepco Holdings, Inc.	219,543	3,138,792	(86,688)	3,271,647
10	Potomac Capital Investment Corporation	1,300,935	1,086,853	(22,585)	2,365,203
11	PHI Operating Services Company	703,267	1,216,914	(951)	1,919,230
12	Thermal Energy Limited Partnership	108,347	684,357	(7,865)	784,839
13	Conectiv Mid-Merit, LLC	940,099	179,868	(902)	1,119,065
14	Conectiv Thermal Systems	138,656	160,340	(1,033)	297,963
15	Atlantic Southern Properties	53,082	90,180	(572)	142,690
16	Conectiv Communications, Inc.	732	37,058	(813)	36,977
17	ATE Investments, Inc.	1,310	26,026	(695)	26,641
18	Atlantic City Electric Transition Funding, LLC	51,570	670,171	(21,846)	699,895
19	Delaware Operating Services Company	2,006			2,006
20	Conectiv Properties and Investments, Inc.	9,125	62,047		71,172
21	Conectiv Pennsylvania Generation, LLC	14	6,175	(45)	6,144
22	Conectiv Solutions LLC	8,461	5,117		13,578
23	Conectiv North East, LLC	80,417	3,130	(37)	83,510
24	Atlantic Generation, Inc.	7,221	1,169	(8)	8,382
25	DCTC-Burney, Inc.	782	348		1,130
26	Conectiv Services II, Inc.	37,593	12,763		50,356
27	Vineland General, Inc.	12,660	150	(1)	12,809
28	Vineland Limited, Inc.		6		6
29	ACE REIT, Inc.	13	21	(1)	33
30	Conectiv	7,625	11,091	(334)	18,382
31	Atlantic Thermal Operating Company	49	119,384		119,433
32	Conectiv Energy Holding Company	424	223,071	(6,983)	216,512
33	Delta, LLC	347			347
34					
35					
36					
37					
38					
39					
40	**Total**	**168,818,638**	**291,703,632**	**(1,494,128)**	**459,028,142**

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)

87,100,863 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	2,204,241				6.5	14,327,567	-	-	-	1,193,964	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	2,204,241	-	-	-		14,327,567	-	-	-	1,193,964	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										1,193,964	-	-	-	
								Input to Line 21 of Appendix A		1,193,964	-		-	1,193,964
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.50	#DIV/0!	#DIV/0!	#DIV/0!	

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

$ 1,193,964 Input to Formula Line 21

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

$ 87,226,269 — 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)

$ 87,226,269

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

$ 88,800,682 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 $ 13,057,248 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	-				11.5	-	-	-	-	-	-	-	-	
Feb	-				10.5	-	-	-	-	-	-	-	-	
Mar	-				9.5	-	-	-	-	-	-	-	-	
Apr	-				8.5	-	-	-	-	-	-	-	-	
May	-				7.5	-	-	-	-	-	-	-	-	
Jun	-				6.5	-	-	-	-	-	-	-	-	
Jul	289,703				5.5	1,593,367	-	-	-	132,781	-	-	-	
Aug	4,367				4.5	19,652	-	-	-	1,638	-	-	-	
Sep	212,224				3.5	742,784	-	-	-	61,899	-	-	-	
Oct	40,424				2.5	101,060	-	-	-	8,422	-	-	-	
Nov	272,625		939659		1.5	408,938	-	1,409,489	-	34,078	-	117,457	-	
Dec	12,237,905		205605		0.5	6,118,953	-	102,803	-	509,913	-	8,567	-	
Total	13,057,248	-	1,145,264	-		8,984,752	-	-	-	748,729	-	126,024	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										748,729	-	126,024	-	
								Input to Line 21 of Appendix A		748,729	-		-	748,729
								Input to Line 43a of Appendix A				126,024		126,024
								Month In Service or Month for CWIP		11.31	#DIV/0!	10.68	#DIV/0!	

87,588,042.26 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			4978597		11.5	-	-	57,253,869	-	-	-	4,771,156	-	
Feb			3833333		10.5	-	-	40,250,000	-	-	-	3,354,167	-	
Mar			3833333		9.5	-	-	36,416,667	-	-	-	3,034,722	-	
Apr			3833333		8.5	-	-	32,583,333	-	-	-	2,715,278	-	
May			3833333		7.5	-	-	28,750,000	-	-	-	2,395,833	-	
Jun			3833333		6.5	-	-	24,916,667	-	-	-	2,076,389	-	
Jul	33,558,380		3833333		5.5	184,571,090	-	21,083,333	-	15,380,924	-	1,756,944	-	
Aug			3833333		4.5	-	-	17,250,000	-	-	-	1,437,500	-	
Sep			3833333		3.5	-	-	13,416,667	-	-	-	1,118,056	-	
Oct			3833333		2.5	-	-	9,583,333	-	-	-	798,611	-	
Nov			3833333		1.5	-	-	5,750,000	-	-	-	479,167	-	
Dec			3833333		0.5	-	-	1,916,667	-	-	-	159,722	-	
Total	33,558,380	-	47,145,264	-		184,571,090	-	-	-	15,380,924	-	24,097,545	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										15,380,924	-	24,097,545	-	
93990377.91								Input to Line 21 of Appendix A		15,380,924	-		-	15,380,924
								Input to Line 43a of Appendix A				24,097,545		24,097,545
								Month In Service or Month for CWIP		6.50	#DIV/0!	5.87	#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		
87,588,042	-	92,052,335	=	(4,464,293)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.3800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(372,024)	0.3800%	11.5	(16,257)	(388,282)
Jul	Year 1	(372,024)	0.3800%	10.5	(14,844)	(386,868)
Aug	Year 1	(372,024)	0.3800%	9.5	(13,430)	(385,454)
Sep	Year 1	(372,024)	0.3800%	8.5	(12,016)	(384,041)
Oct	Year 1	(372,024)	0.3800%	7.5	(10,603)	(382,627)
Nov	Year 1	(372,024)	0.3800%	6.5	(9,189)	(381,213)
Dec	Year 1	(372,024)	0.3800%	5.5	(7,775)	(379,800)
Jan	Year 2	(372,024)	0.3800%	4.5	(6,362)	(378,386)
Feb	Year 2	(372,024)	0.3800%	3.5	(4,948)	(376,972)
Mar	Year 2	(372,024)	0.3800%	2.5	(3,534)	(375,559)
Apr	Year 2	(372,024)	0.3800%	1.5	(2,121)	(374,145)
May	Year 2	(372,024)	0.3800%	0.5	(707)	(372,731)
Total		(4,464,293)				(4,566,079)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(4,566,079)	0.3800%	(389,970)	(4,193,459)
Jul	Year 2	(4,193,459)	0.3800%	(389,970)	(3,819,424)
Aug	Year 2	(3,819,424)	0.3800%	(389,970)	(3,443,967)
Sep	Year 2	(3,443,967)	0.3800%	(389,970)	(3,067,084)
Oct	Year 2	(3,067,084)	0.3800%	(389,970)	(2,688,769)
Nov	Year 2	(2,688,769)	0.3800%	(389,970)	(2,309,016)
Dec	Year 2	(2,309,016)	0.3800%	(389,970)	(1,927,819)
Jan	Year 3	(1,927,819)	0.3800%	(389,970)	(1,545,175)
Feb	Year 3	(1,545,175)	0.3800%	(389,970)	(1,161,076)
Mar	Year 3	(1,161,076)	0.3800%	(389,970)	(775,518)
Apr	Year 3	(775,518)	0.3800%	(389,970)	(388,494)
May	Year 3	(388,494)	0.3800%	(389,970)	(0)
Total with interest				(4,679,645)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(4,679,645)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	93,990,378
Revenue Requirement for Year 3		89,310,733

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

$ 89,310,733 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)

$ 89,310,733

Potomac Electric Power Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	19.6221%
5	B	167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	20.3383%
6	C		Line B less Line A	0.7161%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	8.8879%

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 yea**

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 becom effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in**

Line		Details		B0512 MAPP		B0288 Brighton Sub
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		150
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		19.6221%		19.6221%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		20.6963%		20.6963%
18	Columns A, B or C from Attachment 6	Investment		47,145,264	may be weighted average of small projects	33,558,380
19	Line 18 divided by line 13	Annual Depreciation Exp		1,347,008		958,811
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		5.87		6.50

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
21	Base FCR	2008	1,145,264	-	1,145,264	133,592			-	-	$ 133,592		$ 133,592
22	W Increased ROE	2008	1,145,264	-	1,145,264	140,905	-	-	-	-	$ 140,905	$ 140,905	
23	Base FCR	2009	47,145,264	-	47,145,264	9,250,912	33,558,380	439,455	33,118,925	6,938,099	$ 16,189,011		$ 16,189,011
24	W Increased ROE	2009	47,145,264	-	47,145,264	9,757,335	33,558,380	439,455	33,118,925	7,293,854	$ 17,051,189	$ 17,051,189	
25	Base FCR	2010	47,145,264	-	47,145,264	9,250,912	33,118,925	958,811	32,160,114	7,269,315	$ 16,520,228		$ 16,520,228
26	W Increased ROE	2010	47,145,264	-	47,145,264	9,757,335	33,118,925	958,811	32,160,114	7,614,771	$ 17,372,106	$ 17,372,106	
27	Base FCR	2011	47,145,264	-	47,145,264	9,250,912	32,160,114	958,811	31,201,303	7,081,176	$ 16,332,088		$ 16,332,088
28	W Increased ROE	2011	47,145,264	-	47,145,264	9,757,335	32,160,114	958,811	31,201,303	7,416,333	$ 17,173,668	$ 17,173,668	
29	Base FCR	2012	47,145,264	-	47,145,264	9,250,912	31,201,303	958,811	30,242,492	6,893,037	$ 16,143,949		$ 16,143,949
30	W Increased ROE	2012	47,145,264	-	47,145,264	9,757,335	31,201,303	958,811	30,242,492	7,217,894	$ 16,975,229	$ 16,975,229	
31	Base FCR	2013	47,145,264	-	47,145,264	9,250,912	30,242,492	958,811	29,283,682	6,704,898	$ 15,955,810		$ 15,955,810
32	W Increased ROE	2013	47,145,264	-	47,145,264	9,757,335	30,242,492	958,811	29,283,682	7,019,455	$ 16,776,790	$ 16,776,790	
33	Base FCR	2014	47,145,264	-	47,145,264	9,250,912	29,283,682	958,811	28,324,871	6,516,758	$ 15,767,671		$ 15,767,671
34	W Increased ROE	2014	47,145,264	-	47,145,264	9,757,335	29,283,682	958,811	28,324,871	6,821,017	$ 16,578,352	$ 16,578,352	
35	Base FCR	2015	47,145,264	-	47,145,264	9,250,912	28,324,871	958,811	27,366,060	6,328,619	$ 15,579,531		$ 15,579,531
36	W Increased ROE	2015	47,145,264	-	47,145,264	9,757,335	28,324,871	958,811	27,366,060	6,622,578	$ 16,379,913	$ 16,379,913	
37	Base FCR	2016	47,145,264	-	47,145,264	9,250,912	27,366,060	958,811	26,407,249	6,140,480	$ 15,391,392		$ 15,391,392
38	W Increased ROE	2016	47,145,264	-	47,145,264	9,757,335	27,366,060	958,811	26,407,249	6,424,140	$ 16,181,475	$ 16,181,475	
39	Base FCR	2017	47,145,264	-	47,145,264	9,250,912	26,407,249	958,811	25,448,438	5,952,340	$ 15,203,253		$ 15,203,253
40	W Increased ROE	2017	47,145,264	-	47,145,264	9,757,335	26,407,249	958,811	25,448,438	6,225,701	$ 15,983,036	$ 15,983,036	
41	Base FCR	2018	47,145,264	-	47,145,264	9,250,912	25,448,438	958,811	24,489,627	5,764,201	$ 15,015,114		$ 15,015,114
42	W Increased ROE	2018	47,145,264	-	47,145,264	9,757,335	25,448,438	958,811	24,489,627	6,027,263	$ 15,784,598	$ 15,784,598	
43	Base FCR	2019	47,145,264	-	47,145,264	9,250,912	24,489,627	958,811	23,530,816	5,576,062	$ 14,826,974		$ 14,826,974
44	W Increased ROE	2019	47,145,264	-	47,145,264	9,757,335	24,489,627	958,811	23,530,816	5,828,824	$ 15,586,159	$ 15,586,159	
45	Base FCR	2020	47,145,264	-	47,145,264	9,250,912	23,530,816	958,811	22,572,006	5,387,923	$ 14,638,835		$ 14,638,835
46	W Increased ROE	2020	47,145,264	-	47,145,264	9,757,335	23,530,816	958,811	22,572,006	5,630,386	$ 15,387,720	$ 15,387,720	
47	Base FCR	2021	47,145,264	-	47,145,264	9,250,912	22,572,006	958,811	21,613,195	5,199,783	$ 14,450,696		$ 14,450,696
48	W Increased ROE	2021	47,145,264	-	47,145,264	9,757,335	22,572,006	958,811	21,613,195	5,431,947	$ 15,189,282	$ 15,189,282	
49	Base FCR	2022	47,145,264	-	47,145,264	9,250,912	21,613,195	958,811	20,654,384	5,011,644	$ 14,262,557		$ 14,262,557
50	W Increased ROE	2022	47,145,264	-	47,145,264	9,757,335	21,613,195	958,811	20,654,384	5,233,508	$ 14,990,843	$ 14,990,843	
51	Base FCR	2023	47,145,264	-	47,145,264	9,250,912	20,654,384	958,811	19,695,573	4,823,505	$ 14,074,417		$ 14,074,417
52	W Increased ROE	2023	47,145,264	-	47,145,264	9,757,335	20,654,384	958,811	19,695,573	5,035,070	$ 14,792,405	$ 14,792,405	
53	Base FCR	2024	47,145,264	-	47,145,264	9,250,912	19,695,573	958,811	18,736,762	4,635,366	$ 13,886,278		$ 13,886,278
54	W Increased ROE	2024	47,145,264	-	47,145,264	9,757,335	19,695,573	958,811	18,736,762	4,836,631	$ 14,593,966	$ 14,593,966	
55	Base FCR	2025	47,145,264	-	47,145,264	9,250,912	18,736,762	958,811	17,777,951	4,447,226	$ 13,698,139		$ 13,698,139
56	W Increased ROE	2025	47,145,264	-	47,145,264	9,757,335	18,736,762	958,811	17,777,951	4,638,193	$ 14,395,528	$ 14,395,528	
57	Base FCR	2026	47,145,264	-	47,145,264	9,250,912	17,777,951	958,811	16,819,140	4,259,087	$ 13,510,000		$ 13,510,000
58	W Increased ROE	2026	47,145,264	-	47,145,264	9,757,335	17,777,951	958,811	16,819,140	4,439,754	$ 14,197,089	$ 14,197,089	
59	Base FCR	2027	47,145,264	-	47,145,264	9,250,912	16,819,140	958,811	15,860,330	4,070,948	$ 13,321,860		$ 13,321,860
60	W Increased ROE	2027		-	-	-	16,819,140	958,811	15,860,330	4,241,316	$ 4,241,316	$ 4,241,316	
61		....		....	.....	....	....	....	.....	....			$ -
62		....	....	.....	.....	....	....	.....	.....	....		$ -	
63												$ 289,771,569	$ 284,901,395

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

ATTACHMENT H-8G

PPL Electric Utilities Corporation

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	2008 Data
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	8,494,499
2	Total Wages Expense		p354.28.b	85,375,132
3	Less A&G Wages Expense		p354.27.b	1,245,209
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	84,129,923
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**10.0969%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g	5,177,571,776
7	Accumulated Depreciation (Total Electric Plant)	(Note J)	p219.29.c	2,001,055,053
8	Accumulated Amortization	(Note A)	p200.21.c	10,958,554
9	Total Accumulated Depreciation		(Line 7 + 8)	2,012,013,607
10	Net Plant		(Line 6 - Line 9)	3,165,558,169
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 25 - Line 24)	1,212,087,036
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**23.4103%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 33 - Line 24)	715,196,381
14	**Net Plant Allocator**		(Line 13 / Line 10)	**22.5931%**
	Plant Calculations			
	Plant In Service			
15	Transmission Plant In Service	(Note B)	p207.58.g	1,150,044,754
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	12,644,590
18	**Total Transmission Plant**		(Line 15 - Line 16 + Line 17)	**1,162,689,344**
19	General		p207.99.g	470,510,793
20	Intangible		p205.5.g	18,726,302
21	Total General and Intangible Plant		(Line 19 + Line 20)	489,237,095
22	Wage & Salary Allocator		(Line 5)	10.0969%
23	**Total General and Intangible Functionalized to Transmission**		(Line 21 * Line 22)	**49,397,692**
24	**Land Held for Future Use**	(Note C) (Note P)	Attachment 5	**29,746,261**
25	**Total Plant In Rate Base**		**(Line 18 + Line 23 + Line 24)**	**1,241,833,297**
	Accumulated Depreciation			
26	Transmission Accumulated Depreciation	(Note J)	p219.25.c	**479,905,629**
27	Accumulated General Depreciation	(Note J)	p219.28.c	157,261,949
28	Accumulated Amortization		(Line 8)	10,958,554
29	Total Accumulated Depreciation		(Line 27 + 28)	168,220,503
30	Wage & Salary Allocator		(Line 5)	10.0969%
31	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 29 * Line 30)	16,985,026
32	**Total Accumulated Depreciation**		**(Sum Lines 26 + 31)**	**496,890,655**
33	**Total Net Property, Plant & Equipment**		**(Line 25 - Line 32)**	**744,942,642**

Adjustment To Rate Base

Line	Description	Note	Reference	Amount
	Accumulated Deferred Income Taxes			
34	**ADIT net of FASB 106 and 109**		Attachment 1	**-51,498,840**
	CWIP for Incentive Transmission Projects			
35	CWIP Balances for Current Rate Year	(Note H)	Attachment 6	**16,036,541**
	Prepayments			
36	Prepayments	(Note A) (Note O)	Attachment 5	**445,061**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	p227.16.c	2,992,548
38	Wage & Salary Allocator		(Line 5)	10.0969%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	302,154
40	Transmission Materials & Supplies		p227.8.c	12,832,384
41	**Total Materials & Supplies Allocated to Transmission**		(Line 39 + Line 40)	**13,134,538**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 70)	41,833,003
43	1/8th Rule		1/8	12.5%
44	**Total Cash Working Capital Allocated to Transmission**		(Line 42 * Line 43)	**5,229,125**
45	**Total Adjustment to Rate Base**		(Lines 34 + 35 + 36 + 41 + 44)	**-16,653,575**
46	**Rate Base**		(Line 33 + Line 45)	**728,289,067**

Operations & Maintenance Expense

Line	Description	Note	Reference	Amount
	Transmission O&M			
47	Transmission O&M		Attachment 5	173,864,677
48	Less Account 565		Attachment 5	146,916,352
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)	**26,948,325**
	Allocated Administrative & General Expenses			
51	Total A&G		323.197b	139,379,316
52	Less: Administrative & General Expenses on Securitization Bonds	(Note O)	Attachment 8	222,427
53	Plus: Fixed PBOP expense	(Note J)	Attachment 5	10,028,618
54	Less: Actual PBOP expense		Attachment 5	12,537,495
55	Less Property Insurance Account 924		p323.185.b	2,116,743
56	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	5,162,822
57	Less General Advertising Exp Account 930.1		p323.191.b	0
58	Less EPRI Dues	(Note D)	p352 & 353	204,286
59	Administrative & General Expenses		Sum (Lines 51 + 53) - Line 52 - Sum (Lines 54 to 58)	129,164,161
60	Wage & Salary Allocator		(Line 5)	10.0969%
61	**Administrative & General Expenses Allocated to Transmission**		(Line 59 * Line 60)	**13,041,553**
	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	8,157,927
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 924 and 930.1 - General		(Line 65 + Line 66)	8,157,927
68	Net Plant Allocator		(Line 14)	22.5931%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**1,843,125**
70	**Total Transmission O&M**		**(Lines 50 + 61 + 64 + 69)**	**41,833,003**

	Depreciation & Amortization Expense				
	Depreciation Expense				
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	**19,775,963**
72	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	18,772,812
73	Intangible Amortization		(Note A)	p336.1.d&e	2,735,558
74	Total			(Line 72 + Line 73)	21,508,370
75	Wage & Salary Allocator			(Line 5)	10.0969%
76	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 74 * Line 75)	**2,171,675**
77	**Total Transmission Depreciation & Amortization**			**(Lines 71 + 76)**	**21,947,638**
	Taxes Other than Income Taxes				
78	**Taxes Other than Income Taxes**			Attachment 2	**2,335,550**
79	**Total Taxes Other than Income Taxes**			**(Line 78)**	**2,335,550**
	Return \ Capitalization Calculations				
	Long Term Interest				
80	Long Term Interest			p117.62.c through 66.c	100,602,830
81	Less LTD Interest on Securitization Bonds		(Note O)	Attachment 8	13,186,553
82	**Long Term Interest**			(Line 80 - Line 81)	**87,416,277**
83	**Preferred Dividends**		enter positive	p118.29.c	**18,069,981**
	Common Stock				
84	Proprietary Capital			p112.16.c	1,645,074,908
85	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	25,630
86	Less Preferred Stock			(Line 94)	300,518,900
87	Less Account 216.1			p112.12.c	6,000,130
88	**Common Stock**			(Line 84 - 85 - 86 - 87)	**1,338,530,248**
	Capitalization				
89	Long Term Debt			p112.18.c, 19.c & 21.c	1,769,625,000
90	Less Loss on Reacquired Debt			p111.81.c	26,228,614
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)	1,743,396,386
94	Preferred Stock			p112.3.c	300,518,900
95	Common Stock			(Line 88)	1,338,530,248
96	**Total Capitalization**			(Sum Lines 93 to 95)	**3,382,445,534**
97	Debt %	Total Long Term Debt		(Line 93 / Line 96)	51.5%
98	Preferred %	Preferred Stock		(Line 94 / Line 96)	8.9%
99	Common %	Common Stock		(Line 95 / Line 96)	39.6%
100	Debt Cost	Total Long Term Debt		(Line 82 / Line 93)	0.0501
101	Preferred Cost	Preferred Stock		(Line 83 / Line 94)	0.0601
102	Common Cost	Common Stock	(Note J)	Fixed	0.1164
103	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * Line 100)	0.0258
104	Weighted Cost of Preferred	Preferred Stock		(Line 98 * Line 101)	0.0053
105	Weighted Cost of Common	Common Stock		(Line 99 * Line 102)	0.0461
106	**Rate of Return on Rate Base (ROR)**			(Sum Lines 103 to 105)	**0.0772**
107	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 106)**	**56,259,741**

Composite Income Taxes

Line	Description	Formula / Note	Source	Amount
	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	-656,727
114	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 113 * (1 / (1 - Line 111))	**-1,122,486**
115	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 112 * Line 107 * (1- (Line 103 / Line 106))]	**26,551,302**
116	**Total Income Taxes**		**(Line 114 + Line 115)**	**25,428,817**

Revenue Requirement

Line	Description	Note	Source	Amount
	Summary			
117	Net Property, Plant & Equipment		(Line 33)	744,942,642
118	Total Adjustment to Rate Base		(Line 45)	-16,653,575
119	Rate Base		(Line 46)	728,289,067
120	Total Transmission O&M		(Line 70)	41,833,003
121	Total Transmission Depreciation & Amortization		(Line 77)	21,947,638
122	Taxes Other than Income		(Line 79)	2,335,550
123	Investment Return		(Line 107)	56,259,741
124	Income Taxes		(Line 116)	25,428,817
125	**Gross Revenue Requirement**		**(Sum Lines 120 to 124)**	**147,804,749**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Transmission Plant In Service		(Line 15)	1,150,044,754
127	Excluded Transmission Facilities	(Note M)	Attachment 5	0
128	Included Transmission Facilities		(Line 126 - Line 127)	1,150,044,754
129	Inclusion Ratio		(Line 128 / Line 126)	100.00%
130	Gross Revenue Requirement		(Line 125)	147,804,749
131	**Adjusted Gross Revenue Requirement**		(Line 129 * Line 130)	**147,804,749**
	Revenue Credits			
132	**Revenue Credits**		Attachment 3	**12,532,972**
133	**Net Revenue Requirement**		**(Line 131 - Line 132)**	**135,271,777**
	Net Plant Carrying Charge			
134	Gross Revenue Requirement		(Line 130)	**147,804,749**
135	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**698,820,256**
136	Net Plant Carrying Charge		(Line 134 / Line 135)	**21.1506%**
137	Net Plant Carrying Charge without Depreciation		(Line 134 - Line 71) / Line 135	**18.3207%**
138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 134 - Line 71 - Line 107 - Line 116) / Line 135	**6.6312%**
	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)	**66,116,191**
140	Increased Return and Taxes		Attachment 4	**86,614,588**
141	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 139 + Line 140)	**152,730,779**
142	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**698,820,256**
143	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 141 / Line 142)	**21.8555%**
144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 141 - Line 71) / Line 142	**19.0256%**
145	**Net Revenue Requirement**		(Line 133)	**135,271,777**
146	True-up amount		Attachment 6	**(11,751,003)**
147	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**-**
148	**Net Zonal Revenue Requirement**		(Line 145 + 146 + 147)	**123,520,774**
	Network Zonal Service Rate			
149	1 CP Peak	(Note L)	PJM Data	**7,509.5**
150	Rate ($/MW-Year)		(Line 148 / 149)	**$ 16,449**
151	**Network Service Rate ($/MW/Year)**		**(Line 150)**	**$ 16,449**

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 rated 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.
Within five years from the effective date of the Settlement filed in Docket No. ER08-1457, PPL Electric shall make a filing to update its depreciation rates and to continue treatment of the actual removal costs contained in the Formula Rate. In such filing, PPL Electric shall bear the burden of proof under Section 205 of the Federal Power Act to demonstrate that its depreciation rates and its treatment of the actual removal costs in the Formula Rate are just and reasonable.
Notwithstanding this requirement, PPL Electric may, at any time prior to the expiration of such five-year period from the effective date of the Settlement, make a Section 205 filing to update its depreciation rates, but shall not be required to demonstrate that its treatment of the actual removal costs in the Formula Rate is just and reasonable.
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	(51,535,760)	0	(39,429,789)		From Acct. 282 total, below
ADIT-283	0	(10,883,169)	114,050		From Acct. 283 total, below
ADIT-190	5,975,482	0	4,852,416		From Acct. 190 total, below
Subtotal	(45,560,278)	(10,883,169)	(34,463,323)		Sum lines 1 through 3
Wages & Salary Allocator			10.0969%		
Net Plant Allocator		22.5931%			
ADIT	(45,560,278)	(2,458,841)	(3,479,721)	(51,498,840)	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)	2,988,155	2,988,155				Basis difference between book plant and tax plant basis related to investment tax credits on distributio property
Accumulated Deferred Investment Tax Credits (Transmission)	1,112,729		1,112,729			Basis difference between book plant and tax plant basis related to investment tax credits on transmissio property
Regulatory Liability - Income Taxes Related to ITC (Non-Tx)	2,119,231	2,119,231				Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/ta basis difference on distribution property
Regulatory Liability - Income Taxes Related to ITC (Tx)	789,161		789,161			Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/ta basis difference on transmission property
Contributions in Aid of Construction (Non-Tx)	73,295,911	73,295,911				Distribution related income that is taxable for tax return purposes, but recorded as a reduction to plant fo book purposes.
Contributions in Aid of Construction (Tx-related)	5,975,482		5,975,482			Transmission related income that is taxable for tax return purposes, but recorded as a reduction to plan for book purposes.
Pensions and Post-Retirement	116,483,311	116,483,311				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes
Bad Debts	9,023,531	9,023,531				Retail related book expense not deductible for tax return purposes
Vacation Pay	4,465,920				4,465,920	Book expense not deductible for tax return purposes - labor related to all function
Taxes Other Than Income Taxes	7,250,149	7,250,149				Book expense not deductible for tax return purposes - retail related gross receipts and sales & use taxes
RAR Adjustments	(5,751,470)	(5,751,470)				Distribution related IRS audit adjustments
Workers Compensation	347,758				347,758	Book expense not deductible for tax return purposes - labor related to all function
Obsolete Inventory	60,113	60,113				Distribution related book expense not deductible for tax return purpose
Rate Refund	1,031,891	1,031,891				Retail related book expense not deductible for tax return purposes
Deferred Intercompany Transactions	(905,952)	(905,952)				Retail related income recorded for book purposes not includable in taxable income - related to receivable factoring
Deferred Compensation	38,738				38,738	Book expense not deductible for tax return purposes - labor related to all function
Restructuring Consumer Expense	245,978	245,978				Retail related book expense not deductible for tax return purposes
Environmental Liability	880,342	880,342				Distribution related book expense for manufactured gas plants not deductible for tax return purpose
Post Employment Liabilities	3,748,337	3,748,337				Book expense not deductible for tax return purposes
Deferred Revenue	32,023,390	32,023,390				Retail related income that is taxable for tax return purposes and deferred for book purposes
Company Car Elimination Bonus	(102,904)	(102,904)				Distribution related expense deferred for book purposes and deducted for tax purposes
Prepaid Insurance	(1,100,819)	(1,100,819)				Distribution related expense deferred for book purposes and deducted for tax purposes
Book Contingencies	816,592	816,592				Distribution related book expense not deductible for tax return purposes
Subtotal - p234	254,835,574	242,105,786	7,877,372	0	4,852,416	
Less FASB 109 Above if not separately removed	7,009,276	5,107,386	1,901,890			
Less FASB 106 Above if not separately removed	0					
Total	247,826,298	236,998,400	5,975,482	0	4,852,416	

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)	(402,675,418)	(402,675,418)				Deductions for distribution related tax depreciation in excess of book depreciation at federal rat
ACRS/MACRS Property (Transmission)	(54,509,528)		(54,509,528)			Deductions for transmission related tax depreciation in excess of book depreciation at federal rat
ACRS/MACRS Property (General Plant)	(45,901,439)				(45,901,439)	Deductions for general plant related tax depreciation in excess of book depreciation at federal rat
FAS109 regulatory assets/liabilities related to plant	(152,736,753)	(152,736,753)				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)	(50,422,278)	(50,422,278)				Basis difference between distribution related book plant and tax plant basis at federal & state rate
Basis adjustments between book and tax plant (Tx - related))	2,973,768		2,973,768			Basis difference between transmission related book plant and tax plant basis at federal & state rate
Basis adjustments between book and tax plant (General Plant)	6,471,650				6,471,650	Basis difference between book plant and tax plant basis at federal & state rate:
RAR adjustments related to plant	5,181,907	5,181,907				IRS audit adjustments related to distribution plan
Subtotal - p275	(691,618,091)	(600,652,542)	(51,535,760)	0	(39,429,789)	
Less FASB 109 Above if not separately removed	(152,736,753)	(152,736,753)				
Less FASB 106 Above if not separately removed	0					
Total	(538,881,338)	(447,915,789)	(51,535,760)	0	(39,429,789)	

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 I
3. ADIT items related to Plant and not in Columns C & D are included in Column I
4. ADIT items related to labor and not in Columns C & D are included in Column

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						
Restructuring write-off - CTC	(148,433,964)	(148,433,964)				Retail related income recorded for book purposes not includable in taxable incom
Reacquired debt costs	(10,883,169)			(10,883,169)		Plant related expense deferred for book purposes and deducted for tax purposes
FAS 109 regulatory assets/liabilities	(108,501,441)	(108,501,441)				Asset recorded for regulatory purposes related to book and tax basis plant and non-plant difference
Pension and post-retirement	3,761,176	3,761,176				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purpose
Ice storms	(4,447,496)	(4,447,496)				Distribution related expense deferred for book purposes and deducted for tax purpose:
Deferred intercompany transactions	(4,224,493)	(4,224,493)				Income recorded for book purposes not includable in taxable income - intercompany sale of distributior property
RAR Adjustments	(6,822,079)	(6,822,079)				Distribution related IRS audit adjustments
Deferred intercompany gain - trademark sale	(1,101,961)	(1,101,961)				Income recorded for book purposes not includable in taxable income
Clearing accounts	0					Expense deferred for book purposes and deducted for tax purposes
Severance pay	114,050				114,050	Book expense not deductible for tax return purposes - labor related to all function
Receivables Factoring	(3,591,601)	(3,591,601)				Retail related income recorded for book purposes not includable in taxable incom
TSC over/undercollections	(7,877)	(7,877)				Retail related book expense not deductible for tax return purpose:
Interest on TSC over/undercollections	35,396	35,396				Retail related income recorded for book purposes not includable in taxable incom
Unrealized gains/losses	(18,176)	(18,176)				Equity adjustment for book purposes not includable in taxable income
Rate case expenses	(578,668)	(578,668)				Retail related expense deferred for book purposes and deducted for tax purposes
FAS158 Regulatory Asset	(79,545,234)	(79,545,234)				Asset recorded for regulatory purposes for FAS 158 pension and post-retirement costs
Subtotal - p277	(364,245,537)	(353,476,418)	0	(10,883,169)	114,050	
Less FASB 109 Above if not separately removed	(108,501,441)	(108,501,441)				
Less FASB 106 Above if not separately removed	3,761,176	3,761,176				
Total	(259,505,272)	(248,736,153)	0	(10,883,169)	114,050	

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 I
3. ADIT items related to Plant and not in Columns C & D are included in Column I
4. ADIT items related to labor and not in Columns C & D are included in Column

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)	712,329		
2	PURTA	4,100,000		
3				
4				
5				
6				
7				
8	**Total Plant Related**	4,812,329	22.5931%	1,087,252
	Labor Related		**Wages & Salary Allocator**	
9	Federal FICA	6,606,443		
10	Federal Unemployment	67,766		
11	State Unemployment	238,982		
12				
13				
14	**Total Labor Related**	6,913,191	10.0969%	698,017
	Other Included		**Net Plant Allocator**	
15	PA Capital Stock Tax	2,449,998		
16	PA Capital Stock Tax on Securitization Bonds (Source: Attachment 8)	(14,376)		
17				
18				
19	**Total Other Included**	2,435,622	22.5931%	550,281
20	**Total Included (Lines 8 + 14 + 19)**	14,161,142		2,335,550
	Currently Excluded			
21	Gross Receipts	197,973,591		
22	Sales and Use	(2,140,126)		
23				
24				
25				
26				
27				
28	**Subtotal, Excluded**	195,833,465		
29	**Total, Included and Excluded (Line 20 + Line 28)**	209,994,607		
30	**Total Other Taxes from p114.14.c less Tax on Securitization Bonds**	209,994,607		
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

Line	Description		Amount
	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related		1,098,000
	Account 456 - Other Electric Revenues (Note 1)		
2	Transmission for Others (Note 3)		-
3	Schedule 12 Revenues (Note 3)		1,236,538
4	Schedule 1A		2,712,128
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)		3,463,414
7	Professional Services provided to others		77,052
8	Facilities Charges including Interconnection Agreements (Note 2)		3,945,840
9	Gross Revenue Credits	(Sum Lines 1-10)	12,532,972
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	86,614,588
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
			Appendix A Line or Source Reference	
1	**Rate Base**		(Attachment A Line 46)	728,289,067
	Long Term Interest			
2	Long Term Interest		(Attachment A Line 80)	100,602,830
3	Less LTD Interest on Securitization Bonds		Attachment 8	13,186,553
4	Long Term Interest		(Line 2 - Line 3)	87,416,277
5	**Preferred Dividends**	enter positive	p118.29.c	18,069,981
	Common Stock			
6	Proprietary Capital		p112.16.c	1,645,074,908
7	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	25,630
8	Less Preferred Stock		(Attachment A Line 86)	300,518,900
9	Less Account 216.1		p112.12.c	6,000,130
10	Common Stock		(Line 6 - 7 - 8 - 9)	1,338,530,248
	Capitalization			
11	Long Term Debt		p112.18.c, 19.c & 21.c	1,769,625,000
12	Less Loss on Reacquired Debt		p111.81.c	26,228,614
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)	1,743,396,386
16	Preferred Stock		p112.3.c	300,518,900
17	Common Stock		(Line 10)	1,338,530,248
18	Total Capitalization		(Sum Lines 15 to 17)	3,382,445,534
19	Debt %	Total Long Term Debt	(Line 15 / Line 18)	51.5%
20	Preferred %	Preferred Stock	(Line 16 / Line 18)	8.9%
21	Common %	Common Stock	(Line 17 / Line 18)	39.6%
22	Debt Cost	Total Long Term Debt	(Line 4 / Line 15)	0.0501
23	Preferred Cost	Preferred Stock	(Line 5 / Line 16)	0.0601
24	Common Cost	Common Stock	Fixed	0.1264
25	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 19 * Line 22)	0.0258
26	Weighted Cost of Preferred	Preferred Stock	(Line 20 * Line 23)	0.0053
27	Weighted Cost of Common	Common Stock	(Line 21 * Line 24)	0.0500
28	**Rate of Return on Rate Base (ROR)**		(Sum Lines 25 to 27)	**0.0812**
29	**Investment Return = Rate Base * Rate of Return**		**(Line 1 * Line 28)**	**59,141,788**
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	(656,727)
37	**ITC Adjust. Allocated to Trans. - Grossed Up**		(Line 36 * (1 / (1 - Line 33))	**-1,122,486**
38	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		28,595,285
39	**Total Income Taxes**			**27,472,799**

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	-2,185,697	-656,727	-1,528,970	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 &	32,683,075	25,608,328	4,137,933	2,936,814	
			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
					25,608,328	4,137,933		Balance for Appendix A

Adjustments to A & G Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Prior Period Adjustment	Adjusted Total	Details
	Allocated Administrative & General Expenses					
53	Fixed PBOP expense	FERC Authorized	10,028,618			
54	Actual PBOP expense	Company Records	12,537,495			Current year actual PBOP expense
65	Property Insurance Account 924	p323.185.b	2,116,743	6,041,184	8,157,927	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	5,162,822	0	5,162,822	

Safety Related Advertising Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	

MultiState Workpaper

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates							
			PA					
109	SIT=State Income Tax Rate or Composite	(Note I)	9.99%					

Education and Out Reach Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
63	General Advertising Exp Account 930.1	(Note K)	p323.191.b	-		-	

PPL Electric Utilities Corporation

Attachment 5 - Cost Support

Excluded Plant Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
127	Excluded Transmission Facilities		(Note M)		**General Description of the Facilities**
	Instructions:			**Enter $**	
1	Remove all investment below 69 kV or generator step-up transformers included in transmission plant in service that are not a result of the RTEP process			**0**	**None**
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher, as well as below 69 kV the following formula will be used:	**Example**		**Or Enter $**	
A	Total investment in substation	1,000,000			
B	Identifiable investment in Transmission (provide 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 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	18,627,466	0	14,219,565	4,407,901	10.0969%	445,061	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	178,070,434	4,205,757	173,864,677	Adjustment for Ancillary Services p321.88b and p321.92b.
48	Less Account 565	p.321.96.b	146,916,352	0	146,916,352	**None**

Facility Credits under Section 30.9 of the PJM OATT

	Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Amount	Description & PJM Documentation
	Net Revenue Requirement		
147	Facility Credits under Section 30.9 of the PJM OATT	-	**None**

PJM Load Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
149	1 CP Peak	(Note L)	PJM Data	**7,509.5**	

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 2003	Year 2 2004	Year 3 2005	Year 4 2006	Year 5 2007	Total	5 - Year Amortization
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	18,402,670							
	Transmission Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	1,373,293	1,433,493	1,671,456	700,295	1,574,348	1,486,873	6,866,465	1,373,293
	Total Transmission Depreciation Expense Including Amortization of Limited Term Pl	(Note J)	Company Records	19,775,963							
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	18,115,552							
	General Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	657,260	677,327	756,647	432,927	724,278	695,120	3,286,299	657,260
	Total General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	18,772,812							

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)

$ 142,221,847 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 Hosensack Wavetrap (b0171.2)	(C) Monthly Additions Alburtis Wavetrap (b0172.1)	(D) Monthly Additions S. Akron - Berks Rebuild (b0074)	(E) Monthly Additions Susq-Rose CWIP (b0487)	(F) Monthly Additions Susq-Rose PIS (b0487)	(G) Weighting
CWIP Balance Dec (prior yr.)					250,168		12
Jan	3,014,337			8,938	48,962		11.5
Feb	849,762			5,021	90,356		10.5
Mar	(161,966)			17,382,111	255,692		9.5
Apr	1,709,242			(78,486)	167,610		8.5
May	2,608,644	85,555	53,657	17,333,182	240,528		7.5
Jun	3,112,150	670	568	278,668	242,017		6.5
Jul	6,466,642	1	1,344	98,786	296,039		5.5
Aug	380,000				287,876		4.5
Sep	2,910,317				287,876		3.5
Oct	1,102,130				287,876		2.5
Nov	286,000				287,876		1.5
Dec	1,182,000				287,876		0.5
Total	23,459,258	86,227	55,569	35,028,219	3,030,752	-	
New Transmission Plant Additions and CWIP (weighted by months in service)							

	(H) Other Plant In Service Amount (A x G)	(I) Hosensack Wavetrap Amount (B x G) (b0171.2)	(J) Alburtis Wavetrap Amount (C x G) (b0172.1)	(K) S. Akron - Berks Rebuild Amount (D x G) (b0074)	(L) Susq-Rose CWIP Amount (E x G) (b0487)	(M) Susq-Rose PIS Amount (F x G) (b0487)	(N) Other Plant In Service (H / 12)	(O) Hosensack Wavetrap (I / 12) (b0171.2)	(P) Alburtis Wavetrap (J / 12) (b0172.1)	(Q) S. Akron - Berks Rebuild (K / 12) (b0074)	(R) Susq-Rose CWIP (L / 12) (b0487)	(S) Susq-Rose PIS (M / 12) (b0487)	Total
CWIP Balance Dec (prior yr.)					3,002,016						250,168		
Jan	34,664,878	-	-	102,785	563,063	-	2,888,740	-	-	8,565	46,922	-	
Feb	8,922,500	-	-	52,721	948,738	-	743,542	-	-	4,393	79,062	-	
Mar	(1,538,677)	-	-	165,130,055	2,429,074	-	(128,223)	-	-	13,760,838	202,423	-	
Apr	14,528,559	-	-	(667,133)	1,424,685	-	1,210,713	-	-	(55,594)	118,724	-	
May	19,564,829	641,660	402,428	129,998,861	1,803,960	-	1,630,402	53,472	33,536	10,833,238	150,330	-	
Jun	20,228,976	4,357	3,692	1,811,339	1,573,111	-	1,685,748	363	308	150,945	131,093	-	
Jul	35,566,528	8	7,392	543,323	1,628,215	-	2,963,877	1	616	45,277	135,685	-	
Aug	1,710,000	-	-	-	1,295,442	-	142,500	-	-	-	107,954	-	
Sep	10,186,110	-	-	-	1,007,566	-	848,842	-	-	-	83,964	-	
Oct	2,755,325	-	-	-	719,690	-	229,610	-	-	-	59,974	-	
Nov	429,000	-	-	-	431,814	-	35,750	-	-	-	35,985	-	
Dec	591,000	-	-	-	143,938	-	49,250	-	-	-	11,995	-	
Total	147,609,027	646,026	413,512	296,971,951	16,971,311	-	12,300,752	53,835	34,459	24,747,663	1,414,276	-	-
Input to Line 17 of Appendix A							12,300,752	53,835	34,459	24,747,663		-	37,136,710
Input to Line 35 of Appendix A											1,414,276		1,414,276
Month In Service or Month for CWIP							5.71	4.51	4.56	3.52	6.40	-	

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

$ 147,227,188 — 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

$ 147,227,188 — 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)

$ 147,227,188

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

$ 131,764,202 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 — $ 71,323,245 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 Hosensack Wavetrap (b0171.2)	(C) Monthly Additions Alburtis Wavetrap (b0172.1)	(D) Monthly Additions S. Akron - Berks Rebuild (b0074)	(E) Monthly Additions Susq-Rose CWIP (b0487)	(F) Monthly Additions Susq-Rose PIS (b0487)	(G) Weighting
CWIP Balance Dec (prior yr.)					250,168		12
Jan	3,003,602			8,938	48,548		11.5
Feb	849,762			5,021	90,093		10.5
Mar	(161,966)			17,382,111	255,108		9.5
Apr	1,709,242			(78,486)	166,204		8.5
May	2,641,805	85,555	53,657	17,131,847	239,348		7.5
Jun	3,112,150	670	568	278,668	255,321		6.5
Jul	698,419	1	1,344	98,786	309,101		5.5
Aug	2,081,052		643	110,337	366,497		4.5
Sep	1,444,450		5,996	887,850	852,888		3.5
Oct	836,520			29,742	650,685		2.5
Nov	8,027,445			26,765	931,705		1.5
Dec	11,061,578	400	-141	(11,085)	1,118,790		0.5
Total	35,304,058	86,626	62,067	35,870,494	5,534,456	-	

	(H) Other Plant In Service Amount (A x G)	(I) Hosensack Wavetrap Amount (B x G) (b0171.2)	(J) Alburtis Wavetrap Amount (C x G) (b0172.1)	(K) S. Akron - Berks Rebuild Amount (D x G) (b0074)	(L) Susq-Rose CWIP Amount (E x G) (b0487)	(M) Susq-Rose PIS Amount (F x G) (b0487)	(N) Other Plant In Service (H / 12)	(O) Hosensack Wavetrap (I / 12) (b0171.2)	(P) Alburtis Wavetrap (J / 12) (b0172.1)	(Q) S. Akron - Berks Rebuild (K / 12) (b0074)	(R) Susq-Rose CWIP (L / 12) (b0487)	(S) Susq-Rose PIS (M / 12) (b0487)	Total
CWIP Balance Dec (prior yr.)					3,002,016						250,168		
Jan	34,541,424	-	-	102,787	558,302	-	2,878,452	-	-	8,566	46,525	-	
Feb	8,922,503	-	-	52,721	945,977	-	743,542	-	-	4,393	78,831	-	
Mar	(1,538,681)	-	-	165,130,055	2,423,526	-	(128,223)	-	-	13,760,838	201,961	-	
Apr	14,528,553	-	-	(667,131)	1,412,734	-	1,210,713	-	-	(55,594)	117,728	-	
May	19,813,541	641,663	402,428	128,488,853	1,795,110	-	1,651,128	53,472	33,536	10,707,404	149,593	-	
Jun	20,228,975	4,355	3,692	1,811,342	1,659,587	-	1,685,748	363	308	150,945	138,299	-	
Jul	3,841,302	6	7,392	543,323	1,700,056	-	320,109	0	616	45,277	141,671	-	
Aug	9,364,733	-	2,894	496,517	1,649,237	-	780,394	-	241	41,376	137,436	-	
Sep	5,055,576	-	20,986	3,107,475	2,985,108	-	421,298	-	1,749	258,956	248,759	-	
Oct	2,091,299	-	-	74,355	1,626,713	-	174,275	-	-	6,196	135,559	-	
Nov	12,041,167	-	-	40,148	1,397,558	-	1,003,431	-	-	3,346	116,463	-	
Dec	5,530,789	200	(71)	(5,543)	559,395	-	460,899	17	(6)	(462)	46,616	-	
Total	134,421,181	646,223	437,321	299,174,900	21,715,316	-	11,201,765	53,852	36,443	24,931,242	1,809,610	-	
Input to Line 17 of Appendix A							11,201,765	53,852	36,443	24,931,242		-	36,223,302
Input to Line 35 of Appendix A											1,809,610		1,809,610
Month In Service or Month for CWIP							8.19	4.54	4.95	3.66	8.08	-	

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

$ 127,829,473 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		
127,829,473	-	147,227,188	=	(19,397,715)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of the Current Yr 0.3800%

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	-	0.3800%	11.5	-	-
Jul	Year 1	-	0.3800%	10.5	-	-
Aug	Year 1	-	0.3800%	9.5	-	-
Sep	Year 1	-	0.3800%	8.5	-	-
Oct	Year 1	-	0.3800%	7.5	-	-
Nov	Year 1	(1,616,476)	0.3800%	6.5	(39,927)	(1,656,403)
Dec	Year 1	(1,616,476)	0.3800%	5.5	(33,784)	(1,650,261)
Jan	Year 2	(1,616,476)	0.3800%	4.5	(27,642)	(1,644,118)
Feb	Year 2	(1,616,476)	0.3800%	3.5	(21,499)	(1,637,975)
Mar	Year 2	(1,616,476)	0.3800%	2.5	(15,357)	(1,631,833)
Apr	Year 2	(1,616,476)	0.3800%	1.5	(9,214)	(1,625,690)
May	Year 2	(1,616,476)	0.3800%	0.5	(3,071)	(1,619,548)
Total		(11,315,334)				(11,465,828)

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	(11,465,828)	0.3800%	(979,250)	(10,530,148)
Jul	Year 2	(10,530,148)	0.3800%	(979,250)	(9,590,912)
Aug	Year 2	(9,590,912)	0.3800%	(979,250)	(8,648,107)
Sep	Year 2	(8,648,107)	0.3800%	(979,250)	(7,701,720)
Oct	Year 2	(7,701,720)	0.3800%	(979,250)	(6,751,736)
Nov	Year 2	(6,751,736)	0.3800%	(979,250)	(5,798,142)
Dec	Year 2	(5,798,142)	0.3800%	(979,250)	(4,840,925)
Jan	Year 3	(4,840,925)	0.3800%	(979,250)	(3,880,070)
Feb	Year 3	(3,880,070)	0.3800%	(979,250)	(2,915,564)
Mar	Year 3	(2,915,564)	0.3800%	(979,250)	(1,947,393)
Apr	Year 3	(1,947,393)	0.3800%	(979,250)	(975,543)
May	Year 3	(975,543)	0.3800%	(979,250)	(0)
Total with interest				(11,751,003)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(11,751,003)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$	-
Revenue Requirement for Year 3		(11,751,003)

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 Juniata Wavetrap (b0284.2)	(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.)			-		5,534,456		12
Jan	1,721,241	1,321	32,622		950,127		11.5
Feb	(300,718)	504	32,183		1,181,951		10.5
Mar	820,437	163	5,921		1,570,489		9.5
Apr	930,076		74,445		1,830,075		8.5
May	1,021,920	106,006	114,869		1,734,600		7.5
Jun	12,962,358		126,355		2,148,646		6.5
Jul	456,089		126,355		2,668,378		5.5
Aug	520,125		120,612		2,090,125		4.5
Sep	1,772,409		120,612		2,069,147		3.5
Oct	1,508,620		36,691		2,110,983		2.5
Nov	4,892,313		19,460		1,802,601		1.5
Dec	8,998,480		21,509		2,111,246		0.5
Total	35,303,350	107,994	831,634	-	27,802,824	-	

	(H) Other Plant In Service Amount (A x G)	(I) Juniata Wavetrap Amount (B x G) (b0284.2)	(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)
CWIP Balance Dec (prior yr.)			-		66,413,472	
Jan	19,794,272	15,192	375,153	-	10,926,461	-
Feb	(3,157,539)	5,292	337,922	-	12,410,486	-
Mar	7,794,152	1,549	56,250	-	14,919,646	-
Apr	7,905,646	-	632,783	-	15,555,638	-
May	7,664,400	795,045	861,518	-	13,009,500	-
Jun	84,255,327	-	821,308	-	13,966,199	-
Jul	2,508,490	-	694,953	-	14,676,079	-
Aug	2,340,563	-	542,754	-	9,405,563	-
Sep	6,203,432	-	422,142	-	7,242,015	-
Oct	3,771,550	-	91,728	-	5,277,458	-
Nov	7,338,470	-	29,190	-	2,703,902	-
Dec	4,499,240	-	10,755	-	1,055,623	-
Total	150,918,000	817,077	4,876,452	-	187,562,038	-

	(N) Other Plant In Service (H / 12)	(O) Juniata Wavetrap (I / 12) (b0284.2)	(P) Susq-Rose CWIP (J / 12) < 500kV (b0487.1)	(Q) Susq-Rose PIS (K / 12) < 500kV (b0487.1)	(R) Susq-Rose CWIP (L / 12) >= 500kV (b0487)	(S) Susq-Rose PIS (M / 12) >= 500kV (b0487)	Total
CWIP Balance Dec (prior yr.)			-		5,534,456		
Jan	1,649,523	1,266	31,263	-	910,538	-	
Feb	(263,128)	441	28,160	-	1,034,207	-	
Mar	649,513	129	4,687	-	1,243,304	-	
Apr	658,804	-	52,732	-	1,296,303	-	
May	638,700	66,254	71,793	-	1,084,125	-	
Jun	7,021,277	-	68,442	-	1,163,850	-	
Jul	209,041	-	57,913	-	1,223,007	-	
Aug	195,047	-	45,230	-	783,797	-	
Sep	516,953	-	35,179	-	603,501	-	
Oct	314,296	-	7,644	-	439,788	-	
Nov	611,539	-	2,433	-	225,325	-	
Dec	374,937	-	896	-	87,969	-	
Total	12,576,500	68,090	406,371	-	15,630,170	-	
Input to Line 17 of Appendix A	12,576,500	68,090		-		-	12,644,590
Input to Line 35 of Appendix A			406,371		15,630,170		16,036,541
Month In Service or Month for CWIP	7.73	4.43	6.14	-	5.25	-	

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

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

$ 123,520,774 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)

$ 123,520,774

Attachment 7 - Transmission Enhancement Charge Worksheet

Line				
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
		Formula Line		
3	A	137	Net Plant Carrying Charge without Depreciation	18.3207%
4	B	144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.0256%
5	C		Line B less Line A	0.7049%
6	**FCR if a CIAC**			
7	D	138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.6312%

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	Susquehanna - Roseland PIS (b0487) >= 500kV	Hosensack Wavetrap (b0171.2)	Alburtis Wavetrap (b0172.1)	Juniata Wavetrap (b0284.2)	Susquehanna - Roseland CWIP (b0487.1) < 500kV	Susquehanna - Roseland PIS (b0487.1) < 500kV
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	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
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
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	0	0	0	125	125
15	From line 3 above if "No" on line 13 and from line 7 above if "Yes" on line 13	11.64% ROE		18.3207%	18.3207%	18.3207%	18.3207%	18.3207%	18.3207%	18.3207%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		19.2018%	19.2018%	18.3207%	18.3207%	18.3207%	19.2018%	19.2018%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified	Investment		27,802,824		86,626	62,067	107,994	831,634	
18	Line 17 divided by line 12	Annual Depreciation Exp		661,972	-	2,063	1,478	2,571	19,801	-
19	Month in which project is placed in service (e.g. Jan=1)	Month In Service or Month for CWIP		5.25		4.54	4.95	4.43	6.14	

Line		Invest Yr	Susquehanna - Roseland CWIP (b0487) >= 500kV Beginning	Depreciation	Ending	Revenue	Susquehanna - Roseland PIS (b0487) >= 500kV Beginning	Depreciation	Ending	Revenue
21	W 11.64 % 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 11.64 % ROE	2009	27,802,824	-	27,802,824	3,288,030	-	-	-	-
24	W Increased ROE	2009	27,802,824	-	27,802,824	3,446,167	-	-	-	-
25	W 11.64 % ROE	2010		-	-	-	-	-	-	-
26	W Increased ROE	2010		-	-	-	-	-	-	-
27	W 11.64 % ROE	2011		-	-	-	-	-	-	-
28	W Increased ROE	2011		-	-	-	-	-	-	-
29	W 11.64 % ROE	2012		-	-	-	-	-	-	-
30	W Increased ROE	2012		-	-	-	-	-	-	-
31	W 11.64 % ROE	2013		-	-	-	-	-	-	-
32	W Increased ROE	2013		-	-	-	-	-	-	-
33	W 11.64 % ROE	2014		-	-	-	-	-	-	-
34	W Increased ROE	2014		-	-	-	-	-	-	-
35	W 11.64 % ROE	2015		-	-	-	-	-	-	-
36	W Increased ROE	2015		-	-	-	-	-	-	-
37	W 11.64 % ROE	2016		-	-	-	-	-	-	-
38	W Increased ROE	2016		-	-	-	-	-	-	-
39	W 11.64 % ROE	2017		-	-	-	-	-	-	-
40	W Increased ROE	2017		-	-	-	-	-	-	-
41	W 11.64 % ROE	2018		-	-	-	-	-	-	-
42	W Increased ROE	2018		-	-	-	-	-	-	-
43	W 11.64 % ROE	2019		-	-	-	-	-	-	-
44	W Increased ROE	2019		-	-	-	-	-	-	-
45	W 11.64 % ROE	2020		-	-	-	-	-	-	-
46	W Increased ROE	2020		-	-	-	-	-	-	-
47	W 11.64 % ROE	2021		-	-	-	-	-	-	-
48	W Increased ROE	2021		-	-	-	-	-	-	-
49	W 11.64 % ROE	2022		-	-	-	-	-	-	-
50	W Increased ROE	2022		-	-	-	-	-	-	-
51	W 11.64 % ROE	2023		-	-	-	-	-	-	-
52	W Increased ROE	2023		-	-	-	-	-	-	-
53	W 11.64 % ROE	2024		-	-	-	-	-	-	-
54	W Increased ROE	2024		-	-	-	-	-	-	-
55	W 11.64 % ROE	2025		-	-	-	-	-	-	-
56	W Increased ROE	2025		-	-	-	-	-	-	-
57	W 11.64 % ROE	2026		-	-	-	-	-	-	-
58	W Increased ROE	2026		-	-	-	-	-	-	-
59	W 11.64 % ROE	2027		-	-	-	-	-	-	-
60	W Increased ROE	2027		-	-	-	-	-	-	-
61		....					....	-	.....	....
62		....					....	.....	.....	....

Line		Invest Yr	Hosensack Wavetrap (b0171.2) Beginning	Depreciation	Ending	Revenue	Alburtis Wavetrap (b0172.1) Beginning	Depreciation	Ending	Revenue
21	W 11.64 % ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811
22	W Increased ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811
23	W 11.64 % ROE	2009	85,172	2,063	83,109	17,289	61,076	1,478	59,598	12,397
24	W Increased ROE	2009	85,172	2,063	83,109	17,289	61,076	1,478	59,598	12,397
25	W 11.64 % ROE	2010	-	-	-	-	-	-	-	-
26	W Increased ROE	2010	-	-	-	-	-	-	-	-
27	W 11.64 % ROE	2011	-	-	-	-	-	-	-	-
28	W Increased ROE	2011	-	-	-	-	-	-	-	-
29	W 11.64 % ROE	2012	-	-	-	-	-	-	-	-
30	W Increased ROE	2012	-	-	-	-	-	-	-	-
31	W 11.64 % ROE	2013	-	-	-	-	-	-	-	-
32	W Increased ROE	2013	-	-	-	-	-	-	-	-
33	W 11.64 % ROE	2014	-	-	-	-	-	-	-	-
34	W Increased ROE	2014	-	-	-	-	-	-	-	-
35	W 11.64 % ROE	2015	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-
37	W 11.64 % ROE	2016	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-
39	W 11.64 % ROE	2017	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-
41	W 11.64 % ROE	2018	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-
43	W 11.64 % ROE	2019	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-
45	W 11.64 % ROE	2020	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-
47	W 11.64 % ROE	2021	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-
49	W 11.64 % ROE	2022	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-
51	W 11.64 % ROE	2023	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-
53	W 11.64 % ROE	2024	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-
55	W 11.64 % ROE	2025	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-
57	W 11.64 % ROE	2026	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-
59	W 11.64 % ROE	2027	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-
61			....	....	.....	....	....	....	.....	....
62			....	....	.....	....	....	....	.....	....

Line		Invest Yr	Juniata Wavetrap (b0284.2) Beginning	Depreciation	Ending	Revenue	Susquehanna - Roseland CWIP (b0487.1) < 500kV Beginning	Depreciation	Ending	Revenue
21	W 11.64 % ROE	2008	-	-	-	-	-	-	-	-
22	W Increased ROE	2008	-	-	-	-	-	-	-	-
23	W 11.64 % ROE	2009	107,994	1,835	106,159	15,719	831,634	-	831,634	87,147
24	W Increased ROE	2009	107,994	1,835	106,159	15,719	831,634	-	831,634	91,338
25	W 11.64 % ROE	2010	-	-	-	-	-	-	-	-
26	W Increased ROE	2010	-	-	-	-	-	-	-	-
27	W 11.64 % ROE	2011	-	-	-	-	-	-	-	-
28	W Increased ROE	2011	-	-	-	-	-	-	-	-
29	W 11.64 % ROE	2012	-	-	-	-	-	-	-	-
30	W Increased ROE	2012	-	-	-	-	-	-	-	-
31	W 11.64 % ROE	2013	-	-	-	-	-	-	-	-
32	W Increased ROE	2013	-	-	-	-	-	-	-	-
33	W 11.64 % ROE	2014	-	-	-	-	-	-	-	-
34	W Increased ROE	2014	-	-	-	-	-	-	-	-
35	W 11.64 % ROE	2015	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-
37	W 11.64 % ROE	2016	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-
39	W 11.64 % ROE	2017	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-
41	W 11.64 % ROE	2018	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-
43	W 11.64 % ROE	2019	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-
45	W 11.64 % ROE	2020	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-
47	W 11.64 % ROE	2021	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-
49	W 11.64 % ROE	2022	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-
51	W 11.64 % ROE	2023	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-
53	W 11.64 % ROE	2024	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-
55	W 11.64 % ROE	2025	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-
57	W 11.64 % ROE	2026	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-
59	W 11.64 % ROE	2027	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-
61			....	....	.....	....	....	....	.....	....
62			....	....	.....	....	....	....	.....	....

Line		Invest Yr	Susquehanna - Roseland PIS (b0487.1) < 500kV Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
21	W 11.64 % ROE	2008	-	-	-	-	$ 455,377		$ 455,377
22	W Increased ROE	2008	-	-	-	-	$ 475,473	$ 475,473	
23	W 11.64 % ROE	2009	-	-	-	-	$ 3,420,581		$ 3,420,581
24	W Increased ROE	2009	-	-	-	-	$ 3,582,910	$ 3,582,910	
25	W 11.64 % ROE	2010	-	-	-	-	$ -		$ -
26	W Increased ROE	2010	-	-	-	-	$ -	$ -	
27	W 11.64 % ROE	2011	-	-	-	-	$ -		$ -
28	W Increased ROE	2011	-	-	-	-	$ -	$ -	
29	W 11.64 % ROE	2012	-	-	-	-	$ -		$ -
30	W Increased ROE	2012	-	-	-	-	$ -	$ -	
31	W 11.64 % ROE	2013	-	-	-	-	$ -		$ -
32	W Increased ROE	2013	-	-	-	-	$ -	$ -	
33	W 11.64 % ROE	2014	-	-	-	-	$ -		$ -
34	W Increased ROE	2014	-	-	-	-	$ -	$ -	
35	W 11.64 % ROE	2015	-	-	-	-	$ -		$ -
36	W Increased ROE	2015	-	-	-	-	$ -	$ -	
37	W 11.64 % ROE	2016	-	-	-	-	$ -		$ -
38	W Increased ROE	2016	-	-	-	-	$ -	$ -	
39	W 11.64 % ROE	2017	-	-	-	-	$ -		$ -
40	W Increased ROE	2017	-	-	-	-	$ -	$ -	
41	W 11.64 % ROE	2018	-	-	-	-	$ -		$ -
42	W Increased ROE	2018	-	-	-	-	$ -	$ -	
43	W 11.64 % ROE	2019	-	-	-	-	$ -		$ -
44	W Increased ROE	2019	-	-	-	-	$ -	$ -	
45	W 11.64 % ROE	2020	-	-	-	-	$ -		$ -
46	W Increased ROE	2020	-	-	-	-	$ -	$ -	
47	W 11.64 % ROE	2021	-	-	-	-	$ -		$ -
48	W Increased ROE	2021	-	-	-	-	$ -	$ -	
49	W 11.64 % ROE	2022	-	-	-	-	$ -		$ -
50	W Increased ROE	2022	-	-	-	-	$ -	$ -	
51	W 11.64 % ROE	2023	-	-	-	-	$ -		$ -
52	W Increased ROE	2023	-	-	-	-	$ -	$ -	
53	W 11.64 % ROE	2024	-	-	-	-	$ -		$ -
54	W Increased ROE	2024	-	-	-	-	$ -	$ -	
55	W 11.64 % ROE	2025	-	-	-	-	$ -		$ -
56	W Increased ROE	2025	-	-	-	-	$ -	$ -	
57	W 11.64 % ROE	2026	-	-	-	-	$ -		$ -
58	W Increased ROE	2026	-	-	-	-	$ -	$ -	
59	W 11.64 % 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**	222,427	(See FM 1, note to page 114, line 4)
	Taxes Other Than Income		
78	**Less Taxes Other Than Income on Securitization Bonds**	14,376	(See FM 1, note to page 114, line 14)
	Long Term Interest		
81	**Less LTD Interest on Securitization Bonds**	13,186,553	(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

Account Number	Plant Type	Applied Deprec. Rate (%)
	Transmission	
350.4	Land Rights	2.30
352	Structures and Improvements	2.95
353	Station Equipment	3.02
354	Towers and Fixtures	2.41
354.2	Towers and Fixtures - Clearing Land and Rights of Way	2.21
355	Poles and Fixtures	2.84
355.2	Poles and Fixtures - Clearing Land and Rights of Way	2.17
356	Overhead Conductors and Devices	2.87
357	Underground Conduit	3.76
358	Underground Conductors and Devices	4.90
359	Roads and Trails	2.03
	General	
389.4	Land Rights	3.12
390.2	Structures and Improvements - Buildings	1.92
390.4	Structures and Improvements - Air Conditioning	4.82
391.2	Office Furniture and Equipment - Furniture	5.00
391.4	Office Furniture and Equipment - Mechanical Equipment	6.67
391.6	Office Furniture and Equipment - Computer Equipment - General	20.00
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System	14.28
392.1	Transportation Equipment - 5 Years	31.58
392.2	Transportation Equipment - 8 Years	25.75
392.3	Transportation Equipment - 10 Years	17.77
392.4	Transportation Equipment - Trailers	7.20
392.5	Transportation Equipment - 15 Years	9.67
392.6	Transportation Equipment - 20 Years	7.18
393	Store Equipment	4.00
394	Tools, Shop and Garage Equipment - Distribution Line Crews	5.00
394.2	Tools, Shop and Garage Equipment - Tools	5.00
394.4	Tools, Shop and Garage Equipment - Construction Department	5.00
394.6	Tools, Shop and Garage Equipment - Other	5.00
394.8	Tools, Shop and Garage Equipment - Garage Tools Support	5.00
395	Laboratory Equipment	5.00
396	Power Operated Equipment	6.67
397	Communication Equipment	6.67
398	Miscellaneous Equipment	5.00
	Intangible	
303.2	Intangible Computer Software	20.00
303.4	Other Amortized Property	6.67

Attachment 4f

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2008 and Projected Net Plant at Year-End 2009

OHIO POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 137)					$166,366,835
2	REVENUE CREDITS	(Note A) (Worksheet E)	4,864,700	DA	1.00000	$	4,864,700
3	REVENUE REQUIREMENT For All OPCo Facilities	(ln 1 less ln 2)				$	161,502,135

MEMO: The Carrying Charge Calculations on lines 5 to 11 below is used in calculating project revenue requirements billed on PJM Schedule 12. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.

Line No.			Total	Allocator			Transmission Amount
4	Revenue Requirement for PJM RTEP Regional Facilities (w/o incentives) (Worksheet J)		894,796	DA	1.00000	$	894,796
5	NET PLANT CARRYING CHARGE W/O AFFILIATED LEASE PAYMENTS & T.E.A. ADJUSTMENT ADDBACK (w/o incentives) (Note B						
6	Annual Rate	((ln 1 - ln 106 - ln 107)/ ln 48 x 100)					25.01%
7	Monthly Rate	(ln 6 / 12)					2.08%
8	NET PLANT CARRYING CHARGE ON LINE 6 , W/O DEPRECIATION (w/o incentives) (Note B)						
9	Annual Rate	((ln 1 - ln 106 - ln 107 - ln 112) / ln 48 x 100)					21.18%
10	NET PLANT CARRYING CHARGE ON LINE 8, W/O INCOME TAXES, RETURN (Note B)						
11	Annual Rate	((ln 1 - ln 106 - ln 107 - ln 112 - ln 134 - ln 135) / ln 48 x 100)					9.38%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)						-
13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**						
14	Total Load Dispatch & Scheduling (Account 561)	Line 86 Below					9,339,810
15	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)						3,862,973
16	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.b)						670,559
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					4,806,278

AEP East Companies
Transmission Cost of Service Formula Rate
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OHIO POWER COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	5,315,606,412	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(32,761,806)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & ln 141)	1,109,431,387	DA		1,069,658,956
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C)	(3,120)	TP	0.96415	(3,008)
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		75,138,223	TP	0.96415	72,444,564
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		-	TP	0.96415	-
24	Distribution	(Worksheet A ln 5.C)	1,472,465,990	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	155,506,043	W/S	0.07400	11,507,071
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(165,163)	W/S	0.07400	(12,222)
28	Intangible Plant	(Worksheet A ln 9.C)	98,530,477	W/S	0.07400	7,291,017
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	8,193,748,443			1,160,886,379
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	1,851,240,526	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(13,436,520)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	477,721,183	**TP1=**	0.96750	462,197,014
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	(2,287)	**TP1=**	0.96750	(2,213)
35	Plus: Transmission Plant-in-Service Additions (Worksheet I) ln 21		342,467	DA	1.00000	342,467
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2009 (ln 112)		24,142,570	TP1	0.96750	23,358,026
38	Plus: Additional General & Intangible Depreciation for 2009 (ln 114 + ln 115)		20,226,076	W/S	0.07400	1,496,681
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	477,617,000	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	52,090,758	W/S	0.07400	3,854,590
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(82,226)	W/S	0.07400	(6,085)
44	Intangible Plant	(Worksheet A ln 20.C)	82,497,302	W/S	0.07400	6,104,601
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	2,972,356,849			497,345,081
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	3,445,040,600			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	631,709,371			607,461,147
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		74,795,756			72,102,097
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2009 (-ln 37)		(24,142,570)			(23,358,026)
52	Plus: Additional General & Intangible Depreciation for 2009 (-ln 38)		(20,226,076)			(1,496,681)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	994,848,990			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	103,332,348			7,646,344
56	Intangible Plant	(ln 28 - ln 44)	16,033,175			1,186,416
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	5,221,391,594			663,541,297
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(192,655,821)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(687,189,585)	DA		(83,411,276)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(190,254,388)	DA		(16,046,373)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	218,198,858	DA		16,611,829
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(2,083,912)	DA		(1,237,047)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(853,984,848)			(84,082,867)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.(C) & ln 30.(C)	2,667,975	DA		2,205,322
66	CONSTRUCTION WORK IN PROGRESS	(Worksheet A ln 31.C)	-	TP	0.96415	-
67	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
68	WORKING CAPITAL	(Note E)				
69	Cash Working Capital	(1/8 * ln 105)	15,033,842			3,973,963
70	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	917,697	TP	0.96415	884,798
71	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	689,216	W/S	0.07400	51,000
72	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.13407	-
73	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	157,695,433	W/S	0.07400	11,669,081
74	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	3,080,363	GP(h)	0.13407	412,977
75	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
76	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(150,732,801)	NA	0.00000	-
77	TOTAL WORKING CAPITAL	(sum lns 69 to 76)	26,683,750			16,991,819
78	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.(B))	(2,464,505)	DA	1.00000	(2,464,505)
79	RATE BASE (sum lns 57, 64, 65, 77, 78)		4,394,293,967			596,191,066

AEP East Companies
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Line No.	(1) **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total**	(4) **Allocator**		(5) **Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
80	Production	321.80.b	1,926,704,494			
81	Distribution	322.156.b	69,348,959			
82	Customer Related Expense	322 & 323.164,171,178.b	60,036,228			
83	Regional Marketing Expenses	322.131.b	3,356,418			
84	Transmission	321.112.b	61,361,256			
85	TOTAL O&M EXPENSES	(sum lns 80 to 84)	2,120,807,355			
86	Less: Total Account 561	(Note G) 321.84-92.b	9,339,810			
87	Less: Account 565	(Note H) 321.96.b	15,629,134			
88	Less: Regulatory Deferrals & Amortizations	(Note J) (Worksheet F, ln 4.C)	11,074,148			
89	Total O&M Allocable to Transmission	(lns 84 - 86 - 87 - 88)	25,318,164	TP	0.96415	24,410,524
90	Administrative and General	323.197.b (Note K)	95,686,301			
91	Less: Acct. 924, Property Insurance	323.185.b	3,339,677			
92	Acct. 928, Reg. Com. Exp.	323.189.b	284,922			
93	Acct. 930.1, Gen. Advert. Exp.	323.191.b	727,015			
94	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,383,524			
95	Balance of A & G	(ln 90 - sum ln 91 to ln 94)	89,951,163	W/S	0.07400	6,656,169
96	Plus: Acct. 924, Property Insurance	(ln 91)	3,339,677	GP(h)	0.13407	447,742
97	Acct. 928 - Transmission Specific	Worksheet F ln 16.(E) (Note L)	-	TP	0.96415	-
98	Acct. 928 - Transmission Allocated	Worksheet F ln 16.(F) (Note L)	-	GP(h)	0.13407	-
99	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	DA	1.00000	-
100	Acct 930.1 - Only safety related ads - Allocated	Worksheet F ln 32.(F) (Note L)	-	GP(h)	0.13407	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 38.(E) (Note L)	166,637	DA	1.00000	166,637
102	Acct 930.2 - Misc Gen. Exp. - Allocated	Worksheet F ln 38.(F) (Note L)	972,973	W/S	0.07400	71,998
103	Less: PBOP Expense In Acct. 926 Adjustment	Worksheet F ln 12.(C) (Note L)	(522,124)	W/S	0.07400	(38,636)
104	A & G Subtotal	(sum lns 95 to 102 less ln 103)	94,952,574			7,381,181
105	O & M EXPENSE SUBTOTAL	(ln 89 + ln 104)	120,270,738			31,791,705
106	Plus: TEA Settlement in Account 565	Company Records (Note M)	13,293,709	DA	1.00000	13,293,709
107	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note M)		1,120,888	DA	1.00000	1,120,888
108	TOTAL O & M EXPENSE	(ln 105 + ln 106 + ln 107)	134,685,335			46,206,302
109	DEPRECIATION AND AMORTIZATION EXPENSE					
110	Production	336.2-6.f	142,380,623	NA	0.00000	-
111	Distribution	336.8.f	56,454,550	NA	0.00000	-
112	Transmission	336.7.f	24,142,570	TP	0.96415	23,277,074
113	Plus: Transmission Plant-in-Service Additions (Worksheet I)		342,467	TP	0.96415	330,190
114	General	336.10.f	4,199,639	W/S	0.07400	310,763
115	Intangible	336.1.f	16,026,437	W/S	0.07400	1,185,918
116	TOTAL DEPRECIATION AND AMORTIZATI0N	(sum lns 110 to 115)	243,546,286			25,103,944
117	TAXES OTHER THAN INCOME	(Note N)				
118	Labor Related					
119	Payroll	Worksheet H ln 19 (D)	9,613,905	W/S	0.07400	711,406
120	Plant Related					
121	Property	Worksheet H ln 19 (C)	80,373,183	DA		22,107,492
122	Gross Receipts/Sales & Use	Worksheet H ln 19 (F)	97,657,081	NA	0.00000	-
123	Other	Worksheet H ln 19 (E)	4,246,305	GP(h)	0.13407	569,292
124	TOTAL OTHER TAXES	(sum lns 119 to 123)	191,890,474			23,388,190
125	INCOME TAXES	(Note O)				
126	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.71%			
127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.44%			
128	where WCLTD=(ln 160) and WACC = (ln 163)					
129	and FIT, SIT & p are as given in Note O.					
130	GRCF=1 / (1 - T) = (from ln 126)		1.5800			
131	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(439,885)			
132	Income Tax Calculation	(ln 127 * ln 135)	149,582,282			20,294,414
133	ITC adjustment	(ln 130 * ln 131)	(695,025)	NP(h)	0.11872	(82,516)
134	TOTAL INCOME TAXES	(sum lns 132 to 133)	148,887,257			20,211,897
135	RETURN ON RATE BASE (Rate Base*WACC)	(ln 79 * ln 163)	379,265,993			51,456,502
136	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note E) (Worksheet D, ln 2. (B))		-	DA	1.00000	-
137	TOTAL REVENUE REQUIREMENT (sum lns 108, 116, 124, 134, 135, 136)		1,098,275,345			166,366,835

AEP East Companies
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OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
138	Total transmission plant	(ln 20)						1,109,431,387
139	Less transmission plant excluded from PJM Tariff (Note P)							-
140	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)							39,772,431
141	Transmission plant included in PJM Tariff	(ln 138 - ln 139 - ln 140)						1,069,658,956
142	Percent of transmission plant in PJM Tariff	(ln 141 / ln 138)					**TP=**	**0.96415**
				Payroll Billed from				
143	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
144	Production	354.20.b	81,230,374	20,849,042	102,079,416	NA	0.00000	-
145	Transmission	354.21,22.b	6,875,166	5,195,734	12,070,900	TP	0.96415	11,638,166
146	Distribution	354.23.b	24,812,063	2,976,062	27,788,125	NA	0.00000	-
147	Other (Excludes A&G)	354.24,25,26.b	7,916,182	7,423,026	15,339,208	NA	0.00000	-
148	Total	(sum lns 144 to 147)	120,833,785	36,443,864	157,277,649			11,638,166
149	Transmission related amount						**W/S=**	**0.07400**

150	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
151	Long Term Interest	(Worksheet K)				145,888,188
152	Preferred Dividends	(Worksheet K)				732,108
153	<u>Development of Common Stock:</u>					
154	Proprietary Capital	(FF1 p 112, Ln 16.c)				2,438,571,961
155	Less Preferred Stock (ln 161)	(Worksheet K)				16,627,400
156	Less Account 216.1	(FF1 p 112, Ln 12c)				-
157	Less Account 219	(FF1 p 112, Ln 15.c)				(133,858,575)
158	Common Stock	(ln 154 - ln 155 - ln 156 - ln 157)				2,555,803,136
159			$	%	Cost (Note S)	Weighted
160	Long Term Debt (Note T)	(Worksheet K)	2,709,450,000	51.30%	5.38%	0.0276
161	Preferred Stock	(ln 155)	16,627,400	0.31%	4.40%	0.0001
162	Common Stock	(ln 158)	2,555,803,136	48.39%	12.10%	0.0585
163	Total	(Sum lns 160 to 162)	5,281,880,536		**WACC=**	**0.0863**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2008 and Projected Net Plant at Year-End 2009

OHIO POWER COMPANY

Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: a) revenues for grandfathered PTP contracts included in the load divisor b) revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. c) rental revenues earned on assets included in the rate base. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	Plant balances in this study are projected as of December 31, 2009. Other ratebase amounts are as of December 31, 2008.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission Allocations are shown on WS B.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, excluding AEP transmission equalization transfers, as shown on line 105.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 78 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 136.
G	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
H	Removes cost of transmission service provided by others. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such cost is added back after cash working capital is computed from line 124.
I	Per Note H above, this line is an adjustment to addback the activity in account 565 related to the PJM service at issue in this filing. The amount identified in column is used to remove the impact of this adjustment from the FCR rate calculated on line 11.
J	Removes the impact of regulatory deferrals or their amortization applicable only for state regulatory purposes.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet F allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Addback of activity recorded in 565 that represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
O	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 is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize 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) (ln 131) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 35.00% SIT= 2.63% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes)
P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 151) / long term debt (ln 160). Preferred Stock cost rate = preferred dividends (ln 152) / preferred outstanding (ln 161). Common Stock cost rate (ROE) = 12.1%, the rate accepted by FERC in Docket No. ER08-XXX. It includes an additional 50 basis points for remaining a member of the PJM RTO
T	This note only applies to Indiana Michigan Power Company.

AEP East Companies
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OHIO POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
164	REVENUE REQUIREMENT (w/o incentives)	(ln 300)					$160,350,476
165	REVENUE CREDITS	(Note A) (Worksheet E)	4,864,700	DA	1.00000	$	4,864,700
166	REVENUE REQUIREMENT For All OPCo Facilities	(ln 164 less ln 165)				$	155,485,776

MEMO: The Carrying Charge Calculations on lines 168 to 174 below is used in calculating project revenue requirements billed on PJM Schedule 12. The total non-incentive revenue requirements for these projects shown on line 167 is included in the total on line 166.

167	Revenue Requirement for PJM RTEP Regional Facilities (w/o incentives) (Worksheet J)		-	DA	1.00000	$	-
168	NET PLANT CARRYING CHARGE W/O AFFILIATED LEASE PAYMENTS & T.E.A. ADJUSTMENT ADDBACK (w/o incentives) (Note B						
169	Annual Rate	((ln 164 - ln 269 - ln 270)/ ln 211 x 100)					24.02%
170	Monthly Rate	(ln 169 / 12)					2.00%
171	NET PLANT CARRYING CHARGE ON LINE 169 , W/O DEPRECIATION (w/o incentives) (Note B)						
172	Annual Rate	((ln 164 - ln 269 - ln 270 - ln 275) / ln 211 x 100)					20.19%
173	NET PLANT CARRYING CHARGE ON LINE 171, W/O INCOME TAXES, RETURN (Note B)						
174	Annual Rate	((ln 164 - ln 269 - ln 270 - ln 275 - ln 297 - ln 298) / ln 211 x 100)					9.33%
175	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)						-

176	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
177	Total Load Dispatch & Scheduling (Account 561)	Line 249 Below	9,339,810
178	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)		3,862,973
179	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.b)		670,559
180	Total 561 Internally Developed Costs	(Line 177 - Line 178 - Line 179)	4,806,278

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OHIO POWER COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
181	Production	(Worksheet A ln 1.C)	5,315,606,412	NA	0.00000	-
182	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(32,761,806)	NA	0.00000	-
183	Transmission	(Worksheet A ln 3.C & ln 141)	1,109,431,387	DA		1,069,658,956
184	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C)	(3,120)	TP	0.96415	(3,008)
185	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
186	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
187	Distribution	(Worksheet A ln 5.C)	1,472,465,990	NA	0.00000	-
188	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
189	General Plant	(Worksheet A ln 7.C)	155,506,043	W/S	0.07400	11,507,071
190	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(165,163)	W/S	0.07400	(12,222)
191	Intangible Plant	(Worksheet A ln 9.C)	98,530,477	W/S	0.07400	7,291,017
192	TOTAL GROSS PLANT	(sum lns 181 to 191)	8,118,610,220	**GP(h)=**	**0.134068**	1,088,441,814
				GTD=	**0.41429**	
193	ACCUMULATED DEPRECIATION AND AMORTIZATION					
194	Production	(Worksheet A ln 12.C)	1,851,240,526	NA	0.00000	-
195	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(13,436,520)	NA	0.00000	-
196	Transmission	(Worksheet A ln 14.C & 28.C)	477,721,183	**TP1=**	0.96750	462,197,014
197	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	(2,287)	**TP1=**	0.96750	(2,213)
198	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
199	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
200	Plus: Additional Transmission Depreciation for 2009 (ln 275)		N/A	TP1	0.96750	N/A
201	Plus: Additional General & Intangible Depreciation for 2009 (ln 274 + ln 275)		N/A	W/S	0.07400	N/A
202	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
203	Distribution	(Worksheet A ln 16.C)	477,617,000	NA	0.00000	-
204	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
205	General Plant	(Worksheet A ln 18.C)	52,090,758	W/S	0.07400	3,854,590
206	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(82,226)	W/S	0.07400	(6,085)
207	Intangible Plant	(Worksheet A ln 20.C)	82,497,302	W/S	0.07400	6,104,601
208	TOTAL ACCUMULATED DEPRECIATION	(sum lns 194 to 207)	2,927,645,736			472,147,908
209	NET PLANT IN SERVICE					
210	Production	(ln 181 + ln 182 - ln 194 - ln 195)	3,445,040,600			-
211	Transmission	(ln 183 + ln 184 - ln 196 - ln 197)	631,709,371			607,461,147
212	Plus: Transmission Plant-in-Service Additions (ln 185 - ln 198)		N/A			N/A
213	Plus: Additional Trans Plant on Transferred Assets (ln 186 - ln 199)		N/A			N/A
214	Plus: Additional Transmission Depreciation for 2009 (-ln 200)		N/A			N/A
215	Plus: Additional General & Intangible Depreciation for 2009 (-ln 201)		N/A			N/A
216	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 202)		N/A			N/A
217	Distribution	(ln 187 + ln 188 - ln 203 - ln 204)	994,848,990			-
218	General Plant	(ln 189 + ln 190 - ln 205 - ln 206)	103,332,348			7,646,344
219	Intangible Plant	(ln 191 - ln 207)	16,033,175			1,186,416
220	TOTAL NET PLANT IN SERVICE	(sum lns 210 to 219)	5,190,964,484	**NP(h)=**	**0.118724**	616,293,907
221	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
222	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(192,655,821)	NA		-
223	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(687,189,585)	DA		(83,411,276)
224	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(190,254,388)	DA		(16,046,373)
225	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	218,198,858	DA		16,611,829
226	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	(2,083,912)	DA		(1,237,047)
227	TOTAL ADJUSTMENTS	(sum lns 222 to 226)	(853,984,848)			(84,082,867)
228	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	2,667,975	DA		2,205,322
229	CONSTRUCTION WORK IN PROGRESS	(Worksheet A ln 31.C)	-	TP	0.96415	-
230	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
231	WORKING CAPITAL	(Note E)				
232	Cash Working Capital	(1/8 * ln 268)	15,033,842			3,973,963
233	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	917,697	TP	0.96415	884,798
234	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	689,216	W/S	0.07400	51,000
235	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.13407	-
236	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	157,695,433	W/S	0.07400	11,669,081
237	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	3,080,363	GP(h)	0.13407	412,977
238	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
239	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(150,732,801)	NA	0.00000	-
240	TOTAL WORKING CAPITAL	(sum lns 232 to 239)	26,683,750			16,991,819
241	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.(B))	(2,464,505)	DA	1.00000	(2,464,505)
242	RATE BASE (sum lns 220, 227, 228, 240, 241)		4,363,866,856			548,943,675

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2008 with Year-End Rate Base Balances

OHIO POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	**EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION**	**Data Sources (See "General Notes")**	**TO Total**	**Allocator**		**Total Transmission**
	OPERATION & MAINTENANCE EXPENSE					
243	Production	321.80.b	1,926,704,494			
244	Distribution	322.156.b	69,348,959			
245	Customer Related Expense	322 & 323.164,171,178.b	60,036,228			
246	Regional Marketing Expenses	322.131.b	3,356,418			
247	Transmission	321.112.b	61,361,256			
248	TOTAL O&M EXPENSES	(sum lns 243 to 247)	2,120,807,355			
249	Less: Total Account 561	(Note G) 321.84-92.b	9,339,810			
250	Less: Account 565	(Note H) 321.96.b	15,629,134			
251	Less: Regulatory Deferrals & Amortizations	(Note J) (Worksheet F, ln 4.C)	11,074,148			
252	Total O&M Allocable to Transmission	(lns 247 - 249 - 250 - 251)	25,318,164	TP	0.96415	24,410,524
253	Administrative and General	323.197.b (Note K)	95,686,301			
254	Less: Acct. 924, Property Insurance	323.185.b	3,339,677			
255	Acct. 928, Reg. Com. Exp.	323.189.b	284,922			
256	Acct. 930.1, Gen. Advert. Exp.	323.191.b	727,015			
257	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,383,524			
258	Balance of A & G	(ln 253 - sum ln 254 to ln 257)	89,951,163	W/S	0.07400	6,656,169
259	Plus: Acct. 924, Property Insurance	(ln 254)	3,339,677	GP(h)	0.13407	447,742
260	Acct. 928 - Transmission Specific	Worksheet F ln 16.(E) (Note L)	-	TP	0.96415	-
261	Acct. 928 - Transmission Allocated	Worksheet F ln 16.(F) (Note L)	-	GP(h)	0.13407	-
262	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	DA	1.00000	-
263	Acct 930.1 - Only safety related ads - Allocated	Worksheet F ln 32.(F) (Note L)	-	GP(h)	0.13407	-
264	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 38.(E) (Note L)	166,637	DA	1.00000	166,637
265	Acct 930.2 - Misc Gen. Exp. - Allocated	Worksheet F ln 38.(F) (Note L)	972,973	W/S	0.07400	71,998
266	Less: PBOP Expense In Acct. 926 Adjustment	Worksheet F ln 12.(C) (Note L)	(522,124)	W/S	0.07400	(38,636)
267	A & G Subtotal	(sum lns 258 to 265 less ln 266)	94,952,574			7,381,181
268	O & M EXPENSE SUBTOTAL	(ln 252 + ln 267)	120,270,738			31,791,705
269	Plus: TEA Settlement in Account 565	Company Records (Note M)	13,293,709	DA	1.00000	13,293,709
270	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note M)		1,120,888	DA	1.00000	1,120,888
271	TOTAL O & M EXPENSE	(ln 268 + ln 269 + ln 270)	134,685,335			46,206,302
272	DEPRECIATION AND AMORTIZATION EXPENSE					
273	Production	336.2-6.f	142,380,623	NA	0.00000	-
274	Distribution	336.8.f	56,454,550	NA	0.00000	-
275	Transmission	336.7.f	24,142,570	TP	0.96415	23,277,074
276	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**			**N/A**
277	General	336.10.f	4,199,639	W/S	0.07400	310,763
278	Intangible	336.1.f	16,026,437	W/S	0.07400	1,185,918
279	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 273 to 278)	243,203,819			24,773,754
280	TAXES OTHER THAN INCOME	(Note N)				
281	Labor Related					
282	Payroll	Worksheet H ln 19 (D)	9,613,905	W/S	0.07400	711,406
283	Plant Related					
284	Property	Worksheet H ln 19 (C)	80,373,183	DA		22,107,492
285	Gross Receipts/Sales & Use	Worksheet H ln 19 (F)	97,657,081	NA	0.00000	-
286	Other	Worksheet H ln 19 (E)	4,246,305	GP(h)	0.13407	569,292
287	TOTAL OTHER TAXES	(sum lns 282 to 286)	191,890,474			23,388,190
288	INCOME TAXES	(Note O)				
289	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.71%			
290	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.44%			
291	where WCLTD=(ln 323) and WACC = (ln 326)					
292	and FIT, SIT & p are as given in Note O					
293	GRCF=1 / (1 - T) = (from ln 289)		1.5800			
294	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(439,885)			
295	Income Tax Calculation	(ln 290 * ln 298)	148,546,540			18,686,107
296	ITC adjustment	(ln 293 * ln 294)	(695,025)	NP(h)	0.11872	(82,516)
297	TOTAL INCOME TAXES	(sum lns 295 to 296)	147,851,515			18,603,591
298	RETURN ON RATE BASE (Rate Base*WACC)	(ln 242 * ln 326)	376,639,867			47,378,639
299	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note E) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
300	TOTAL REVENUE REQUIREMENT (sum lns 271, 279, 287, 297, 298, 299)		1,094,271,010			160,350,476

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OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
301	Total transmission plant	(ln 183)						1,109,431,387
302	Less transmission plant excluded from PJM Tariff (Note P)							-
303	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)							39,772,431
304	Transmission plant included in PJM Tariff	(ln 301 - ln 302 - ln 303)						1,069,658,956
305	Percent of transmission plant in PJM Tariff	(ln 304 / ln 301)					**TP=**	**0.96415**
			Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
306	WAGES & SALARY ALLOCATOR (W/S)	(Note R)						
307	Production	354.20.b	81,230,374	20,849,042	102,079,416	NA	0.00000	-
308	Transmission	354.21,22.b	6,875,166	5,195,734	12,070,900	TP	0.96415	11,638,166
309	Distribution	354.23.b	24,812,063	2,976,062	27,788,125	NA	0.00000	-
310	Other (Excludes A&G)	354.24,25,26.b	7,916,182	7,423,026	15,339,208	NA	0.00000	-
311	Total	(sum lns 307 to 310)	120,833,785	36,443,864	157,277,649			11,638,166
312	Transmission related amount						**W/S=**	**0.07400**

ln No.						
313	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
314	Long Term Interest	(Worksheet K)				145,888,188
315	Preferred Dividends	(Worksheet K)				732,108
316	<u>Development of Common Stock:</u>					
317	Proprietary Capital	(FF1 p 112, Ln 16.c)				2,438,571,961
318	Less Preferred Stock (ln 324)	(Worksheet K)				16,627,400
319	Less Account 216.1	(FF1 p 112, Ln 12.c)				-
320	Less Account 219	(FF1 p 112, Ln 15.c)				(133,858,575)
321	Common Stock	(ln 317 - ln 318 - ln 319 - ln 320)				2,555,803,136
322			$	%	Cost (Note S)	Weighted
323	Long Term Debt (Note T)	(Worksheet K)	2,709,450,000	51.30%	5.38%	0.027621
324	Preferred Stock	(ln 318)	16,627,400	0.31%	4.40%	0.000139
325	Common Stock	(ln 321)	2,555,803,136	48.39%	12.10%	0.058550
326	Total	(Sum lns 323 to 325)	5,281,880,536		**WACC=**	**0.086309**

AEP East Companies
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Utilizing Historic Cost Data for 2008 with Year-End Rate Base Balances

OHIO POWER COMPANY

Letter	**Notes**
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: a) revenues for grandfathered PTP contracts included in the load divisor b) revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. c) rental revenues earned on assets included in the rate base. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	Plant balances in this study are as of December 31, 2008.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission Allocations are shown on WS B.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, excluding AEP transmission equalization transfers, as shown on line 268.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 241 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 299.
G	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
H	Removes cost of transmission service provided by others. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such cost is added back after cash working capital is computed from line 287.
I	Per Note H above, this line is an adjustment to addback the activity in account 565 related to the PJM service at issue in this filing. The amount identified in column is used to remove the impact of this adjustment from the FCR rate calculated on line 174.
J	Removes the impact of regulatory deferrals or their amortization applicable only for state regulatory purposes.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet F allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Addback of activity recorded in 565 that represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
O	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 is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize 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) (ln 294) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:			
	FIT =	35.00%	
	SIT=	2.63%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 314) / long term debt (ln 323). Preferred Stock cost rate = preferred dividends (ln 315) / preferred outstanding (ln 324). Common Stock cost rate (ROE) = 12.1%, the rate accepted by FERC in Docket No. ER08-XXX. It includes an additional 50 basis points for remaining a member of the PJM RTO
T	This note only applies to Indiana Michigan Power Company.

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

OHIO POWER COMPANY

Line No.			Total		Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 137)					$0
2	REVENUE CREDITS	(Note A) (Worksheet E)	-	DA	1.00000	$	-
3	REVENUE REQUIREMENT For All OPCo Facilities	(ln 1 less ln 2)				$	-

MEMO: The Carrying Charge Calculations on lines 5 to 11 below is used in calculating project revenue requirements billed on PJM Schedule 12. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.

Line No.			Total		Allocator		Transmission Amount
4	Revenue Requirement for PJM RTEP Regional Facilities (w/o incentives) (Worksheet J)		-	DA	1.00000	$	-
5	NET PLANT CARRYING CHARGE W/O AFFILIATED LEASE PAYMENTS & T.E.A. ADJUSTMENT ADDBACK (w/o incentives) (Note B						
6	Annual Rate	((ln 1 - ln 106 - ln 107)/ ln 48 x 100)					0.00%
7	Monthly Rate	(ln 6 / 12)					0.00%
8	NET PLANT CARRYING CHARGE ON LINE 6 , W/O DEPRECIATION (w/o incentives) (Note B)						
9	Annual Rate	((ln 1 - ln 106 - ln 107 - ln 112) / ln 48 x 100)					0.00%
10	NET PLANT CARRYING CHARGE ON LINE 8, W/O INCOME TAXES, RETURN (Note B)						
11	Annual Rate	((ln 1 - ln 106 - ln 107 - ln 112 - ln 134 - ln 135) / ln 48 x 100)					0.00%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)						-

Line No.	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES		
13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
14	Total Load Dispatch & Scheduling (Account 561)	Line 86 Below	-
15	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)		
16	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.b)		
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	-

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

OHIO POWER COMPANY

	(1)	(2)	(3)	(4)		(5)
Line No.	**RATE BASE CALCULATION**	**Data Sources (See "General Notes")**	**TO Total** NOTE C	**Allocator**		**Total Transmission**
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & ln 141)	-	DA		-
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C)	-	TP	0.00000	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	NA	0.00000	**N/A**
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		**N/A**	NA	0.00000	**N/A**
24	Distribution	(Worksheet A ln 5.C)	-	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	-	W/S	0.00000	-
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-	W/S	0.00000	-
28	Intangible Plant	(Worksheet A ln 9.C)	-	W/S	0.00000	-
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	-	**GP(h)=**	**0.00000**	-
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	-	**TP1=**	0.00000	-
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.00000	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I) ln 21		**N/A**	DA	1.00000	**N/A**
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
37	Plus: Additional Transmission Depreciation for 2009 (ln 112)		**N/A**	TP	0.00000	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2009 (ln 114 + ln 115)		**N/A**	W/S	0.00000	**N/A**
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
40	Distribution	(Worksheet A ln 16.C)	-	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	-	W/S	0.00000	-
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-	W/S	0.00000	-
44	Intangible Plant	(Worksheet A ln 20.C)	-	W/S	0.00000	-
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	-			-
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	-			-
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		**N/A**			**N/A**
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		**N/A**			**N/A**
51	Plus: Additional Transmission Depreciation for 2009 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2009 (-ln 38)		**N/A**			**N/A**
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		**N/A**			**N/A**
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	-			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	-			-
56	Intangible Plant	(ln 28 - ln 44)	-			-
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	-	**NP(h)=**	**0.00000**	-
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	-	DA		-
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	-	DA		-
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	-	DA		-
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	-			-
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.(C) & ln 30.(C)	-	DA		-
66	CONSTRUCTION WORK IN PROGRESS	(Worksheet A ln 31.C)	-	TP	0.00000	-
67	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
68	WORKING CAPITAL	(Note E)				
69	Cash Working Capital	(1/8 * ln 105)	-			-
70	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	-	TP	0.00000	-
71	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	-	W/S	0.00000	-
72	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.00000	-
73	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	-	W/S	0.00000	-
74	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	-	GP(h)	0.00000	-
75	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
76	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	-	NA	0.00000	-
77	TOTAL WORKING CAPITAL	(sum lns 69 to 76)	-			-
78	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.(B))	-	DA	1.00000	-
79	RATE BASE (sum lns 57, 64, 65, 77, 78)		-			-

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

OHIO POWER COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
80	Production	321.80.b				
81	Distribution	322.156.b				
82	Customer Related Expense	322 & 323.164,171,178.b				
83	Regional Marketing Expenses	322.131.b				
84	Transmission	321.112.b				
85	TOTAL O&M EXPENSES	(sum lns 80 to 84)	-			
86	Less: Total Account 561	(Note G) 321.84-92.b				
87	Less: Account 565	(Note H) 321.96.b				
88	Less: Regulatory Deferrals & Amortizations	(Note J) (Worksheet F, ln 4.C)	-			
89	Total O&M Allocable to Transmission	(lns 84 - 86 - 87 - 88)	-	TP	0.00000	-
90	Administrative and General	323.197.b (Note K)				
91	Less: Acct. 924, Property Insurance	323.185.b				
92	Acct. 928, Reg. Com. Exp.	323.189.b				
93	Acct. 930.1, Gen. Advert. Exp.	323.191.b				
94	Acct. 930.2, Misc. Gen. Exp.	323.192.b				
95	Balance of A & G	(ln 90 - sum ln 91 to ln 94)	-	W/S	0.00000	-
96	Plus: Acct. 924, Property Insurance	(ln 91)	-	GP(h)	0.00000	-
97	Acct. 928 - Transmission Specific	Worksheet F ln 16.(E) (Note L)	-	TP	0.00000	-
98	Acct. 928 - Transmission Allocated	Worksheet F ln 16.(F) (Note L)	-	GP(h)	0.00000	-
99	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	GP(h)	0.00000	-
100	Acct 930.1 - Only safety related ads - Allocated	Worksheet F ln 32.(F) (Note L)	-	DA	1.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 38.(E) (Note L)	-	DA	1.00000	-
102	Acct 930.2 - Misc Gen. Exp. - Allocated	Worksheet F ln 38.(F) (Note L)	-	W/S	0.00000	-
103	Less: PBOP Expense In Acct. 926 Adjustment	Worksheet F ln 12.(C) (Note L)	-	W/S	0.00000	-
104	A & G Subtotal	(sum lns 95 to 102 less ln 103)	-			-
105	O & M EXPENSE SUBTOTAL	(ln 89 + ln 104)	-			-
106	Plus: TEA Settlement in Account 565	Company Records (Note M)		DA	1.00000	-
107	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note M)			DA	1.00000	-
108	TOTAL O & M EXPENSE	(ln 105 + ln 106 + ln 107)	-			-
109	DEPRECIATION AND AMORTIZATION EXPENSE					
110	Production	336.2-6.f		NA	0.00000	-
111	Distribution	336.8.f		NA	0.00000	-
112	Transmission	336.7.f		TP	0.00000	-
113	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
114	General	336.10.f		W/S	0.00000	-
115	Intangible	336.1.f		W/S	0.00000	-
116	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 110 to 115)	-			-
117	TAXES OTHER THAN INCOME	(Note N)				
118	Labor Related					
119	Payroll	Worksheet H ln 19 (D)	-	W/S	0.00000	-
120	Plant Related					
121	Property	Worksheet H ln 19 (C)	-	DA		-
122	Gross Receipts/Sales & Use	Worksheet H ln 19 (F)	-	NA	0.00000	-
123	Other	Worksheet H ln 19 (E)	-	GP(h)	0.00000	-
124	TOTAL OTHER TAXES	(sum lns 119 to 123)	-			-
125	INCOME TAXES	(Note O)				
126	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.71%			
127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		0.00%			
128	where WCLTD=(ln 160) and WACC = (ln 163)					
129	and FIT, SIT & p are as given in Note O					
130	GRCF=1 / (1 - T) = (from ln 126)		1.5800			
131	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)				
132	Income Tax Calculation	(ln 127 * ln 135)	-			-
133	ITC adjustment	(ln 130 * ln 131)	-	NP(h)	0.00000	-
134	TOTAL INCOME TAXES	(sum lns 132 to 133)	-			-
135	RETURN ON RATE BASE (Rate Base*WACC)	(ln 79 * ln 163)	-			-
136	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note E) (Worksheet D, ln 2. (B))		-	DA	1.00000	-
137	TOTAL REVENUE REQUIREMENT (sum lns 108, 116, 124, 134, 135, 136)		-			-

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln No.									
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
138	Total transmission plant	(ln 20)							-
139	Less transmission plant excluded from PJM Tariff (Note P)								-
140	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)								-
141	Transmission plant included in PJM Tariff	(ln 138 - ln 139 - ln 140)							-
142	Percent of transmission plant in PJM Tariff	(ln 141 / ln 138)						**TP=**	**0.00000**
143	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
144	Production	354.20.b			-	NA	0.00000		-
145	Transmission	354.21,22.b			-	TP	0.00000		-
146	Distribution	354.23.b			-	NA	0.00000		-
147	Other (Excludes A&G)	354.24,25,26.b			-	NA	0.00000		-
148	Total	(sum lns 144 to 147)	0	0	0				-
149	Transmission related amount							**W/S=**	**0.00000**

ln No.							
150	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
151	Long Term Interest	(Worksheet K)					-
152	Preferred Dividends	(Worksheet K)					-
153	Development of Common Stock:			12/31/2008		12/31/2009	Average
154	Proprietary Capital	(FF1 p 112, Ln 16.c)		-			-
155	Less Preferred Stock (ln 161)	(Worksheet K)		-			-
156	Less Account 216.1	(FF1 p 112, Ln 12c)		-			-
157	Less Account 219	(FF1 p 112, Ln 15.c)		-			-
158	Common Stock	(ln 154 - ln 155 - ln 156 - ln 157)					-
159			Average $	%		Cost (Note S)	Weighted
160	Long Term Debt (Note T)	(Worksheet K)	-	0.00%		0.00%	0.0000
161	Preferred Stock	(ln 155)	-	0.00%		0.00%	0.0000
162	Common Stock	(ln 158)	-	0.00%		12.10%	0.0000
163	Total	(Sum lns 160 to 162)	-			**WACC=**	**0.0000**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

OHIO POWER COMPANY

Letter	**Notes**
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: a) revenues for grandfathered PTP contracts included in the load divisor b) revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. c) rental revenues earned on assets included in the rate base. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	No true-up.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission Allocations are shown on WS B.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, excluding AEP transmission equalization transfers, as shown on line 105.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 78 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 136.
G	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
H	Removes cost of transmission service provided by others. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such cost is added back after cash working capital is computed from line 124.
I	Per Note H above, this line is an adjustment to addback the activity in account 565 related to the PJM service at issue in this filing. The amount identified in column is used to remove the impact of this adjustment from the FCR rate calculated on line 11.
J	Removes the impact of regulatory deferrals or their amortization applicable only for state regulatory purposes.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet F allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Addback of activity recorded in 565 that represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
O	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 is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize 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) (ln 131) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	2.63%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 151) / long term debt (ln 160). Preferred Stock cost rate = preferred dividends (ln 152) / preferred outstanding (ln 161). Common Stock cost rate (ROE) = 12.1%, the rate accepted by FERC in Docket No. ER08-XXX. It includes an additional 50 basis points for remaining a member of the PJM RTO
T	This note only applies to Indiana Michigan Power Company.

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Plant Balances
OHIO POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balances @ 12/31/2008	(D) Balances For Update Use	(E) Average Balance
NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.					
Plant Investment Blalances					
1	**Production Plant In Service**	FF1, page 204/205, ln 46, Col. (b)/(g)	5,315,606,412		-
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 204/205, lns 15,24,34,44, Col. (b)/(g)	32,761,806		-
3	**Transmission Plant In Service**	FF1, page 206/207, ln 58, Col. (b)/(g)	1,109,431,387		-
4	**Transmission Asset Retirement Obligation**	FF1, page 206/207, ln 57, Col. (b)/(g)	3,120		-
5	**Distribution Plant In Service**	FF1, page 206/207, ln 75, Col. (b)/(g)	1,472,465,990		-
6	**Distribution Asset Retirement Obligation**	FF1, page 206/207, ln 74, Col. (b)/(g)	-		-
7	**General Plant In Service**	FF1, page 206/207, ln 99, Col. (b)/(g)	155,506,043		-
8	**General Asset Retirement Obligation**	FF1, page 206/207, lns 98, Col. (b)/(g)	165,163		-
9	**Intangible Plant In Service**	FF1, page 204/205, ln 5, Col. (b)/(g)	98,530,477		-
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	8,151,540,309	-	-
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	32,930,089	-	-
Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	1,851,240,526		-
13	**Production ARO Accumulated Depreciation**	Company Records	13,436,520		-
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	477,721,183		-
15	**Transmission ARO Accumulated Depreciation**	Company Records	2,287		-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	477,617,000		-
17	**Distribution ARO Accumulated Depreciation**	Company Records			-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	52,090,758		-
19	**General ARO Accumulated Depreciation**	Company Records	82,226		-
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	82,497,302		-
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	2,941,166,769	-	-
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	13,521,033	-	-
Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records	39,772,431		-
24	**GSU Accumulated Depreciation**	Company Records	15,524,169		-
25	**GSU Net Balance**	(Line 23 - Line 24)	24,248,262	-	-
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	477,721,183	-	-
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	15,524,169	-	-
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	462,197,014	-	-
Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	2,667,975		-
30	**Transmission Plant Held For Future**	Company Records	2,205,322		-
31	**Construction Work In Progress**	Company Records	-		-
Regulatory Assets Approved for Recovery In Ratebase					
31					-
32					-
33					-
34					-
35					-
36	Total Regulatory Deferrals Included in Ratebase		-	-	-

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting ADIT and ITC Balances
OHIO POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	Description	Source	Balance @ December 31, 2008	Balances For Update Use	Average Balance
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	192,655,821		-
3	Less: ARO Related Deferrals	Company Records			-
4	Less: Other Excluded Deferrals	Company Records	192,655,821		-
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	**Account 282**				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	687,189,585		-
8	Less: ARO Related Deferrals	Company Records	93,525,218		-
9	Less: Other Excluded Deferrals	Company Records	510,253,091		-
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	83,411,276	-	-
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	190,254,388		-
13	Less: ARO Related Deferrals	Company Records	0		-
14	Less: Other Excluded Deferrals	Company Records	174,208,015		-
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	16,046,373	-	-
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	218,198,858		-
18	Less: ARO Related Deferrals	Company Records	31,254,802		-
19	Less: Other Excluded Deferrals	Company Records	170,332,227		-
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	16,611,829	-	-
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	2,916,950		-
23	Less: Balances Not Qualified for Ratebase	Company Records	833,038		-
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	2,083,912	-	-
25	Transmission Related Deferrals	Company Records	1,237,047		-

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Working Capital Rate Base Adjustments
OHIO POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2008	(E) Balance For Update Use	(F) Average Balance for Rate Year 2008
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c)	917,697		-
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c)	689,216		-
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c)	0		-

Prepayment Balance Summary

Line		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
5							
6	Totals as of December 31, 2008	10,042,995	(150,732,801)	0	3,080,363	157,695,433	160,775,796
7	Totals as of December 31, 2009						
8	**Average Balance**	-	-	-	-	-	-

Prepayments Account 165 - Balance @ 12/31/2008

9	Acc. No.	Description	2008 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	
10	1650001	Prepaid Insurance	3,080,363	-		3,080,363		3,080,363	Plant Related Insurance Policies
11	1650003	Prepaid Rents	46,896	46,896				-	Prepaid Rents Generation
12	1650004	Prepaid Interest	17,596	17,596			-	-	Prepaid Interest-Generation
13	1650005	Prepaid Employee Benefits	2,349	-			2,349	2,349	Prepaid Employee Benefits
14	1650006	Other Prepayments	0	-			-	-	
15	1650009	Prepaid Carry Cost-Factored AR	202,657	202,657				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	157,693,084				157,693,084	157,693,084	Prepaid Pension Expense
17	165001206	Prepaid Sales/Use Taxes	0					-	
18	165001208	Prepaid Sales/Use Taxes	113,254	113,254				-	Sales Use Tax
19	1650013	Gavin JMG ST Prepaid Exp - Aff	5,336,553	5,336,553				-	Generation
20	1650014	FAS 158 Qual Contra Asset	(157,693,084)	(157,693,084)				-	FAS 158 Liability
21	1650016	FAS 112 ASSETS	1,243,327	1,243,327				-	FAS 112 Asset
		Subtotal - Form 1, p 111.57.c	10,042,995	(150,732,801)	0	3,080,363	157,695,433	160,775,796	

Prepayments Account 165 - Balance For Update Use

1	Acc. No.	Description	For Update Use YE Balance	Excludable Balalnces	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
2								-
3								-
4								-
5								-
6								-
7								-
8								-
9								-
10								-
11								-
								-
		Subtotal - Form 1, p 111.57.c						

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting IPP Credits
OHIO POWER COMPANY

Line Number	(A) Description	(B) 2008	(C) For Update Use
1	Net Funds from IPP Customers 12/31/2007 (FORM 1, P269, line 12 (b))	(2,464,505.00)	
2	Interest Accrual	-	
3	Revenue Credits to Generators		
4	Other Adjustments		
5	Accounting Adjustment	-	
6			
7	Net Funds from IPP Customers 12/31/2008 (FORM 1, P269, line 12(f))	(2,464,505.00)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	(2,464,505.00)	-

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Revenue Credits
OHIO POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts**	1,107,361	1,107,361	-
2	**Account 451,Miscellaneous Service Revenues**	2,732,594	2,727,467	5,127
3	**Account 454, Rent from Electric Property**	12,883,329	10,613,724	2,269,605
4	**Account 4560015, Associated Business Development**	1,230,543	1,078,188	152,355
5	**Account 456 - Other Electric Revenues**	25,487,624	25,487,624	-
6	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts**	2,525,109	87,496	2,437,613
7	**Total Other Operating Revenues To Reduce Revenue Requirement**	45,966,560	41,101,860	4,864,700

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Allocation of Specific O&M or A&G Expenses
OHIO POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C) 2008 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Transmission Allocated	(G) Explanation
		Regulatory Deferals & Amortizations					
1	5660005	Ohio E-TCR Rider UnderRecovery	11,074,148				
2			-				
3							
4		**Total**	11,074,148				
		Account 926					
		2007 Base Year OPEB Expense (Note 1)					
5	9260021	Postretirement Benefits - OPEB	14,435,661				
6	9260057	Postret Ben Medicare Subsidy	(5,245,264)				
7		Net 2007 Base Year Expense	9,190,397				
8		2008 Current Year Expense					
9	9260021	Postretirement Benefits - OPEB	14,067,802				
10	9260057	Postret Ben Medicare Subsidy	(5,399,529)				
11		Net 2008 Expense	8,668,273				
12		**Net Increase (Decrease) in OPEB Expense**	(522,124)	This Amount Is Allocated on Wages & Salaries			

Note 1: Absent a 205 Filing with FERC, this base amount will not change in subsequent years.

Line Number	(A) Item No.	(B) Description	(C) 2008 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Transmission Allocated	(G) Explanation
		Account 928					
13	9280000	Regulatory Commission Exp	19	19	-	-	Misc Expenditures
14	9280001	Regulatory Commission Exp-Adm	255,425	255,425	-	-	Cost of Hearings
15	9280002	Regulatory Commission Exp-Case	29,478	29,478	-	-	Misc Expenditures
16		**Total**	284,922	284,922	-	-	
		Account 930.1					
17	9301000	General Advertising Expenses	11,894	11,894	-	-	
18	9301001	Newspaper Advertising Space	2,132	2,132	-	-	
19	9301002	Radio Station Advertising Time	-	-	-	-	
20	9301003	TV Station Advertising Time	-	-	-	-	
21	9301005	Radio &TV Advertising Prod Exp	-	-	-	-	
22	9301006	Spec Corporate Comm Info Proj	6,141	6,141	-	-	
23	9301007	Special Adv Space & Prod Exp	62,065	62,065	-	-	
24	9301008	Direct Mail and Handouts	3,663	3,663	-	-	
25	9301009	Fairs, Shows, and Exhibits	5,150	5,150	-	-	
26	9301010	Publicity	40,939	40,939	-	-	
27	9301011	Dedications, Tours, & Openings	62	62	-	-	
28	9301012	Public Opinion Surveys	92,587	92,587	-	-	
29	9301013	Movies Slide Films & Speeches	111,368	111,368	-	-	
30	9301014	Video Communications	890	890	-	-	
31	9301015	Other Corporate Comm Exp	390,124	390,124	-	-	
32		**Total**	727,015	727,015	-	-	
		Account 930.2					
33	9302000	Misc General Expenses	760,219			760,219	
34	9302003	Corporate & Fiscal Expenses	212,754			212,754	
35	9302004	Research, Develop&Demonstr Exp	34,727	34,727			
36	9302005	Nucl Fac Ins - Replce Engy Cst	-	-		-	
37	9302007	Assoc Business Development Exp	375,824	209,187	166,637		
38		**Total**	1,383,524	243,914	166,637	972,973	

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting - Development of Composite State Income Tax Rate
OHIO POWER COMPANY

West Virginia Corporate Income Tax	8.75%	
Apportionment Factor	13.35%	
Effective State Tax Rate		1.17%
Illinois Corporation Income Tax	7.30%	
Apportionment Factor	0.10%	
Effective State Tax Rate		0.01%
State Income Tax Rate - Ohio	8.50%	
Phase-out Factor	20.00%	
Apportionment Factor	62.66%	
Effective State Tax Rate		1.0652%
Michigan Business Income Tax	6.04%	
Apportionment Factor	0.88%	
Effective State Tax Rate		0.05%
Ohio Municipal Net Income Tax	0.46%	
Apportionment Factor	73.22%	
Effective State Tax Rate		0.3368%
Total Effective State Income Tax Rate		2.63%

Note 1

The Ohio State Income Tax is being phased-out over a 5 year period and is being replaced with a Commercial Activites Tax. The taxable portion of income is 20% in 2008.

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Taxes Other than Income
OHIO POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Account**	**Total Company**	**Property**	**Labor**	**Other**	**Non-Allocable**
1	**Revenue Taxes**					
2	Gross Receipts Tax	80,544,609				80,544,609
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Ohio	70,166,548	70,166,548			
5	Real and Personal Property - West VA.	10,191,239	10,191,239			
6	Real and Personal Property - Other	15,396	15,396			
7	**Payroll Taxes**					
8	Federal Insurance Contribution (FICA)	9,276,230		9,276,230		
9	Federal Unemployment Tax	108,758		108,758		
10	State Unemployment Insurance	228,917		228,917		
11	**Miscellaneous Taxes**					
12	State Public Service Commission Fees	2,553,925			2,553,925	
13	State Franchise Taxes	1,646,221			1,646,221	
14	State Lic/Registration Fee	46,159			46,159	
15	Misc. State and Local Tax	-			-	
16	Sales & Use	80,639				80,639
17	Federal Excise Tax	66,708				66,708
18	State B & O Taxes	16,965,125				16,965,125
19	Total Taxes by Allocable Basis	191,890,475	80,373,183	9,613,905	4,246,305	97,657,081
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
		Functional Property Tax Allocation				
		Production	Transmsission	Distributions	General	Total
20	Functionalized Net Plant (Hist. TCOS, Lns 210 thru 220)	3,445,040,600	631,709,371	994,848,990	103,332,348	5,174,931,309
	OHIO JURISDICTION					
21	Percentage of Plant in OHIO JURISDICTION	49.42%	90.46%	99.96%	93.55%	
22	Net Plant in OHIO JURISDICTION (Ln 20 * Ln 21)	1,702,539,065	571,444,297	994,451,050	96,667,412	3,365,101,823
23	Less: Net Value Exempted Generation Plant	559,494,300				
24	Taxable Property Basis (Ln 22 - Ln 23)	1,143,044,765	571,444,297	994,451,050	96,667,412	2,805,607,523
25	Relative Valuation Factor	24%	85%	85%	24%	
26	Weighted Net Plant (Ln 24 * Ln 25)	274,330,743	485,727,652	845,283,393	23,200,179	
27	General Plant Allocator (Ln 26 / (Total - General Plant))	17.09%	30.26%	52.65%	-100.00%	
28	Functionalized General Plant (Ln 27 * General Plant)	3,964,590	7,019,669	12,215,919	(23,200,179)	-
29	Weighted OHIO JURISDICTION Plant (Ln 26 + 28)	278,295,333	492,747,321	857,499,312	(0)	1,628,541,968
30	Functional Percentage (Ln 29/Total Ln 29)	17.09%	30.26%	52.65%		
31	Functionalized Payment in OHIO JURISDICTION	11,990,494	21,230,266	36,945,788		70,166,548
	WEST VA. JURISDICTION					
32	Net Plant in WEST VA. JURISDICTION (Ln 20 - Ln 22)	1,742,501,535	60,265,074	397,940	6,664,936	1,809,829,486
33	Less: Net Value Exempted Generation Plant	1,101,569,129				
34	Taxable Property Basis	640,932,406	60,265,074	397,940	6,664,936	708,260,357
35	Relative Valuation Factor	100%	100%	100%	100%	
36	Weighted Net Plant (Ln 34 * Ln 35)	640,932,406	60,265,074	397,940	6,664,936	
37	General Plant Allocator (Ln 36 / (Total - General Plant)	91.35%	8.59%	0.06%	-100.00%	
38	Functionalized General Plant (Ln 38 * General Plant)	6,088,657	572,499	3,780	(6,664,936)	
39	Weighted WEST VA. JURISDICTION Plant (Ln 36 + 38)	647,021,063	60,837,573	401,720	0	708,260,357
40	Functional Percentage (Ln 39/Total Ln 39)	91.35%	8.59%	0.06%		
41	Functionalized Payment in WEST VA. JURISDICTION	9,310,060	875,399	5,780		10,191,239
42	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		1,828			15,396
43	Total Functionalized Property Taxes (Sum Lns 31, 41, 42)	21,300,554	22,107,492	36,951,569		80,373,183

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Transmission Plant in Service Additions
OHIO POWER COMPANY

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2008) (P.206, ln 58,(b)):	1,064,829,446
2	Transmission Plant @ End of Historic Period (2008) (P.207, ln 58,(g)):	1,109,431,387
3		2,174,260,833
4	Average Balance of Transmission Investment	1,087,130,417
5	Annual Depreciation Expense, Historic TCOS, ln 275	24,142,570
6	Composite Depreciation Rate	2.22%
7	Round to 2% to Reflect a Composite Life of 50 Years	2.00%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

8	Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	$ 2,445,406	2.00%	$ 48,908	$ 4,076	11	$ 44,836
10	February	$ 2,617,491	2.00%	$ 52,350	$ 4,362	10	$ 43,620
11	March	$ 2,701,383	2.00%	$ 54,028	$ 4,502	9	$ 40,518
12	April	$ 2,905,707	2.00%	$ 58,114	$ 4,843	8	$ 38,744
13	May	$ 2,718,840	2.00%	$ 54,377	$ 4,531	7	$ 31,717
14	June	$ 4,782,809	2.00%	$ 95,656	$ 7,971	6	$ 47,826
15	July	$ 2,563,341	2.00%	$ 51,267	$ 4,272	5	$ 21,360
16	August	$ 2,565,279	2.00%	$ 51,306	$ 4,275	4	$ 17,100
17	September	$ 2,805,285	2.00%	$ 56,106	$ 4,675	3	$ 14,025
18	October	$ 5,801,055	2.00%	$ 116,021	$ 9,668	2	$ 19,336
19	November	$ 14,030,722	2.00%	$ 280,614	$ 23,385	1	$ 23,385
20	December	$ 29,200,906	2.00%	$ 584,018	$ 48,668	0	$ -
21	Investment	$ 75,138,223				Depreciation Expense	$ 342,467

III. Plant Transferred

22	$ -	<== This input area is for original cost plant
23	$ -	<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.
24 (Ln 7 * Ln 22)	$ -	<== This input area is for additional Depreciation Expense

IV. List of Major Projects Expected to be In-Service in 2009

			Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**			
26 000011993	TS/OPCO/RELAY REHAB/REPL		$8,549	Nov-09
27 000014647	TL/OPC/Cambridge Area Subtrans		$2,742	Oct-09
28 000015523	TS/OPC/Purchase-Rebuild Maj Eq		$5,215	Dec-09
29 000015871	TL/OP/Moreland Trans Line Imp		$2,126	Jun-09
30 000016206	T/OPCO/EHV Metering/CB Upgrade		$11,129	Dec-09
31		Subtotal	$29,761	
32	**PJM Socialized/Beneficiary Allocated Regional Projects**			
33			$0	
34		Subtotal	$0	

I. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified for Regional Billing.

A. Determine 'R' with hypothetical basis point increase in ROE for Identified Projects

ROE w/o incentives (Page 9 of 27, ln 325)			12.10%
Project ROE Incentive Adder			
ROE with additional basis point incentive			12.10%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from Attachment H, lns 323 through325)

	%	Cost	Weighted cost
Long Term Debt	51.30%	5.38%	2.762%
Preferred Stock	0.31%	4.40%	0.014%
Common Stock	48.39%	12.10%	5.855%
		R =	8.631%

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (Page 7 of 27, ln 242)	548,943,675
R (fom A. above)	8.631%
Return (Rate Base x R)	47,378,639

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

Return (from B. above)	47,378,639
Effective Tax Rate (Page 8 of 27, ln 290)	39.44%
Income Tax Calculation (Return x CIT)	18,686,107
ITC Adjustment	(82,516)
Income Taxes	18,603,591

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (Page 6 of 27, ln 164)	160,350,476
T.E.A. & Lease Payments (Page 8 of 27, Lns 269 & 270)	14,414,597
Return (Page 8 of 27, ln 298)	47,378,639
Income Taxes (Page 8 of 27, ln 297)	18,603,591
Annual Revenue Requirement, Less T.E.A., Leases, Return Taxes	79,953,649

B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.

Annual Revenue Requirement, Less T.E.A., Leases, Return Taxes	79,953,649
Return (from I.B. above)	47,378,639
Income Taxes (from I.C. above)	18,603,591
Annual Revenue Requirement, with Basis Point ROE increase	145,935,879
Depreciation (Page 8 of 27, ln 275)	23,277,074
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	122,658,805

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Page 7 of 27, ln 211)	607,461,147
Annual Revenue Requirement, with Basis Point ROE increase	145,935,879
FCR with Basis Point increase in ROE	24.02%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	122,658,805
FCR with Basis Point ROE increase, less Depreciation	20.19%
FCR less Depreciation (Page 6 of 27, ln 172)	20.19%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, ln 58,(b)):	1,064,829,446
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	1,109,431,387
Subtotal	2,174,260,833
Average Transmission Plant Balance for 2008	1,087,130,417
Annual Depreciation Rate (Page 8 of 27, ln 275)	24,142,570
Composite Depreciation Rate	2.22%
Depreciable Life for Composite Depreciation Rate	45.03
Round to nearest whole year	45

SUMMARY OF ANNUAL PJM RTEP APPROVED REGIONAL REVENUE REQUIREMENTS

		Rev Require	W Incentives	Incentive Amounts
HISTORIC YEAR	2008			
	As Projected in Prior Year	$ -	$ -	$ -
	Actual after True-up	$ -	$ -	$ -
	Incremental Revenue Requirement	-	-	-
PROJECTED YEAR	2009	894,796	894,796	$ -

OPCo Worksheet J - ATRR Calculation for PJM RTEP Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000)

Project Description: 765 kV circuit breaker installations at Hanging Rock

Details			
Investment	5,455,688	Current Year	2009
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	20.19%
Useful life	45	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)	No	Annual Depreciation Expense	121,238

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:
PROJECT'S 2008 HISTORIC YEAR REV. REQ. PER THIS TCOS FILING
LESS: PROJECT'S 2008 PROJECTED REV. REQ. PER PRIOR PERIOD TCOS

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	BPU Rev. Req't. w/o Incentives	BPU Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	BPU Rev. Req't.From Prior Year Template w/o Incentives	BPU Rev Req't True-up w/o Incentives	BPU Rev. Req't.From Prior Year Template with Incentives **	BPU Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2009	5,455,688	80,825	5,374,863	894,796	894,796	$ -	$ -	$ -		$ -	$ -
2010	5,374,863	121,238	5,253,625	1,182,052	1,182,052	$ -		$ -		$ -	$ -
2011	5,253,625	121,238	5,132,388	1,157,571	1,157,571	$ -		$ -		$ -	$ -
2012	5,132,388	121,238	5,011,150	1,133,091	1,133,091	$ -		$ -		$ -	$ -
2013	5,011,150	121,238	4,889,913	1,108,611	1,108,611	$ -		$ -		$ -	$ -
2014	4,889,913	121,238	4,768,675	1,084,130	1,084,130	$ -		$ -		$ -	$ -
2015	4,768,675	121,238	4,647,438	1,059,650	1,059,650	$ -		$ -		$ -	$ -
2016	4,647,438	121,238	4,526,200	1,035,170	1,035,170	$ -		$ -		$ -	$ -
2017	4,526,200	121,238	4,404,963	1,010,689	1,010,689	$ -		$ -		$ -	$ -
2018	4,404,963	121,238	4,283,725	986,209	986,209	$ -		$ -		$ -	$ -
2019	4,283,725	121,238	4,162,488	961,729	961,729	$ -		$ -		$ -	$ -
2020	4,162,488	121,238	4,041,250	937,248	937,248	$ -		$ -		$ -	$ -
2021	4,041,250	121,238	3,920,013	912,768	912,768	$ -		$ -		$ -	$ -
2022	3,920,013	121,238	3,798,775	888,288	888,288	$ -		$ -		$ -	$ -
2023	3,798,775	121,238	3,677,538	863,807	863,807	$ -		$ -		$ -	$ -
2024	3,677,538	121,238	3,556,300	839,327	839,327	$ -		$ -		$ -	$ -
2025	3,556,300	121,238	3,435,063	814,847	814,847	$ -		$ -		$ -	$ -
2026	3,435,063	121,238	3,313,825	790,366	790,366	$ -		$ -		$ -	$ -
2027	3,313,825	121,238	3,192,588	765,886	765,886	$ -		$ -		$ -	$ -
2028	3,192,588	121,238	3,071,350	741,406	741,406	$ -		$ -		$ -	$ -
2029	3,071,350	121,238	2,950,113	716,925	716,925	$ -		$ -		$ -	$ -
2030	2,950,113	121,238	2,828,875	692,445	692,445	$ -		$ -		$ -	$ -
2031	2,828,875	121,238	2,707,638	667,965	667,965	$ -		$ -		$ -	$ -
2032	2,707,638	121,238	2,586,400	643,485	643,485	$ -		$ -		$ -	$ -
2033	2,586,400	121,238	2,465,163	619,004	619,004	$ -		$ -		$ -	$ -
2034	2,465,163	121,238	2,343,925	594,524	594,524	$ -		$ -		$ -	$ -
2035	2,343,925	121,238	2,222,688	570,044	570,044	$ -		$ -		$ -	$ -
2036	2,222,688	121,238	2,101,450	545,563	545,563	$ -		$ -		$ -	$ -
2037	2,101,450	121,238	1,980,213	521,083	521,083	$ -		$ -		$ -	$ -
2038	1,980,213	121,238	1,858,975	496,603	496,603	$ -		$ -		$ -	$ -
2039	1,858,975	121,238	1,737,738	472,122	472,122	$ -		$ -		$ -	$ -
2040	1,737,738	121,238	1,616,500	447,642	447,642	$ -		$ -		$ -	$ -
2041	1,616,500	121,238	1,495,263	423,162	423,162	$ -		$ -		$ -	$ -
2042	1,495,263	121,238	1,374,025	398,681	398,681	$ -		$ -		$ -	$ -
2043	1,374,025	121,238	1,252,788	374,201	374,201	$ -		$ -		$ -	$ -
2044	1,252,788	121,238	1,131,550	349,721	349,721	$ -		$ -		$ -	$ -
2045	1,131,550	121,238	1,010,313	325,240	325,240	$ -		$ -		$ -	$ -
2046	1,010,313	121,238	889,075	300,760	300,760	$ -		$ -		$ -	$ -
2047	889,075	121,238	767,838	276,280	276,280	$ -		$ -		$ -	$ -
2048	767,838	121,238	646,600	251,799	251,799	$ -		$ -		$ -	$ -
2049	646,600	121,238	525,363	227,319	227,319	$ -		$ -		$ -	$ -
2050	525,363	121,238	404,125	202,839	202,839	$ -		$ -		$ -	$ -
2051	404,125	121,238	282,888	178,358	178,358	$ -		$ -		$ -	$ -
2052	282,888	121,238	161,650	153,878	153,878	$ -		$ -		$ -	$ -
2053	161,650	121,238	40,413	129,398	129,398	$ -		$ -		$ -	$ -
2054	40,413	40,413	-	40,413	40,413	$ -		$ -		$ -	$ -
2055	-	-	-	-	-	$ -		$ -		$ -	$ -
2056	-	-	-	-	-	$ -		$ -		$ -	$ -
2057	-	-	-	-	-	$ -		$ -		$ -	$ -
2058	-	-	-	-	-	$ -		$ -		$ -	$ -
2059	-	-	-	-	-	$ -		$ -		$ -	$ -
2060	-	-	-	-	-	$ -		$ -		$ -	$ -
2061	-	-	-	-	-	$ -		$ -		$ -	$ -
2062	-	-	-	-	-	$ -		$ -		$ -	$ -
2063	-	-	-	-	-	$ -		$ -		$ -	$ -
2064	-	-	-	-	-	$ -		$ -		$ -	$ -
2065	-	-	-	-	-	$ -		$ -		$ -	$ -
2066	-	-	-	-	-	$ -		$ -		$ -	$ -
2067	-	-	-	-	-	$ -		$ -		$ -	$ -
2068	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals		5,455,688		29,787,094	29,787,094	-					

** This is the total amount that needs to be reported to PJM for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

AEP East Companies
Cost of Service Formula Rate Using 2008 FF1 Balances
Worksheet Supporting Cost of Debt
OHIO POWER COMPANY

Calculation of Interest Expense Based on Outstanding Debt at Year End

(A) Issuance		(B) Principle Amount	(C) Interest Rate	(D) Annual Expense	(E) Notes
Long Term Debt (FF1.p. 256-257.h)					
Fixed Rate Prom. Notes Payable to Parent		200,000,000	5.250%	10,500,000	
Reacquired Bonds: IPC 04/2022		(35,000,000)	4.250%	(1,487,500)	
Reacquired Bonds: IPC 06/2022		(50,000,000)	3.700%	(1,850,000)	
Reacquired Bonds: IPC 04/2022		35,000,000	4.250%	1,487,500	
Reacquired Bonds: IPC 06/2022		50,000,000	3.700%	1,850,000	
Air Quality Bonds 05/2026		50,000,000	5.150%	2,575,000	
Air Quality Bonds 06/2037		65,000,000	4.900%	3,185,000	
Air Quality Bonds 06/2041		79,450,000	7.125%	5,660,813	
WVEDA - Mitchell - 2007 Series A		65,000,000	0.850%	552,500	
WVEDA - Kammer - 2007 Series B		50,000,000	1.000%	500,000	
WVEDA - Sporn - 2007 Series C		50,000,000	1.050%	525,000	
Unsecured Medium Term Notes due 02/2013		250,000,000	5.500%	13,750,000	
Unsecured Medium Term Notes due 02/2033		250,000,000	6.600%	16,500,000	
Unsecured Medium Term Notes due 01/2014		225,000,000	4.850%	10,912,500	
Unsecured Medium Term Notes due 07/2033		225,000,000	6.375%	14,343,750	
Unsecured Medium Term Notes due 11/2010		200,000,000	5.300%	10,600,000	
Unsecured Medium Term Notes due 06/2016		350,000,000	6.000%	21,000,000	
Unsecured Medium Term Notes due 04/2010		400,000,000	4.388%	17,552,000	
Unsecured Medium Term Notes due 09/2013		250,000,000	5.750%	14,375,000	
Issuance Discount, Premium, & Expenses:					
Financial Hedges & Auction Fees	FF1.p. 256 & 257.Lines Described as Hedges or Fees			(472,882)	
Amort of Debt Discount and Expenses	FF1.p. 117.63.c			2,211,243	
Amor of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
Reacquired Debt:					
Amortization of Loss	FF1.p. 117.64.c			1,618,264	
Amortization of Gain	FF1.p. 117.66.c			-	
Total Interest on Long Term Debt		2,709,450,000	5.384%	145,888,188	
Preferred Stock (FF1.p. 250-251)		**Preferred Shares Outstanding**			
4.08% Series - $103		1,459,500	4.08%	59,548	
4.20% Series - $103.20		2,282,400	4.20%	95,861	
4.40% Series - $104		3,148,200	4.40%	138,521	
4.50% Series - $110		9,737,300	4.50%	438,179	
Dividends on Preferred Stock		16,627,400	4.403%	732,108	

Calculation of Average Debt Balance in Rate Year

Long Term Debt @ December 31, 2008	2,709,450,000	
Long Term Debt @ December 31, 2009		(FF1, p.257.33.h)
Average Balance During 2009	2,709,450,000	

Calculation of Average Preferred Stock Balance in Rate Year

	Balance	Dividend	
Preferred Stock @ December 31, 2008	16,627,400		(FF1 p 112, Ln 3.c)
Preferred Stock @ December 31, 2009			(FF1 p 112, Ln 3.c)
Average Balance During 2009	16,627,400		(FF1 p. 118. Ln 29.c)

Attachment 5a
FERC Order on PPL Formula Rate

Attachment 5b
FERC Order on AEP-East Formula Rate

Attachment 5c
FERC Order on Formula Rate Modification for PHI Companies related to MAPP Project

125 FERC ¶ 61,121
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

PPL Electric Utilities Corporation — Docket Nos. ER08-1457-000, ER08-1457-001

ORDER ACCEPTING AND SUSPENDING TARRIFF SHEETS SUBJECT TO REFUND AND SUBJECT TO CONDITION, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEEDINGS

(Issued October 29, 2008)

1. On August 28, 2008, as amended on August 29, 2008, PPL Electric Utilities Corporation (PPL) submitted, pursuant to section 205 of the Federal Power Act (FPA),[1] revised tariff sheets to PJM Interconnection, L.L.C.'s (PJM) Open Access Transmission Tariff (OATT) to substitute a formula rate for its stated rates for the provision of network and point-to-point transmission service.[2] The formula rate incorporates a return on equity (ROE) of 12.84 percent, which includes a transmission rate incentive of 50 basis points for continued membership in PJM. The Commission accepts and suspends the revised tariff sheets to be effective November 1, 2008, subject to refund and condition, and the outcome of hearing and settlement judge procedures.

I. Background

2. PPL is a wholly-owned subsidiary of PPL Corporation and owns transmission and distribution facilities within PJM serving eastern and central Pennsylvania, and provides transmission service in accordance with PJM's OATT. PPL and its predecessors have been members of PJM and its predecessor organizations since 1927. PPL's currently-effective stated rates have been in effect since 1998.[3]

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[1] 16 U.S.C. § 824d (2006).

[2] *See* Appendix for list of tariff sheets.

[3] *PPL Electric Utilities Corp.*, 85 FERC ¶ 61,347 (1998).

3. On December 21, 2007 in Docket No. ER08-23-000, PPL, jointly with Public Service Electric and Gas Company, filed a petition for declaratory order pursuant to section 219 of the FPA[4] and Order No. 679[5] seeking rate incentives for a proposed 500-kV transmission project, the Susquehanna-Roseland Line (Susquehanna Line). The Susquehanna Line is a baseline project under PJM's Regional Transmission Expansion Plan.[6] It will span 130 miles across Pennsylvania to northern New Jersey and is expected to be completed by 2012. PPL's 84-mile portion of the Susquehanna Line is estimated to cost between $300 and $350 million.

4. In its petition for declaratory order, PPL requested the following Order No. 679 incentives: (1) a 50-basis point ROE adder for all of its transmission facilities for continued membership in an RTO; (2) a 150-basis point ROE adder for the risks and challenges faced by the Susquehanna Line; (3) authority to include 100 percent of construction work in progress (CWIP) expenses in rate base; and (4) 100 percent recovery of prudently incurred construction costs in the event that the Susquehanna Line is abandoned as a result of factors beyond its control.

5. On April 22, 2008, the Commission granted the request for declaratory order and approved PPL's requested incentives for continued membership in PJM, CWIP, and abandonment costs.[7] The Commission denied the request for a 150-basis point ROE adder, finding that based on the risks associated with the Susquehanna Line, a 125-basis point adder was more appropriate. The Commission noted that the 125-basis point adder would be bound by the upper end of the zone of reasonableness, which would be determined in a future section 205 filing.[8]

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[4] 16 U.S.C. § 824s (2006).

[5] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222; *order on reh 'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006); *order denying reh 'g*, 119 FERC ¶ 61,062 (2007).

[6] *See* PJM 2007 Regional Transmission Expansion Plan, http://www.pjm.com/planning/reg-trans-exp-plan.html. at 54 (noting that the PJM Board formally approved the Susquehanna Line in June 2007).

[7] *PPL Electric Utilities Corp. and Public Service Electric & Gas Co.*, 123 FERC ¶ 61,229 (2008).

[8] *Id.* P 39.

II. <u>Proposal</u>

6. On August 28, 2008, in Docket No. ER08-1457-000, PPL filed revised tariff sheets to implement a formula rate for transmission service based on its projected annual transmission revenue requirement (ATRR). On August 29, 2008, in Docket No. ER08-1457-001, PPL filed a substitute Exhibit No. 103 to it August 28 Filing. PPL proposes to use actual calendar year cost data from its FERC Form No. 1 to populate the formula rate spreadsheet or template. The formula rate includes inputs for ROE, forecasted plant additions, and CWIP for Commission-approved incentive projects. The ATRR produced by the formula is the sum of the return on rate base, operation and maintenance expense, depreciation expense, taxes other than income taxes, and income taxes less any applicable revenue credits. PPL proposes that the initial projected ATRR be in effect from November 1, 2008, through May 31, 2009. The initial ATRR will be based on actual costs as reflected in PPL's Form No. 1. Subsequent ATRRs will go into effect on June 1 of each succeeding year, based on the prior year actual costs and projected transmission capital additions for the rate year. The true-up mechanism reconciles projected costs with actual costs.

7. PPL proposes a base ROE of 12.34 percent as a stated value that is only subject to change pursuant to a filing under section 205 or 206 of the FPA. PPL states that this base ROE plus a 50-basis point adder for continued membership in PJM will result in an ROE for non-incentive projects that falls well within the zone of reasonableness. PPL further states that the 125 basis-point incentive for the Susquehanna Line will result in an ROE of 14.09 percent for that project, which it states is still within the zone of reasonableness.

8. To develop its proposed ROE, PPL states that it applied a discounted cash flow analysis to a sample of publicly-owned regulated electric utilities (or their holding companies) based on the Northeastern proxy group prescribed in *PATH*[9] and the guidance provided by the Commission in *SoCal Edison* and *Consumers Energy*.[10] PPL states that consistent with *PEPCO* and *VEPCO*,[11] its sample did not include: (1) companies that do not pay common dividends; (2) companies for whom no I/B/E/S growth rate or Value Line data is available; (3) companies who are involved in merger activities; and (4) companies whose business is comprised mainly of natural gas operations.

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[9] PPL Exhibit No. PPL-300 at 8, *citing Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 95-105 (2008) (*PATH)*.

[10] *Id.*, *citing Southern California Edison Co.*, 92 FERC ¶ 61,070 (2000) (*SoCal Edison)*; *Consumers Energy Co.,* 98 FERC ¶ 61,333 (2002) (*Consumers Energy*).

[11] *Id.* at 9, *citing Pepco Holdings, Inc.,* 124 FERC ¶ 61,176, at P 113 (2008) (*PEPCO*); *Va. Electric & Power Co.,* 123 FERC ¶ 61,098, at P 61 (2008) (*VEPCO*).

9. PPL states that it did not include companies that do not have a Standard and Poor's or Moody's credit quality rating equivalent to, one notch above, or one notch below the ratings for PPL and companies that have unsustainably high growth rates.[12] PPL states that consistent with the Commission's orders in *PEPCO* and *VEPCO*, it eliminated those utilities whose Standard and Poor's or Moody's credit ratings were more than one rating above or below its rating of A- (Standard and Poor's) and Baa1 (Moody's).[13] The resulting proxy group included utilities with a Standard and Poor's credit rating between A to BBB+ (or Moody's equivalent), which consists of American Electric Power Company Inc., Consolidated Edison Inc., Dominion Resources Inc., DPL Inc., Exelon Corporation, FPL Group, Inc., Northeast Utilities and Public Service Enterprise Group Inc. Based on this proxy group, PPL states that the zone of reasonable returns for its cost of equity is 8.35 percent to 16.32 percent. PPL is proposing a baseline ROE of 12.34 percent, which is the midpoint of this range.[14]

10. In addition to filing revised tariff sheets which include the non-populated formula template and protocols, PPL submitted a spreadsheet which shows the inputs for the initial projected ATRR.

III. Notice

11. Notice of PPL's filing was published in the *Federal Register*, 73 Fed. Reg. 52,348 (2008), with interventions and protests due on or before September 19, 2008. The Pennsylvania Public Utility Commission filed a notice of intervention. The Maryland Office of Peoples' Counsel, Pennsylvania Office of Consumer Advocate, Office of the Ohio Consumer Counsel, New Jersey Division of Rate Control, West Virginia Consumer Advocate Division, D.C. Office of People's Counsel (collectively, Consumer Advocates), American Municipal Power-Ohio, PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., PP&L Industrial Customer Alliance, Citizen's Electric Company, and Allegheny Power filed timely motions to intervene. Old Dominion Electric Cooperative filed an out-of-time motion to intervene.

[12] Consistent with the methodology prescribed in *PATH*, PPL used a starting sample of publicly-owned companies in PJM, New York Independent System Operator, Inc. and ISO-New England Inc. However, PPL's starting sample is not identical to the starting sample the Commission adopted in *PATH*. PPL did not explain why there was a difference in the starting group, nor did any party challenge the composition of the starting group. *See* PPL Exhibit No. PPL-300 at 9.

[13] *Id*.

[14] *Id.* at 12.

12. American Municipal Power-Ohio, PP&L Industrial Customer Alliance and Citizen's Electric Company (collectively, Joint Customers) and Consumer Advocates protested PPL's filing and requested that the proceeding be set for hearing. They contend that the inputs to the formula template, including the proposed ROE, are overstated, and therefore result in unjust and unreasonable rates. In addition, Joint Customers request that the filing be suspended for five months.

13. On October 6, 2008, PPL filed an answer to the protests of the Joint Customers.

IV. Commission Determination

A. Procedural Matters

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[15] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Given the early stage of the proceeding, its interests, and the absence of undue prejudice or delay, we will grant the untimely motion to intervene of Old Dominion Electric Cooperative.

15. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure,[16] prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept PPL's answer because it has provided information that assisted us in our decision-making process.

B. Formula Rate

16. PPL's proposed formula rate for transmission service is based on actual calendar year data as reflected in Form No. 1 and projected plant additions. PPL proposes to true-up its projected costs in its Annual Update. PPL's proposed formula rate incorporates the Order No. 679 rate incentives it received for the Susquehanna Line. Specifically, it reflects an ROE of 14.09 percent and 100 percent recovery of CWIP expenses in rate base. PPL's proposal reflects an ROE of 12.84 percent for all other transmission facilities.

17. We will accept and suspend PPL's revised tariff sheets to become effective November 1, 2008, subject to refund and condition. We will make substantive findings on certain issues regarding PPL's proposed protocols and set all remaining issues for hearing and settlement judge proceedings.

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[15] 18 C.F.R. § 385.214 (2008).

[16] *Id.* § 385.213(a)(2).

1. **Protests**

18. Consumer Advocates and Joint Customers argue that the ROE requested by PPL is unjust and unreasonable. Consumer Advocates argue that the base ROE of 12.34 percent appears to be excessive and when combined with the ROE incentive and the risk reducing formula rate may produce rates which are unjust and unreasonable. Joint Customers contend that PPL's proposed ROE is overstated, arguing that the transmission business is less risky than the generation business. Furthermore, Joint Customers contend that the conversion from stated rates to formula rates eliminates uncertainty regarding the collections of earnings. Joint Customers contend that the conversion prevents over- and under-recovery of transmission costs, thus reducing risk.

19. Joint Customers contend that PPL's zone of reasonableness is not appropriate and is excessive due to the inclusion of companies that have unsustainable growth rates and the use of duel credit rating criteria. Specifically, Joint Customers contend that PPL's proxy group is unreasonable due to the inclusion of Exelon and DPL which, it contends, have unsustainable growth rates of 13.62 percent and 11.72 percent, respectively. Joint Customers also contend that PPL's proposed 12.34 percent ROE is inflated due to the use of both Standard and Poor's and Moody's credit rating criteria, and therefore the ratings for the proxy group span four rating notches. Joint Customers further contend that the use of four notches results in PPL being less risky than the proxy group average and inflates its requested ROE. Joint Customers also contend that PPL's use of the midpoint instead of the median is not consistent with Commission precedent. Joint Customers recommend a zone of reasonableness of from 8.35 percent to 12.07 percent with a median of 10.21 percent.

20. Joint Customers raise a concern with PPL's proposal to use the year-end balances of plant in service to calculate its annual update and true-up transmission cost-of-service. They contend that Commission regulations require the use of 13-month average plant balances. They note that replacing the beginning and end-of-year average for transmission and general plant accumulated depreciation (with 13-month plant balances) reduces PPL's proposed increase by approximately $1.3 million or 10.6 percent of the requested increase.

21. Joint Customers are also concerned with several unexplained increase in costs. For example, *Account No. 923- Outside Service Employed,* as shown in PPL's 2006 and 2007 Form No. 1, increased by $2.7 million or 240 percent between 2006 and 2007. In addition, *Account No. 924 – Property Insurance* increased from 2006 by $7.5 million or 77 percent over the previous year. Further, Joint Customers note that a comparison of the Form No. 1 for 2006 and 2007 shows an increase in costs for *Account No. 926 – Employee Pensions and Benefits* from a credit of $4.5 million in 2006 to a debit of $32.6 million in 2007.

22. Joint Customers request that non-current liabilities that have already been funded through rates be treated as an offset to the transmission rate base. In addition, Joint Customers are concerned that accumulated deferred income tax costs, which reduce the transmission cost-of-service, are not allocated properly. Specifically, they are concerned with costs for pension and post retirement, revenue agent rulings, deferred inter-company gains, trademark sales, and receivables factoring.

23. Joint Customers request that *Account No. 190 – Contribution in Aid of Construction*, be examined to determine if the cost is properly allocated to the transmission cost-of-service. They are also concerned that PPL's formula template indicates that the interest rate will be calculated based on the interest rate for "March of the Current Year,"[17] may not be consistent with Commission regulations, which require a change in the interest rate with each calendar quarter.

24. Joint Customers request further information to determine the reasonableness of *Account No. 165 - Prepayments* which shows an increase of $13.4 million, or 92 percent, over the previous year's balance sheet.

25. Joint Customers note that the sole support for PPL's amortized investment tax credits, land held for future use, and post-retirement benefits other than pension, as shown on Attachment 5 to the formula template, is "company records." They state that this information is not sufficient to determine if these components of the rate were properly developed.

26. Joint Customers state that PPL provides no explanations of the revenue credits or the method used to assign those credits between transmission and non-transmission functions. They note that the 2007 Form No. 1 total for two revenue credit accounts, *Account No. 454 – Rents* and *Account No. 456 – Other Electric Revenues*, was $38.4 million. They further note that only $10.8 million was included in Attachment 3 to the formula template as transmission-related revenue credits. Joint Customers request further analysis to determine if PPL properly allocated the transmission-related credits. Finally, Joint Customers state that PPL's filing is unclear as to whether labor costs associated with PPL's merchant function operations are included in the determination of labor allocators.

2. Commission Determination

27. Our preliminary analysis indicates that PPL's proposed tariff sheets have not been shown to be just and reasonable and may be unjust and unreasonable and unduly discriminatory or preferential, or otherwise unlawful. We will therefore accept and

[17] PPL Exhibit No. PPL-103 at 14.

suspend PPL's revised tariff sheets to become effective November 1, 2008, subject to refund and condition. We also set the proposed formula rate for hearing and settlement judge procedures. In order to allow the parties to resolve their concerns, we will not limit the scope of the proceeding, except to the extent that the specific issues are addressed *infra.*

28. The Commission has encouraged public utilities to explore the benefits of filing transmission-related formula rates.[18] Further, the Commission has found that the use of formula rates encourages the construction and timely placement into service of needed transmission infrastructure.[19] In *West Texas*,[20] The Commission explained that, when its preliminary examination indicates that the proposed rates may be unjust and unreasonable and substantially excessive, the Commission will impose a maximum, five-month suspension. In this proceeding, our preliminary analysis indicates that PPL's proposed formula rate raises issues of material fact that cannot be resolved based on the record before us. Accordingly, we will accept PPL's revised tariff sheets subject to condition, and suspend PPL's proposed transmission formula rate to become effective November 1, 2008, subject to refund, and to the outcome of hearing and settlement judge procedures. In balancing our previous finding that formula rates encourage timely investment in needed transmission infrastructure with our concern that the proposed rates may be unjust and unreasonable, we find that a minimum suspension period is appropriate.

C. Annual Updates

1. Information Provided with Annual Update

a. Proposal

29. PPL proposes detailed protocols for populating and updating the formula rate template. Under its proposed protocols, in May of each year, PPL will provide its Annual Update. The Annual Update will be used to develop the next rate year's ATRR by populating the formula rate template using data contained in its Form No. 1 for the prior calendar year, plus projected capital additions for the current year. The Annual Update

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[18] *See Promoting Transmission Investment through Pricing Reform*, Order No. 679 at P 386, citing *Allegheny Power System Operating Companies*, 111 FERC ¶ 61,308, at P 51 (2005); *Allegheny Power System Operating Companies,* 106 FERC ¶ 61,003, at P 32 (2004).

[19] *See Northeast Utilities Service Company,* 105 FERC ¶ 61,089, at P 23 (2003).

[20] *West Texas Utilities Company*, 18 FERC ¶ 61,189 (1982) (*West Texas*).

will also be used to true-up the previous rate year's ATRR. The true-up mechanism, which is a line item in the formula template, compares the estimated ATRR for the previous rate year with the actual costs for that year. The difference between the projected and actual costs, plus interest, will be added or subtracted from the next year's projected ATRR. PPL will post the populated formula template, cost support and exhibits on PJM's website. In addition, PPL will file the Annual Update with the Commission, for informational purposes only. PPL states that it has established protocols to provide a process for parties to challenge the formula rate calculations and cost support. It further states that any changes to the data used to populate the rate formula template will be reflected in the ATRR for the following year, with interest.

b. Protest and Answer

30. Joint Customers contend that, as a general matter, PPL will post the numerical inputs with little explanatory material in the Annual Update. To facilitate a less adversarial process, Joint Customers request that the Commission direct PPL to provide more explanatory material, such as workpapers, adjustments not shown in the Form No. 1, and material changes, as part of its Annual Update. Joint Customers further contend that PPL's proposal limits the review and challenges of the Annual Update to the "accuracy of data" and "consistency" with the formula template and contains no protections to ensure that only prudent costs are passed through the formula. Joint Customers also contend that PPL's protocols do not address the specific rights and procedures which will apply to the true-up mechanism. Finally, Joint Customers request that the last sentence of section 3.b. be deleted from the revised tariff sheets because it is superfluous, ambiguous and overly broad. The sentence reads:

> In addition, such information requests shall not solicit information concerning costs or allocations where the costs or allocation method have been determined by FERC or in the context of other Annual Updates, except that such information requests shall be permitted if they seek to determine if there has been a material change in circumstances.

31. In its answer, PPL states that Joint Customers misread its filing and that the information necessary to review the formula inputs is either available in Form No. 1, or posted as a supplement on the PJM website. Further, PPL states that the proposed protocols place no limits on either the substance or coordination of discovery. Finally, PPL explains that the above sentence only limits information requests on matters that have already been settled by the Commission or in response to previous Annual Updates.

c. Commission Determination

32. The Commission finds that section 1.g. of PPL's proposed protocols provide the type of specific information requested by the Joint Customers with respect to the source of the data, supporting workpapers and explanations, and the accuracy and prudency of

costs. Therefore, the Commission finds that the Joint Customers' recommendations are not necessary. In addition, the Commission finds that the concerns of the Consumer Advocates are fully addressed.

2. Challenges to Annual Update

a. Proposal

33. PPL's proposed protocols establish a process for review of inputs to the formula rate, and define time limits for raising preliminary and formal challenges to the application of the formula rate, including challenges related to material accounting changes, and resolution of challenges.[21] Under PPL's proposed protocols, parties have an opportunity to challenge the calculations and cost support, including the prudence of the costs and the accuracy of the data. Specifically, parties will have 150 days from the date the calculations and cost support are published on PJM's website to review the data. If necessary, the parties may submit preliminary written challenges to PPL. Further, the protocols provide that during the review period, parties will have 120 days to serve "reasonable" information requests on PPL and PPL will make a good faith attempt to respond to such requests within 15 days. If a preliminary challenge is made, the protocols provide that parties will have a 21-day period to resolve the dispute regarding the formula inputs. However, if parties are unable to resolve the dispute, the protocols provide that they have an additional 21 days to file a complaint with the Commission pursuant to FPA section 206. Subsection 4(d) further provides:

> Subject to judicial review of FERC orders, each annual update shall become final and no longer subject to challenge pursuant to these Annual Review Protocols or by any other means by FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) following the Review Period for making a Formal Challenge if no such challenge has been made and FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by FERC to consider the Annual Update.

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[21] FERC Electric Tariff, Sixth Revised Volume No. 1, Attachment H-8H, Sheets No. 309VVV- XXX, Sections 3 and 4.

b. Protest and Answer

34. Joint Customers contend that section 4(d) is directly contrary to the Commission's order in *VEPCO,*[22] and requests that the Commission direct PPL to remove the provision from its protocols.

35. In its answer, PPL offers to submit a compliance filing to address this concern, in light of the Commission's findings in *PSE&G* and *AEP*.[23] In the compliance filing, PPL states that it will amend section 4.e [sic] of its protocols to eliminate the cut-off date by which parties must file a complaint or the omission may institute a complaint pursuant to section 206 of the FPA.

c. Commission Determination

36. As we stated in *VEPCO*, *PSE&G* and *AEP*, the courts have recognized that FPA section 206 permits customers to challenge formula rates.[24] The Commission's long-standing precedent is that, under formula rates, parties have the right to challenge the inputs to or the implementation of the formula at whatever time they discover errors in the inputs to or implementation of the formula.[25] Indeed, customers may not uncover

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[22] Joint Customers Protest at 28, *citing VEPCO*, 123 FERC ¶ 61,098 at P 46.

[23] *Pub. Serv. Elec. & Gas Co.*, 124 FERC ¶ 61,303 (2008) (*PSE&G*); *American Elec. Power Co.*, 124 FERC ¶ 61,306 (2008) (*AEP*).

[24] *Citing Public Utilities Commission of California v. FERC*, 254 F.3d 250, 258 (D.C. Cir. 2001) ("Because relief can be sought pursuant to section 206 in the event a pass through of … costs results in unjust and unreasonable rates, the Commission's acceptance of the ISO's formula rate without additional section 205 filings does not leave the [state public utilities commission] or ratepayers without any statutory recourse.").

[25] *North Carolina Electric Membership Cooperative v. Carolina Power & Light Co.*, 57 FERC ¶ 61,332, at 62,065 (1991) (rejecting the utility's efforts to limit the period of review to the prior 12 months by stating "[w]hile prompt identification of disputes is certainly a reasonable goal to strive for, the Commission cannot allow utilities to recover excessive rates through automatic adjustment clauses because the customer did not complain in as prompt a manner as the company believes the customer should have."). The Commission has held repeatedly that it may order refunds for past periods where a utility has either misapplied a formula rate or otherwise charged rates contrary to the filed rate. *See Appalachian Power Co.*, 23 FERC ¶ 61,032, at 61,088 (1983); *DTE Energy Trading, Inc. v. Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,062, at P 28 (2005); *Quest Energy, L.L.C. v. The Detroit Edison Co.*, 106 FERC ¶ 61,227, at P 21 (2004).

errors in data or imprudent or otherwise inappropriate costs until well after the challenge period.[26] Accordingly, we will require PPL to make a compliance filing within 30 days of the date of this order to revise the protocols so that they do not limit a customer's or the Commission's rights with respect to challenges to the inputs into the formula rate.

D. Informational Filing

37. Section 1.b. of PPL's proposed protocols provides that PPL file its Annual Update,[27] with supporting documentation, with the Commission on or before May 15 of each year. The provision states:

> The submission of such information filing with FERC shall not be noticed nor require any action by the agency.

38. Although PPL states that its proposed formula is "virtually identical" to numerous formula rates approved by the Commission for other utilities in PJM,[28] the Commission finds that the language is a deviation from the language approved as part of the formula rates for other utilities in PJM. In all of the formula rates contained in PJM's OATT, the tariff language specifies that the utility will make an information filing with the Commission and that the filing will not require Commission action. PPL's proposed language, without explanation, restricts the Commission's ability to notice the Annual Updates when they are filed. This Commission will not bind future Commissions from noticing an Annual Filing. Therefore, PPL is required to make a compliance filing within 30 days of the date of this order to delete the words "be noticed nor" from section 1.b. of its proposed protocols.

E. Hearing and Settlement Judge Procedures

39. Although we are setting issues relating to the formula rate inputs, including ROE, for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge

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[26] *See, e.g., Yankee Atomic Electric Co.*, 60 FERC ¶ 61,316, at 62,096-97 (1992) (allowing review of potentially imprudent costs charged to customers in prior-year formula rates).

[27] FERC Electric Tariff, Sixth Revised Volume No. 1, Attachment H-8H, Sheet No. 309SSS, Section 1.b.

[28] PPL Exhibit No. PPL-100 at 6-7.

be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[29] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[30] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

F. <u>Waiver Requests</u>

40. PPL requests waiver of the following sections of the Commission's regulations: section 35.13(d)(1)-(2) (requiring submission of Period I and Period II data for Statements AA through BL);[31] section 35.13(d)(5) (requiring submission of workpapers related to Period I and Period II data);[32] and section 35.13(h) (requiring cost of service statements).[33] In addition, PPL requests a limited waiver of the requirements under section (c)(7) of Schedule 12 of the PJM OATT in order to coordinate the timing of the annual filing under that section with the annual updates under the proposed formula rates. In Statement BM, PPL also requests waiver of section 35.25(c)(4) (forward looking Allocation ratios),[34] and section 35.25(g) (anticompetitive procedures).[35]

41. Joint Consumers contends that PPL should be required to file the Period I and Period II date required by section 35.13 of the Commission's regulations. Joint Consumers state that this information will assist the Commission and parties in the evaluation of overall system costs and in the allocation of costs to PPL's transmission

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[29] 18 C.F.R. § 385.603 (2008).

[30] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their background and experience (www.ferc.gov – click on Office of Administrative Law Judges).

[31] 18 C.F.R. § 35.13(d)(1)-(2) (2008).

[32] *Id.* § 35.13(d)(5).

[33] *Id.* § 35.13(h), except Statement BM, 18 C.F.R. § 35.13(h)(38).

[34] *Id.* § 35.25(c)(4).

[35] *Id.* § 35.25(g).

function. The Commission grants PPL the requested waivers. The waiver of the Period I and Period II filing requirements does not preclude parties from requesting additional information on cost inputs and supporting documentation as part of the hearing and settlement judge proceedings.

The Commission orders:

(A) PPL's revised tariff sheets to the PJM OATT are accepted for filing, as discussed in the body of this order, and suspended for a nominal period to be effective November 1, 2008, subject to refund.

(B) PPL is ordered to file revised tariff sheets to PJM's OATT within 30 days of this order, as discussed in the body of this order.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act, and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held concerning PPL's proposed formula rate filing. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (E) and (F) below.

(D) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2008), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(E) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(F) If settlement judge procedures fail, and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in this proceeding in a hearing room of the Commission, 888 First Street, N.E., Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

Tariff Sheets Accepted and Suspended
Subject to Condition and Subject to Refund
Effective November 1, 2008

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Sixth Revised Sheet No. 26
Seventh Revised Sheet No. 245
Thirteenth Revised Sheet No. 247
Third Revised Sheet No. 270E.08b
Second Revised Sheet No. 307
First Revised Sheet No. 308
Original Sheet No. 309AAA
Original Sheet No. 309BBB
Original Sheet No. 309CCC
Original Sheet No. 309DDD
Original Sheet No. 309EEE
Original Sheet No. 309FFF
Original Sheet No. 309GGG
Original Sheet No. 309HHH
Original Sheet No. 309III
Original Sheet No. 309JJJ
Original Sheet No. 309KKK
Original Sheet No. 309LLL
Original Sheet No. 309MMM
Original Sheet No. 309NNN
Original Sheet No. 309OOO
Original Sheet No. 309PPP
Original Sheet No. 309QQQ
Original Sheet No. 309RRR
Original Sheet No. 309SSS
Original Sheet No. 309TTT
Original Sheet No. 309UUU
Original Sheet No. 309VVV
Original Sheet No. 309WWW
Original Sheet No. 309XXX

124 FERC ¶ 61,306
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

American Electric Power Service Corporation — Docket No. ER08-1329-000

ORDER ACCEPTING AND SUSPENDING FORMULA RATE SUBJECT TO REFUND AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued September 30, 2008)

1. On July 31, 2008, American Electric Power Service Corporation (AEP) submitted, pursuant to section 205 of the Federal Power Act (FPA),[1] revised tariff sheets on behalf of its seven 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 (collectively, AEP East Companies). The revised tariff sheets would increase transmission rates in AEP's zone by 12.15 percent in the initial year and would establish formula rates that would be automatically adjusted each year based on changes to AEP's costs as reported annually in the FERC Form No. 1, without contemporaneous requests for approval under section 205. We accept the revised tariff sheets for filing, suspend their effectiveness for five months, to be effective March 1, 2009, subject to refund and condition, and to the outcome of hearing and settlement judge procedures.

I. Background

2. The Open Access Transmission Tariff (OATT) of the PJM Interconnection, L.L.C. (PJM) contains zonal rates and allows each transmission owning member to make filings to maintain a current revenue requirement. The annual transmission revenue requirement

[1] 16 U.S.C. § 824d (2006).

for the AEP's Zone in PJM is reflected in Attachment H-14 of the PJM OATT.[2] Each pricing zone's transmission revenue requirement forms the basis for deriving unit charges for Network Integration Transmission Service (NITS) for load located within the pricing zone. On December 20, 2005, as amended on April 26, 2006, the Commission approved a settlement agreement that established the current stated transmission revenue requirements.[3] AEP's existing zonal rate is fixed at $1,757.40/MW-month and is based a projected 2005 transmission revenue requirement of $487.6 million.

II. Filing

3. AEP proposes tariff sheets that would revise Attachment H-14 of the PJM OATT to provide for a forward looking formula rate, an annual true-up of that rate, and customer protocols governing such annual updates. The revised tariff sheets are in two parts: Attachment H-14A, the Formula Rate Implementation Protocols, and H-14B, the Formula Rate Template. The revised tariff sheets would convert AEP's existing transmission service rate to an annually updated cost-of-service formula rate. The proposed formula rate contains three cost-of-service provisions: (1) a historic cost-of-service, (2) a projected cost-of-service, and (3) a true-up cost-of-service, including protocols for updating the formula rate.[4] AEP proposes to recalculate the revenue requirement under the formula rate with historical data, using FERC Form No. 1 cost data as well as data from its accounting ledgers. For each subsequent year, the historical cost-of-service data is based on the prior year's expenses and plant in service. For the projected cost-of-service, AEP proposes to calculate adjustments to recognize transmission plant additions and associated depreciation for new plant that have gone into

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[2] The operating companies in AEP's East zone provide transmission service in Ohio, Virginia, West Virginia, Indiana, Michigan, Kentucky, and Tennessee.

[3] *See American Electric Power Service Corporation*, 113 FERC ¶ 61,294 (2005); *American Electric Power Service Corporation*, 115 FERC ¶ 61,114 (2006). Different transmission revenue requirements were tied to the in-service date of the Wyoming Jackson's Ferry 765 kV transmission line. (*See E*xhibit AEP - 303 Revised Sheet No. 314B-01.)

[4] AEP also provides *pro forma* Schedules 1A, Transmission Owner Scheduling, System Control and Dispatch Service, *pro forma* Schedule 7, Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service, and *pro forma* Schedule 8, Non-Firm Point-To-Point Transmission Service. AEP's rates under these schedules will change after each Annual Update, these schedules however relate to multiple PJM pricing zones, as opposed to Schedule H-14 which is specific to the AEP East Companies. *See* Exhibit AEP – 302 for AEP's tariff sheets proposed under the PJM OATT.

service or are expected to go into service in the current calendar year in order to produce an estimate of the cost-of-service for that year.[5] AEP notes that the only elements in its cost-of-service that are projected are those related to transmission plant in service additions and depreciation expense on new and existing plant in service. The true-up cost-of-service will use the prior year actual cost-of-service, and the difference between the collected cost-of-service and the true-up cost-of-service will be collected (or refunded) with the projected cost-of-service when AEP makes its annual update. Subject to true-up, the first year annual transmission revenue requirement for network service under the proposed formula is approximately $586.8 million.[6] AEP contends that its proposal for annual updates to its formula rate is similar to recently approved protocols in the PJM region.[7]

4. The return on equity is a stated rate, subject to change pursuant to section 205 or 206 of the FPA. AEP uses a proxy group of transmission owning utilities from PJM, the New York Independent System Operator, and New England RTO to determine central tendency. In calculating the return on equity, AEP proposes to apply the midpoint as opposed to the median of the proxy group, as most recently applied by the Commission for individual utilities.[8] AEP believes that using a midpoint methodology is more appropriate for a utility of its size, serving customers in multiple RTOs, and because it raises capital as a single entity. AEP proposes a 12.1 percent return on equity, including

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[5] AEP also advises that Attachment H-14 has been modified to delete the network contract demand reservation service option used by customers with behind-the-meter generation. AEP explains that customers that used a similar option in the AEP OATT now take standard NITS service and the PJM OATT has been amended, pursuant to a settlement agreement. *See PJM Interconnection, L.L.C.*, 113 FERC ¶ 61,279 (2005) (clarifying the conditions under which behind-the-meter generation may be used to reduce a customer's Network Load).

[6] The overall AEP zone cost of service is $606.7 million before other transmission-related revenue credits. When the proposed annual transmission revenue requirement is divided by the single annual coincident peak (24,809.3 MW) in AEP's pricing zone, and then by twelve months, the resulting rate for network transmission service is $1,970.92/kW-month, reflecting a 12.15 percent increase from AEP's existing $1,757.40/MW-month stated rate. See Exhibit AEP-901.

[7] *Citing Duquesne Light Co.*, 123 FERC ¶ 61,139 (2008) (*Duquesne*); *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008) (*Commonwealth Edison*).

[8] *Citing Virginia Electric and Power Company*, 123 FERC ¶ 61,098 (2008) (*VEPCO*).

a proposed 50 basis point incentive adder for continued participation in PJM.[9] AEP does not propose, at this time, incentive rate treatment except for the adder for its continued participation in PJM. However, in order to allow AEP to include certain rate treatments that it may seek and the Commission may authorize in the future, AEP's proposed formula rate includes a placeholder for recovery of Construction Work In Progress (CWIP), which may include 100 percent of CWIP,[10] as may be allowed by the Commission. No CWIP balances have been included in rate base in the proposed formula rate proposal, and AEP does not anticipate requesting CWIP for short lead-time projects, but has provided for the possibility for projects that will require a multi-year construction period.

5. In addition, AEP proposes to use the annual beginning and ending rate base balances from FERC Form No. 1 instead of the 13-month average method to determine the true-up rate base to construct the true-up cost-of-service study. Because this information can be derived from annual FERC filings, AEP supports this methodology as administratively simple, verifiable and using readily available FERC Form No. 1 data rather than through monthly financial statements.

6. AEP explains that it has chosen to move from stated rates to a formula rate because, in addition to the Commission's encouragement,[11] more current cost recovery will assist AEP and PJM in developing needed transmission infrastructure. AEP requests an effective date of October 1, 2008, and that its proposed rates be accepted for filing without an evidentiary hearing or with only a nominal suspension.[12] AEP further requests that, if the Commission establishes a hearing, the Commission should specify the issues set for hearing and not permit parties to litigate formula rate provisions that the Commission has approved for other transmission owners.

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[9] AEP derives a base return on equity of 11.6 percent from a range of 7.8 percent to 15.5 percent.

[10] *See Promoting Transmission Investment through Pricing Reform*, Order No. 679 at P 115, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[11] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386.

[12] AEP cites instances in which the Commission has accepted formula rates with a nominal suspension, citing *Idaho Power Co.*, 115 FERC ¶ 61,281, at P 30 (2006); *Duquesne*, 118 FERC ¶ 61,087 at P 69; and *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 (2007).

III. Notice, Intervention, Comments, and Protests and Answer

7. Notice of AEP's filing was published in the *Federal Register*, 73 Fed. Reg. 46,621 (2008), with interventions and protests due on or before August 21, 2008, which was subsequently extended to August 29, 2008.

8. IMPA, American Municipal Power-Ohio, Inc., Wabash Valley Power Association, Blue Ridge Power Agency, Buckeye Power, Inc., AEP Intervenor Group, Dominion Resources Services, Inc.,[13] PPL Electric Utilities Corporation, Steel Dynamics, Inc., FirstEnergy Companies,[14] North Carolina Electric Membership Corporation, PHI Companies,[15] Ameren Services Company,[16] Old Dominion Electric Cooperative, PSEG Companies, Hoosier Energy Rural Electric Cooperative, Inc., Exelon Corporation, City of Dowagiac, Indiana and Michigan Municipal Distributors Association, Consumers Energy Company, Joint Intervenors,[17] Office of the Attorney General of the Commonwealth of Virginia (VA Consumer Counsel), Maryland Office of People's Counsel (Maryland OPC), and Craig Botetourt Electric Cooperative filed timely motions

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[13] On behalf of Virginia Electric and Power Company.

[14] The FirstEnergy Companies are Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company.

[15] On behalf of Pepco Holdings, Inc., Potomac Electric Power Company, Atlantic City Electric Company, and Delmarva Power & Light Company.

[16] On behalf of Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Company, Illinois Power Company, Ameren Energy Marketing Company, Ameren Energy Generating Company, and Ameren Energy Resources Generating Company.

[17] The Joint Intervenors are IMPA, American Municipal Power-Ohio, Inc., Wabash Valley Power Association, Blue Ridge Power Agency, Buckeye Power, Inc., AEP Intervenor Group, Craig Botetourt Electric Cooperative, Old Dominion Electric Cooperative, City of Dowagiac, Indiana and Michigan Municipal Distributors Association, and Musser Companies.

to intervene. Protests were filed by the Joint Intervenors,[18] VA Consumer Counsel, and Maryland OPC.[19]

9. The protestors assert numerous instances where AEP's protocols for updating the formula rate and challenging application of the formula rate are insufficient to ensure that AEP's rates are just and reasonable, are unreasonably restrictive on customers as to the scope of what can be challenged. Joint Intervenors also complain that AEP's revenue requirements are the results of seven separate companies, and its formula rate proposal is significantly more complex than that presented by the *Commonwealth Edison* and *Duquesne* formula rate proposals.[20] Joint Intervenors argue that AEP's proposal needs clarification and supporting workpapers, pointing to the timing, format, and scope of information to be posted as part of AEP's annual update. Joint Intervenors contend that they, and other interested parties, have the obligation and right to a thorough investigation of sufficient information to fully understand the nature of the current transmission-related costs incurred by the AEP East Companies as well as how those costs are intended to be recovered in the proposed formula rate. Joint Intervenors contend that the annual update protocols should provide for a meeting of interested parties each year to discuss the annual update, rather than trying to pursue potential issues through successive rounds of interrogatories.

10. The protestors assert that AEP's protocols impose unlawful limits on a party's statutory rights pursuant to FPA section 206. Specifically, protestors complain that the proposal seeks to include a "Preliminary Challenge" as prerequisite to an "Interested Party" filing a complaint under FPA section 206 (referred to as a "Formal Challenge" in AEP's Formula Rate Implementation Protocols).[21] Protestors complain that the definition of Interested Party is too narrowly limited. Further, protestors complain that the protocols establishing Preliminary Challenge procedures are inconsistent with FPA section 206. Protestors also contend that the protocol's provisions to modify the formula rate pursuant to either a Preliminary or Formal Challenge establish a standard that

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[18] Joint Intervenors included supporting affidavits of Robert C. Smith and J. Bertram Solomon.

[19] Maryland OPC included a supporting affidavit of Charles W. King. On September 5, 2008, Maryland OPC filed an erratum to the affidavit of Charles W. King.

[20] Joint Intervenors' Protest at 11-12.

[21] VA Consumer Council's Protest at 7-9; Joint Intervenors' Protest at 22-27, *citing VEPCO*, 123 FERC ¶ 61,098 (2008).

exceeds the requirements of section 206 of the FPA. In addition, the protestors contend that the proposed protocols place unreasonable limits on prudence challenges, and that the protocols treatment of material accounting changes is unclear, confusing, and may be unreasonably restrictive.

11. The protestors contend that AEP's proposed total return on equity is likely to result in rates that are unjust and unreasonable. Joint Intervenors and Maryland OPC raise concern with the appropriateness, given the Commission's precedent,[22] of AEP's proposal to use the midpoint rather than median of the proxy group data points for return on equity. In addition, protesters contend that AEP's proposed 11.6 percent return on equity, which is equal to the midpoint of the 7.8 percent and 15.5 percent range of the proxy group, is due to the competitive and unregulated portions of the proxy group companies' revenues that have contributed to the high growth rates, rather than the regulated transmission portion of these companies' revenues.[23] Thus, Maryland OPC and Joint Intervenors contend that AEP's proxy group has not been sufficiently screened for risk and unsustainable growth rates.[24] Maryland OPC argues that AEP's request is disputed by expert testimonial and factual evidence, and because expert testimony requires evaluation expert witnesses' credibility, the Commission should deny or reject AEP's request and set the case for evidentiary hearing.

12. As demonstrated within its protest, and supported with attached affidavits, Joint Intervenors contend that AEP's proposed $63.6 million rate increase should be reduced by $48.1 million or 75 percent, as follows:

Issue	Reduction in Revenue Requirement
1. Return on Equity	$30,400,000
2. Prepaid Pensions in Rate Base	$4,000,000
3. Hedging cost in LTD rates	$6,700,000

[22] *Citing VEPCO*, 123 FERC ¶ 61,098 at P 67; *Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Company*, Opinion No. 501, 123 FERC ¶ 61,047 (2008); *Northwest Pipeline Corporation*, 99 FERC ¶ 61,305 (2002).

[23] *Citing* Standard & Poor's "Research Summary," February 13, 2007; and Form 10-K, Public Service Enterprise Group, Inc. (accessed July 20, 2008).

[24] *Citing Potomac-Appalachian Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 105 & n.110 (2008); *see* Joint Intervenors' Protest at 30-34.

4. ADIT items unrelated to Transmission	$2,700,000
5. 13-month Average Rate Base	$4,300,000
Total Quantifiable Impacts	$48,100,000

13. In addition, Joint Intervenors contend that other questionable areas where discovery could well yield further reductions are to include: (a) Cash Working Capital in Rate Base, (b) Property Taxes Allocations, (c) Revenue Credits, (d) Business Development Expense, and the Wages & Salaries allocator.

14. Joint Intervenors request that the Commission reject AEP's request to accept its formula rate without a hearing or put its proposed rates into effect only after a nominal suspension period. Joint Intervenors request that the Commission follow its traditional suspension policy under *West Texas*,[25] and suspend AEP's rates for the full five-month suspension period, and set this matter for an evidentiary hearing. However, given AEP's history of working cooperatively toward settlement and AEP's contemplation of such process as an alternative form of relief, Joint Intervenors request that the Commission direct the Chief Administrative Law Judge to appoint a settlement judge while the evidentiary hearing is being held in abeyance.

15. On September 15, 2008, AEP filed an answer to the protests. AEP contends that its protocols for review of its annual update are adequate, and consistent with or more extensive and customer friendly than the Commission has approved in other cases.[26] Specifically, AEP argues that the protocols for annual updates places appropriate limits on inquiries and challenges that are related to the proper application of the formula, not to the just and reasonableness of the formula itself. AEP contends that the protestors incorrectly read the protocols as imposing limits on parties and the Commission, and that the protocols do not limit any party's FPA rights.[27] AEP also contends that the protocols provide a reasonable process for ensuring that application of the formula rate, once determined by the Commission to be just and reasonable, is accurate.

[25] *West Texas Utilities Company*, 18 FERC ¶ 61,189 (1982) (*West Texas*) (five-month suspension warranted when more than ten percent of the proposed increase is found to be excessive).

[26] AEP Answer at 3-4.

[27] *Id.* at 6-8.

16. In addition, AEP contends that the protestors seem to have confused the Formal Challenge within its protocols with a FPA section 206 complaint process. AEP argues that the protocols in its proposal contain no language prohibiting any party from raising any issue in a FPA section 206 complaint. AEP states that a complaint filed under the Formal Challenge procedures established by its protocols is filed pursuant to Rule 206 of the Commission's Rules of Practice and Procedure. In this instance, AEP has the burden of proving that its annual update is consistent with the filed rate under a preliminary challenge. However, AEP contends that complainants would have that burden in complaints filed pursuant to FPA section 206.

17. AEP differentiates provisions related to material accounting changes from other provisions to determine the accuracy of its formula rate annual update.[28] AEP contends that the central question surrounding the application of a material accounting change is not whether the change is consistent with the filed rate, rather whether the change renders the filed rate no longer just and reasonable. AEP contends that the question of whether a formula rate change proposed by an Interested Party in response to a material accounting change would change the original intent of the formula is relevant to the determination of the justness and reasonableness of such a proposed change. AEP contends that this is a reasonable attempt to limit unnecessary litigation over issues already addressed in the approval of the formula rate.

18. AEP objects to proposed language changes related to the burden of proof standards for challenges to the prudency of new expenditures.[29] AEP contends that protestors proposed language has the potential to create additional issues for litigation,[30] and that the language in the protocols is consistent with Commission precedent. Additionally, AEP states that it did not intend to exclude any customer who is eligible to take service from the PJM OATT, and would be willing to change the definition of Interested Party. AEP also states that it did not intend to obligate parties to coordinate information requests.

19. AEP answers that its proposed average rate base calculation is appropriate.[31] AEP also contends that its proposed return on equity is just and reasonable and supported by

[28] *Id.* at 8-9.

[29] *Id.* at 9-10.

[30] Id. at 10, referencing Joint Intervenors' Protest at 25.

[31] *Id.* at 11.

its analysis, and that its proxy group selection is consistent with Commission precedent.[32] AEP also disputes the cost-of-service issues raised by the protestors, agrees that some issues may warrant hearing or settlement procedures, and contends that many of these issues do not warrant a hearing for the Commission to address.[33]

IV. Discussion

A. Procedural Matters

20. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[34] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

21. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure,[35] prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept AEP's answer because it has provided information that assisted us in our decision-making process.

B. Substantive Determinations

22. We will accept, subject to a compliance filing as discussed below, and suspend AEP's proposed transmission cost of service formula rate for NITS service in PJM, to become effective March 1, 2009, subject to refund, and to the outcome of hearing and settlement judge procedures. In addition, we are granting the request for the 50 basis point adder for continued participation in an RTO. However, in conformity with *VEPCO*,[36] we condition our acceptance on AEP's revising its proposed protocols to remove the restriction on the rights to challenge the underlying inputs into the formula rates and file complaints with the Commission and likewise the Commission's rights to act *sua sponte* under section 206.

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[32] *Id.* at 15-23 *citing Midwest Independent Transmission System Operator, Inc.*, 100 FERC ¶ 61,292 (2002); *Bangor Hydro-Electric Company*, 117 FERC ¶ 61,129 (2006); *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008); *Atlantic Path 15*, 122 FERC ¶ 61,135 (2008).

[33] *Id.* at 24.

[34] 18 C.F.R. § 385.214 (2008).

[35] 18 C.F.R. § 385.213(a)(2) (2008).

[36] *VEPCO*, 123 FERC ¶ 61,098.

1. <u>Acceptance and Suspension of the Formula Rate</u>

23. The Commission has encouraged public utilities to explore the benefits of filing transmission-related formula rates.[37] Further, the Commission has found that the use of formula rates encourages the construction and timely placement into service of needed transmission infrastructure.[38]

24. The protestors complain that AEP's proposed formula rates are unjust and unreasonable. The Maryland OPC requests that the Commission deny or reject AEP's formula rate proposal because it produces unreasonable results. Joint Intervenors and the Maryland OPC have protested various inputs to the formula rate and have requested clarification and supporting documentation for the reasonableness of many of the implementation protocols. The inputs to the formula rate are primarily from AEP companies' books and records. AEP proposes to true-up the plant estimates with actual data and provide interest on the differences.

25. We find that AEP's proposed formula rate raises issues of material fact that cannot be resolved based on the record before us, and are more appropriately addressed in the hearing ordered below. In order to allow the parties to fully investigate their concerns with the proposed formula rate inputs, we will not limit the scope of the issues included in the hearing ordered below, except to the extent that specific issues are addressed as discussed by this order.

26. Our preliminary analysis indicates that AEP's proposed revised tariff sheets have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. In *West Texas*, the Commission explained that, when our preliminary analysis indicates that proposed rates may be unjust and unreasonable and substantially excessive, the Commission will generally impose a maximum suspension (i.e., five months).[39] In the instant proceeding, our preliminary analysis indicates that the proposed rates may be substantially excessive. Therefore, we

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[37] *See Promoting Transmission Investment through Pricing Reform*, Order No. 679 at P 386, citing *Allegheny Power System Operating Companies*, 111 FERC ¶ 61,308, at P 51 (2005); *Allegheny Power System Operating Companies*, 106 FERC ¶ 61,003, at P 32 (2004).

[38] *See Northeast Utilities Service Company*, 105 FERC ¶ 61,089, at P 23 (2003).

[39] 18 FERC ¶ 61,189 at 61,374-75 (the Commission will suspend a proposed rate for the maximum period, five months, if the proposed rate increase is found to be substantially excessive); *Tucson Elec. Co.*, 76 FERC ¶ 61,235 at 62,147 & nn.25-26 (1996).

will accept AEP's filing, suspend it for five months to be effective on March 1, 2009, subject to refund, and set it for hearing and settlement judge procedures.

27. AEP has proposed, as part of its formula rate, placeholders for the recovery of future incentives, should those incentives be authorized by the Commission. We direct AEP, in its formula template, to maintain a value of zero in all incentive placeholders. Should AEP seek authorization to recover incentives, AEP may file under section 205 of the FPA to replace the zero values in the placeholders with the approved amounts.[40] Specifically with respect to CWIP that might be approved by the Commission, AEP will need to demonstrate in the relevant, future filing that it meets the applicable requirements.

28. In addition, AEP has included a placeholder for regulatory assets. We direct AEP, in its formula template, to maintain a value of zero for regulatory assets, which have not been approved. AEP may file pursuant to section 205 of the FPA to replace the zero value for such regulatory assets with appropriate amounts.

29. We also direct the parties at the hearing to ensure that the formula components, including the placeholders for future incentives, will work as intended and will reflect correctly incentives that may be authorized for specific projects. For example, the formula should be able to track incentives for individual projects, since all projects might not be approved for incentives or for the same incentives.[41]

2. Specific Finding On Incentive ROE

30. We will grant up to 50 basis points of incentive ROE for AEP's continued participation in PJM, subject to the conditions of this order and the zone of reasonable returns determined following the hearing ordered below.[42] Our decision to grant AEP an incentive for participation in the PJM is consistent with the stated purpose of section 219

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[40] In permitting the placeholders for future incentives, we are not prejudging the outcome of future requests by AEP for authorization for such incentives.

[41] *San Diego Gas & Elec.*, 118 FERC ¶ 61,073, at P 23 (2007) (SDG&E).

[42] *See, e.g.,* SDG&E, 118 FERC ¶ 61,073 at P 25-26 & n.30; *American Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205, at P 34 (2007), *order on reh'g*, 121 FERC ¶ 61,245, at P 4 (2007). We recognize that the actual incentive that AEP may receive (up to 50 basis points) may be limited by the top of the zone of reasonableness that we ultimately adopt in this proceeding. Accordingly, we grant AEP the full 50 basis point ROE incentive for participation in the PJM only so long as the additional 50 basis points do not result in an ROE above the zone of reasonableness.

of the FPA[43] – that the incentive applies to all utilities joining the transmission organization – and is intended to encourage AEP's continued involvement with PJM.[44] Granting up to 50 basis points of incentive ROE does not remove any other issue pertaining to the ROE from consideration during the hearing and settlement judge procedures, including the appropriate proxy group and the screening criteria for the proxy group.

3. Specific Findings on Proposed Protocols

31. We address specific concerns regarding AEP's unilaterally-filed proposed protocols raised by the protests. While we support the use of review protocols for establishing a process for the orderly review of and challenges to the application of a formula rate during any annual update, the review protocols may not place limits on a party's ability to contest the inputs to a formula rate pursuant to a FPA section 206 complaint (or the Commission's rights to act *sua sponte*).[45]

32. The protocols define Interested Party as wholesale customers, affected utility regulatory commission or consumer advocate. Protestors contend that this limits participation, and AEP answers that this was not the intent of the protocols. The protocols may not limit participation allowed by the FPA. Accordingly, AEP needs to revise its protocols to expand the definition of the term Interested Party to include all parties having standing under section 206.[46]

33. The proposed protocols establish a process for review of inputs to the formula rate, and define time limits for raising Preliminary and Formal Challenges to the application of the formula rate, including challenges related to material accounting changes.[47] Subsection 3(d) provides:

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[43] 16 U.S.C § 824s (2006).

[44] *See SDG&E*, 118 FERC ¶ 61,073 at P 26 (finding that there are considerable benefits associated with a utility's membership in a transmission organization).

[45] *VEPCO*, 123 FERC ¶ 61,098 at P 46.

[46] *Id.* P 45.

[47] OATT, Sixth Revised Volume No. 1, First Revised Sheet No. 314C, Attachment H-14A, Sections 2 and 3.

> Subject to judicial review, each annual update shall become final and no longer subject to challenge pursuant to these Annual Review Protocols or by any other means by the FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by FERC to consider the Annual Update.[48]

34. Although AEP claims that its protocols do not take away parties' rights to challenge inputs into the formula, we read this provision as precluding such challenges after the 21 day period or an extended period. In approving any formula rate, the Commission approves the formula itself, the algebraic equation used to calculate the rates. It does not approve the inputs into the formula or the charges resulting from the application of the inputs to the algebraic equation. AEP has cited no authority permitting it to restrict the filing of a complaint under section 206 regarding the inputs used in the formula or the right of the Commission to institute a section 206 investigation. The courts have recognized that section 206 permits customers to challenge formula rates.[49]

35. The Commission's long-standing precedent is that, under formula rates, parties have the right to challenge the inputs to or the implementation of the formula at whatever time they discover errors in the inputs to or implementation of the formula.[50] Indeed,

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[48] *Id.*, Section 3(d).

[49] *Public Utilities Commission of California v. FERC*, 254 F.3d 250, 258 (D.C. Cir. 2001) ("Because relief can be sought pursuant to section 206 in the event a pass through of … costs results in unjust and unreasonable rates, the Commission's acceptance of the ISO's formula rate without additional section 205 filings does not leave the [state public utilities commission] or ratepayers without any statutory recourse.").

[50] *North Carolina Electric Membership Cooperative v. Carolina Power & Light Co.*, 57 FERC ¶ 61,332, at 62,065 (1991) (rejecting the utility's efforts to limit the period of review to the prior 12 months by stating "[w]hile prompt identification of disputes is certainly a reasonable goal to strive for, the Commission cannot allow utilities to recover excessive rates through automatic adjustment clauses because the customer did not complain in as prompt a manner as the company believes the customer should have."). The Commission has held repeatedly that it may order refunds for past periods where a utility has either misapplied a formula rate or otherwise charged rates contrary to the filed rate. *See Appalachian Power Co.*, 23 FERC ¶ 61,032 at, 61,088 (1983); *DTE Energy*

(continued)

customers may not uncover errors in data or imprudent or otherwise inappropriate costs until well after the challenge period.[51]

36. As we found in *VEPCO,*[52] any challenge to the projected costs, True-Up Adjustment or Material Accounting Change would not require the complainant to bear the ultimate burden of proof. Rather, AEP continues to bear the ultimate burden of proof, i.e., to demonstrate the justness and reasonableness of the charges resulting from application of the formula rate, and it recognizes this burden in its proposed tariff sheets:

> AEP shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate, and the applicable procedures in these Formula Rate Implementation Protocols.…[53]

37. Accordingly, we will accept these provisions under the condition that AEP make a compliance filing within 30 days of the date of this order to revise the protocols so that they do not limit a customer's or the Commission's rights with respect to challenges to the inputs into the formula rate.

C. Hearing and Settlement Judge Procedures

38. Joint Intervenors indicate that AEP has a history of working cooperatively toward settlement. Accordingly, while we are setting this matter for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[54] If the parties desire,

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Trading, Inc. v. Midwest Independent Transmission System Operator, Inc., 111 FERC ¶ 61,062, at P 28 (2005); *Quest Energy, L.L.C. v. The Detroit Edison Co.*, 106 FERC ¶ 61,227, at P 21 (2004).

[51] *See, e.g., Yankee Atomic Electric Co.*, 60 FERC ¶ 61,316, at 62,096-97 (1992) (allowing review of potentially imprudent costs charged to customers in prior-year formula rates).

[52] *VEPCO*, 123 FERC ¶ 61,098 at P 47.

[53] OATT, Sixth Revised Volume No. 1, First Revised Sheet No. 314C, Attachment H-14A, Section 3(c). AEP's proposed tariff provisions correctly find that any party challenging the formula rate itself would bear the burden of proof. *Id.*, Section 2(e).

[54] 18 C.F.R. § 385.603 (2008).

they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[55] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

The Commission orders:

(A) AEP's proposed formula rate is hereby accepted for filing and suspended for five months, to become effective March 1, 2009, subject to refund and conditions, and to the outcome of the hearing and settlement judge procedures ordered below, as discussed in the body of this order.

(B) Within 30 days of the date of this order, AEP must make a compliance filing, as discussed in the body of this order.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act, and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held concerning AEP's proposed formula rate. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (D) and (E) below.

(D) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2008), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

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[55] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their background and experience (www.ferc.gov – click on Office of Administrative Law Judges).

(E) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(F) If settlement judge procedures fail, and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in this proceeding in a hearing room of the Commission, 888 First Street, N.E., Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

125 FERC ¶ 61,130
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Pepco Holdings, Inc. Docket No. ER08-1423-000

ORDER ON TRANSMISSION RATE INCENTIVES AND PROPOSED RATE FORMULA MODIFICATIONS

(Issued October 31, 2008)

1. On August 18, 2008, Pepco Holdings, Inc. (PHI), on behalf of its transmission-owning public utility affiliates,[1] filed revised tariff sheets to the PJM Interconnection, L.L.C. (PJM) Open Access Transmission Tariff pursuant to section 205 of the Federal Power Act (FPA),[2] Part 35 of the Commission's regulations,[3] and Order Nos. 679 and 679-A[4] to implement certain transmission rate incentives for its Mid-Atlantic Power Pathway (MAPP) Project. The MAPP Project was identified in the PJM Regional Transmission Expansion Plan (RTEP) as a baseline project and has been approved by the PJM Board of Managers (PJM Board). PHI requests an effective date of November 1, 2008, for the tariff sheets submitted. For the reasons discussed below, we grant PHI's

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[1] PHI's transmission-owning public utility affiliates are: Atlantic City Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company (collectively, the PHI Companies).

[2] 16 U.S.C. § 824d (2006).

[3] 18 C.F.R. § 35 (2008).

[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

request for transmission rate incentives for the MAPP Project, to be effective November 1, 2008.

I. Background

A. Description of the Company

2. Atlantic City Electric Company and Delmarva Power & Light Company are wholly-owned subsidiaries of Conectiv which in turn is a wholly-owned subsidiary of PHI. Potomac Electric Power Company is a wholly-owned subsidiary of PHI. The PHI Companies provide electric transmission and distribution, and gas distribution services to several states along the Atlantic seaboard and are regulated by the Commission and various state commissions.[5]

B. The MAPP Project

3. The MAPP Project is a 500 kV, 230-mile transmission line that begins at Virginia Electric and Power Company's Possum Point substation in Virginia, crosses southern Maryland (including an above-ground crossing of the Potomac and Patuxent Rivers), includes a 10-12 mile submarine crossing of the Chesapeake Bay, traverses the Delmarva Peninsula crosses the Delaware River, and ends in southern New Jersey.[6]

4. The MAPP Project was approved as a PJM RTEP baseline project with a projected construction cost of nearly $1.05 billion, for which PHI is responsible to construct approximately $950 million. PHI explains that line construction will be completed in segments, and as each segment is completed, it will be placed into service. PHI states that the full line is expected to be placed into service by 2013.[7]

5. In describing the reliability benefits, PHI explains that the prevailing flows of electricity in PJM are from west to east, and are restricted at three main points: the eastern interface, the central interface, and the western interface. These interfaces impose binding constraints on PJM's ability to import power to the eastern Mid-Atlantic and Baltimore/Washington/Northern Virginia load centers, often resulting in congestion charges and out-of-merit generation dispatch.[8]

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[5] PHI August 18, 2008 Transmittal Letter at 4.

[6] William M. Gausman Testimony (Gausman Test.) Ex. No. PHI-1 at 14-16.

[7] Gausman Test. Ex. No. PHI-1 at 14.

[8] Gausman Test. Ex. No. PHI-5B at 17.

6. The PJM 2007 RTEP includes four major backbone transmission lines: the Susquehanna-Roseland Line, the Amos - Beddington - Kemptown Line (the PATH Project),[9] the 502 Junction-Loudoun 500kV Line (the TRAIL Project),[10] and the MAPP Project.[11] PJM made a determination as part of the 2007 RTEP that the MAPP Project is one of the major backbone transmission line solutions needed to resolve numerous NERC reliability criteria violations that would be encountered beginning in 2012.[12]

7. PHI states that PJM has made reliability findings that the MAPP Project will resolve 33 overloads on several interfaces in the Mid-Atlantic region,[13] and will bring congestion relief and reliability benefits to the Baltimore-Washington area despite the retirement of Benning and Buzzards Point Generating units. The MAPP Project will improve reactive performance equivalent to approximately 2,500 MVARs in Eastern PJM,[14] and create a new west to east path across the PJM interface providing a conduit for energy from new generation in northern Virginia and Southern Maryland into the Baltimore-Washington area.[15]

8. PHI states that the MAPP Project will provide a second 500 kV transmission line supplying the Delmarva Peninsula, lessening the potential for blackouts and brownouts as a result of reliance on one transmission source into the peninsula.[16] PHI also provides

[9] This line is referenced in Commission proceedings as the PATH Project. *See Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (*PATH*).

[10] This line is referenced in Commission proceedings as the TRAIL Project. *See Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, *order on reh'g*, 21 FERC ¶ 61,009 (2007) (*TRAIL*).

[11] Ex. No. PHI-5B at 18, Ex. No. PHI-5C at 54.

[12] PJM's RTEP 2007 analysis included the 2006-approved TRAIL Project in its base case studies. Ex. No. PHI-5B at 18.

[13] Gausman Test. Ex. No. PHI-1 at 28.

[14] Gausman Test. Ex. No. PHI-1 at 32.

[15] Ex. No. PHI-5C at 71.

[16] Gausman Test. Ex. No. PHI-1 at 30.

evidence that the MAPP Project will provide access to more than 1,300 MW of renewable wind generation in the western portion of PJM.[17]

9. In describing the economic benefits of the MAPP Project,[18] PHI demonstrates that if the MAPP Project were constructed solely as an AC line, it would provide $113 million of annual savings to the Mid-Atlantic region, and $70 million of annual savings to the entire PJM region. If the portion of the MAPP Project crossing the Chesapeake Bay is built as a 640 kV HVDC line, the annual savings across the Mid-Atlantic region would increase to $174 million and $91 million for the entire PJM region, with production costs dropping by $58 million annually for the entire PJM region.[19]

C. Technology Statement

10. Order No. 679 requires an applicant to provide a technology statement that describes any advanced technology the project will use. PHI provided a technology statement that proposes several different types of advanced transmission technologies mentioned in section 1223 of EPAct 2005. The proposed technologies include: advanced HVDC technology, underwater AC cable, phase angle regulators, switchable shunt reactors, advanced conductor materials, microprocessor-based relays, digital fault recorders, fiber optic protection and communication links, substation-wide area networks, integrated substation automation and equipment and line monitoring.[20]

11. PHI states that they are awaiting a decision from PJM on whether to proceed with a 500 kV AC cable or a 640 kV Voltage Source Converter HVDC underwater crossing of the Chesapeake Bay. If the AC option is chosen, PHI states that the MAPP Project will likely be the highest capacity AC submarine cable system anywhere in the world. In the event the HVDC option is chosen, PHI states that the resulting cable will be completely unprecedented in its size and application. Under either option, the submarine line will be installed approximately six to fifteen feet below the bottom of the Chesapeake Bay.[21]

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[17] Gausman Test. Ex. No. PHI-1 at 35-37, Ex. No. PHI-14 at 1.

[18] The economic benefit analysis was performed by a PHI consultant, ICF Resources.

[19] Gausman Test. Ex. No. PHI-1 at 35.

[20] Ex. No PHI-19 at 2-11.

[21] Ex. No PHI-19 at 10.

12. PHI states that the MAPP Project will utilize 1,000 MW phase angle regulators to control power flow on the system. Although similar in function to the existing phase angle regulators, PHI states that the size of these units make them uncommon. The project will also implement switchable shunt reactors which will be installed at substations to control voltage levels on high-voltage transmission lines. In addition, these units unlike others in the industry will employ self-monitoring devices.

13. PHI asserts that the MAPP Project will also utilize advanced conductor materials such as exotic metallurgical composites, non-metallic cores, and specialized hardware and materials in the manufacture and design of conductors. PHI states that these advanced conductors permit an increase in power flows across existing right of ways without an increase in tower height, maximize the existing width of rights of ways for the addition of new towers, and allow for optimized structure application. PHI also plans to use microprocessor-based relays and digital fault recorders that represent a digital enhancement of electromechanical relays and analog fault recorders. PHI claims that microprocessor-based relays and digital fault recorders provide a higher level of performance, reliability, and efficiency than their analog counterparts.

14. Additionally, fiber optic protection and communication links will provide high-speed, reliable communications. PHI states that substation-wide area networks will be used to provide high-speed communication utilizing industry standard Ethernet capabilities at PHI's substations.[22] These networks will allow for additional data gathering from across the network leading to increased information and feedback. PHI states that integrated substation automation and equipment and line monitoring refer to "smart" remote terminal units, "smart" sensors, and other sensors that permit the remote and at times automatic operation and monitoring of substations, equipment, and interconnecting circuits that will make up the MAPP Project.[23]

15. PHI asserts that the combined effect of these advanced technologies will be to render the MAPP Project a "Smart Grid." PHI explains that at the transmission level, "smart grid" features should allow the grid operator considerably more control, and provide better optimization of resources, than a typical transmission system. Among other key goals of a "smart grid" at the transmission level, PHI lists the Project's abilities to: (1) optimize assets and operate efficiently; (2) minimize sags, spikes, and other disturbances; (3) correct any problems quickly and with a minimum of intervention by the grid operator; and (4) monitor, self-analyze and diagnose the health and condition of

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[22] Ex. No PHI-19 at 7.

[23] Ex. No PHI-19 at 8.

equipment, and predict the malfunction or failure of a device before the event occurs in order to take action to prevent the malfunction or failure from occurring.[24]

16. PHI's filing includes significant discussion of this subject including its efforts to make its investments in the MAPP Project support interoperability of "smart grid" equipment and conformance with new or emerging standards in this area. As part of this interoperability effort, PHI has committed to ". . . provide a method of upgrading systems and firmware remotely (through the data network as opposed to local/site upgrades) and ensure that unforeseen problems or changes can be quickly and easily made by PHI engineers and system operators on short notice."[25]

D. Incentive Rate Proposal

17. PHI requests Commission authorization for the following incentives: (1) a 150-basis point return on equity (ROE) adder for the MAPP Project to be added, not to a midpoint return, but rather to its previously-accepted 11.3 percent ROE, resulting in an overall ROE of 12.8 percent, (2) authorization to recover 100 percent of construction work in progress (CWIP); and (3) authorization to recover 100 percent of all prudently-incurred development and construction costs if the MAPP Project is abandoned or cancelled for reasons beyond the control of the PHI Companies. PHI also submits proposed amendments to the PJM Open Access Transmission Tariff necessary to permit the PHI Companies to recover the rate treatments requested in this filing.

18. PHI asserts that the MAPP Project ensures regional reliability by eliminating anticipated overloading of transmission facilities and preserves competition by improving import capability. PHI states that it is bound by its prior settlement to apply any requested ROE incentives to a base ROE of 10.8 percent.[26] According to the settlement provisions, multiple ROE incentives are added cumulatively to this base ROE of 10.8 percent. Since the settlement, PHI was also granted a 50 basis point adder for RTO participation, bringing the adjusted ROE from which to add incentives to 11.3 percent.[27] The resultant ROE for the MAPP Project if this application is granted will be 12.8 percent, which will be implemented through PHI Companies' individual formula rates.

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[24] *Id*. at 66.

[25] Gausman Test. Ex. No. PHI-1 at 70-71.

[26] *See Baltimore Gas and Electric Co.*, Order Approving Uncontested Settlement, 115 FERC ¶ 61,066 (2006).

[27] *Pepco Holdings Inc.*, 121 FERC ¶ 61,169, at P 15 (2007).

19. In addressing incentive eligibility, PHI states that MAPP Project satisfies the Commission's requirements under Order No. 679 that "the facilities for which [a public utility] seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219 [of the Federal Power Act] . . . ,"[28] and that "the total package of incentives is tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project. . . ."[29] PHI states that the requested incentives also fulfill Order No. 679's requirement that the "resulting rates are just and reasonable,"[30] as discussed in more detail below.

II. Notice of Filing and Responsive Pleadings

20. Notice of PHI's filing was published in the *Federal Register*, 73 Fed. Reg. 51,460-51,461 (2008), with interventions and protests due on or before September 8, 2008. Timely interventions were filed by Public Service Electric & Gas Co., PJM Interconnection, L.L.C. (PJM), Exelon Corporation, Old Dominion Electric Cooperative, Allegheny Power and Trans-Allegheny Interstate Line Co., "FPL Energy Generators,"[31] and the New Jersey Board of Public Utilities.

21. The Public Service Commission of Maryland (Maryland Commission) filed a late notice of intervention and comments, and the Maryland Office of People's Counsel (Maryland People's Counsel) filed a late motion to intervene, protest, and request for hearing.[32] The New Jersey Division of Rate Counsel and the Office of People's Counsel of the District of Columbia filed late motions to intervene. On September 19, 2008, PHI filed a motion for leave to answer and answer to the protests. On October 10, 2008, the Delaware Public Service Commission (Delaware PSC) filed a late motion to intervene and comments out of time. On October 16, 2008, PHI filed a motion for leave to answer and answer to the Delaware PSC protest.

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[28] PHI Transmittal Letter at 8 (citing 18 C.F.R. § 35.35(d)).

[29] PHI Transmittal Letter at 9 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 48).

[30] PHI Transmittal Letter at 9 (citing 18 C.F.R. § 35.35(d)).

[31] FPL Energy Generators consist of FPL Energy Marcus Hook, L.P., North Jersey Energy Associates, L.P., Doswell Limited Partnership, Backbone Mountain Windpower LLC, Mill Run Windpower LLC, Somerset Windpower LLC, Meyersdale Windpower LLC, Waymart Wind Farm, LP, and Pennsylvania Windfarms, Inc.

[32] Both the Maryland Commission and Maryland People's Counsel cite technical difficulties with the Commission's E-Filing system.

III. Discussion

A. Procedural Matters

22. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2008), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

23. In view of the early stage of this proceeding, the parties' interests and the interests of the citizens they represent, and the absence of undue prejudice or delay, the Commission grants the motions to intervene out-of-time of the Maryland Commission, Maryland People's Counsel, the Office of People's Counsel of the District of Columbia, the New Jersey Division of Rate Counsel, and the Delaware Public Service Commission, pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure.

24. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers from PHI because they have provided information that assisted us in our decision-making process.

B. Incentives Request

1. Section 219 Demonstration

25. PHI states that the MAPP Project satisfies the rebuttable presumption and the requirements of section 219 by virtue of its approval in the PJM RTEP as a baseline project, and based upon the reliability and congestion issues that the MAPP Project will resolve.[33] PHI also asserts that "the MAPP Project will strengthen reliability *and* reduce congestion."[34] PHI provides a detailed listing of reliability benefits of the MAPP Project,[35] demonstrating reliability benefits throughout the PJM footprint.[36]

26. PHI estimates that the MAPP Project will significantly improve the voltage profile and reactive performance equivalent to approximately 2,500 MVARs in the eastern PJM

[33] PHI Transmittal Letter at 1.

[34] PHI Transmittal Letter at n. 8, Ex. No. PHI-1 at 38.

[35] Ex. No. PHI-9.

[36] Gausman Test. Ex. No. PHI-1.

region.[37] PHI states the recent analysis from outside experts demonstrates that the project will allow a minimum of 2,500 MW of transfer capability across the eastern PJM region. PHI states that if it is authorized by PJM to incorporate HVDC technology into the MAPP Project, then the additional transfer capability will increase to 5,100 MW.[38]

27. PHI states that there are also environmental benefits associated with the MAPP Project, giving the Mid-Atlantic region access to substantial wind resources in the western and southern portion of PJM.

28. PHI notes that the MAPP Project is also located within the Mid-Atlantic Area National Electric Transmission Corridor designated by the Department of Energy in October 2007.[39]

a. <u>Protests</u>

29. No parties protest that the MAPP Project satisfies the rebuttable presumption.

b. <u>Commission Determination</u>

30. In the Energy Policy Act of 2005 (EPAct 2005), Congress added section 219 to the FPA – directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure. The Commission subsequently issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219.

31. Order No. 679 provides that a public utility may file a petition for declaratory order or a section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of section 219. That is, the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[40] Order No. 679 established a process for an applicant to follow to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if: (i) the

[37] Gausman Test. Ex. No. PHI-1 at 31.

[38] Gausman Test. Ex. No. PHI-1 at 34.

[39] Gausman Test. Ex. No. PHI-1 at 39, citing National Electric Transmission Congestion Report, Docket Nos. 2007-OE-01 and -02, issued by the U.S. Department of Energy, October 5, 2007, 72 Fed. Reg. 56,922.

[40] 18 C.F.R. § 35.35(i).

transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (ii) a project has received construction approval from an appropriate state commission or state siting authority.[41] Order No. 679-A clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (such as a regional planning process, state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[42]

32. We find that the MAPP Project meets the requirements of section 219 as a result of the rebuttable presumption established in Order No. 679. It was included in the PJM RTEP as a baseline project, which means that PJM determined that the project is regional in nature and will mitigate congestion or ensure PJM's ability to continue to serve load reliably.

2. Nexus Demonstration

33. PHI states that the Commission has clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is tailored to address the demonstrable risks or challenges faced by the applicant, and that in evaluating whether the applicant has met this test it has found the question of whether a project is "routine" to be particularly probative.[43] PHI notes that in considering whether a project is routine the Commission stated that it will consider all relevant factors presented by the applicant, including project's scope, effect, and the challenges or risks faced by the project.[44]

34. On scope, PHI states that the MAPP Project is the largest infrastructure project ever undertaken by PHI, and forms the core of its transmission expansion plans over the next decade. PHI states that annual MAPP construction expenditures will average $180 million/year, which is triple the PHI Companies' historic annual average investment

[41] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 58.

[42] *Id.* P 49.

[43] PHI Transmittal Letter at 3 (citing *Baltimore Gas & Electric Co.*, 120 FERC ¶ 61,084, at P48 (2007) (*BG&E*).

[44] *Id*. at 46 (citing *PPL Elec*. *Utils*. *Corp*., 123 FERC ¶ 61,068, at P 31, *reh'g denied*, 124 FERC ¶ 61,229 (2008)).

levels. PHI further states that the MAPP Project will virtually double the PHI Companies' transmission rate base of $942 million.[45]

35. In terms of effect, PHI demonstrates that the MAPP Project will significantly improve voltage profile and reactive performance equivalent to approximately 2,500 MVARs in the eastern PJM region.[46] PHI states the recent analysis from outside experts demonstrates that the project will allow a minimum of 2,500 MW of transfer capability across the eastern PJM region. PHI states that if it is authorized by PJM to incorporate HVDC technology into the MAPP Project, then the additional transfer capability will increase to 5,100 MW.[47] Further, PHI asserts that the project will provide access to renewable energy.

36. PHI presents that it faces risks and challenges that merit the full incentives in terms of financial risk, regulatory risk, environmental risk, and technology risk. PHI explains that the size, complexity, and risk inherent in the MAPP Project are larger than any other project the PHI Companies have undertaken in history, and the incentives are vital to PHI's ability to access capital markets on reasonable terms.[48] PHI explains that the largest source of funding will be from external sources and will include corporate debt and PHI's issuances of common equity.[49]

37. On financial risk, PHI states that the substantial outlay of cash could weaken PHI's credit rating over the near- and mid-term.[50] PHI cites one debt coverage metric, FFO/Debt.[51] PHI states that for 2007 PHI's FFO/Debt ratio was 16.1 percent. Without incentives, the FFO/Debt would decline to 13.5 percent by 2011. Granting all of the incentives reduces PHI's FFO/Debt ratio to 15.4 percent during the construction period,

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[45] Anthony J. Kamerick Test. Ex. No. PHI-21 at 6.

[46] Gausman Test. Ex. No. PHI-1 at 31.

[47] Gausman Test. Ex. No. PHI-1 at 34.

[48] Kamerick Test. Ex. No. PHI-21 at 3-4.

[49] Kamerick Test. Ex. No. PHI-21 at 7.

[50] Kamerick Test. Ex. No. PHI-21 at 11-13.

[51] FFO/Debt is Funds Flow from Operations as a ratio of Total Debt and is a measure of a company's ability to repay debt.

but it keeps it within the acceptable range, thereby protecting PHI's credit rating from being downgraded to below investment grade.[52]

38. Moody's benchmark FFO/Debt ratio for utilities such as PHI is a range of 13 percent to 25 percent. However, PHI cites to several reports by Moody's Investors Service and Standard and Poor's, indicating that both Moody's and Standard and Poor's will take a negative rating action if the PHI Companies are unable to maintain *higher than average* debt coverage metrics during its intensive capital investment program.[53] PHI stresses therefore, that it cannot afford for the FFO/Debt ratio to weaken any further.

39. PHI explains that companies with non-investment grade credit rating bear higher costs of borrowing, less access to capital, and in unfavorable market periods, they can be effectively shut out of the capital markets - an unacceptable result for a capital intensive company like PHI.[54]

40. Additionally, PHI concludes that "including CWIP in rate base would ease the financial pressure on the PHI Companies associated with the MAPP Project by improving cash flow and providing greater regulatory certainty, both of which are instrumental in supporting the PHI Companies financial integrity and ability to attract new capital."[55]

41. PHI states that CWIP incentive treatment will result in lower transmission rates for customers over the life of the MAPP Project,[56] while providing $125 million in additional cash flow during the construction phase.[57] PHI further notes the increased financial stresses of the project are due to the substantial financial outlay required and the long lead-time, as the projected completion date is in 2013.

[52] Kamerick Test. Ex. No. PHI-21 at 14-15.

[53] Kamerick Test. Ex. No. PHI-21 at 10 and 15 (internal citations omitted).

[54] Kamerick Test. Ex. No. PHI-21 at 10.

[55] Gausman Test. Ex. No. PHI-1 at 26.

[56] Alan C. Heintz Test. Ex. No. PHI-30 at 6.

[57] Kamerick Test. Ex. No. PHI-21 at 13.

42. PHI states that the abandonment incentive will provide for certainty of cost recovery to investors and consumers alike for such a large-scale high-risk project such as the MAPP Project.[58]

43. On regulatory risk, PHI states that the MAPP Project requires numerous federal and state regulatory approvals in Virginia, Maryland, Delaware, and New Jersey. In particular, because it will be the first-ever crossing of the Chesapeake Bay, the MAPP Project will require approvals for new rights-of-way.[59] PHI provides a working list of more than 30 regulatory approvals that will be needed for the MAPP Project,[60] an additional list of more than 70 government agencies that will need to be consulted for the MAPP Project,[61] and a list of more than 50 additional non-governmental agencies that PHI will solicit input from during the MAPP permitting process.[62]

44. On environmental risks, PHI states that approximately 20 percent of the MAPP Project will traverse new rights-of-way over wetlands and similarly-sensitive areas, requiring field studies on threatened and endangered species, possibly causing significant delays in the project schedule. PHI illustrates several environmental approvals that are required as part of the project, taking into consideration such issues as oyster beds, subaqueous vegetation, shipwrecks, essential fish habitats, bathymetry, and wetlands.[63]

45. On technology risks, PHI states that some of the technologies that it is proposing to use are unprecedented, requiring specialized personnel and equipment. PHI states that the underwater portion of the MAPP Project is without precedent, whether AC or DC technology is used; it will be the highest capacity submarine cable system in the world.[64]

46. PHI argues the record supports a finding that the MAPP Project is material in scope, non-routine, faces identifiable financing and completion risks, and will address

[58] Kamerick Test. Ex. No. PHI-21 at 21.

[59] Gausman Test. Ex. No. PHI-1 at 43-44.

[60] Ex. No. PHI-15.

[61] Ex. No. PHI-16.

[62] Ex. No. PHI-17.

[63] Gausman Test. Ex. No. PHI-1 at 48-51.

[64] Gausman Test. Ex. No. PHI-1 at 65-66.

regionally-identified reliability and/or economic objectives as determined independently by the regional planning entity.

a. Protests

47. Maryland People's Counsel's witness Peter J. Lanzalotta asserts that because the PJM RTEP requires PHI to construct the MAPP Project, incentives are not a necessary condition for PHI to build. Maryland People's Counsel states that PHI has failed to demonstrate that there is a valid nexus between the incentives sought and the investment made.

48. The Delaware PSC states that while PHI asserts that ratepayers would save approximately $200 million over the term of the MAPP Project as well as avoid rate shock by including CWIP in rate base, PHI provides no support for this analysis, nor does this analysis take into account the fact that the project will be completed and placed into service in stages.[65]

49. The Delaware PSC states that PHI has not made an adequate showing as to whether the incentive rate treatment is warranted, or whether it will result in just and reasonable rates.

b. Answers

50. PHI asserts that Maryland People's Counsel ignores the essential elements of the Commission's nexus standard and its protest should therefore be rejected. According to PHI, the essential question in a nexus analysis is whether or not a proposed project is routine. To determine whether a project is routine, PHI states that the Commission examines three factors: (1) the scope of the project; (2) the effect of the project; (3) the challenges faced by the project – and the MAPP Project meets all these factors. In contrast, PHI answers that Maryland People's Counsel disregards all these factors and states that the package of incentives has been appropriately adjusted commensurate with the risks of the project.

51. PHI asserts that for the aforementioned reasons the Commission should accept its application in this proceeding without condition or hearing.

c. Commission Determination

52. In addition to satisfying the section 219 requirement of ensuring reliability or reducing the cost of delivered power by reducing congestion, an applicant must

[65] Delaware PSC October 10, 2008 Protest at 3.

demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[66] As part of our evaluation of whether the incentives requested are tailored to address the demonstrable risks or challenges faced by the applicant, the Commission has found the question of whether a project is "routine" to be particularly probative. In *BG&E*,[67] the Commission clarified how it will evaluate projects to determine whether they are routine. Specifically, to determine whether a project is routine, the Commission will consider all relevant factors presented by the applicant. For example, an applicant may present evidence on: (i) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the effect of the project (e.g., improving reliability or reducing congestion costs); and (iii) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).

53. As discussed below, we find that PHI has sufficiently demonstrated a nexus by demonstrating that the MAPP Project is not routine, based on the project's scope, effects, and risks and challenges.

54. As to the scope of the project, an applicant may, as in *Duquesne Light Company*,[68] compare the total investment in a range of projects to some other aggregate measure of investment, such as total rate base or recent annual investment levels, as delineated in *BG&E*.[69] Here, PHI has taken the approach delineated in *BG&E*, comparing its investment to recent annual investment levels. PHI indicates that the PHI Companies' project will require significant capital investments, up to $950 million, which will virtually double the combined PHI Companies' transmission rate base.

55. We find that the MAPP Project will improve import capability, reduce congestion, and improve reliability in the mid-Atlantic region. We agree with PHI that the incentives will promote those goals by recognizing the importance of these new facilities and the risks inherent in bringing them to completion.

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[66] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[67] *BG&E*, 120 FERC ¶ 61,084 at P 52-55.

[68] 118 FERC ¶ 61,087, at P 52 (2007) (*Duquesne*)

[69] *See BG&E*, 120 FERC ¶ 61,084 at P 53.

56. We reject Maryland People's Counsel's assertion that because PHI has an obligation to build the facilities that PJM requires in RTEP, it should not be granted incentives. PHI has made a sufficient demonstration that this Project is not a routine investment made in the ordinary course of expanding its system. Moreover, it has demonstrated that it will face multiple risks and challenges in constructing the project, and that the requested package of incentives is necessary to preserve PHI's financial health.

57. In *BG&E*, we found that the challenges or risks faced by a project can include: siting, internal competition for financing with other projects, long lead times, regulatory risks, specific financing challenges and other similar impediments.[70] Incentives help to counter these risks and thereby send the correct message to transmission owners and the investors who supply the capital to build transmission. PHI has demonstrated similar challenges and risks here. We agree that PHI will face competition for financing of the project while at the same time maintaining positive financial metrics and credit ratings to avoid increased borrowing costs.[71] We also agree that the incentives will address financial, technology-related, regulatory, and construction risks.

58. As noted above, the project will require input from more than 100 agencies and cross multiple states; an important factor in consideration of risk in Order No. 679.[72] This project also presents an unprecedented capital investment for the PHI Companies.

59. We also find that the abandonment incentive will be an effective means to encourage the MAPP Project's completion. For example, in addition to challenges presented by its scope and size, the MAPP Project requires approvals from multiple municipalities, multiple state siting authorities, and various federal approvals. Moreover, the MAPP Project risks cancellation should it fail to receive siting authority. These factors introduce a significant element of risk; authorizing abandonment will help ameliorate this risk by providing PHI with some degree of certainty as it moves forward.

60. In Order No. 679, the Commission established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base.[73] It noted that this rate treatment will further the goals of section 219 by

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[70] *Id*.

[71] Ex. No. PHI-21 at 12-18.

[72] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94; Gausman Test. Ex. No. PHI-1.

[73] *Id*. P 29, 117.

providing up-front regulatory certainty, rate stability, and improved cash flow for applicants, thereby reducing the pressures on their finances caused by investing in transmission projects.[74] We find that the PHI Companies have shown a nexus between the proposed CWIP incentive and their investment in the MAPP Project.

61. Consistent with Order No. 679, we find that authorizing 100 percent of CWIP treatment for the MAPP Project will enhance the PHI Companies' cash flow, reduce interest expense, assist with financing, and improve coverage ratios used by rating agencies to determine credit quality by replacing non-cash Allowance for Funds Used During Construction (AFUDC) with cash earnings. PHI has also committed to employ appropriate accounting controls in place to prevent charging customers for both capitalized AFUDC and CWIP for the MAPP Project, as discussed further herein.[75]

62. Cash flow projections provided in Exhibit PHI-21 indicate a CWIP recovery to total over $125 million during the construction period from 2008 to 2012 for the MAPP Project.[76] The Commission believes this substantial increase in cash flow will greatly assist PHI's ability to obtain financing for the project because it will lower the amount of debt PHI would need to issue by improving PHI's FFO/Debt ratio.[77] This, in turn, will reduce the risk of a downgrade in the PHI Companies' corporate credit and debt ratings.

63. We also find that allowing PHI to recover 100 percent of CWIP in its rate base for this project will result in better rate stability for customers. As we have explained in prior orders,[78] we find that, without CWIP in rate base, a new project has no direct effect on consumer prices until it begins being used to provide service. The MAPP Project is estimated to cost $1.05 billion, with PHI having a responsibility for $950 million, and has a lead time of several years. If the Commission does not permit PHI to recover CWIP in rate base, all of its MAPP Project borrowing costs will be accrued over several years, and then capitalized after the MAPP Project goes into service, along with a return of the investment cost through depreciation. Such a process has the potential to produce a rate shock for consumers. By permitting PHI to recover CWIP, the Commission is mitigating this rate shock to consumers. For example, PHI has demonstrated that over the life of the

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[74] *Id.* P 115.

[75] Smiley Test. Ex. No. PHI-36 at 2.

[76] Kamerick Test. Ex. No. PHI-21 at 13.

[77] *Id.* at 14.

[78] *See, e.g.*, *American Electric Power Co.*, 116 FERC ¶ 61,059, at P 59 (2006), *on reh'g*, 118 FERC ¶ 61,041, at P 27 (2007).

project customers will experience overall revenue savings of $200 million as a result of the CWIP incentive and cessation of AFUDC.[79]

3. Total Package

64. PHI states that there is no need for the Commission to reduce the 12.8 percent ROE in light of the non-ROE incentives for several reasons. First, PHI states that the Commission has concluded that, "in some instances, where the risks and challenges faced by a new investment are substantial, we may grant an ROE at the top end of the zone of reasonableness."[80]

65. PHI concludes that the MAPP Project is such a project. PHI states that the high end of the zone of reasonableness here is 15.6 percent and therefore, were PHI requesting only an ROE incentive, it would be appropriate to receive a 15.6 percent ROE in light of the substantial risks and challenges presented in this case.[81]

66. PHI claims, however, in light of the package of incentives, that it has adjusted its request to a 12.8 percent ROE rather than the high end of the zone. PHI asserts that the ROE "is already significantly below the high end of the ROE zone of reasonableness." PHI states that "the incentive ROE requested by the PHI Companies falls below the middle of the upper end of the [discounted cash flow analysis] range," and therefore, has already been adjusted downward.[82]

67. PHI also asserts that inclusion of 100 percent of CWIP in rate base, while supporting the PHI Companies' credit standing, will not have a measurable effect on investment risk.[83] PHI states that the Commission distinguished between incentives that reduce risk, and CWIP in Order No. 679-A at P 38. PHI argues that while the abandonment incentive may reduce risk, this reduction is offset by the uncertainties inherent in the future section 205 filing requirement if abandonment recovery is sought.

[79] Heintz Test. Ex. No. PHI-30 at 6-7.

[80] Dr. William E. Avera Test. (Avera Test.) Ex. No. PHI-24 at 89 citing Order No. 679-A at P 67.

[81] Avera Test. Ex. No. PHI -24 at 89.

[82] Avera Test. Ex. No. PHI -24 at 89-91, referencing the discounted cash flow analysis (DCF) provided in its application.

[83] Avera Test. Ex. No. PHI -24 at 90.

68. PHI states that the Commission should also take into consideration the extensive use of advanced technologies and smart grid technology in this case, in keeping with the Commission's past willingness to grant incentives for the use of advanced technologies.[84]

69. PHI states that "[t]he MAPP Project incorporates far more advanced technology than any other project that has been submitted to the Commission for incentive rates, even those that have attempted to incorporate substantial advanced technology."[85] For example, PHI compares the advanced technologies in the MAPP Project with those that the Commission approved for the Southern California Edison projects in Docket No. EL08-62-000 and the PATH Project in Docket No. ER08-386-000. PHI states that the technologies incorporated in the MAPP Project far exceed both the Southern California Edison and PATH Projects.[86]

70. Finally, PHI asserts that "the 12.8 percent ROE requested by the PHI Companies falls below the return approved by the Commission for other similarly situated transmission projects, which also included multiple incentives."[87] PHI concludes that therefore, "[t]here is no basis for a downward adjustment."[88]

a. <u>Protests</u>

71. The Maryland Commission states that while it supports the use of appropriate rate incentives for transmission investment providing regional benefits the resulting rates must be just and reasonable. The Maryland Commission, the Delaware PSC, and Maryland People's Counsel argue that the level of PHI's requested ROE incentive adder does not take into account the reduction in risk associated with PHI's formula rate recovery, PHI's proposed recovery of 100 percent CWIP, and PHI's proposed recovery of 100 percent of abandonment costs.

72. The Maryland Commission acknowledges that the direct testimony of PHI witness Kamerick,[89] appears to address a need for both ROE and CWIP stating that "[t]hough an

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[84] Avera Test. Ex. No. PHI-24 at 91 (internal citations omitted).

[85] Avera Test. Ex. No. PHI-19 at 20.

[86] Ex. No. PHI 19 at 20-21.

[87] Avera Test. Ex. No. PHI-24 at 92.

[88] Avera Test. Ex. No. PHI-24 at 6, and 90.

[89] Kamerick Test. Ex. No. PHI-21 at 22.

incentive ROE and CWIP in rate base provides some similar benefits both are critically needed and complement one another." However, the Maryland Commission states that "In contrast, the PHI filing does not appear to address the connection between the guarantee of 100 percent recovery of abandonment costs and the level of the requested [ROE] incentive."[90]

73. Maryland People's Counsel cites to the direct testimony of its witness, Peter J. Lanzalotta, who argues, "[F]ormula rates that track current costs accurately reduce a disincentive to construct transmission and were a factor that was considered by at least one state regulatory agency in supporting the PHI Companies' request at FERC for formula rates."[91] Maryland People's Counsel also cites to the assurance of cost recovery in Delaware through a settlement in the Delaware Standard Offer Service Docket No. 04-391. For these reasons, parties assert that the ROE incentive should either be denied or more narrowly tailored to reflect the reduced risk faced by PHI.[92] The Maryland Commission and the Delaware PSC request settlement and hearing proceedings to ensure that the incentives will not result in transmission charges that are unjust and unreasonable. Further, the Delaware PSC requests that the Commission consider suspension because of the extraordinary 100 percent increase in rate base that will result from inclusion of the MAPP Project in rates when the MAPP Project goes into service.

b. Answers

74. PHI disputes Maryland People's Counsel's contention that cost-recovery in retail transmission rates are guaranteed. PHI states that its subsidiary companies are load–serving entities in PJM with an obligation to provide Standard Offer Service with a corresponding purchase of supply and network transmission service from PJM. Each jurisdiction requires a filing and state commission approval to allow recovery of these costs and therefore, PHI asserts that timely cost recovery could be at risk.

c. Commission Determination

75. PHI has sufficiently demonstrated that the MAPP Project faces risks and challenges that warrant the full package of incentives including the ROE incentive. We are not persuaded by the parties' protests that the 150 basis point incentive is unreasonable. The 150 basis point adder is reasonable in light of the risks of this project. The MAPP Project is a high voltage 500 kV line, extending 230 miles, crossing through

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[90] Maryland Commission Protest at 3.

[91] Aff. Peter J. Lanzalotta at 7-8.

[92] *Id.*, Maryland Commission at 3.

four states, and providing access to more than 1,300 MW of renewable wind generation in the western portion of PJM.[93] The projected cost of this project is substantial, with the PHI's share amounting to $950 million, creating financial risks for PHI. PHI also faces regulatory and other risks, as fully explained above.

76. We further find that PHI's use of advanced technology warrants the 150 basis point adder. The MAPP Project will incorporate the only 500 kV underwater cable in the world with 2,500 MW of transfer capability.[94] PHI is also incorporating smart grid technology, to improve reliability and efficiency of the electric system. In particular, PHI is utilizing advanced sensors and controls across the entirety of the project, as well as the high-speed communications and IT infrastructure needed to make full use of this level of data and control options, and is committed to interoperability of smart grid equipment and conformance with new or emerging standards in this area.

77. This project provides significant regional benefits both from an economic and reliability standpoint. PJM has found that the MAPP Project will resolve 33 overloads on several interfaces in the Mid-Atlantic region,[95] and will provide a minimum of 2,500 MW of transfer capability. In addition to providing needed transmission capacity, the use of this advanced technology will improve the reliability and efficiency of the electric system. We also note that the ROE incentive granted here is not near the high end of the zone of reasonableness.

78. We find that this combination of factors merits the package of incentives requested and granted herein.[96] We also find that the requested incentives and the formula rate are

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[93] Gausman Test. Ex. No. PHI-1 at 35-37, Ex. No. PHI-14 at 1.

[94] Further, we note that PJM is considering an alternative proposal from PHI to use a 640 kV HVDC underwater cable. If this option is adopted, the MAPP Project will be the first project using such an underwater cable.

[95] Gausman Test. Ex. No. PHI-1 at 28.

[96] We recognize in other cases that where similar packages of incentives were requested, the Commission has reduced the utility's requested ROE incentive. *Cf. Duquesne*, 118 FERC ¶ 61,087; *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 (2008); *Southern California Edison Co.*, 122 FERC ¶ 61,187 (2008). In those cases the Commission examined the entirety of the project and the requested incentives and determined that the package of incentives requested by the utilities were too high. Those cases do not stand for the proposition that whenever a utility requests CWIP, an ROE incentive, and abandonment that the utility's ROE request is automatically reduced. Such a conclusion would simply result in utilities requesting even larger incentives to offset a

(continued…)

not mutually exclusive but together will encourage investors to invest in the MAPP Project.[97]

79. Regarding the request for a hearing, the parties have not presented an issue of material fact that warrants a hearing on whether to grant the incentives. The Commission stated in Order No. 679, "the Commission does not intend to routinely convene trial-type, evidentiary hearings to review … [transmission incentive requests,] but will attempt to render a decision based on the paper submissions whenever possible."[98] We further find no reason to suspend the collection of CWIP, because permitting such recovery will help expedite the construction of an important project needed for reliability.[99] Accordingly, the Commission will permit the incentives to become effective November 1, 2008, as requested.

C. Section 205 Demonstrations

1. Range of Reasonableness

80. PHI currently has an adjusted ROE of 11.3 percent, after applying the Commission-approved RTO participation adder to the 10.8 percent base ROE that was agreed upon as part of its formula rate settlement. When the 150 basis point incentive adder is added to the 11.3 percent ROE, the resulting ROE for the MAPP Project would be 12.8 percent. Pursuant to Order No. 679-A, any ROE must be within the range of reasonableness.[100] In this case, because the settled rate contains no range of reasonableness, PHI submitted testimony to establish a range of reasonable returns.

a. ROE

81. PHI submitted testimony supporting a zone of reasonable returns of 8.6 percent (set by PHI) to 15.61 percent (set by DPL, Inc.) after adjusting for risk by applying a

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possible reduction. Each case must be analyzed on its merits to determine if the incentives requested are justified.

[97] *Duquesne Light Company*, 125 FERC ¶ 61,028, at P 57 (2008).

[98] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 79.

[99] *Cf., Allegheny Power System Operating Companies*, 111 FERC ¶ 61,308, at P 51 (2005).

[100] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 38.

corporate credit rating screen.[101] PHI states that it is bound by prior settlement to apply any requested ROE incentives to a base ROE of 10.8 percent.[102] According to the settlement provisions, multiple ROE incentives are added cumulatively to the base ROE of 10.8 percent. Since the settlement, PHI was also granted a 50 basis point adder for RTO participation, bringing the adjusted ROE from which to add incentives to 11.3 percent.[103] Based on PHI's analysis, its requested 150-basis point ROE adder for the MAPP Project would be within the range of reasonable returns produced by its DCF analysis.

82. PHI adds that its DCF calculation does not include an adjustment for the cost of "floating" new equity securities. Nevertheless, PHI states that the fact that flotation costs will be incurred should be recognized as a legitimate consideration that supports the reasonableness of the ROE. PHI asserts that a review of financial studies indicates that flotation costs can average between 3.6 percent to 10 percent additional on the return.[104]

83. PHI explains that rather than developing annual estimates of cash flows into perpetuity, it has implemented the DCF model in its simplified "constant growth" form.[105] PHI states that the constant growth form of the DCF recognizes that the rate of return consists of two parts: dividend yield and growth. In other words, investors expect to receive a portion of their return on investment through dividends, and the remainder of their return on investment through price appreciation.

84. In addition, PHI explains that in developing the proxy group, the DCF model analysis focused on a group of 15 transmission-owning utilities in the Northeast.[106] PHI

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[101] Avera Test. Ex. No. PHI-27.

[102] *See Baltimore Gas and Electric Co.*, Order Approving Uncontested Settlement, 115 FERC ¶ 61,066 (2006).

[103] *Pepco Holdings Inc.*, 121 FERC ¶ 61,169, at P 15 (2007).

[104] Avera Test. Ex. No. PHI-24 at 72-74 (internal citations omitted).

[105] *Id.* at 29.

[106] *Id*. at 32-34. The utilities are: American Electric Power Co., Central Vermont Public Service Corp., Consolidated Edison, Inc., Constellation Energy Group (Constellation), Dominion Resources Inc., Dayton Power Light Inc. (DPL Inc.), Exelon Corp. (Exelon), FirstEnergy Corp., Florida Power Light Group, Inc., Northeast Utilities, NSTAR, Pepco Holdings, Inc., PPL Corp., Public Service Enterprise Group (PSEG), and UIL Holdings Corporation.

states that this publicly-traded 15 company proxy group resulted by excluding companies based on the following screens: (1) companies who don't pay common dividends; (2) companies for whom no Institutional Brokers Estimation System (IBES) or Value Line data is available; (3) companies who were in the process of merger activity; and (4) companies whose business was comprised mainly of natural gas operations. PHI also states that it evaluated the proxy group based on three objective measures of investment risk: Standard and Poor's corporate credit rating, Value Line's Safety Rank, and Financial Strength Rating.[107] PHI points out that the PHI Companies have a corporate credit rating of "BBB." PHI filed two additional analyses to ensure the validity of and increase confidence in its results.[108]

b. Protests

85. Maryland People's Counsel argues that in justifying its requested ROE, PHI includes companies within its proxy group that derive substantial revenues from unregulated business activities, such as Constellation, PSEG, and Exelon. Maryland People's Counsel also argues that PHI's expert testimony submitted by Dr. Avera used an unusually large proxy group of 15 companies in wide geographic regions with large variations in business risk and then removed companies from the proxy group subjectively.

86. Maryland People's Counsel argues that the best way to evaluate a business and its commensurate risks is to determine where its revenues are derived. Therefore, Maryland People's Counsel argues that utilities with a large portion of unregulated merchant generation revenues such as Constellation, PSEG and Exelon, should be excluded from a proxy group establishing an ROE for a transmission line. To support their proxy group argument, Maryland People's Counsel cites to Standard and Poor's rating of BGE, a regulated transmission and distribution subsidiary of Constellation Energy. Standard and Poor's notes that BGE's business risk is "influenced by the growing scope of parent Constellation Energy Group Inc.'s unregulated activities, which has resulted in accretion to the company's business risk in the past year."[109]

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[107] Avera Test. Ex. PHI-24 at 35 and Ex. No. PHI-29.

[108] PHI filed a DCF analysis resulting in a range of returns of 8.1 percent to 15.6 percent, which does *not* apply a corporate credit rating screen (Avera Test. Ex. No. PHI-26), and a capital asset pricing model analysis that results in a range of returns of 10.9 percent to 14.3 percent.

[109] Maryland People's Counsel September 10, 2008 Protest at 33 (internal citations omitted).

87. Similarly, Maryland People's Counsel argues that over the past three years, PSEG's revenues from competitive merchant generation have doubled from $434 million to $949 million, while its revenues from its largest regulated subsidiary, PSE&G,[110] grew by only 10 percent. Maryland People's Counsel argues that it is clear in this case that PSEG's high growth rate, as well as its high implied cost of equity, are driven by the growth in revenues from its competitive merchant generation business, and not from its regulated transmission business.[111] Maryland People's Counsel states that PSEG should therefore be removed from a proxy group that is intended to assess risk on regulated transmission.

88. Maryland People's Counsel argues that because PHI's investment is assured cost recovery, these investments are no more risky than investment in a medium-grade corporate bond, and the return should be commensurate with this low risk investment.[112]

c. <u>Answers</u>

89. PHI asserts that Dr. Avera properly applied the DCF methodology and selected the correct proxy group in accordance with the *PATH* and *VEPCO* case precedent.[113] PHI notes that the 15-utility proxy group identifies all transmission owning members of PJM, New York Independent System Operator, Inc., (NYISO) and ISO-New England Inc. (ISO-NE) with publicly traded stock and excludes firms that do not pay common dividends and firms that do not have Value Line data or IBES growth rate data.

90. PHI also disputes the Maryland People's Counsel's assertion that sources of revenue is an appropriate criterion to judge the proxy group based on recent Commission precedent. PHI notes that the Commission rejected a similar argument made by the

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[110] Public Service Enterprise Group, Inc. (PSEG) is the parent company of subsidiary Public Service Electric and Gas Company (PSE&G).

[111] Maryland People's Counsel Protest at 34 (internal citations omitted).

[112] Maryland People's Counsel Protest at 36. For example, Moody's Credit Perspectives reports a public utility corporate bond yield index of 6.32 percent for "A" rated bonds, and 6.42 percent for "Baa" rated bonds, after averaging the 6 months ending September 2008.

[113] *See* PHI September 19, 2008 Answer at 6 nn.13 & 14 (citing *PATH*, 122 FERC ¶ 61,188 at P 105 and *Virginia Electric & Power Co.*, 123 FERC ¶ 61,098, at P60 (2008) (*VEPCO*)).

Maryland People's Counsel regarding the appropriateness of including PSEG in a proxy group because of its revenue sources.[114]

d. Commission Determination

91. We find that PHI's proposed ROE analysis demonstrates that its requested 150 basis point ROE incentive, when added to the 10.8 percent base ROE that was agreed upon as part of PHI's formula rate settlement and the previously approved 50 basis point RTO participation adder, produces an ROE that is within the range of reasonable returns.

92. We have previously found that it is reasonable to use a proxy group of entities within the interrelated RTO markets operated by PJM, ISO-NE, and NYISO, as PHI proposes for its DCF analysis. We find that the DCF presented in Exhibit PHI-27 has applied the following screening criteria to exclude companies consistent with Commission precedent: (1) companies who don't pay common dividends; (2) companies for whom no IBES or Value Line data is available; (3) companies who were involved in merger activities; (4) companies whose business was comprised mainly of natural gas operations; (5) companies whose corporate credit ratings are outside the band of BBB- to BBB+, (in consideration of PHI's BBB corporate credit rating); and (6) companies whose growth rates are considered outliers – those that "fail the economic test of logic," or whose implied cost of equity is "unsustainable."[115]

93. Maryland People's Counsel argues that PHI includes companies within its proxy group, including PHI, that derive substantial revenues from unregulated business activities, and that we should, therefore, exclude several of these companies from the analysis. We deny Maryland People's Counsel's protest as inconsistent with Commission precedent. We have previously found that in cases where these entities will ultimately raise funds for the subject utility, these entities' cost of capital should be considered.[116] Even if we excluded the companies that the Maryland People's Counsel

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[114] *See* PHI September 19, 2008 Answer at 7 (citing *Pepco Holdings Inc.*, 124 FERC ¶ 61,176 (2008) (citing *PATH*, 122 FERC ¶ 61,188 at P 105)).

[115] *Bangor Hydro-Electric Co.*, Opinion No. 489, 117 FERC ¶ 61,129, at P 24-28, 53-60 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008).

[116] *See Id. See also Midwest Independent Transmission System Operator, Inc.*, Initial Decision, 99 FERC ¶ 63,011, at P 9, 15-16, Order Approving Initial Decision with Modification, 100 FERC ¶ 61,292, at P 12 (2002) (rejecting a proposal to restrict a proxy group for transmission owners to the use of generation-divested utilities, permitting the inclusion of parent companies with some generation and unregulated revenues in the proxy group), *order on reh'g*, 102 FERC ¶ 61,143 (2003), *order on remand*, 106 FERC

(continued…)

protests from the analysis, the ROE of 12.8 percent would still be within the range of reasonable returns.

94. Based on the proxy group presented in Exhibit PHI-27 and the scope, effect, risks, and challenges of the MAPP Project, we will grant PHI's requested return to result in an ROE of 12.8 percent.[117] PHI is directed to file revised tariff sheets to reflect this ROE incentive.

2. <u>CWIP Accounting Procedures and Regulations</u>

95. Order No. 679 and 18 C.F.R. §35.25(f) require that a company requesting CWIP in its rate base must propose accounting procedures that ensure that customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP in rate base. Additionally, to promote comparability of financial information between entities,[118] the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects of having CWIP in rate base.[119]

96. PHI provides several submissions to demonstrate that it is in compliance with the Commission's regulations for CWIP. PHI submits a Construction Program Statement, consistent with the requirements of 18 C.F.R. §35.13 (h)(38), demonstrating that the program adopted is prudent and consistent with a least-cost energy supply program.

97. PHI describes the procedural controls that it will use to prevent capitalization of AFUDC associated with the MAPP Project prior to and after the project goes into

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¶ 61,302,(2004), *aff'd in pertinent part and rev'd in other parts sub nom. Publ. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[117] An ROE of 12.8 percent is the summation of 10.8 percent (settled rate) + 50 basis points (RTO participation) + 150 basis points we are granting herein.

[118] The Commission's Uniform System of Accounts (USofA), Electric Plant Instruction No. 3, requires AFUDC to be capitalized as a component cost of construction and depreciated over the service life of the asset. Public utilities that receive a current return on CWIP through rate base recover this cost in a different period than it would ordinarily be charged to expense under the general requirements of the Commission's USofA.

[119] *See, e.g., American Transmission Co. LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 (2004); *TRAIL*, 119 FERC ¶ 61,219; *Southern California Edison Co.*, 122 FERC ¶ 61,187 (2008).

service, consistent with the Commission's regulations for CWIP.[120] Specifically, PHI explains that it has accounting procedures to ensure that all costs will be properly classified in its accounting records using both the SAP Project and the PowerPlant asset accounting systems. PHI also states that it will incorporate unique project identification and work order numbers to accumulate MAPP construction costs in accordance with Electric Plant Instruction 3 and its capitalization policy.[121] PHI explains that PowerPlant allows the user to determine if and when AFUDC should be capitalized on work orders. According to PHI, the PowerPlant system will recognize the unique identifiers and will not calculate or capitalize AFUDC on the MAPP Project as a component of the costs to be recorded in Account 101, Electric Plant in Service. PHI states that this process will ensure that the CWIP included in the formula rate filing will not include AFUDC for the MAPP Project. Finally, PHI states that its independent auditor will verify this planned CWIP in rate base accounting, as determined necessary by the auditor.

a. <u>Protests</u>

98. Maryland People's Counsel claims that PHI does not expressly detail the accounting procedures that it will use to ensure that it does not double recover AFUDC and CWIP in rate base, including any unique project numbering system to be used and any procedures to prevent double counting of expenditures as CWIP and additions to plant once the project, or portion thereof, goes into service. Maryland People's Counsel also argues that PHI should be required to segregate all work orders for the MAPP Project from those for other projects, whether incentive or non-incentive, and to prepare monthly reports summarizing all costs incurred under the MAPP Project, and showing, at a minimum, additions to CWIP and plant in service.

99. The Delaware PSC states that it is not clear from the application that PHI would provide any support in its annual report to document whether amounts of CWIP that would be put into plant-service have accurately reduced the balance of CWIP.[122]

100. The Delaware PSC argues that PHI's requested waiver of certain portions of § 35.13(h)(38) is dependent on the fact that PHI owns no generation projects that serve wholesale requirements. The Delaware PSC states that there is no consideration of the possibility that this will continue through the life of the MAPP Project for Delmarva, or any of the other affiliates of the PHI Companies.

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[120] 18 C.F.R. §§35.25(e) and (f)(1).

[121] *See* Appendix G – Affidavit of Warren Smiley (Smiley Aff.) Ex. PHI-36.

[122] Delaware PSC October 10, 2008 Protest at 2-3.

b. **Answers**

101. PHI asserts that Maryland People's Counsel ignored the testimony of PHI's witness Alan Heintz and the affidavit of Warren Smiley describing the changes needed in the formula to implement the CWIP recovery as well as the accounting procedures in place to ensure no double-recovery of MAPP-related CWIP and AFUDC. PHI states that it has supplied the appropriate information with the Commission, and will more fully explain Statement BM to the Delaware PSC to address their concerns if circumstances change such that Delmarva becomes a generation owner.

c. **Commission Determination**

102. There may be several reasonable approaches to the Delaware PSC's request for additional transparency regarding the amounts removed from CWIP and placed into plant in service related to the MAPP Project. In this particular case, PHI provides several forms of assurance that amounts will not recover a return on CWIP at the same time they are recovering a return on and of investment through plant-in-service. First, PHI explains that each work order for the MAPP Project will be given a unique identifier. PHI explains that the PowerPlant asset accounting system that they employ will recognize these unique identifiers, and not calculate the unique identifier to both accounts in the same time period.[123] Second, PHI provides a monthly calculation of the CWIP associated with the MAPP Project, as well as the monthly calculation of the plant-in-service associated with the MAPP Project as part of its formula rate.[124] Finally, PHI states that the PHI Companies' independent auditor has the ability to consider compliance with the accounting requirements of the Uniform System of Accounts, which also requires that work orders be cleared from the CWIP account and included in electric plant in service upon completion and readiness for service of the first unit. [125]

103. The Commission also finds that PHI's proposed accounting procedures in Exhibit PHI-36 of its filing sufficiently demonstrate that it has accounting procedures and internal controls in place to prevent recovery of AFUDC to the extent it is allowed to include CWIP in rate base, contrary to the Maryland People's Counsel's assertions. However, public utilities that receive a current return on CWIP through rate base recover this cost in a different period than it would ordinarily be charged to expense under the general requirements of the Commission's USofA. To promote comparability of financial

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[123] Smiley Aff. Ex. PHI-36.

[124] PJM Interconnection, LLC, FERC Electric Tariff Sixth Rev. Vol. No. 1, First Rev. Sheet Nos. 298S-298R, 300V-300W, and 310S-310R,

[125] 18 C.F.R. Part 101, FERC Accounts 101 and 107.

information between entities, the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects of having CWIP in rate base.

104. PHI has failed to address the Commission's requirement for comparability of financial information. The Commission therefore directs PHI to provide footnote disclosures in the notes to the financial statements of its annual FERC Form No. 1 and its quarterly FERC Form No. 3-Q which (1) fully explain the impact of the transmission rate incentives it receives insofar as the incentives provide for a deviation from the general requirements of the USofA; (2) include details of amounts not capitalized because of the transmission rate incentives for the current year, the previous two years, and the sum of all years; and (3) include a partial balance sheet consisting of the Assets and Other Debits section of the balance sheet to include the amounts not capitalized because of the transmission rate incentives.

105. We reject the Delaware PSC's contention on generation-related requirements of § 35.13(h)(38) as inapposite. This provision, as adopted by Order No. 679, has its advent in Order No. 298.[126] The Commission determined that to "facilitate the review of the prudence of CWIP costs in rate cases" the Commission required "a general statement of the utility's program for providing reliable and economic power." If the filing utility did not have certain specified information available, the Commission allowed the filing utility to "submit instead any pertinent information upon which it relied in deciding to replace or expand its [ ] facilities."[127]

106. PHI has done so here, stating that it has relied upon the PJM RTEP in deciding on this expansion.[128] PJM is responsible for considering 10 year load forecasts, congestion events, and operational performance of the transmission system as the FERC- approved Regional Transmission Organization, and therefore, is responsible for developing required transmission enhancements needed to maintain reliability on a least-cost basis.[129] Therefore, we find that PHI has sufficiently fulfilled the requirements of § 35.13(h)(38).

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[126] *Construction Work In Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, 48 Fed. Reg., 24,323 (June 1, 1983), FERC Stats. & Regs. ¶ 30,455 at p. 30,516 (1983), *order on reh'g*, Order No. 298-B, 48 Fed. Reg. 55,281 (December 12, 1983), FERC Stat. & Regs. ¶ 30,524 (1983).

[127] Order No. 298, 48 Fed. Reg., 24,323 at p. 30,156-7.

[128] Heintz Test. Ex. No. PHI-33 at 1-3.

[129] *Id.* at 3.

3. Formula Rate Modifications

107. PHI modified its formula rates to include the data necessary to accommodate the requested ROE and CWIP incentives. It states that these revisions make its formula rates substantially similar to the formula rates of other transmission-owning utilities that operate within PJM.[130]

108. PHI explains that in addition to showing the changes to the formula rates in redline, it has also populated the formula using 2007 Form No. 1 data for illustrative purposes.[131]

a. Protests

109. Maryland People's Counsel states that, because of the requested incentives, the circumstances under which the parties to the settlement agreed to the formula rate and related protocols in 2006 have changed dramatically. Maryland People's Counsel asserts that the formula rate and related protocols should be revised in light of these changes. Maryland People's Counsel requests several modifications:

a. In-person meeting of interested parties regarding the review of the Annual Updates;

b. Requiring more explanatory material with the Annual Updates;

c. Removal of restrictions on challenges to the "appropriateness of the application of the formula rate" and to whether the formula rate has been "properly applied";

d. Removal of restrictions on information requests concerning costs or cost allocations;

e. Clarification of interest and true-up rules on any under- or over-recoveries;

f. Requiring segregation of all work orders for the MAPP Project from other projects, and preparation of monthly reports summarizing all costs; and

g. Requiring more detailed explanation of how affiliates will share costs and responsibilities.

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[130] Heintz Test. Ex. No. PHI-30 at 4 (citing *TRAIL*, 119 FERC ¶ 61,219 and *Commonwealth Edison Co.*, 119 FERC ¶ 61,234 (2007)).

[131] Heintz Test. Ex. PHI-30 at 4, and Appendix B.

110. Maryland People's Counsel states that PHI's existing formula rates were designed to apply to PHI Companies' existing transmission infrastructure and facilities. Maryland People's Counsel asserts that if the formula rates are applied to the large scale and long-term MAPP Project, the formula rates will cease to be just and reasonable, especially with the inclusion of added incentives such as CWIP in rate base. Specifically, Maryland People's Counsel takes issue with PHI's request for cost recovery of incentives for the MAPP Project under "Option 2" of PJM's Schedule 12.[132] Maryland People's Counsel argues that by using Option 2 to recover the costs of the MAPP Project, PHI's amendments to its tariff sheets are materially insufficient to carry PHI's burden of proof.

b. Answers

111. In its answer, PHI urges the Commission to reject Maryland People's Counsel's protest as an impermissible collateral attack on the March 20, 2006 uncontested settlement.[133] PHI asserts that challenges to the mechanics and protocols of PHI's formula rates are irrelevant to whether PHI should receive incentive rates for the MAPP Project. Therefore, PHI asks the Commission to reject Maryland People's Counsel's challenges to the formula rates.

112. Specifically, PHI states that Maryland People's Counsel is incorrect that the terms, formula, and protocols apply to existing transmission infrastructure only. PHI states that the companies' formula rate is designed to apply to both new and existing transmission facilities. Moreover PHI asserts that Maryland People's Counsel cited to a dissent that did not apply to the March 20, 2006 settlement order, but rather applied to an order in the ER05-513 docket. PHI states that the "Option 2" method of establishing a revenue

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[132] Maryland People's Counsel Protest at 10-11. Maryland People's Counsel references the revisions accepted in *Allegheny Power System Operating Cos.*, 111 FERC ¶ 61,308 (2005). Schedule 12 of the PJM OATT lays out three cost recovery options which PJM transmission owners may use to recover the costs of constructing new transmission upgrades resulting from the RTEP process. Under Option 1, the transmission owner could defer recovering the costs of RTEP upgrades until it filed to make a general revision to its zonal transmission rates. Under Option 2, the TO could file under section 205 of the FPA to establish an incremental revenue requirement for the new transmission project without a general revision to its modified zonal transmission rates. Under Option 3, the transmission owner could establish a revenue requirement for both the new and existing transmission facilities under a formula rate.

[133] *See Baltimore Gas & Electric Co.*, 115 FERC ¶ 61,066 (2006).

requirement under Schedule 12 for new transmission facilities cost recovery does not apply to PHI. Instead, PHI states that "Option 3" applied to the PHI companies.[134]

c. Commission Determination

113. We reject Maryland People's Counsel's protest in which it asks for revisions to the formula rate protocols governing disclosure of information about the costs and other inputs that go into the formula rate. The Commission accepted these protocols to apply to both existing rate base and new projects. PHI has not in this proceeding filed tariff revisions related to these protocols.[135] Unchanged tariff provisions are not subject to revision as part of an FPA section 205 filing.[136] Moreover, Maryland People's Counsel has provided no reason for us to find that the same protocols that apply to existing rate-based projects and new projects that do not receive incentives are not appropriate for the review of the costs and inputs for new projects that happen to receive incentives.[137] The

[134] *See* PHI Answer at n.10.

[135] In addressing International Transmission's proposal to revise its Attachment O rate formula to use projected test-period data instead of historic test-period data, the Commission found the justness and reasonableness of the unchanged ROE component of the rate formula to be beyond the scope of that section 205 proceeding. *International Transmission Co.*, 116 FERC ¶ 61,036, at P 35 (2006) (*International Transmission*); *accord Boston Edison Co.*, 65 FERC ¶ 61,311, at 62,425-27 (1993), *reh'g denied*, 66 FERC ¶ 61,337 (1994). These holdings are on point in the instant proceeding, where PHI proposes to revise the PHI Companies' formula rate to provide for 100 percent CWIP Recovery, but not the protocols. Moreover, like the switch to use of projected test-period data, 100 percent CWIP Recovery does not change the amount that the utility ultimately recovers for service, just the timing of such recovery. *See, e.g., International Transmission*, 116 FERC ¶ 61,036 at P 19; *Michigan Elec. Transmission Co.*, 117 FERC ¶ 61,314 (2006), *order on reh'g*, 118 FERC ¶ 61,139, *order on compliance*, 119 FERC ¶ 61,203, at P 17 (2007). With respect to 100 percent Abandoned Plant Recovery, no rate change is being sought at this time.

[136] *See, e.g., Pub. Serv. Comm'n of New York v. Federal Energy Regulatory Comm'n*, 866 F.2d 487, 488 (D.C. Cir. 1989) (upholding a statutory distinction between review of new filings and complaints challenging existing filings).

[137] Maryland People's Counsel also incorrectly suggests that PHI's existing protocols have never been applied before to an incentive rate project. In August, in *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008), we granted PHI incentive rates for other projects using the same formula rate and related protocols.

review of the costs and inputs associated with new projects that receive incentives are no different than those associated with other new projects that do not receive incentives.

4. Annual Reporting Requirement

114. Maryland People's Counsel protests the lack of an annual reporting requirement for PHI to provide the current status of the various components of the MAPP Project and their estimated or actual in-service dates. As a result of approving incentives in this order, however, our regulations will require PHI to file a FERC Form No. 730 report for incentive-based rate treatments for transmission, and we find this annual report to be sufficient. Form 730 provides, for each incentive project, the most up-to-date, expected completion date, percentage completion as of the date of filing, and reasons for delay. As the Commission previously has found, this report satisfies the Commission's requirement for an annual filing for CWIP recovery through a rate formula.

The Commission orders:

(A) PHI's request for incentives, as modified are granted, and proposed tariff sheets are hereby accepted for filing, effective November 1, 2008, subject to revision as discussed in the body of this order.

(B) PHI is ordered to file revised tariff sheets within 30 days of this order to reflect the ROE incentive granted herein.

By the Commission. Commissioner Kelly concurring with a separate statement to be issued at a later date.
Commissioner Wellinghoff concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pepco Holdings, Inc. Docket No. ER08-1423-000

(Issued October 31, 2008)

WELLINGHOFF, Commissioner, concurring:

In today's order, the Commission approves a 150 basis point incentive ROE adder for PHI in connection with its Mid-Atlantic Power Pathway (MAPP) Project. I agree with that decision. I write separately to highlight important characteristics of this project that I believe warrant this significant incentive ROE adder.

I have dissented from numerous orders in which I felt that the majority undermined the nexus requirement that is an essential component of Order No. 679 and inappropriately granted incentive ROE adders.[138] By contrast, I agree that the MAPP Project satisfies the nexus requirement. It is noteworthy that this project is, as described in today's order, "a high voltage 500 kV line … crossing through four states, and providing access to more than 1,300 MW of renewable generation in the western portion of PJM."[139] At least as important, I believe that this project is a non-routine investment worthy of the significant incentive ROE adder granted here because it will use advanced technologies that will benefit all users of the grid and ultimate consumers.

With respect to the use of advanced technologies, PHI provides substantial detail in its testimony and the technology statement required by Order No. 679.[140] PHI Witness William Gausman states that "[t]he MAPP Project will be using the most state of the art and innovative electrical power equipment available today, and the project will allow PHI to be at the forefront of accepting, embracing and deploying new technologies."[141] For example, Witness Gausman states that the portion of the MAPP Project that will cross under the Chesapeake Bay will likely be either "the highest capacity AC submarine cable system anywhere in the world" or "the highest voltage and highest capacity voltage

[138] *See, e.g.*, *Commonwealth Edison Co.*, 122 FERC ¶ 61,037 (2008) (dissent in part of Commissioner Wellinghoff); *Pepco Holdings, Inc.*., 124 FERC ¶ 61,176 (2008) (dissent of Commissioner Wellinghoff); *Duquesne Light Co.*, 125 FERC ¶ 61,028 (2008) (dissent in part of Commissioner Wellinghoff).

[139] *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130 at P 75 (2008).

[140] PHI's required technology statement is Exhibit No. PHI-19.

[141] Gausman Test. Ex. No. PHI-1 at 55.

source control DC submarine cable system, utilizing XLPE cable, anywhere in the world," depending on whether PJM approves the use of VSC-based HVDC technology for the Project.[142] Witness Gausman also describes key features of a "smart grid" at the transmission level,[143] and he explains how various advanced technologies to be incorporated into the MAPP Project will promote those features.[144] In addition, PHI Witness William Avera states that "the advanced technologies incorporated in the MAPP project will enhance its potential to provide dependable, efficient energy delivery, but the associated complexities also imply greater risks and uncertainties."[145]

As I have discussed previously, I believe that consideration of advanced technologies and their associated risks and challenges is an appropriate component of the nexus analysis that the Commission conducts in evaluating applications for incentives under Order No. 679.[146] Consistent with such consideration, today's order accounts for technology-related risks in evaluating PHI's incentives request.[147]

For these reasons, I concur with today's order.

Jon Wellinghoff
Commissioner

[142] *Id*. at 56, 65-66.

[143] Among other "smart grid" features, Witness Gausman identifies the ability to: (1) optimize assets and operate efficiently; (2) monitor, self-analyze, and diagnose the health and condition of equipment and predict the malfunction or failure of a device before the event occurs in order to take preventative action; and (3) correct any problems quickly and with a minimum of intervention by the grid operator. *Id*. at 66.

[144] *Id*. at 67-71.

[145] Avera Test. Ex. PHI-24 at 91.

[146] *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (dissent in part of Commissioner Wellinghoff at 1-4); *Northeast Utilities Service Co*., 124 FERC ¶ 61,044 (2008) (dissent of Commissioner Wellinghoff at 2-3).

[147] *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130 at P 57, 76-77 (2008).

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