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June 22, 2010

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, 2008
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2009
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2010

Docket Nos. EO03050394, ER07060379, ER08050310, EO09050351
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Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No. _______________

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

Dear Secretary Izzo:

This letter (original and 11 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) the annual formula rate update filings made by PPL Electric Utilities Corporation ("PPL") in Federal Energy Regulatory Commission ("FERC") Docket No. ER08-1457, by American Electric Power Service Corporation ("AEP") in FERC Docket No. ER08-1329, and by Trans-Allegheny Interstate Line Company ("TrAILCo") in FERC Docket No. ER07-562, and (ii) the formula rate update filings made by the public utility affiliates of Pepco Holdings Inc. ("PHI") in FERC Docket No. ER08-1423 and the respective utility affiliate compliance filings for formula rate updates made by Atlantic City Electric Company ("ACE") in Docket No ER09-1156, Delmarva Power and Light ("Delmarva") in Docket No. ER09-1158, and Potomac Electric Power Company ("PEPCO") in Docket No. ER09-1159 (the filings referred to in (i) and (ii) above are collectively referred to as the "Filings").

Background

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), the Board 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. EO090305351), the Board discussed this issue and concluded that such a "pass through" of FERC-approved transmission rate changes was in the best interests of BGS customers.

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

Request for Board Approval

The EDCs request Board approval to implement revised BGS-FP and BGS-CIEP tariff rates effective September 1, 2010. In support of this request, the EDCs have included pro-forma tariff sheets shown in Attachment 1. The proposed BGS tariff rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets. The attached pro-forma tariff sheets propose an effective date of September 1, 2010 and will remain in effect until changed. The BGS-FP and BGS-CIEP rates included in the amended tariff sheets for each EDC are revised to reflect costs effective on June 1, 2010 for TECs resulting from all of the FERC-approved Filings, except the AEP-East filing which is effective on July 1, 2010.

Attachment 2 shows the cost impact for the 2010/2011 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the projects covered by the Filings, as posted on the PJM website. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs assuming implementation on September 1, 2010 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.

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

The EDCs also request that the BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the updates from formula rates effective June 1 and July 1, 2010. 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.

Attachments

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Frank Perrotti
Alice Bator
Stacy Peterson
Stefanie Brand, Division of Rate Counsel
Service List (via e-mail)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION CHARGE UPDATE - JUNE 2009
BPU DOCKET NO. EO09060440

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

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

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 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	$ 0.114810	$ 0.122847	$ 0.114539	$ 0.122557
RS – in excess of 600 kWh	0.114810	0.122847	0.123660	0.132316
RHS – first 600 kWh	0.098238	0.105115	0.109908	0.117602
RHS – in excess of 600 kWh	0.098238	0.105115	0.122104	0.130651
RLM On-Peak	0.161725	0.173046	0.157135	0.168134
RLM Off-Peak	0.074832	0.080070	0.078935	0.084460
WH	0.095282	0.101952	0.107117	0.114615
WHS	0.077482	0.082906	0.089246	0.095493
HS	0.103881	0.111153	0.139781	0.149566
BPL	0.073379	0.078516	0.076450	0.081802
BPL-POF	0.073379	0.078516	0.076450	0.081802
PSAL	0.073379	0.078516	0.076450	0.081802

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..$ 4.5466
Charge including New Jersey Sales and Use Tax (SUT) ....$ 4.8649

Charge applicable in the months of October through May..$ 4.5280
Charge including New Jersey Sales and Use Tax (SUT) ....$ 4.8450

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 ....$ 21,221.01 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 .... $ 81.62 per MW per month
Virginia Electric and Power Company ....$ 9.37 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ 15.09 per MW per month
PPL Electric Utilities Corporation ....$ 5.35 per MW per month
American Electric Power Service Corporation ....$ 0.86 per MW per month
Atlantic City Electric Company. ....$ 5.50 per MW per month
Delmarva Power and Light Company..$ 2.23 per MW per month
Potomac Electric Power Company. ....$ 4.06 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months..$ 1.8926
Charge including New Jersey Sales and Use Tax (SUT) .... $ 2.0251

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	$ 21,221.01 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	$ 81.62 per MW per month
Virginia Electric and Power Company	$ 9.37 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 15.09 per MW per month
PPL Electric Utilities Corporation	$ 5.35 per MW per month
American Electric Power Service Corporation	$ 0.86 per MW per month
Atlantic City Electric Company.	$ 5.50 per MW per month
Delmarva Power and Light Company	$ 2.23 per MW per month
Potomac Electric Power Company.	$ 4.06 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 1.8926
Charge including New Jersey Sales and Use Tax (SUT)	$ 2.0251

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

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

Rider BGS-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) 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, 2009 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, 2010.

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 September 1, 2010, a TRAILCO4-TEC surcharge of **$0.000305** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000014** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000072** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000007** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000003** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000018** 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 February 1, 2010, a PATH3-TEC surcharge of **$0.000054** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000033** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001018** 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: ($0.004542) (includes Sales and Use Tax as provided in Rider SUT)

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

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

3) BGS Transmission Charge per KWH: (Continued)

Effective September 1, 2010, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	TRAILCO4-TEC	PEPCO2-TEC	ACE2-TEC
GT – High Tension Service	**$0.000044**	**$0.000002**	**$0.000011**
GT	**$0.000165**	**$0.000007**	**$0.000039**
GP	**$0.000193**	**$0.000009**	**$0.000045**
GS and GST	**$0.000305**	**$0.000014**	**$0.000072**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000001**	**$0.000000**	**$0.000003**
GT	**$0.000004**	**$0.000002**	**$0.000010**
GP	**$0.000005**	**$0.000002**	**$0.000012**
GS and GST	**$0.000007**	**$0.000003**	**$0.000018**

Effective February 1, 2010, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	PATH3-TEC	VEPCO3-TEC	PSEG2-TEC
GT – High Tension Service	**$0.000009**	**$0.000005**	**$0.000168**
GT	**$0.000030**	**$0.000018**	**$0.000562**
GP	**$0.000032**	**$0.000019**	**$0.000596**
GS and GST	**$0.000054**	**$0.000033**	**$0.001018**

4) BGS Reconciliation Charge per KWH: ($0.000179) (includes Sales and Use Tax as provided in Rider SUT)

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

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh	0.153 ¢ per kWh	0.153 ¢ per kWh

(4) Societal Benefits Charge

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

(5) Regional Greenhouse Gas Initiative Surcharge

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

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.087 ¢ per kWh	0.087 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.039 ¢ per kWh	0.039 ¢ per kWh

(4) Societal Benefits Charge

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

(5) Regional Greenhouse Gas Initiative Surcharge

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

(6) Securitization Charges

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

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* Definition of Summer Billing Months - June through September

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh .....@	0.025 ¢ per kWh	0.025 ¢ per kWh

(4) Societal Benefits Charge

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

(5) Regional Greenhouse Gas Initiative Surcharge

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh ... @	0.092 ¢ per kWh	0.092 ¢ per kWh

(4) Societal Benefits Charge

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

(5) Regional Greenhouse Gas Initiative Surcharge

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

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

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.144 ¢ per kWh	0.144 ¢ per kWh

(4) Societal Benefits Charge

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

(Continued)

Attachment 2a
Cost Allocation of 2010/2011 TrailCo Schedule 12 Charges

Attachment 2b
Cost Allocation of 2010/2011 Delmarva Schedule 12 Charges

Attachment 2c
Cost Allocation of 2010/2011 ACE Schedule 12 Charges

Attachment 2d
Cost Allocation of 2010/2011 PEPCo Schedule 12 Charges

Attachment 2e
Cost Allocation of 2010/2011 PPL Schedule 12 Charges

Attachment 2f
Cost Allocation of 2010/2011 AEP-East Schedule 12 Charges

PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
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 2010- May 2011 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[1]	b0321.1	$ 1,463,024.88	1.99%	4.22%	7.12%	0.27%	$29,114	$61,740	$104,167	$3,950	$198,971
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 117,384,012.77	1.99%	4.22%	7.12%	0.27%	$2,335,942	$4,953,605	$8,357,742	$316,937	$15,964,226
Wylie Ridge [2]	b0218	$ 1,985,339.29	11.83%	15.56%	0.00%	0.00%	$234,866	$308,919	$0	$0	$543,784
Black Oak	b0216	$ 7,663,479.90	1.99%	4.22%	7.12%	0.27%	$152,503	$323,399	$545,640	$20,691	$1,042,233
Meadowbrook 200 MVAR capacitor	b0559	$ 1,028,001.42	1.99%	4.22%	7.12%	0.27%	$20,457	$43,382	$73,194	$2,776	$139,808
Replace Kammer 765/500 kV TXfmr	b0495	$ 5,707,904.04	1.99%	4.22%	7.12%	0.27%	$113,587	$240,874	$406,403	$15,411	$776,275
Totals							**$2,886,469**	**$5,931,918**	**$9,487,145**	**$359,765**	**$18,665,298**
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 10/11**	**2010TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2010 Impact (7 months)**	**2011 Impact (5 months)**	**2010-2011 Impact (12 months)**
PSE&G	$ 790,595.44	9,686.7	$ 81.62	$ 5,534,168	$ 3,952,977	$ 9,487,145
JCP&L	$ 494,326.49	5,738.4	$ 86.14	$ 3,460,285	$ 2,471,632	$ 5,931,918
ACE	$ 240,539.12	2,706.6	$ 88.87	$ 1,683,774	$ 1,202,696	$ 2,886,469
RE	$ 29,980.45	371.1	$ 80.79	$ 209,863	$ 149,902	$ 359,765
Total Impact on NJ Zones	**$ 1,555,441.50**			**$ 10,888,090**	**$ 7,777,207**	**$ 18,665,298**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010/2011 allocation share percentages (columns b-e) from PJM OATT Sheets 270F-270F.01i
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

(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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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%)

* 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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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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%)

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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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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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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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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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Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0590	Replace #1 and #2 breakers at Charleroi 138 kV		APS (100%)
b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV		APS (100%)
b0673	Rebuild Elko – Carbon Center Junction using 230 kV construction		APS (100%)
b0674	Construct new Osage – Whiteley 138 kV circuit		APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.03%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.03%)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.03%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.03%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.03%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP**(0.03%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP**(0.03%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP**(0.03%)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.03%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.08%) / PECO (3.09%) / PPL (2.25%) / PSEG (2.42%) / RE (0.09%) / ECP**(0.03%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.82%) / DPL (0.53%) / JCPL (1.93%) / ME (4.05%) / NEPTUNE* (0.09%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.93%) / RE (0.11%) / ECP** (0.04%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.82%) / DPL (0.53%) /JCPL (1.93%) / ME (4.05%) / NEPTUNE* (0.09%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.93%) / RE (0.11%) / ECP** (0.04%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT’s at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT’s at Whiteley 138 kV		APS (100%)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (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%)

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

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

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

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

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

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

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
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 2010 - May 2011 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	$ 3,635,730.00	1.99%	4.22%	7.12%	0.27%	$72,351	$153,428	$258,864	$9,816	$494,459
Totals							**$72,351**	**$153,428**	**$258,864**	**$9,816**	**$494,459**
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 10/11**	**2010TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2010 Impact (7 months)**	**2011 Impact (5 months)**	**2010-2011 Impact (12 months)**
PSE&G	$ 21,572.00	9,686.7	$ 2.23	$ 151,004	$ 107,860	$ 258,864
JCP&L	$ 12,785.65	5,738.4	$ 2.23	$ 89,500	$ 63,928	$ 153,428
ACE	$ 6,029.25	2,706.6	$ 2.23	$ 42,205	$ 30,146	$ 72,351
RE	$ 818.04	371.1	$ 2.20	$ 5,726	$ 4,090	$ 9,816
Total Impact on NJ Zones	**$ 41,204.94**			**$ 288,435**	**$ 206,025**	**$ 494,459**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010 allocation share percentages (columns b-e) are from PJM OATT sheets 270E.09
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0261	Replace 1200 Amp disconnect switch on the Red Lion – Reybold 138 kV circuit		DPL (100%)
b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV		DPL (100%)
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River – Frankford 138 kV line		DPL (100%)
b0272.1	Replace line trap and disconnect switch at Keeney 500 kV substation – 5025 Line Terminal Upgrade		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0282	Install 46 MVAR capacitors on the DPL distribution system		DPL (100%)
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony – Edgemoor 230 kV circuit, increase the operating temperature of the conductor		DPL (100%)

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

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

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0295	Raise conductor temperature of North Seaford – Pine Street – Dupont Seaford		DPL (100%)
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade		DPL (100%)
b0320	Create a new 230 kV station that splits the 2nd Milford to Indian River 230 kV line, add a 230/69 kV transformer, and run a new 69 kV line down to Harbeson 69 kV		DPL (100%)

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Vice President, Federal Government Policy
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Attachment 2c

PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
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 2010 - May 2011 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								
Upgrade AE portion of Delco Tap	b0265	$ 706,419.00	89.87%	9.48%	0.00%	0.00%	$634,859	$66,969	$0	$0	$0
Replace Monroe 230/69 kV TXfmrs	b0276	$ 1,068,224.00	91.28%	0.00%	8.29%	0.23%	$975,075	$0	$88,556	$2,457	$1,066,088
Reconductor Union - Corson 138 kV	b0211	$ 1,871,604.39	65.23%	25.87%	6.35%	0.00%	$1,220,848	$484,184	$118,847	$0	$1,823,878
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210	$ 3,706,795.00	1.99%	4.22%	7.12%	0.27%	$73,765	$156,427	$263,924	$10,008	$504,124
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.1	$ 2,643,082.00	65.23%	25.87%	6.35%	0.00%	$1,724,082	$683,765	$167,836	$0	$2,575,683
Totals							**$4,628,629**	**$1,391,345**	**$639,162**	**$12,465**	**$5,969,774**
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 10/11**	**2010TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2010 Impact (7 months)**	**2011 Impact (5 months)**	**2010-2011 Impact (12 months)**
PSE&G	$ 53,263.51	9,686.7	$ 5.50	$ 372,845	$ 266,318	$ 639,162
JCP&L	$ 115,945.39	5,738.4	$ 20.21	$ 811,618	$ 579,727	$ 1,391,345
ACE	$ 385,719.06	2,706.6	$ 142.51	$ 2,700,033	$ 1,928,595	$ 4,628,629
RE	$ 1,038.77	371.1	$ 2.80	$ 7,271	$ 5,194	$ 12,465
Total Impact on NJ Zones	**$ 555,966.74**			**$ 3,891,767**	**$ 2,779,834**	**$ 6,671,601**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010 allocation share percentages (columns e,f) are from PJM OATT sheets 270E.08-270E.08c
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

(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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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%)
b0431	Monroe Upgrade New Freedom strand bus		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)
b0871	Install 35 MVAR capacitor at Motts Farm 69 kV		AEC (100%)
b0872	Build a new Lincoln-Landis 138 kV line		AEC (100%)
b1072	Modify the existing EMS load shedding scheme at Cedar to additionally sense the loss of both Cedar 230/69 kV transformers and shed load accordingly		AEC (100%)

* 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.

PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
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 2010- May 2011 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	$ 6,624,632.00	1.99%	4.22%	7.12%	0.27%	$131,830	$279,559	$471,674	$17,887	$900,950
Totals							**$131,830**	**$279,559**	**$471,674**	**$17,887**	**$900,950**
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 10/11**	**2010TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2010 Impact (7 months)**	**2011 Impact (5 months)**	**2010-2011 Impact (12 months)**
PSE&G	$ 39,306.15	9,686.7	$ 4.06	$ 275,143	$ 196,531	$ 471,674
JCP&L	$ 23,296.62	5,738.4	$ 4.06	$ 163,076	$ 116,483	$ 279,559
ACE	$ 10,985.85	2,706.6	$ 4.06	$ 76,901	$ 54,929	$ 131,830
RE	$ 1,490.54	371.1	$ 4.02	$ 10,434	$ 7,453	$ 17,887
Total Impact on NJ Zones	**$ 75,079.16**			**$ 525,554**	**$ 375,396**	**$ 900,950**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010 allocation share percentages (columns b-e) are from PJM OATT sheets 270F.20a
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

(10) Potomac Electric Power Company

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

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

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0367.2	Reconductor circuit "23033" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)
b0375	Install 0.5% reactor at Dickerson on the Pleasant View – Dickerson 230 kV circuit		AEC (1.02%) / BGE (25.42%) / DPL (2.97%) / ME (1.72%) / PECO (3.47%) / PEPCO (65.40%)
b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.76%) / 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 Burches Hill to Palmers Corner		APS (1.68%) / BGE (1.83%) / PEPCO (96.49%)
b0496	Replace existing 500/230 kV transformer at Brighton		APS (5.67%) / BGE (29.68%) / Dominion (10.91%) / PEPCO (53.74%)
b0499	Install third Burches Hill 500/230 kV transformer		APS (3.54%) / BGE (7.31%) / PEPCO (89.15%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.7	Advance n0772 (Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.18	Advance n0783 (Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.22	Advance n0787 (Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.26	Advance n0791 (Replace Chalk Point 230 Kv breaker (4C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0526	Build two Ritchie – Benning Station A 230 kV lines		AEC (0.77%) / BGE (16.77%) / DPL (1.22%) / JCPL (1.39%) / ME (0.59%) / Neptune* (0.07%) / PECO (2.10%) / PEPCO (74.91%) / PSEG (2.10%) / RE (0.08%)
b0561	Install 300 MVAR capacitor at Dickerson Station "D" 230 kV substation		AEC (8.00%) / APS (2.62%) / DPL (10.91%) / JCPL (19.24%) / ME (1.56%) / Neptune* (0.95%) / PECO (21.39%) / PPL (5.67%) / ECP** (0.46%) / PSEG (28.15%) / RE (1.05%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.00%) / APS (2.62%) / DPL (10.91%) / JCPL (19.24%) / ME (1.56%) / Neptune* (0.95%) / PECO (21.39%) / PPL (5.67%) / ECP** (0.46%) / PSEG (28.15%) / RE (1.05%)
b0637	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0638	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0639	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0640	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0641	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0642	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0643	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)

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Potomac Electric Power Company (cont.)

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

Potomac Electric Power Company (cont.)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0809	Advance n0267 (Replace Dickerson Station H Circuit Breaker 45B)		PEPCO (100%)
b0810	Advance n0270 (Replace Dickerson Station H Circuit Breaker 47A)		PEPCO (100%)
b0811	Advance n0726 (Replace Dickerson Station H Circuit Breaker SPARE)		PEPCO (100%)

PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for PPL Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2010- May 2011 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 Susquehana-Roseland Line	b0487	$ 8,458,095.00	1.99%	4.22%	7.12%	0.27%	$168,316	$356,932	$602,216	$22,837	$0
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 21,512.00	1.99%	4.22%	7.12%	0.27%	$428	$908	$1,532	$58	$2,926
Replace wavetrap at Hosensack 500KV Sub	b0171.1	$ 15,425.00	1.99%	4.22%	7.12%	0.27%	$307	$651	$1,098	$42	$2,098
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 40,475.00	1.99%	4.22%	7.12%	0.27%	$805	$1,708	$2,882	$109	$5,505
New S-R additions < 500kV[2]	b0487.1	$ 282,056.00	0.00%	0.00%	5.13%	0.19%	$0	$0	$14,469	$536	$15,005
Totals							**$169,857**	**$360,198**	**$622,198**	**$23,582**	**$25,533**
		$ 8,817,563									
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 10/11**	**2010 Peak Load** *per PJM website*	**Rate in \$/MW-mo.**	**2010 Impact (7 months)**	**2011 Impact (5 months)**	**2010-2011 Impact (12 months)**
PSE&G	$ 51,849.80	9,686.7	$ 5.35	$ 362,949	$ 259,249	$ 622,198
JCP&L	$ 30,016.53	5,738.4	$ 5.23	$ 210,116	$ 150,083	$ 360,198
ACE	$ 14,154.72	2,706.6	$ 5.23	$ 99,083	$ 70,774	$ 169,857
RE	$ 1,965.15	371.1	$ 5.30	$ 13,756	$ 9,826	$ 23,582
Total Impact on NJ Zones	**$ 97,986.19**			**$ 685,903**	**$ 489,931**	**$ 1,175,834**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010 allocation share percentages (columns e,f) are from PJM OATT sheets 270E.08-270E.08c
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

(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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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%)
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%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		AEC (1.89%) / 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%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (16.91%) / PPL (77.67) / ECP (0.10%) / PSEG (5.13%) / RE (0.19%)
b0500.1	Conastone – Otter Creek 230 kV – Reconductor approximately 17.2 miles of 795 kcmil ACSR with new 795 kcmil ACSS operated at 160 deg C		AEC (6.33%) / 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.

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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.

PPL Electric Utilities Corporation (cont.)

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

PPL Electric Utilities Corporation (cont.)

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

PPL Electric Utilities Corporation (cont.)

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

PPL Electric Utilities Corporation (cont.)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1074	Install motor operators on the Jenkins 230 kV ‘2W’ disconnect switch and build out Jenkins Bay 3 and have MOD ‘3W’ operated as normally open		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0881	Install motor operators on Susquehanna T21 - Susquehanna 230 kV line East CB at Susquehanna 230 kV switching station		PPL (100%)
b0908	Install motor operators at South Akron 230 kV		PPL (100%)
b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus		PPL (100%)
b0910	Install a second 230 kV line between Jenkins and Stanton		PPL (100%)
b0911	Install motor operators at Frackville 230 kV		PPL (100%)
b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV		PPL (100%)
b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV line		PPL (100%)
b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps		PPL (100%)
b0915	Replace Walnut-Center City 69 kV cable		PPL (100%)
b0916	Reconductor Sunbury-Dalmatia 69 kV line		PPL (100%)
b1021	Install a new (#4) 138/69 kV transformer at Wescosville		PPL (100%)

PJM Schedule 12 - Transmission Enhancement Charges for July 2010 - December 2011
Calculation of costs and monthly PJM charges for AEP -East Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) July 2010 - Dec 2011 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(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 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 1,399,436.00	1.99%	4.22%	7.12%	0.27%	$27,849	$59,056	$99,640	$3,778	$0
Totals							**$27,849**	**$59,056**	**$99,640**	**$3,778**	**$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 10/11	(l) 2010TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2010 Impact (7 months)	(o) 2011 Impact (5 months)	(p) 2010-2011 Impact (12 months)
PSE&G	$ 8,303.32	9,686.7	$ 0.86	$ 58,123	$ 41,517	$ 99,640
JCP&L	$ 4,921.35	5,738.4	$ 0.86	$ 34,449	$ 24,607	$ 59,056
ACE	$ 2,320.73	2,706.6	$ 0.86	$ 16,245	$ 11,604	$ 27,849
RE	$ 314.87	371.1	$ 0.85	$ 2,204	$ 1,574	$ 3,778
Total Impact on NJ Zones	**$ 15,860.27**			**$ 111,022**	**$ 79,301**	**$ 190,323**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2010 allocation share percentages (columns b-e) are from PJM OATT sheets 270F.20a
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2011, however resultant customer rates will not be changed.

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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / 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%)
b0838	Hazard Area 138 kV and 69 kV Improvement Projects		AEP (100%)
b0839	Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer		AEP (99.73%) / Dayton (0.27%)
b0840	String a second 138 kV circuit on the open tower position between Twin Branch and East Elkhart		AEP (100%)

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

Attachment 3a
Translation of 2010/2011 Schedule 12 Charges into Rates – JCP&L

Attachment 3b
Translation of 2010/2011 Schedule 12 Charges into Rates – PSE&G

Attachment 3c
Translation of 2010/2011 Schedule 12 Charges into Rates - RECO

Attachment 3a

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL2-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly PPL2-TEC Costs Allocated to JCP&L Zone	$	30,016.53	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
PPL2-Transmission Enhancement Rate ($/MW-month)	$	5.23	

				Effective September 1, 2010:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL2-TEC Surcharge ($/kWh)	PPL2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	316,329	18,279,161,890	$ 0.000017	$ 0.000018
Primary	367.9	23,093	2,108,881,324	$ 0.000011	$ 0.000012
Transmission @ 34.5 kV	319.3	20,042	2,149,537,086	$ 0.000009	$ 0.000010
Transmission @ 230 kV	11.7	734	291,993,252	$ 0.000003	$ 0.000003
Total	5738.4	360,198	22,829,573,552		

(1) Attachment 2 Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months PPL Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	PPL2-Transmission Enhancement Costs to FP Suppliers	$	337,576	= Line 3 x $5.23 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.02	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East2-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly AEP-East2-TEC Costs Allocated to JCP&L Zone	$	4,921.35	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
AEP-East2-Transmission Enhancement Rate ($/MW-month)	$	0.86	

				Effective September 1, 2010:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	AEP-East2-TEC Surcharge ($/kWh)	AEP-East2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	51,864	18,279,161,890	$ 0.000003	$ 0.000003
Primary	367.9	3,786	2,108,881,324	$ 0.000002	$ 0.000002
Transmission @ 34.5 kV	319.3	3,286	2,149,537,086	$ 0.000002	$ 0.000002
Transmission @ 230 kV	11.7	120	291,993,252	$ -	$ -
Total	5738.4	59,056	22,829,573,552		

(1) Attachment 2 Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months AEP-East Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	AEP-East2-Transmission Enhancement Costs to FP Suppliers	$	55,347	= Line 3 x $0.86 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed Delmarva Project Transmission Enhancement Charge (Delmarva2-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved Delmarva Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly Delmarva2-TEC Costs Allocated to JCP&L Zone	$	12,785.65	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
Delmarva2-Transmission Enhancement Rate ($/MW-month)	$	2.23	

				Effective September 1, 2010:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Delmarva2-TEC Surcharge ($/kWh)	Delmarva2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	134,741	18,279,161,890	$ 0.000007	$ 0.000007
Primary	367.9	9,837	2,108,881,324	$ 0.000005	$ 0.000005
Transmission @ 34.5 kV	319.3	8,537	2,149,537,086	$ 0.000004	$ 0.000004
Transmission @ 230 kV	11.7	313	291,993,252	$ 0.000001	$ 0.000001
Total	5738.4	153,428	22,829,573,552		

(1) Attachment 2 Cost Allocation of Delmarva Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months Delmarva Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	Delmarva2-Transmission Enhancement Costs to FP Suppliers	$	143,792	= Line 3 x $2.23 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE2-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	115,945.39	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
ACE2-Transmission Enhancement Rate ($/MW-month)	$	20.21	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective September 1, 2010: ACE2-TEC Surcharge ($/kWh)	Effective September 1, 2010: ACE2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	1,221,888	18,279,161,890	$ 0.000067	$ 0.000072
Primary	367.9	89,202	2,108,881,324	$ 0.000042	$ 0.000045
Transmission @ 34.5 kV	319.3	77,418	2,149,537,086	$ 0.000036	$ 0.000039
Transmission @ 230 kV	11.7	2,837	291,993,252	$ 0.000010	$ 0.000011
Total	5738.4	1,391,345	22,829,573,552		

(1) Attachment 2 Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months ACE Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	ACE2-Transmission Enhancement Costs to FP Suppliers	$	1,303,961	= Line 3 x $20.21 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.07	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO2-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly PEPCO2-TEC Costs Allocated to JCP&L Zone	$	23,296.62	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
PEPCO2-Transmission Enhancement Rate ($/MW-month)	$	4.06	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective September 1, 2010:** PEPCO2-TEC Surcharge ($/kWh)	PEPCO2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	245,511	18,279,161,890	$ 0.000013	$ 0.000014
Primary	367.9	17,923	2,108,881,324	$ 0.000008	$ 0.000009
Transmission @ 34.5 kV	319.3	15,555	2,149,537,086	$ 0.000007	$ 0.000007
Transmission @ 230 kV	11.7	570	291,993,252	$ 0.000002	$ 0.000002
Total	5738.4	279,559	22,829,573,552		

(1) Attachment 2 Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months PEPCO Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	PEPCO2-Transmission Enhancement Costs to FP Suppliers	$	262,002	= Line 3 x $4.06 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO4-TEC Surcharge) effective September 1, 2010
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2010 - May 2011

2010/2011 Average Monthly TRAILCO4-TEC Costs Allocated to JCP&L Zone	$	494,326.49	(1)
2010 JCP&L Zone Transmission Peak Load (MW)		5738.4	
TRAILCO4-Transmission Enhancement Rate ($/MW-month)	$	86.14	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective September 1, 2010:** TRAILCO4-TEC Surcharge ($/kWh)	TRAILCO4-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5039.5	5,209,449	18,279,161,890	$ 0.000285	$ 0.000305
Primary	367.9	380,307	2,108,881,324	$ 0.000180	$ 0.000193
Transmission @ 34.5 kV	319.3	330,068	2,149,537,086	$ 0.000154	$ 0.000165
Transmission @ 230 kV	11.7	12,095	291,993,252	$ 0.000041	$ 0.000044
Total	5738.4	5,931,918	22,829,573,552		

(1) Attachment 2 Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2010/2011
(2) Based on 12 months TRAILCO Project costs from June 2010 through May 2011
(3) September 2010 through August 2011

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		17,683,245	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		19,471,383	MWH
3	BGS-FP Eligible Transmission Obligation		5,378	MW
4	TRAILCO4-Transmission Enhancement Costs to FP Suppliers	$	5,559,364	= Line 3 x $86.14 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.29	= Line 4 / Line 2

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2010 - May 2011	$	639,162	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010		9,686.7	
Term (Months)		12	
OATT rate	$	5.50	/MW/month
converted to $/MW/yr =	$	66.00	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0193	$ 0.0116	$ 0.0180	$ 0.0118	$ -	$ 0.0157	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000019**	**0.000012**	**0.000018**	**0.000012**	**0**	**0.000016**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/MW/month - rounded to 6 places	**$ 5.5000**	**$ 5.5000**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #						
1	Total BGS-FP eligbile Trans Obl		8,039.0	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	530,574		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0153	/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	$	695,195		unrounded	= (6) * (3)
8	Difference due to rounding	$	164,621		unrounded	= (7) - (4)

Attachment 3b

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for July 2010 - December 2011
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for June 2010 - May 2011	$	99,640	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010		9,686.7	
Term (Months)		12	
OATT rate	$	0.86	/MW/month
converted to $/MW/yr =	$	10.32	/MW/yr

all values show w/o NJ SUT

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0030	$ 0.0018	$ 0.0028	$ 0.0018	$ -	$ 0.0024	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000003**	**0.000002**	**0.000003**	**0.000002**	**0**	**0.000002**	**0**	**0**

	GLP	**LPL-S**
Change in Transmission Obligation Charge		
in $/MW/month - rounded to 6 places	**$ 0.8600**	**$ 0.8600**

<< same increase to BGS-CIEP Transmission Obligation Charges

Line #						
1	Total BGS-FP eligbile Trans Obl		8,039.0	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	82,962		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0024	/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	$	(82,962)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for Delmarva Projects

TEC Charges for June 2010 - May 2011	$ 258,864	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010	9,686.7	
Term (Months)	12	
OATT rate	$ 2.23	/MW/month
converted to $/MW/yr =	$ 26.76	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0078	$ 0.0047	$ 0.0073	$ 0.0048	$ -	$ 0.0063	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000008**	**0.000005**	**0.000007**	**0.000005**	**0**	**0.000006**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/MW/month - rounded to 6 places	**$ 2.2300**	**$ 2.2300**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #				
1	Total BGS-FP eligbile Trans Obl	8,039.0 MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	32,518,909 MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	34,759,755 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 215,124	unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0062 /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	$ 347,598	unrounded	= (6) * (3)
8	Difference due to rounding	$ 132,474	unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2010 - May 2011	$	471,674	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010		9,686.7	
Term (Months)		12	
OATT rate	$	4.06	/MW/month
converted to $/MW/yr =	$	48.72	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0143	$ 0.0086	$ 0.0133	$ 0.0087	$ -	$ 0.0116	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000014**	**0.000009**	**0.000013**	**0.000009**	**0**	**0.000012**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/MW/month - rounded to 6 places	**$ 4.0600**	**$ 4.0600**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl		8,039.0 MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909 MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	391,660	unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0113 /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	$	347,598	unrounded	= (6) * (3)
8	Difference due to rounding	$	(44,063)	unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2010 - May 2011	$	622,198	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010		9,686.7	
Term (Months)		12	
OATT rate	$	5.35	/MW/month
converted to $/MW/yr =	$	64.20	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0188	$ 0.0113	$ 0.0175	$ 0.0115	$ -	$ 0.0152	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000019**	**0.000011**	**0.000017**	**0.000011**	**0**	**0.000015**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/MW/month - rounded to 6 places	**$ 5.3500**	**$ 5.3500**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl		8,039.0 MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909 MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	516,104	unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0148 /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	$	347,598	unrounded	= (6) * (3)
8	Difference due to rounding	$	(168,506)	unrounded	= (7) - (4)

Attachment 3b

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2010 - May 2011
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

TEC Charges for June 2010 - May 2011	$	9,487,145	
PSE&G Zonal Transmission Load for Effective Yr. (MW) 1/1/2010		9,686.7	
Term (Months)		12	
OATT rate	$	81.62	/MW/month
converted to $/MW/yr =	$	979.44	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3897.2	29.8	75.3	0.5	0.0	5.4	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.2868	$ 0.1726	$ 0.2666	$ 0.1748	$ -	$ 0.2323	$ -	$ -
in dollars/kWh - rounded to 6 places	**0.000287**	**0.000173**	**0.000267**	**0.000175**	**0**	**0.000232**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/MW/month - rounded to 6 places	**$ 81.6200**	**$ 81.6200**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	8,039.0	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 7,873,718		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.2265	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.23	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 7,994,744		unrounded	= (6) * (3)
8	Difference due to rounding	$ 121,025		unrounded	= (7) - (4)

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes effective September 1, 2010
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2010
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2010
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2010
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 2010
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2010
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2010
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Delmarva - TEC	(4)	0.00001	0.00000	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PATH - TEC	(5)	0.00007	0.00004	0.00002	0.00000	0.00000	0.00004	0.00000	0.00007
PEPCO - TEC	(6)	0.00002	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PPL - TEC	(7)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00002
PSE&G - TEC	(8)	0.00093	0.00055	0.00024	0.00000	0.00000	0.00058	0.00000	0.00093
TrAILCo - TEC	(9)	0.00034	0.00018	0.00008	0.00020	0.00000	0.00019	0.00000	0.00026
VEPCo - TEC	(10)	0.00004	0.00002	0.00001	0.00000	0.00000	0.00002	0.00000	0.00004
Total ($/kWh and excl SUT)		$0.00144	$0.00082	$0.00036	$0.00024	$0.00000	$0.00087	$0.00000	$0.00135
Total (¢/kWh and excl SUT)		0.144 ¢	0.082 ¢	0.036 ¢	0.024 ¢	0.000 ¢	0.087 ¢	0.000 ¢	0.135 ¢

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Delmarva - TEC	(4)	0.00001	0.00000	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PATH - TEC	(5)	0.00007	0.00004	0.00002	0.00000	0.00000	0.00004	0.00000	0.00007
PEPCO - TEC	(6)	0.00002	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
PPL - TEC	(7)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00002
PSE&G - TEC	(8)	0.00100	0.00059	0.00026	0.00000	0.00000	0.00062	0.00000	0.00100
TrAILCo - TEC	(9)	0.00036	0.00019	0.00009	0.00021	0.00000	0.00020	0.00000	0.00028
VEPCo - TEC	(10)	0.00004	0.00002	0.00001	0.00000	0.00000	0.00002	0.00000	0.00004
Total ($/kWh and incl SUT)		$0.00153	$0.00087	$0.00039	$0.00025	$0.00000	$0.00092	$0.00000	$0.00144
Total (¢/kWh and incl SUT)		0.153 ¢	0.087 ¢	0.039 ¢	0.025 ¢	0.000 ¢	0.092 ¢	0.000 ¢	0.144 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2010.
(2) ACE-TEC rates calculated in Attachment 5 of the joint EDC filing.
(3) AEP-East-TEC rates calculated in Attachment 5 of the joint EDC filing.
(4) Delmarva-TEC rates calculated in Attachment 5 of the joint EDC filing.
(5) Current PATH-TEC rates pursuant to the Board's Order dated January 21, 2010 in Docket No. ER09120995.
(6) PEPCO-TEC rates calculated in Attachment 5 of the joint EDC filing.
(7) PPL-TEC rates calculated in Attachment 5 of the joint EDC filing.
(8) Current PSE&G-TEC rates pursuant to the Board's Order dated January 21, 2010 in Docket No. ER09120995.
(9) TrAILCo-TEC rates calculated in Attachment 5 of the joint EDC filing.
(10) Current VEPCo-TEC rates pursuant to the Board's Order dated January 21, 2010 in Docket No. ER09120995.

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2010
To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly ACE-TEC Costs Allocated to RECO	$	1,039	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	3.10	

	Col. 1	Col. 2	Col.3=Col.2 x $1,039 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$	8,457	709,814,000	$	0.00001	$	0.00001
SC2 Secondary	79.5	23.72%	$	2,957	470,254,000	$	0.00001	$	0.00001
SC2 Primary	6.7	2.01%	$	251	92,604,000	$	-	$	-
SC3	0.1	0.02%	$	2	287,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,943,000	$	-	$	-
SC5	3.1	0.91%	$	114	17,539,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	3,999,000	$	-	$	-
SC7	18.4	5.49%	$	684	76,036,000	$	0.00001	$	0.00001
Total	335.2 (2)	100.00%	$	12,465	1,377,476,000				

(1) Attachment 5 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2010 through May 2011
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	11,786.59	= Line 3 x $3.10 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP-East) effective September 1, 2010
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	315	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.94	

	Col. 1	Col. 2	Col.3=Col.2 x $315 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$ 2,564	709,814,000	$ -	$ -
SC2 Secondary	79.5	23.72%	$ 896	470,254,000	$ -	$ -
SC2 Primary	6.7	2.01%	$ 76	92,604,000	$ -	$ -
SC3	0.1	0.02%	$ 1	287,000	$ -	$ -
SC4	0.0	0.00%	$ -	6,943,000	$ -	$ -
SC5	3.1	0.91%	$ 34	17,539,000	$ -	$ -
SC6	0.0	0.00%	$ -	3,999,000	$ -	$ -
SC7	18.4	5.49%	$ 207	76,036,000	$ -	$ -
Total	335.2 (2)	100.00%	$ 3,778	1,377,476,000		

(1) Attachment 5 - Cost Allocation of AEP-East Schedule 12 Charges to RECO Zone for June 2010 through May 2011
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	3,574.00	= Line 3 x $0.94 * 12
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 September 1, 2010

To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	818	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.44	

	Col. 1	Col. 2	Col.3=Col.2 x $818 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$	6,660	709,814,000	$	0.00001	$	0.00001
SC2 Secondary	79.5	23.72%	$	2,329	470,254,000	$	-	$	-
SC2 Primary	6.7	2.01%	$	198	92,604,000	$	-	$	-
SC3	0.1	0.02%	$	2	287,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,943,000	$	-	$	-
SC5	3.1	0.91%	$	89	17,539,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	3,999,000	$	-	$	-
SC7	18.4	5.49%	$	539	76,036,000	$	0.00001	$	0.00001
Total	335.2 (2)	100.00%	$	9,817	1,377,476,000				

(1) Attachment 5 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2010 through May 2011

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	9,277.19	= Line 3 x $2.44 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective September 1, 2010
To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	1,491	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.45	

	Col. 1	Col. 2	Col.3=Col.2 x $1,491 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$ 12,135	709,814,000	$ 0.00002	$ 0.00002
SC2 Secondary	79.5	23.72%	$ 4,243	470,254,000	$ 0.00001	$ 0.00001
SC2 Primary	6.7	2.01%	$ 360	92,604,000	$ -	$ -
SC3	0.1	0.02%	$ 3	287,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,943,000	$ -	$ -
SC5	3.1	0.91%	$ 163	17,539,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	3,999,000	$ -	$ -
SC7	18.4	5.49%	$ 982	76,036,000	$ 0.00001	$ 0.00001
Total	335.2 (2)	100.00%	$ 17,886	1,377,476,000		

(1) Attachment 5 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2010 through May 2011
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	16,919.46	= Line 3 x $4.45 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PPL) effective September 1, 2010
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly PPL-TEC Costs Allocated to RECO	$	1,965	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	5.86	

	Col. 1	Col. 2	Col.3=Col.2 x $1,965 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$ 15,999	709,814,000	$ 0.00002	$ 0.00002
SC2 Secondary	79.5	23.72%	$ 5,595	470,254,000	$ 0.00001	$ 0.00001
SC2 Primary	6.7	2.01%	$ 475	92,604,000	$ 0.00001	$ 0.00001
SC3	0.1	0.02%	$ 4	287,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,943,000	$ -	$ -
SC5	3.1	0.91%	$ 215	17,539,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	3,999,000	$ -	$ -
SC7	18.4	5.49%	$ 1,295	76,036,000	$ 0.00002	$ 0.00002
Total	335.2 (2)	100.00%	$ 23,583	1,377,476,000		

(1) Attachment 5 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2010 through May 2011
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	22,280.46	= Line 3 x $5.86 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective September 1, 2010
To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2010 to May 2011

2010/2011 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	29,980	(1)
2010 RECO Zone Transmission Peak Load (MW)		335.2	(2)
Transmission Enhancement Rate ($/MW-month)	$	89.43	

	Col. 1	Col. 2	Col.3=Col.2 x $29,980 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	Full Service Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	Full Service BGS Eligible Sales Sep 2010 - Aug 2011 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	227.5	67.85%	$ 244,086	709,814,000	$ 0.00034	$ 0.00036
SC2 Secondary	79.5	23.72%	$ 85,352	470,254,000	$ 0.00018	$ 0.00019
SC2 Primary	6.7	2.01%	$ 7,240	92,604,000	$ 0.00008	$ 0.00009
SC3	0.1	0.02%	$ 57	287,000	$ 0.00020	$ 0.00021
SC4	0.0	0.00%	$ -	6,943,000	$ -	$ -
SC5	3.1	0.91%	$ 3,278	17,539,000	$ 0.00019	$ 0.00020
SC6	0.0	0.00%	$ -	3,999,000	$ -	$ -
SC7	18.4	5.49%	$ 19,752	76,036,000	$ 0.00026	$ 0.00028
Total	335.2 (2)	100.00%	$ 359,765	1,377,476,000		

(1) Attachment 5 - Cost Allocation of TrailCo Schedule 12 Charges to RECO Zone for June 2010 through May 2011
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,226,436	MWH
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,311,152	MWH
3	BGS-FP Eligible Transmission Obligation		317	MW
4	Transmission Enhancement Costs to FP Suppliers	$	340,024.09	= Line 3 x $89.43 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.26	= Line 4/Line 2

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

		Notes	FERC Form 1 Page # or Instruction	TrAILCo 2010 Forecast
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	407,605
2	Total Wages Expense		p354.28.b	2,725,759
3	Less A&G Wages Expense		p354.27.b	2,318,154
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	407,605
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	188,154,696
7	Total Plant In Service		(Line 6)	188,154,696
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	3,794,254
9	Total Accumulated Depreciation		(Line 8)	3,794,254
10	Net Plant		(Line 7 - Line 9)	184,360,442
11	Transmission Gross Plant		(Line 15 + Line 21)	188,154,696
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	184,360,442
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	137,773,984
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	3,961,674
17	**Total Transmission Plant**		(Line 15 + Line 16)	**141,735,658**
18	General & Intangible		Attachment 5	50,380,711
19	Total General & Intangible		(Line 18)	50,380,711
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**50,380,711**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**192,116,369**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	3,773,948
24	Accumulated General Depreciation		Attachment 5	10,011
25	Accumulated Intangible Amortization		Attachment 5	10,295
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	20,306
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**20,306**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**3,794,254**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**188,322,116**

Adjustment To Rate Base

Line	Description	Note	Source	Amount
	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109 — Enter Negative		Attachment 1	-24,127,015
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**-24,127,015**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**763,251,167**
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	**283,843**
	Prepayments			
36	**Transmission Related Prepayments**	(Note A)	Attachment 5	**334,829**
	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)	7,560,524
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**945,066**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**740,687,889**
46	**Rate Base**		(Line 30 + Line 45)	**929,010,005**

O&M

Line	Description	Note	Source	Amount
	Transmission O&M			
47	Transmission O&M		p321.112.b	1,979,028
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	746,349
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)	**1,232,679**
	A&G Expenses			
53	Total A&G		p323.197.b	5,556,437
54	Less Property Insurance Account 924		p323.185.b	33,620
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	3,275
56	Less General Advertising Exp Account 930.1		p323.191.b	6,433
57	Less PBOP Adjustment		Attachment 5	-25,059
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	5,538,168
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**5,538,168**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	3,275
63	General Advertising Exp Account 930.1	(Note J)	Attachment 5	6,433
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**9,708**
65	Property Insurance Account 924		p323.185.b	33,620
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	33,620
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**33,620**
	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	0
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	178,663
73	Total Account 566		Sum (Lines 70 to 72)	**746,349**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**7,560,524**

	Depreciation & Amortization Expense				
	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	2,124,148
76	General Depreciation			Attachment 5	20,306
77	Intangible Amortization		(Note A)	Attachment 5	0
78	Total			(Line 76 + Line 77)	20,306
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**20,306**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**2,144,454**
	Taxes Other than Income				
82	**Transmission Related Taxes Other than Income**			Attachment 2	**1,488,230**
83	**Total Taxes Other than Income**			**(Line 82)**	**1,488,230**
	Return / Capitalization Calculations				
84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	223,162,651
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	0
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	223,162,651
	Capitalization				
90	Long Term Debt		(Note N)		455,000,000
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)	455,000,000
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	223,162,651
97	**Total Capitalization**			(Sum Lines 94 to 96)	678,162,651
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			0.049
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)	0.02440
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)	**0.08290**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**77,012,701**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			8.57%
111	p	(percent of federal income tax deductible for state purpc	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.57%
113	T/ (1-T)			68.27%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**37,105,409**
115	**Total Income Taxes**		**(Line 114)**	**37,105,409**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	188,322,116
117	Total Adjustment to Rate Base		(Line 45)	740,687,889
118	**Rate Base**		(Line 46)	**929,010,005**
119	Total Transmission O&M		(Line 74)	7,560,524
120	Total Transmission Depreciation & Amortization		(Line 81)	2,144,454
121	Taxes Other than Income		(Line 83)	1,488,230
122	Investment Return		(Line 108)	77,012,701
123	Income Taxes		(Line 115)	37,105,409
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**125,311,318**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	192,116,369
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	192,116,369
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	125,311,318
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**125,311,318**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	655,508
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**124,655,810**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**124,655,810**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**901,212,878**
135	FCR		(Line 133 / Line 134)	**13.8320%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**13.5963%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**13.5333%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**0.9336%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**10,537,700**
140	Increased Return and Taxes		Attachment 4	**121,934,563**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**132,472,262**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**901,212,878**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**14.69933%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**14.4636%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**14.4006%**
146	**Net Revenue Requirement**		(Line 132)	**124,655,810**
147	Reconciliation amount		Attachment 6	**8,721,669**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**7,102,890**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**140,480,369**
	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	4,971,980	21,944,661	21,944,661	[redacted]	21,944,661	-	-	21,944,661	
ADIT-283 From Account Total Below	3,820,002	12,708,159	12,708,159	[redacted]	12,708,159	-	-	12,708,159	
ADIT-190 From Account Total Below	(4,059,478)	(10,525,805)	(10,525,805)	[redacted]	(10,525,805)	-	-	(10,525,805)	Enter Negative
Subtotal					24,127,015	-	-	24,127,015	
Wages & Salary Allocator							100.0000%		
Gross Plant Allocator						100.0000%			
ADIT					24,127,015	-	-	24,127,015	

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	3,304,578	10,002,984	10,002,984			10,002,984	-		Actual amount of tax interest capitalized
Depreciation	662,231	-	-			-			Book depreciation
Intercompany Charges	21,843	-	-			-			Intercompany charges from the AP service company
Worker's Compensation	68,830	104,674	104,674			104,674			Actual amount of reserve for workers' compensation
Long Term Disability Accrual	1,950	2,479	2,479			2,479			Long term disability accrual
Excess Over/Under Prior Service	46	0	-			-			Excess over under prior service cost
Amortization Expense		4,177	4,177			4,177			Amortization of intangible plant
WV Rate Change Consolidated Benefit		(140)	(140)			(140)			Temporary difference due to change in state tax rate in West Virginia
CIAC - Taxable		411,631	411,631			411,631			Taxable CIAC
Subtotal	4,059,478	10,525,805	10,525,805	-	-	10,525,805	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	4,059,478	10,525,805	10,525,805	-	-	10,525,805	-	-	

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	552,983	913,516	913,516			913,516			Allowance for borrowed funds used during construction (ABFUDC)
Property Related - Tax Depreciation	4,418,997	22,571,513	22,571,513			22,571,513			Tax depreciation
FASB 109 Fixed Asset Adjustment	540,106	2,918,387	2,918,387			2,918,387			Increase in AOFDC
Book Depreciation Expense	-	(1,540,368)	(1,540,368)			(1,540,368)			Book depreciation
Subtotal	5,512,086	24,863,048	24,863,048	-	-	24,863,048	-	-	
Less FASB 109 included above	540,106	2,918,387	2,918,387	-	-	2,918,387	-	-	Increase in AOFDC
Less FASB 106 included above	-	-	-	-	-	-	-	-	
Total	4,971,980	21,944,661	21,944,661		-	21,944,661	-	-	

Instructions for Account 282:

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

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-283	**Beg of Year Balance** p276.19.b	**End of Year Balance** p277.19.k	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Deferred Tax Reclassification	-	-	-	-	-	-	-	-	ADIT balance sheet reclassification
Regulated Asset Prexy LT	540,486	588,449	588,449	-	-	588,449	-	-	Regulatory asset for Prexy reclassification
WV Rate Change Consol Benefit	140	-	-	-	-	-	-	-	Temporary difference due to change in state tax rate in West Virginia
Reg Asset PJM Receivable	3,279,376	10,629,496	10,629,496	-	-	10,629,496	-	-	Comparison of actual to forecast revenues - non-property related
Reg Asset PJM Receivable		1,501,980	1,501,980			1,501,980			Comparison of actual to forecast revenues - non-property related
WV State Property Tax		50,475	50,475			50,475			West Virginia property tax payment
Tax Intercompany Charges AESC		(62,241)	(62,241)			(62,241)			Intercompany charges from the AP service company
Subtotal	3,820,002	12,708,159	12,708,159		-	12,708,159	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	3,820,002	12,708,159	12,708,159		-	12,708,159	-	-	

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	2009 State Property WV	p263.36(i)	103,466	100.0000%	$ 103,466	
2	2008 Local Property WV	p263.1.5(i)	2,123	100.0000%	2,123	
3	2009 Local Property WV	p263.1.6(i)	4,166	100.0000%	4,166	
4	2009 Local Property VA	p263.1.10(i)	49,277	100.0000%	49,277	
5	2008 Local Property PA	p263.1.14(i)	9,780	100.0000%	9,780	
6	2009 Local Property PA	p263.1.15(i)	5,043	100.0000%	5,043	
7	2008 Local Property MD	p263.1.18(i)	750,749	100.0000%	750,749	
8	2009 Local Property MD	p263.1.19(i)	500,535	100.0000%	500,535	
9	2009 Capital Stock Tax/Franchise MD	p263.13(i)	300	100.0000%	300	
10	2009 Capital Stock Tax/Franchise PA	p263.24(i)	38,045	100.0000%	38,045	
11	Gross Premium MD	p263.16(i)	1,768	100.0000%	1,768	
12	Gross Premium PA	p263.25(i)	514	100.0000%	514	
13	State Use Tax Billed PA	p263.22(i)	34,574	100.0000%	34,574	
14	State Use Tax Billed VA	p263.30(i)	341	100.0000%	341	
15						
16						
17	**Total Plant Related**		1,500,681	100.0000%	1,500,681	
	Labor Related			**Wages & Salary Allocator**		
18	Accrued Federal FICA	p263.3(i)	-12,185			
19	Accrued Federal Unemployment	p263.4(i)	-51			
20	State Unemployment	p263.1.2(i)	-215			
21						
22						
23	**Total Labor Related**		-12,451	100.0000%	(12,451)	
	Other Included			**Gross Plant Allocator**		
24						
25						
26						
27						
28	**Total Other Included**		0	100.0000%	-	
29	**Total Included (Lines 8 + 14 + 19)**		1,488,230		**1,488,230**	Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded					
30	Federal Income Tax	p263.2(i)	-1,151,228			
31	Corporate Net Income Tax MD	p263.12(i)	-140,260			
32	Corporate Net Income Tax PA	p263.20(i)	-6,292			
33	Corporate Net Income Tax VA	p263.29(i)	-18,375			
34	Corporate Net Income Tax WV	p263.35(i)	-101,631			
35						
36						
37						
38						
39						
40	**Subtotal, Excluded**		-1,417,786			
41	**Total, Included and Excluded (Line 20 + Line 28)**		70,444			
42	**Total Other Taxes from p114.14.c**		1,488,230			
43	Difference (Line 41 - Line 42)		-1,417,786			

Criteria for Allocation:

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

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

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

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

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

Trans-Allegheny Interstate Line Company

Attachment 3 - Revenue Credit Workpaper

			Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		3,780	Page 300 Line: 19 Column: b
2	Total Rent Revenues	(Line 1)	3,780	
	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		654,385	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)	658,165	
12	Less line 14g		2,657	
13	Total Revenue Credits	(Line 11 - Line 12)	655,508	Input to Appendix A, Line 131
	<u>Revenue Adjustment to determine Revenue Credit</u>			
14a	Revenues associated with lines 14b-g are to be included in lines 2-10 and total of those revenues entered here		3,780	
14b	Costs associated with revenues in line 14a		1,534	
14c	Net Revenues (14a - 14b)		2,246	
14d	50% Share of Net Revenues (14c / 2)		1,123	
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)		1,123	
14g	Line 14a less line 14f		2,657	
15	Amount offset in line 4 above		-	
16	Total Account 454 and 456		655,508	

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

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

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

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

Trans-Allegheny Interstate Line Company

Attachment 4 - Calculation with Incentive ROE

	Return and Taxes at High End of the range of Reasonableness				
A	Return and Taxes at High End of the range of Reasonableness	(Sum Lines 26 and 33 from below)		121,934,563	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		929,010,005
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		223,162,651
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		0
5	Less Preferred Stock		Appendix A, Line 87		0
6	Less Account 216.1		Appendix A, Line 88		0
7	Common Stock		Appendix A, Line 89		223,162,651
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		455,000,000
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		455,000,000
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		223,162,651
15	Total Capitalization		Appendix A, Line 97		678,162,651
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		0.049
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)		0.02440
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)		**0.0879**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**81,657,751**

Composite Income Taxes

	Income Tax Rates			
27	FIT=Federal Income Tax Rate		Appendix A, Line 109	35.00%
28	SIT=State Income Tax Rate or Composite		Appendix A, Line 110	8.57%
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	40.57%
31	T/ (1-T)		Appendix A, Line 113	68.27%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		40,276,812
33	**Total Income Taxes**		**(Line 32)**	**40,276,812**

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			
	December	p207.58.b	For 2008	74,486,606	
	January	company records	For 2009	74,541,505	
	February	company records	For 2009	74,767,613	
	March company	records	For 2009	75,595,266	
	April	company records	For 2009	83,075,520	
	May	company records	For 2009	84,892,835	
	June company	records	For 2009	86,209,211	
	July	company records	For 2009	87,593,707	
	August	company records	For 2009	87,763,920	
	September	company records	For 2009	88,954,349	
	October company	records	For 2009	94,799,900	
	November	company records	For 2009	135,874,807	
	December	p207.58.g	For 2009	137,773,984	137,773,984
15	**Transmission Plant In Service**			**91,256,094**	**137,773,984**
				Link to Appendix A, line 15	**Link to Appendix A, line 15**
	Calculation of Distribution Plant In Service	Source			
	December	p206.75.b	For 2008	-	
	January	company records	For 2009	-	
	February	company records	For 2009	-	
	March company	records	For 2009	-	
	April	company records	For 2009	-	
	May	company records	For 2009	-	
	June company	records	For 2009	-	
	July	company records	For 2009	-	
	August	company records	For 2009	-	
	September	company records	For 2009	-	
	October	company records	For 2009	-	
	November	company records	For 2009	-	
	December	p207.75.g	For 2009	-	-
	Distribution Plant In Service			-	-
	Calculation of Intangible Plant In Service	Source			
	December	p204.5.b	For 2008	-	
	December	p205.5.g	For 2009	-	-
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 2008	3,448,444	-
	December	p207.99.g	For 2009	50,380,711	50,380,711
18	**General Plant In Service**			**26,914,578**	**50,380,711**
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of Production Plant In Service	Source			
	December	p204.46b	For 2008	-	
	January	company records	For 2009	-	
	February	company records	For 2009	-	
	March company	records	For 2009	-	
	April	company records	For 2009	-	
	May	company records	For 2009	-	
	June company	records	For 2009	-	
	July	company records	For 2009	-	
	August	company records	For 2009	-	
	September	company records	For 2009	-	
	October	company records	For 2009	-	
	November	company records	For 2009	-	
	December	p205.46.g	For 2009	-	-
	Production Plant In Service			-	-
6	**Total Plant In Service**	Sum of averages above		118,170,672	188,154,696
				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	Bedington Transformer	Meadow Brook SS Capacitor	Kammer Transformers	Total
December	45,842,798	13,291,705	5,213,431	2,928	244,984	7,973,203	1,917,557	-	-	-	74,486,606
January	45,831,189	13,294,046	5,254,114	2,928	244,984	7,995,440	1,918,804	-	-	-	74,541,505
February	45,860,100	13,294,046	5,450,539	2,928	244,984	7,996,211	1,918,804	-	-	-	74,767,613
March	45,878,500	13,295,091	6,258,349	2,928	244,984	7,996,610	1,918,804	-	-	-	75,595,266
April	45,879,790	13,294,500	6,424,110	2,928	244,984	7,996,811	1,841,729	7,390,667	-	-	83,075,520
May	45,880,890	13,295,566	8,228,792	2,928	244,984	7,997,082	1,841,729	7,400,865	-	-	84,892,835
June	45,896,999	13,295,566	9,512,160	2,928	244,984	7,997,435	1,841,729	7,417,410	-	-	86,209,211
July	46,518,292	13,295,566	10,247,103	2,928	244,984	7,997,637	1,841,729	7,445,469	-	-	87,593,707
August	46,543,861	13,295,566	10,389,603	2,928	244,984	7,997,838	1,841,729	7,447,412	-	-	87,763,920
September	46,550,534	13,295,566	11,266,106	2,928	244,984	8,004,240	1,858,835	7,731,158	-	-	88,954,349
October	46,563,904	13,295,566	11,267,836	2,928	244,984	8,004,444	1,923,902	7,726,173	5,770,165	-	94,799,900
November	46,567,643	13,295,566	11,544,763	2,928	244,984	8,004,654	1,923,902	7,713,990	5,889,051	40,687,326	135,874,807
December	46,572,419	13,295,566	11,545,561	2,928	244,984	8,202,934	1,923,902	7,713,990	6,283,316	41,988,386	137,773,984
Transmission Plant In Service	**46,183,609**	**13,294,917**	**8,661,728**	**2,928**	**244,984**	**8,012,657**	**1,885,627**	**5,229,780**	**1,380,195**	**6,359,670**	**91,256,094**

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 2008	1,649,800	
	January	company records	For 2009	1,793,718	
	February	company records	For 2009	2,014,120	
	March company	records	For 2009	2,167,658	
	April	company records	For 2009	2,321,245	
	May	company records	For 2009	2,487,632	
	June company	records	For 2009	2,655,867	
	July	company records	For 2009	2,825,470	
	August	company records	For 2009	2,996,279	
	September	company records	For 2009	3,167,831	
	October	company records	For 2009	3,339,890	
	November	company records	For 2009	3,521,149	
	December	p219.25.b	For 2009	3,773,948	3,773,948
23	**Transmission Accumulated Depreciation**			**2,670,354**	**3,773,948**
				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 2008	-	
	January	company records	For 2009	-	
	February	company records	For 2009	-	
	March company	records	For 2009	-	
	April	company records	For 2009	-	
	May	company records	For 2009	-	
	June company	records	For 2009	-	
	July	company records	For 2009	-	
	August	company records	For 2009	-	
	September	company records	For 2009	-	
	October company	records	For 2009	-	
	November	company records	For 2009	-	
	December	p219.26.b	For 2009	-	-
	Distribution Accumulated Depreciation			-	-
	Calculation of Intangible Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p200.21.b	For 2008	-	
	December	p200.21b	For 2009	10,295	10,295
25	**Accumulated Intangible Depreciation**			**5,148**	**10,295**
				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 2008	-	
	December	p219.28.b	For 2009	10,011	10,011
24	**Accumulated General Depreciation**			**5,006**	**10,011**
				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-2	For 2008	-	
	January	company records	For 2009	-	
	February	company records	For 2009	-	
	March company	records	For 2009	-	
	April	company records	For 2009	-	
	May	company records	For 2009	-	
	June company	records	For 2009	-	
	July	company records	For 2009	-	
	August	company records	For 2009	-	
	September	company records	For 2009	-	
	October company	records	For 2009	-	
	November	company records	For 2009	-	
	December	p219.20.b thru 219.24.b	For 2009	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**2,680,507**	**3,794,254**
				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	**Bedington Transformer**	**Meadow Brook SS Capacitor**	**Kammer Transformers**	**Total**
December	1,323,133	279,191	718	51	40	46,667	-	-	-	-	1,649,800
January	1,435,935	302,451	787	56	44	54,445	-	-	-	-	1,793,718
February	1,548,414	325,716	857	61	48	115,036	23,989	-	-	-	2,014,120
March	1,661,258	348,980	926	67	52	129,029	27,347	-	-	-	2,167,658
April	1,774,147	372,247	996	72	56	143,023	30,705	-	-	-	2,321,245
May	1,887,040	395,512	1,065	77	60	157,017	33,928	12,934	-	-	2,487,632
June	1,999,935	418,779	2,959	82	64	171,012	37,151	25,885	-	-	2,655,867
July	2,112,870	442,047	6,151	87	68	185,008	40,374	38,866	-	-	2,825,470
August	2,226,893	465,314	9,412	92	72	199,004	43,597	51,895	-	-	2,996,279
September	2,340,964	488,581	13,366	97	76	213,000	46,820	64,928	-	-	3,167,831
October	2,455,002	511,848	17,320	102	80	227,007	50,073	78,458	-	-	3,339,890
November	2,569,068	535,116	21,277	108	84	241,015	53,271	91,979	9,232	-	3,521,149
December	2,683,134	558,383	25,235	113	88	255,023	56,638	105,478	18,655	71,203	3,773,948
Transmission Accumulated Depreciation	**2,001,369**	**418,782**	**7,775**	**82**	**64**	**164,330**	**34,145**	**36,186**	**2,145**	**5,477**	**2,670,354**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

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

Transmission / Non-transmission Cost Support

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

CWIP & Expensed Lease Worksheet

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	Attachment 5	77,935,050	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	74,486,606	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	1,649,800	-	-	

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	$ 567,686	$ 567,686	$ -	$ 283,843

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	3,275	3,275	-	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	6,433	-	-	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 8.50%	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)	8.57%					

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	6,433	6,433	-	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	62,670	606,987	334,829	100%	334,829	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		62,670	606,987	334,829		334,829	

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		-	
72	Miscellaneous Transmission Expense		178,663	
	Total Account 566 Miscellaneous Transmission Expenses	p.321	$ 746,349	

Summary of Pre-Commercial Expenses

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

(1) Labor & overhead amount includes costs allocated to preparation of the preliminary survey and investigation.
(2) Miscellaneous amount includes rental of volunteer fire department facilities for open houses, Fed EX fees for various mailings from Legal, Procurement, Transmission & Finance, fees for various conference calls and PJM application fee.
(3) Outside legal services includes the cost for research and preparation of the filing to determine incentive rate availability.
(4) Other services other includes fees for website development, media relations services, campaign management, open houses and research services.
(5) Outside services rates includes the advice of a rate consultant regarding rate design.
(6) Advertising includes newspaper and other media announcements of public scoping meetings related to the proposed project.
(7) Travel, lodging and meals are the direct expenses for Allegheny staff to attend the scoping meetings.

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

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Depreciation Rates

TRANSMISSION PLANT		Life		Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	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	Bedington Transformer	Meadow Brook SS Capacitor	Kammer Transformers	Total
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43	-	-	217	-	-	-	-	-	-	-	217
352	Structures & Improvements	50	-	R3	(10)	2.20	-	-	-	-	-	-	-	-	-	-	-
	SVC	35	-			2.86	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-
353	Station Equipment						-	-	-	-	-	-	-	-	-	-	-
	Other	50	-	R2	(5)	2.10	5,670	279,192	616	61	48	208,356	56,638	105,478	-	71,203	727,261
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96	1,354,331	-	-	-	-	-	-	-	-	-	1,354,331
	SCADA	15	-	S3	0	6.67	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-
354	Towers & Fixtures	65	-	R4	(25)	1.92	-	-	-	-	-	-	-	-	18,655	-	18,655
355	Poles & Fixtures	55	-	R2.5	(20)	2.18	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-
356	Overhead Conductors & Devices						-	-	23,684	-	-	-	-	-	-	-	23,684
	Other	55	-	R2.5	(40)	2.80	-	-	-	-	-	-	-	-	-	-	-
	Clearing	70	-	R4	0	1.43	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-
357	Underground conduit	55	-	S3	(5)	1.91	-	-	-	-	-	-	-	-	-	-	-
358	Underground conductor and devices	45	-	R3	(5)	2.33	-	-	-	-	-	-	-	-	-	-	-
	SVC	35				2.86	-	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant Depreciation							1,360,001	279,192	24,517	61	48	208,356	56,638	105,478	18,655	71,203	2,124,148

Total Transmission Depreciation Expense (must tie to p336.7.f) 2,124,148

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	10,403
391	Office Furniture & Equipment	20	SQ	0	5.00	1,562
	Information Systems	10	SQ	0	10.00	243
	Data Handling	10	SQ	0	10.00	-
392	Transportation Equipment					
	Other	15	SQ	20	5.33	-
	Autos	7	S3	20	11.43	1,053
	Light Trucks	11.5	L4	20	6.96	7,046
	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						20,306

Total General Plant Depreciation Expense (must tie to p336.10.b & c) 20,306

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 Amortization (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	26.33
	7	TrAILCo PBOP Expense for base year	84,041
	8	TrAILCo PBOP Expense in Account 926 for current year	58,981
57	9	PBOP Adjustment for Appendix A, Line 57	25,059
		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 C 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)	-		60,937		12,247,402		
	Prexy - 502 Junction 500 kV (CWIP)	-		78,492		9,775,015		
	502 Junction - Territorial Line (CWIP)	-		428,257		741,228,750		
	Total	-	567,686	567,686		763,251,167		

		Pre-Commercial Costs						
		Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year	**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	AFUDC (If CWIP was not in Rate Base)
Step 3	**For Reconciliation:**							
	Prexy - 502 Junction 138 kV (CWIP)							
	1	-	60,937	60,937				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	-	60,937	60,937				
	Prexy - 502 Junction 500 kV (CWIP)							
	1	-	78,492	78,492				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	-	78,492	78,492				
	502 Junction - Territorial Line (CWIP)							
	1	-	428,257	428,257				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	-	428,257	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. 1	Refer to Attachment 5 - Cost Support Plant in Service Worksheet
Difference (must be zero)	

Notes:

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

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

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

Trans-Allegheny Interstate Line Company

Attachment 6 - Estimate and Reconciliation Worksheet

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

Reconciliation Details

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

Rev Req based on Year 1 data

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

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

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Other Projects PIS (monthly additions)	Meadow Brook SS Capacitor (monthly additions)	Bedington Transformer (monthly additions)	Kammer Transformers (monthly additions)	Black Oak (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
Dec (Prior Year CWIP) p216.b.43					-	94,947,300	9,677,269	11,774,984
Jan 2009					-	16,462,989	8,209	16,158
Feb					-	15,756,860	(667	5,117
Mar					-	23,616,986	2,744	337,218
Apr			7,390,667		-	27,801,175	15,822	(22,120)
May			86,965		-	43,283,026	150,006	106,332
Jun			219		-	25,112,454	82,381	205,951
Jul			1,371		-	26,367,587	62,381	155,952
Aug			-		-	19,580,901	62,381	155,953
Sep			-		-	18,288,188	62,381	155,952
Oct			-		-	15,090,492	52,857	132,143
Nov			-	51,636,975	-	16,641,875	52,857	132,143
Dec		7,276,323	-	-		20,484,265	52,857	132,143
Total	-	7,276,323	7,479,222	51,636,975	-	363,434,098	10,281,477	13,287,925

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

Month End Balances								
	Other Projects PIS (Monthly additions)	Meadowbrook Transformer (monthly balance)	Bedington Transformer (monthly additions)	Kammer Transformers (monthly additions)	Black Oak (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
		-	-	-	-	94,947,300	9,677,269	11,774,984
		-	-	-	-	111,410,289	9,685,477	11,791,142
		-	-	-	-	127,167,149	9,684,810	11,796,259
		-	-	-	-	150,784,135	9,687,554	12,133,476
		-	7,390,667	-	-	178,585,310	9,703,376	12,111,356
		-	7,477,632	-	-	221,868,336	9,853,382	12,217,688
		-	7,477,851	-	-	246,980,790	9,935,763	12,423,639
		-	7,479,222	-	-	273,348,377	9,998,144	12,579,591
		-	7,479,222	-	-	292,929,278	10,060,525	12,735,544
		-	7,479,222	-	-	311,217,466	10,122,906	12,891,496
		-	7,479,222	-	-	326,307,958	10,175,763	13,023,639
		-	7,479,222	51,636,975	-	342,949,833	10,228,620	13,155,782
		7,276,323	7,479,222	51,636,975	-	363,434,098	10,281,477	13,287,925
		7,276,323	67,221,483	103,273,951	-	3,041,930,322	129,095,070	161,922,524
Average 13 Month Balance		559,717	5,170,883	7,944,150	-	233,994,640	9,930,390	12,455,579
		(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	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	77,998.22	720,577.68	1,107,040.49	1,151,253.17	267,217.23	7,908,192.03	2,092,522.47	$ 35,885,563.06	$ 1,561,497.95	$ 1,950,184.24

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)
		Doubs Transformer #4 (monthly additions)	Meadow Brook SS Capacitor (monthly additions)	Bedington (monthly additions)	Kammer (monthly additions)	Black Oak (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)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual					-	550,957,894.28	9,755,229.83	12,230,784.33
Jan 2010	Actual	-	193,560.90	199.35	(564.17)	448.21	30,629,758.64	396.24	648.30
Feb	Actual	-	(82,699.89)	74.99	58.88	167.64	40,246,922.51	7,085.79	6,880.58
Mar	Actual	-	84,239.05	1,662.96	-	6,942.03	49,067,580.09	9,734.46	6,988.74
Apr	Actual	-	6,547.93	5,734.86	-	10,827.92	40,168,805.29	8,573.88	6,964.14
May	Budget	-			1,422,505.29	31,614.20	35,104,182.47	-	-
Jun	Budget	5,299,034.31					39,855,100.00	-	-
Jul	Budget	36,962.40					19,559,015.00	-	-
Aug	Budget	-					14,807,850.00	-	-
Sep	Budget	-					7,917,838.00	-	-
Oct	Budget	-					5,060,466.00	-	-
Nov	Budget	-					4,298,730.00	-	-
Dec	Budget	-					4,390,118.00	-	-
Total		5,335,997	201,647.99	7,672	1,422,000	50,000	842,064,260	9,781,020	12,252,266.09

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

Month End Balances

Other Projects PIS (Monthly additions)	Doubs Transformer #4 (monthly additions)	Meadow Brook SS Capacitor (monthly additions)	Bedington (monthly additions)	Kammer (monthly additions)	Black Oak (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
[redacted]	-	-	-	-	-	550,957,894	9,755,230	12,230,784
	-	193,561	199	(564)	448	581,587,653	9,755,626	12,231,433
	-	110,861	274	(505)	616	621,834,575	9,762,712	12,238,313
	-	195,100	1,937	(505)	7,558	670,902,156	9,772,446	12,245,302
	-	201,648	7,672	(505)	18,386	711,070,961	9,781,020	12,252,266
	-	201,648	7,672	1,422,000	50,000	746,175,143	9,781,020	12,252,266
	5,299,034	201,648	7,672	1,422,000	50,000	786,030,243	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	805,589,258	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	820,397,108	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	828,314,946	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	833,375,412	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	837,674,142	9,781,020	12,252,266
	5,335,997	201,648	7,672	1,422,000	50,000	842,064,260	9,781,020	12,252,266
	37,315,015	**2,314,354**	**71,460**	**11,373,920**	**427,008**	**9,635,973,753**	**127,075,196**	**159,216,227**
	2,870,386	178,027	5,497	874,917	32,847	741,228,750	9,775,015	12,247,402

Total Revenue Requirement	Doubs Transformer #4 (Monthly additions)	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)
$ 131,758,700.06	388,458	890,564	1,135,906	5,862,392	1,283,972	309,340	7,685,069	2,002,955	108,853,463	1,486,624	1,859,956

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)
		Meadow Brook SS Capacitor (monthly additions)	Bedington Transformer (monthly additions)	Kammer Transformers (monthly additions)	Black Oak (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
					-	94,947,299.60	9,677,268.70	11,774,984.11
Jan 2009				-	-	16,422,306.41	8,208.62	16,157.67
Feb				-	-	15,560,434.69	(667.19	5,116.97
Mar				-	-	23,424,327.59	2,744.17	678,527.72
Apr				-	-	27,551,566.67	15,822.10	(363,430.16)
May		-	-	-	-	39,345,212.54	11,332.50	9,404.97
Jun		-	-	-	-	43,240,445.18	759.14	616.61
Jul		-	-	-	-	44,259,165.80	11,189.10	5,329.97
Aug		-	-	-	-	46,452,404.67	8,554.56	7,598.21
Sep		-	-	-	-	56,288,645.82	1,025.66	959.91
Oct		.	-	-	-	53,488,281.42	9,838.55	78,903.98
Nov		-	-	-	-	44,036,973.29	2,214.90	10,954.00
Dec		-	-	-	-	45,940,830.60	6,939.02	5,660.37
Total		-	-	-	-	550,957,894	9,755,230	12,230,784

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	
	[redacted]	-	-	-	-	94,947,300	9,677,269	11,774,984	
		-	-	-	-	111,369,606	9,685,477	11,791,142	
		-	-	-	-	126,930,041	9,684,810	11,796,259	
		-	-	-	-	150,354,368	9,687,554	12,474,786	
		-	-	-	-	177,905,935	9,703,376	12,111,356	
		-	-	-	-	217,251,148	9,714,709	12,120,761	
		-	-	-	-	260,491,593	9,715,468	12,121,378	
		-	-	-	-	304,750,758	9,726,657	12,126,708	
		-	-	-	-	351,203,163	9,735,212	12,134,306	
		-	-	-	-	407,491,809	9,736,237	12,135,266	
		-	-	-	-	460,980,090	9,746,076	12,214,170	
		-	-	-	-	505,017,064	9,748,291	12,225,124	
		-	-	-	-	550,957,894	9,755,230	12,230,784	
		-	**-**	**-**	**-**	**3,719,650,769**	**126,316,367**	**157,257,025**	
Average 13 Month Balance		-	-	-	-	286,126,982	9,716,644	12,096,694	307,940,320

Result of Formula for Reconciliation

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)
$ 61,155,930.75	210,901	830,014	957,650	1,303,243	314,930	7,887,315	2,075,488	44,134,634	1,538,678	1,903,078

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		
61,155,931	-	52,722,047	=	8,433,884

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

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr 0.2700%

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	702,824	0.2700%	11.5	21,823	724,646
Jul	Year 1	702,824	0.2700%	10.5	19,925	722,749
Aug	Year 1	702,824	0.2700%	9.5	18,027	720,851
Sep	Year 1	702,824	0.2700%	8.5	16,130	718,953
Oct	Year 1	702,824	0.2700%	7.5	14,232	717,056
Nov	Year 1	702,824	0.2700%	6.5	12,335	715,158
Dec	Year 1	702,824	0.2700%	5.5	10,437	713,261
Jan	Year 2	702,824	0.2700%	4.5	8,539	711,363
Feb	Year 2	702,824	0.2700%	3.5	6,642	709,465
Mar	Year 2	702,824	0.2700%	2.5	4,744	707,568
Apr	Year 2	702,824	0.2700%	1.5	2,846	705,670
May	Year 2	702,824	0.2700%	0.5	949	703,772
Total		8,433,884				8,570,513

		Balance	Interest	Amort	Balance
Jun	Year 2	8,570,513	0.2700%	726,806	7,866,848
Jul	Year 2	7,866,848	0.2700%	726,806	7,161,282
Aug	Year 2	7,161,282	0.2700%	726,806	6,453,812
Sep	Year 2	6,453,812	0.2700%	726,806	5,744,432
Oct	Year 2	5,744,432	0.2700%	726,806	5,033,136
Nov	Year 2	5,033,136	0.2700%	726,806	4,319,920
Dec	Year 2	4,319,920	0.2700%	726,806	3,604,778
Jan	Year 3	3,604,778	0.2700%	726,806	2,887,705
Feb	Year 3	2,887,705	0.2700%	726,806	2,168,696
Mar	Year 3	2,168,696	0.2700%	726,806	1,447,746
Apr	Year 3	1,447,746	0.2700%	726,806	724,849
May	Year 3	724,849	0.2700%	726,806	(0)
Total with interest				8,721,669	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest		8,721,669	Input to Appendix A, Line 143
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$	131,758,700	
Revenue Requirement for Year 3		140,480,369	

Reconciliation Amount by Project

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)
$ 8,721,669	$ 137,437	$ 113,171	$ (154,488)	$ 157,176	$ 49,341	$ (21,589)	$ (17,616)	$ 8,530,549	$ (23,599)	$ (48,713)

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

$ 140,480,369

10 June Year 3 Results of Step 8 go into effect

$ 140,480,369

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

Line		Formula Line		
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3	A	137	FCR without Depreciation and Pre-Commercial Costs	13.5333%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	14.4006%
5	C		Line B less Line A	0.8673%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxes	0.9336%

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

Line				**PJM Upgrade ID: 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		13.5333%	13.5333%
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		14.4006%	14.4006%
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		12,492,298	9,777,830
17	Annual Depreciation Exp from Attachment 5			48	61

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation Amount**	Revenue	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue
19	See Calculations for each item below	Wo Incentive ROE	2009	1,690,622.04	47.76	60,937.24	(48,713.14)	1,702,893.91	1,323,264.56	61.44	78,492.14	(23,598.90)	1,378,219.23
20	See Calculations for each item below	W Incentive ROE	2009	1,798,970.98	47.76	60,937.24	(48,713.14)	1,811,242.84	1,408,070.21	61.44	78,492.14	(23,598.90)	1,463,024.88

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

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Line	Description													
		PJM Upgrade ID: b0328.2; b0347.1; b0347.2; b0347.3; b0347.4					**PJM Upgrade ID: b0218**				**PJM Upgrade ID: b0216**			
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	13.5333%					13.5333%				13.5333%			
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	14.4006%					13.5333%				14.4006%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	752,749,076					12,737,183				43,922,132			
17	Annual Depreciation Exp from Attachment 5	24,517					279,192				1,360,001			
18		Return	Depreciation	Pre-Commercial Exp.	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue
19	See Calculations for each item below	101,871,902.61	24,516.56	428,256.62	8,530,549.42	110,855,225.21	1,723,763.08	279,192.15	(17,615.94)	1,985,339.29	5,944,120.42	1,360,000.80	(21,589.34)	7,282,531.88
20	See Calculations for each item below	108,400,690.17	24,516.56	428,256.62	8,530,549.42	117,384,012.77	1,723,763.08	279,192.15	(17,615.94)	1,985,339.29	6,325,068.44	1,360,000.80	(21,589.34)	7,663,479.90

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

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Line		PJM Upgrade ID: b0323	PJM Upgrade ID: b0230	PJM Upgrade ID: b0559	PJM Upgrade ID: b0229
10		North Shenandoah Transformer (Plant In Service)	Meadowbrook Transformer (Plant In Service)	Meadow Brook SS Capacitor (Plant In Service)	Bedington Transformer (Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No	No
13	Input the allowed ROE	11.70%	11.70%	11.70%	11.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.5333%	13.5333%	13.5333%	13.5333%
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	13.5333%	13.5333%	13.5333%	13.5333%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,867,264	7,947,911	6,442,688.02	7,614,009.06
17	Annual Depreciation Exp from Attachment 5	56,638	208,356	18,655	105,478

Line		b0323 Return	b0323 Depreciation	b0323 Reconciliation Amount	b0323 Revenue	b0230 Return	b0230 Depreciation	b0230 Reconciliation Amount	b0230 Revenue	b0559 Return	b0559 Depreciation	b0559 Reconciliation Amount	b0559 Revenue	b0229 Return	b0229 Depreciation	b0229 Reconciliation Amount	b0229 Revenue
18		Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue
19	See Calculations for each item below	252,702.73	56,637.65	49,340.99	358,681.37	1,075,615.83	208,355.68	157,176.04	1,441,147.54	871,909.26	18,654.75	137,437.42	1,028,001.42	1,030,427.82	105,478.00	113,171.02	1,249,076.84
20	See Calculations for each item below	252,702.73	56,637.65	49,340.99	358,681.37	1,075,615.83	208,355.68	157,176.04	1,441,147.54	871,909.26	18,654.75	137,437.42	1,028,001.42	1,030,427.82	105,478.00	113,171.02	1,249,076.84

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: b0495				PJM Upgrade ID: b0345							
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6													
7													
8													
9													
10		Kammer Transformers (Plant In Service)				Doubs Transformer #4 (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	13.5333%				13.5333%							
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	13.5333%				13.5333%							
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	42,792,099.78				2,870,385.74							
17	Annual Depreciation Exp from Attachment 5	71,203				-							
18		Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Total	Incentive Charged	Revenue Credit	$7,102,890.17
19	See Calculations for each item below	5,791,189.60	71,202.83	(154,488.38)	5,707,904.04	388,458.34	0.00	0.00	388,458.34	133,377,479.08		133,377,479.08	**Ax A Line 148**
20	See Calculations for each item below	5,791,189.60	71,202.83	(154,488.38)	5,707,904.04	388,458.34	0.00	0.00	388,458.34	140,480,369.24	140,480,369.24		

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

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

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
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

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

Total Loan Amount	**$**	**800,000,000**

Internal Rate of Return[1] **4.88%**
Based on following Financial Formula[2]**:**

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

Origination Fees	
Origination Fees for Original Loan	9,554,717
Origination Fees for Subsequent Loan	11,628,097
Total Issuance Expense	**21,182,814**

	New Borrowing	Old Borrowing
Revolving Credit Commitment Fee	0.005	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%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
Bond $200M Interest Rate	$ 450,000,000					4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Revolver Interest Rate	$ 350,000,000	Draw 1				3.249%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 2, 3, 4				3.247%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 5				3.251%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 6				3.316%	4.50%	6.21%			

(A) Year	(B)	(C) Capital Expenditures	(D) Principle Drawn In Quarter ($000's)	(E) Principle Drawn To Date	(F) Interest Expense	(G) Origination Fees	(H) Commitment	(I) Net Cash Flows (D-F-G-H)
2008								
12/24/2007	Q4	68,183,000	10,000,000	10,000,000		734,955		9,265,045
01/31/2008	Q1			10,000,000		31,013		(31,013)
02/4/2008	Q1			10,000,000		69,578		(69,578)
02/6/2008	Q1			10,000,000		138		(138)
02/29/2008	Q1			10,000,000		2,960		(2,960)
03/5/2008	Q1			10,000,000		125,384		(125,384)
3/24/2008	Q1	25,543,000		10,000,000	155,048			(155,048)
03/31/2008	Q1			10,000,000		17,011		(17,011)
04/30/2008	Q2			10,000,000		197,270		(197,270)
05/19/2008	Q2			10,000,000		109,825		(109,825)
6/23/2008	Q2	20,509,000		10,000,000	97,477			(97,477)
06/26/2008	Q2			10,000,000		43,099		(43,099)
06/30/2008	Q2			10,000,000		13,268		(13,268)
08/8/2008	Q3			10,000,000		1,578		(1,578)
08/13/2008	Q3			10,000,000		62,777		(62,777)
8/15/2008	Q3		55,000,000	65,000,000	59,689	7,780,954		47,159,357
8/20/2008	Q3			65,000,000		530		(530)
8/25/2008	Q3			65,000,000		15,125		(15,125)
9/3/2008	Q3			65,000,000		82,655		(82,655)
9/8/2008	Q3			65,000,000		1,958		(1,958)
9/11/2008	Q3			65,000,000		41,846		(41,846)
9/15/2008	Q3		(20,000,000)	45,000,000	243,199			(20,243,199)
9/25/2008	Q3			45,000,000		7,525		(7,525)
9/29/2008	Q3			45,000,000		98,058		(98,058)
9/30/2008	Q3	24,995,000		45,000,000		18,137	235,521	(253,658)
10/2/2008	Q4		20,000,000	65,000,000			78,507	19,921,493
10/17/2008	Q4			65,000,000		2,030		(2,030)
10/29/2008	Q4			65,000,000		267		(267)
11/19/2008	Q4			65,000,000		96,049		(96,049)
11/21/2008	Q4			65,000,000		730		(730)
12/15/2008	Q4		25,000,000	90,000,000	718,999			24,281,001
(1) 1/6/2009	Q1	42,068,000	-	90,000,000	-		618,334	(618,334)
2/17/2009	Q1		30,000,000	120,000,000	-		-	30,000,000
3/16/2009	Q1	75,475,000	40,000,000	160,000,000	933,988			39,066,013
3/25/2009	Q1		-	160,000,000			1,100,000	(1,100,000)
4/6/2009	Q2		-	160,000,000			549,167	(549,167)
5/15/2009	Q2		50,000,000	210,000,000				50,000,000
6/16/2009	Q2		40,000,000	250,000,000	1,405,039			38,594,961
6/30/2009	Q2		-	250,000,000				-
7/31/2009	Q3		-	250,000,000			453,194	(453,194)
8/3/2009	Q3		30,000,000	280,000,000				30,000,000
9/4/2009	Q3		50,000,000	330,000,000				50,000,000

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

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

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
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

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

Total Loan Amount	**$ 800,000,000**

Internal Rate of Return[1]	**4.88%**
Based on following Financial Formula[2]:	

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

Origination Fees	
Origination Fees for Original Loan	9,554,717
Origination Fees for Subsequent Loan	11,628,097
Total Issuance Expense	**21,182,814**

	New Borrowing	Old Borrowing
Revolving Credit Commitment Fee	0.005	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%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	
Bond $200M Interest Rate	$ 450,000,000					4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
Revolver Interest Rate	$ 350,000,000	Draw 1				3.249%	4.50%	6.21%				
Revolver Interest Rate	$ 350,000,000	Draw 2, 3, 4				3.247%	4.50%	6.21%				
Revolver Interest Rate	$ 350,000,000	Draw 5				3.251%	4.50%	6.21%				
Revolver Interest Rate	$ 350,000,000	Draw 6				3.316%	4.50%	6.21%				

9/16/2009	Q3		-	330,000,000	1,596,826			(1,596,826)
10/5/2009	Q4		45,000,000	375,000,000	207,916			44,792,084
10/16/2009	Q4			375,000,000			321,250	(321,250)
11/5/2009	Q4		30,000,000	405,000,000	-			30,000,000
12/4/2009	Q4		50,000,000	455,000,000				50,000,000
12/16/2009	Q4	73,715,000	-	455,000,000	1,374,479			(1,374,479)
1/4/2010	Q1			455,000,000			138,490	(138,490)
1/5/2010	Q1		30,000,000	485,000,000	892,331			29,107,669
1/15/2010	Q1		-	485,000,000	440,625			(440,625)
1/25/2010	Q1		(485,000,000)	-	423,000		18,490	(485,441,490)
1/25/2010	Q1		450,000,000	450,000,000		4,533,000		445,467,000
1/25/2010	Q1		45,000,000	495,000,000		5,852,579		39,147,421
1/27/2010	Q1			495,000,000		6,980		(6,980)
2/3/2010	Q1			495,000,000		58,000		(58,000)
2/3/2010	Q1			495,000,000		5,500		(5,500)
2/5/2010	Q1			495,000,000		82,117		(82,117)
2/12/2010	Q1		20,000,000	515,000,000				20,000,000
2/24/2010	Q1			515,000,000		23,770		(23,770)
3/10/2010	Q1		30,000,000	545,000,000		90,000		29,910,000
3/17/2010	Q1		-	545,000,000		195,720		(195,720)
3/26/2010	Q1		20,000,000	565,000,000		17,821		19,982,179
4/1/2010	Q2			565,000,000			255,417	(255,417)
4/5/2010	Q2			565,000,000		123,661		(123,661)
4/7/2010	Q2			565,000,000		201,250		(201,250)
4/8/2010	Q2			565,000,000		224,588		(224,588)
4/12/2010	Q1		30,000,000	595,000,000				30,000,000
4/14/2010	Q2			595,000,000		194,135		(194,135)
4/21/2010	Q2			595,000,000		18,977		(18,977)
4/26/2010	Q2		(65,000,000)	530,000,000	369,574			(65,369,574)
4/26/2010	Q2		65,000,000	595,000,000	55,921			64,944,079
5/7/2010	Q2		30,000,000	625,000,000				30,000,000
5/12/2010	Q2			625,000,000	160,546			(160,546)
5/12/2010	Q2			625,000,000	81,275			(81,275)
6/10/2010	Q2			625,000,000	248,937			(248,937)
6/25/2010	Q2			625,000,000	81,058			(81,058)
6/25/2010	Q2			625,000,000	41,450			(41,450)
6/25/2010	Q2			625,000,000	121,587			(121,587)
6/25/2010	Q2			625,000,000	135,403			(135,403)
6/26/2010	Q2		47,827,000	672,827,000				47,827,000
7/1/2010	Q2		-	672,827,000			201,540	(201,540)
7/15/2010	Q2			672,827,000	8,550,000			(8,550,000)
7/26/2010	Q2			672,827,000	544,837		-	(544,837)
7/26/2010	Q2			672,827,000	228,436			(228,436)
7/26/2010	Q2			672,827,000	132,162			(132,162)
7/26/2010	Q2			672,827,000	221,067			(221,067)
9/26/2010	Q3		53,386,000	726,213,000	1,272,540			52,113,460
10/1/2010				726,213,000			167,623	(167,623)
12/26/2010	Q4		39,514,000	765,727,000	2,315,248			37,198,752

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

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Total Loan Amount	**$**	**800,000,000**

Internal Rate of Return[1] **4.88%**

Based on following Financial Formula[2]:

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

Origination Fees	
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Total Issuance Expense	21,182,814

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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%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
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Revolver Interest Rate	$ 350,000,000	Draw 1				3.249%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 2, 3, 4				3.247%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 5				3.251%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 6				3.316%	4.50%	6.21%			

1/15/2011		-	765,727,000	9,000,000		(9,000,000)
1/1/2011			765,727,000		96,115	(96,115)
3/26/2011	Q1	34,273,000	800,000,000	2,617,377		31,655,623
4/1/2011			800,000,000		42,841	(42,841)
6/26/2011	Q2	(350,000,000)	450,000,000	4,025,000		(354,025,000)
7/15/2011			450,000,000	9,000,000		(9,000,000)
9/26/2011	Q3		450,000,000			-
12/26/2011	Q4		450,000,000			-
1/15/2012			450,000,000	9,000,000		(9,000,000)
3/26/2012	Q1		450,000,000			-
6/26/2012	Q2		450,000,000			-
7/15/2012			450,000,000	9,000,000		(9,000,000)
9/26/2012	Q3		450,000,000			-
12/26/2012	Q4		450,000,000			-
1/15/2013	Q1		450,000,000			-
1/15/2013			450,000,000	9,000,000		(9,000,000)
3/26/2013	Q1		450,000,000			-
6/26/2013	Q2		450,000,000			-
7/15/2013			450,000,000	9,000,000		(9,000,000)
9/26/2013	Q3		450,000,000			-
12/26/2013	Q4		450,000,000			-
1/15/2014			450,000,000	9,000,000		(9,000,000)
3/26/2014	Q1		450,000,000			-
6/26/2014	Q2		450,000,000			-
7/15/2014			450,000,000	9,000,000		(9,000,000)
9/26/2014	Q3		450,000,000			-
12/26/2014	Q4		450,000,000			-
1/15/2015			450,000,000	9,000,000		(9,000,000)
1/25/2015		(450,000,000)		500,000		(450,500,000)

(1) Commitment fees for 4th quarter 2008

Attachment 4b - Delmarva Formula Rate Update

ATTACHMENT H-3D

Delmarva Power & Light Company

Formula Rate - Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	2009
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 1,830,026
2	Total Wages Expense		p354.28b	$ 30,010,403
3	Less A&G Wages Expense		p354.27b	$ 2,516,713
4	Total		(Line 2 - 3)	27,493,690
5	**Wages & Salary Allocator**		(Line 1 / 4)	**6.6562%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,215,671,431
7	Common Plant In Service - Electric		(Line 24)	74,499,676
8	Total Plant In Service		(Sum Lines 6 & 7)	2,290,171,107
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 840,401,055
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 23,040,093
11	Accumulated Common Amortization - Electric	(Note A)	p356	17,196,214
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	$ 40,754,997
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	921,392,359
14	Net Plant		(Line 8 - 13)	1,368,778,748
15	Transmission Gross Plant		(Line 29 - Line 28)	716,710,039
16	**Gross Plant Allocator**		(Line 15 / 8)	**31.2950%**
17	Transmission Net Plant		(Line 39 - Line 28)	445,035,771
18	**Net Plant Allocator**		(Line 17 / 14)	**32.5133%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 684,020,338
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	21,036,297
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**705,056,635**
23	General & Intangible		p205.5.g & p207.99.g	100,577,114
24	Common Plant (Electric Only)	(Notes A & B)	p356	74,499,676
25	Total General & Common		(Line 23 + 24)	175,076,790
26	Wage & Salary Allocation Factor		(Line 5)	6.65617%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**11,653,404**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**716,710,039**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 264,005,938
31	Accumulated General Depreciation		p219.28.c 34,215,090	$
32	Accumulated Intangible Amortization		(Line 10)	23,040,093
33	Accumulated Common Amortization - Electric		(Line 11)	17,196,214
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	40,754,997
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	115,206,394
36	Wage & Salary Allocation Factor		(Line 5)	6.65617%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**7,668,330**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**271,674,268**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**445,035,771**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-124,763,825
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	-5,680,297
42	Net Plant Allocation Factor		(Line 18)	32.51%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-126,610,680**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**	(Note B)	p216.43.b as Shown on Attachment 6	16,289,728
	Transmission O&M Reserves			
44	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**-1,666,047**
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	13,179,102
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**13,179,102**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 1,391,978
48	Wage & Salary Allocation Factor		(Line 5)	6.656%
49	Total Transmission Allocated		(Line 47 * 48)	92,652
50	Transmission Materials & Supplies		p227.8c	3,803,218
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**3,895,870**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	14,523,277
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**1,815,410**
	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)	**-93,096,616**
59	**Rate Base**		(Line 39 + 58)	**351,939,154**

O&M

	Transmission O&M			
60	Transmission O&M		p321.112.b	$ 11,067,816
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)	**11,067,816**
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	0
68	Total A&G		p323.197.b	$ 59,911,917
69	Less Property Insurance Account 924		p323.185b	555,303
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	3,465,325
71	Less General Advertising Exp Account 930.1		p323.191b	79,645
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	6,510,586
73	Less EPRI Dues	(Note D)	p352-353	99,873
74	**General & Common Expenses**		(Lines 67 + 68) - Sum (69 to 73)	49,201,185
75	Wage & Salary Allocation Factor		(Line 5)	6.6562%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**3,274,913**
	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	555,303
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
82	Total		(Line 80 + 81)	555,303
83	Net Plant Allocation Factor		(Line 18)	32.51%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**180,548**
85	**Total Transmission O&M**		**(Line 66 + 76 + 79 + 84)**	**14,523,277**

Depreciation & Amortization Expense

	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	**16,121,454**
87	General Depreciation		p336.10b&c	3,915,184
88	Intangible Amortization	(Note A)	p336.1d&e	148,323
89	Total		(Line 87 + 88)	4,063,507
90	Wage & Salary Allocation Factor		(Line 5)	6.6562%
91	**General Depreciation Allocated to Transmission**		(Line 89 * 90)	**270,474**
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	3,380,844
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	3,380,844
95	Wage & Salary Allocation Factor		(Line 5)	6.6562%
96	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 94 * 95)	**225,035**
97	**Total Transmission Depreciation & Amortization**		**(Line 86 + 91 + 96)**	**16,616,962**

Taxes Other than Income

98	**Taxes Other than Income**		Attachment 2	**4,722,800**
99	**Total Taxes Other than Income**		**(Line 98)**	**4,722,800**

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	$ 44,185,940
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	44,185,940
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	787,377,818
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)	789,555,597
	Capitalization				
108	Long Term Debt			p112.17c through 21c	791,570,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-17,703,624
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	3,371,305
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	777,237,681
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	789,555,597
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,566,793,278
117	Debt %	Total Long Term Debt		(Line 113 / 116)	49.61%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	50.39%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0568
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)	0.0282
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0569
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0851**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**29,966,108**

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	-227,903
134	T/(1-T)			(Line 132)	67.94%
135	Net Plant Allocation Factor			(Line 18)	32.5133%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-124,440**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**13,615,418**
138	**Total Income Taxes**			**(Line 136 + 137)**	**13,490,977**
REVENUE REQUIREMENT					
	Summary				
139	Net Property, Plant & Equipment			(Line 39)	445,035,771
140	Adjustment to Rate Base			(Line 58)	-93,096,616
141	**Rate Base**			(Line 59)	**351,939,154**
142	O&M			(Line 85)	14,523,277
143	Depreciation & Amortization			(Line 97)	16,616,962
144	Taxes Other than Income			(Line 99)	4,722,800
145	Investment Return			(Line 127)	29,966,108
146	Income Taxes			(Line 138)	13,490,977
147	**Gross Revenue Requirement**			**(Sum Lines 142 to 146)**	**79,320,125**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	684,020,338
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	684,020,338
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	79,320,125
153	**Adjusted Gross Revenue Requirement**			(Line 151 * 152)	**79,320,125**
	Revenue Credits & Interest on Network Credits				
154	**Revenue Credits**			Attachment 3	7,343,450
155	**Interest on Network Credits**		(Note N)	PJM Data	-
156	**Net Revenue Requirement**			**(Line 153 - 154 + 155)**	**71,976,676**
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	**71,976,676**
158	Net Transmission Plant			(Line 19 - 30)	**420,014,400**
159	Net Plant Carrying Charge			(Line 157 / 158)	**17.1367%**
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	**13.2984%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	**2.9518%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	**28,519,590**
163	Increased Return and Taxes			Attachment 4	**46,435,520**
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	**74,955,110**
165	Net Transmission Plant			(Line 19 - 30)	**420,014,400**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	**17.8458%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation			(Line 163 - 86) / 165	**14.0075%**
168	**Net Revenue Requirement**			(Line 156)	**71,976,676**
169	True-up amount			Attachment 6	**(450,972)**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	**770,557**
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)	**72,296,260**
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	**3,843**
174	Rate ($/MW-Year)			(Line 172 / 173)	**18,810**
175	**Network Service Rate ($/MW/Year)**			**(Line 174)**	**18,810**

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	(372,327,360)	0	
ADIT-283	0	(16,121,840)	(63,525,283)	
ADIT-190	0	2,184,686	5,200,758	
Subtotal	0	(386,264,514)	(58,324,525)	(444,589,039)
Wages & Salary Allocator			6.6562%	
Gross Plant Allocator		31.2950%		
ADIT	0	(120,881,647)	(3,882,178)	(124,763,825)

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 111
Amount (3,371,305)

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

A	B	C	D	E	F	G
ADIT-190	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Above Market Sales Contracts	1,342,007	1,342,007				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	(360,653)	(360,653)				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	-	-				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.
Merrill Creek Excess Capacity	6,259,507	6,259,507				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
Merrill Creek - Rent	3,832,606	3,832,606				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
Environmental Expense	(899,526)	(899,526)				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 occu
Claims Reserve	1,657,947			1,657,947		aside a reserve for General and Auto liability claims. For Tax no deduction is
Allowance for Doubtful Accounts	4,855,576	4,855,576				Under the Tax Reform Act of 1986, taxpayers were required to switch from the
Deferred ITC	3,006,814			3,006,814		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must
Emissions Allowances	(50,829)	(50,829)				Proceeds from the sale of emissions allowances are deferred, pending future rate
Building Maintenance Accrual	88,468	88,468				Acct 242650 immaterial
Miscellaneous	(364,881)	(364,881)				Timing differences related to Gas operations.
OPEB	10,364,782				10,364,782	Book accruals of OPEB expenses are reversed. A tax deduction results only when OPEB contributions are made to the trust. These deferred taxes are the result of this book/tax difference. Affects company personnel across all functions.
Pension And Other Labor Related	5,178,334				5,178,334	Affects company personnel across all functions.
PJM Member Defaults	2,852			2,852		This relates to the reversal of the accural that was book for GAAP.During December 2007 two members of PJM were declared in default on their obligations to PJM.
Reg Liab - DE SOS Energy	2,885,700	2,885,700				Retail SOS, Other
Reg Liab - DE SOS Transmission	1,131,756	1,131,756				Retail SOS, Other
Reg Liab - MD SOS Transmission	564,273	564,273				Retail SOS, Other
Reg - DE SOS Adm	326,478	326,478				Retail SOS, Other
State NOL	7,186,606	6,640,295		523,887	22,424	MD NOL of 6.6M as a result of Amended Tax Returns and 546K NOL generated on the 2008 tax return to be carried forward to 2009
AMT Credit	621,737	621,737				Federal AMT credit carryforward from 2008 tax return, carry forward to 2009
SFAS 109- Regulatory Liability Electric	14,874,656			14,874,656		FASB 109 gross up, removed below
SFAS 109- Regulatory Liability Gas	790,447	790,447				FASB 109 gross up, removed below
Subtotal - p234	63,294,657	27,662,961	-	20,066,156	15,565,540	
Less FASB 109 Above if not separately removed	18,671,917	790,447		17,881,470	-	
Less FASB 106 Above if not separately removed	10,364,782				10,364,782	
Total	34,257,958	26,872,514	-	2,184,686	5,200,758	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D

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

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

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company
hment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Plant Related	(432,943,013)	(60,615,653)		(372,327,360)		Plant
Subtotal - p275	(432,943,013)	(60,615,653)	-	(372,327,360)	-	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	(432,943,013)	(60,615,653)	-	(372,327,360)	-	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

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

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company
hment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT-283	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Blueprint for the Future	(1,862,437)			(1,862,437)		The "Blueprint for the Future" program was announced during 2007. This initiative is designed to help customers, both residential and business, manage their energy efficiency. The estimated cost to implement these proposals is approximately $646M over t
Copco DSM Costs	(26,176)	(26,176)				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.
Deferred Fuel	(422,521)	(422,521)				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	86,025	86,025				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
Mark to Market Adj	204,453	204,453				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
Materials Reserve	(950,749)	(950,749)				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
Merger Costs	(6,551,941)	(6,644,742)			92,801	Reflects deferred taxes generated on Delmarva Power & Light Company /Atlantic City Electric Company merger costs deducted for tax purposes. For books these costs were capitalized. Tax amortization of organizational costs related to the ACE/DPL merger.
Wilmington Coal Gas Site Cleanup	63,525	63,525				Timing differences related to Gas operations
Reg Asset- COPCO Acquisition Adjustment	(14,259,403)			(14,259,403)		Amortization of COPCO acquisition adjustment. Beginning unamortized balance $40,456,550.00 represents recovery of the regulatory asset per Docket 9093, Order 81518, refers to MD Docket 8583, Order 71719; offset account 114000 Plant Acq Adj. Amortizing monthly.
Reg Asset- Other Reg Assets	(1,920,781)	(1,920,781)				Represents various costs which we are, or will be through a future rate case, getting recovery through rate base.
Charitable Contributions	(66,270)	(66,270)				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
SFAS 109- Regulatory Asset Electric	(29,968,024)			(29,968,024)		FASB 109 gross up, removed below
SFAS 109- Regulatory Asset Gas	20,481	20,481				FASB 109 gross up, removed below
Pension/OPEB AND Other Labor Related	(63,618,084)				(63,618,084)	Affects company personnel across all functions.
Miscellaneous	(10,011,683)	(10,011,683)				Miscellaneous temporary differences that are less than $100,000 for each item.
Reacquired Debt	(3,371,305)	(3,371,305)				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
Property Taxes	(1,863,889)	(1,863,889)				For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Unregulated related

Reg Liab - MD SOS Energy	(2,124,490)	(2,124,490)				Retail SOS, Other
	-					
Subtotal - p277 (Form 1-F filer: see note 6, below)	(136,643,269)	(27,028,122)	-	(46,089,864)	(63,525,283)	
Less FASB 109 Above if not separately removed	(29,947,543)	20,481		(29,968,024)		
Less FASB 106 Above if not separately removed	-				-	
Total	(106,695,726)	(27,048,603)	-	(16,121,840)	(63,525,283)	

Instructions for Account 283:

Sewer) or Production are directly assigned to Column A

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 income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company

hment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

	Item		Balance	Amortization	
Rate Base Treatment					
Balance to line 41 of Appendix A	Total		5,680,297	523,955	
Amortization					
Amortization to line 133 of Appendix A	Total		1,092,666	227,903	Excludes $56,665related to gas function amortization
					Excludes $658,955related to gas function balance
Total			6,772,963	751,858	
Total Form No. 1 (p 266 & 267)			6,772,963	751,858	
Difference /1			0	0	

/1 Difference must be zero

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)	**14,457,252**		
2 Personal property	74,393		
3 Federal/State Excise	**276**		
4			
5			
6			
Total Plant Related	14,531,921	31.2950%	4,547,771
Labor Related		***Wages & Salary Allocator***	
7 Federal FICA & Unemployment	**2,539,798**		
8 Unemployment	**34,089**		
9			
10			
11			
Total Labor Related	2,573,887	6.6562%	171,322
Other Included		***Gross Plant Allocator***	
12 Miscellaneous	11,845		
13			
14			
Total Other Included	11,845	31.2950%	3,707
Total Included	17,117,653	4,722,800	
Excluded			
15 State Franchise Tax	**6,072,767**		
16 Gross Receipts			
17 Sales and Use	**577,695**		
18 Utility Tax for Delmarva	**7,822,043**		
19 City License	**(9,332)**		
20			
21 Total "Other" Taxes (included on p. 263)	31,580,826		
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	31,580,826		
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

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		1,185,830
2	Total Rent Revenues	(Sum Line 1)	1,185,830
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 1,389,092
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)		1,134,741
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)		4,466,561
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	8,176,224
12	Less line 17g		(832,774)
13	Total Revenue Credits		7,343,450

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.	1,185,830
17b	Costs associated with revenues in line 17a	479,719
17c	Net Revenues (17a - 17b)	706,111
17d	50% Share of Net Revenues (17c / 2)	353,056
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)	353,056
17g	Line 17f less line 17a	(832,774)
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.	13,480,958
19	Amount offset in line 4 above	63,270,114
20	Total Account 454, 456 and 456.1	84,927,296
21	Note 4: SECA revenues booked in Account 447.	

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)	46,435,520
B		100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	351,939,154
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	44,185,940
101	Less LTD Interest on Securitization Bonds			Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	44,185,940
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	787,377,818
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)	789,555,597
	Capitalization				
108	Long Term Debt			p112.17c through 21c	791,570,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-17,703,624
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	3,371,305
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	777,237,681
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	789,555,597
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,566,793,278
117	Debt %	Total Long Term Debt		(Line 113 / 116)	49.61%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	50.39%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0568
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)	0.0282
124	Weighted Cost o	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost o	Common Stock		(Line 119 * 122)	0.0620
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0902**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**31,739,639**

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	(227,903)
134	T/(1-T)			(Line 132)	68%
135	Net Plant Allocation Factor			(Line 18)	32.5133%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-124,440**
137	**Income Tax Component =**		CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		**14,820,322**
138	**Total Income Taxes**			**(Line 136 + 137)**	**14,695,882**

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			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	47,398,308	23,040,093	24,358,215	See Form 1
11	Accumulated Common Amortization - Electric	(Note A)	p356	20,471,683	17,196,214	3,275,469	See Form 1
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	48,517,854	40,754,997	7,762,857	See Form 1
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	88,690,092	74,499,676	14,190,416	See Form 1
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	7,431,918	6,772,962	658,956	See Form 1
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 1,391,978	1,331,845	60,133	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	148,323	148,323	0	See FERC Form 2, Page 337, Line 1, Column h for non-electric portion.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	$ 4,024,815	3,380,844	643,971	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			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	397,132	0	397,132	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			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	$ 2,215,671,431	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 684,020,338	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	74,499,676	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	264,005,938	0	0	See Form 1

EPRI Dues Cost Support

Line	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	99873	99873	See Form 1

Delmarva Power & Light Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 3,465,325	0	3,465,325	FERC related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	3,465,325	0	3,465,325	FERC related

Safety Related Advertising Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	79,645	0	79,645	None

MultiState Workpaper

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

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	79,645	0	79,645	None

Excluded Plant Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Note	Reference	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	6,934,953	6.656%	461,602	
	Plant Related	3,848,677	31.295%	1,204,445	
	Other		0.00%	-	
	Total Transmission Related Reserves	10,783,630		1,666,047	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
				Allocator	To Line 45	
	Pension Liabilities, if any, in Account 242		-	5.591%	-	
	Prepayments	$	73,311,307	5.591%	4,098,968	
	Prepaid Pensions if not included in Prepayments	$	162,401,025	5.591%	9,080,134	
			235,712,332	5.59%	13,179,102	
5	Wages & Salary Allocator		6.656%			
	Electric vs Gas		84%	Based on Modified Wisconsin Method		
	Modified Wages & Salaries Allocator		5.591%			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	3,843.4	See Form 1

Statements BG/BH (Present and Proposed Revenues)

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

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 4,776,200	$ 4,206,278	$ 11,176,729	$ 11,422,465	$ 31,581,672
Security Services Administration	531,601	350,190	993,436	240,207	2,115,434
Purchasing, Storeroom & Materials Mgt	919,078	651,941	2,487,044	92,788	4,150,851
Vehicle Resource Management	927,590	651,080	717,229	20,800	2,316,699
General Services	2,508,024	1,236,672	2,036,503	891,824	6,673,023
Building Services	1,170,573	1,002,154	2,358,359	555,940	5,087,026
Real Estate	1,126,058	996,620	336,051	38,847	2,497,576
Corporate Insurance Administration	180,103	124,022	272,694	152,806	729,625
Claims Administration	594,597	550,445	1,346,080	-	2,491,122
Regulatory Affairs	3,638,374	3,135,445	5,884,208	27,180	12,685,207
Accounts Payable Accounting Services	591,850	440,696	500,847	222,724	1,756,117
Payroll Services	410,386	246,398	627,209	97,863	1,381,856
Asset & Project Accounting Services	528,719	434,792	1,403,906	355,773	2,723,190
Investor Relations	155,445	138,572	359,753	284,773	938,543
Shareholder Services	232,179	206,012	538,394	415,127	1,391,712
Financial Reporting	836,383	744,405	1,914,097	1,493,091	4,987,976
Sarbanes-Oxley Compliance	153,467	155,750	354,939	282,860	947,016
Investment Financial Management	309,277	284,564	623,004	511,886	1,728,731
Other Financial Services	4,751,222	3,951,602	6,244,083	6,209,663	21,156,570
Insurance Premiums & Claims	2,146,823	1,567,582	3,357,127	3,069,819	10,141,351
Cost of Benefits	13,342,891	8,411,214	19,826,849	7,519,685	49,100,639
Executive Compensation Services	79,333	71,356	182,639	152,071	485,399
Other Human Resources Services	4,653,174	2,818,636	6,309,870	4,100,477	17,882,157
Legal Services	2,495,233	2,391,093	4,766,020	1,140,122	10,792,468
Audit Services	1,156,972	727,079	1,478,923	782,490	4,145,464
Special Billing	580,006	621,015	1,127,265	28,989	2,357,275
Other Customer Care	34,879,364	34,292,030	10,358,342	62	79,529,798
Marketing Services	1,346,830	970,132	1,832,720	74,530	4,224,212
Information Technology	7,180,933	4,115,177	28,620,279	5,014,635	44,931,024
PHI Corporate Contributions	11,474	10,172	26,664	20,427	68,737
Federal Government Affairs	244,765	217,449	567,270	440,610	1,470,094
Other Corporate Communications	982,347	657,377	1,508,623	656,193	3,804,540
Environmental & Safety Services	1,541,344	1,076,227	2,396,773	646,793	5,661,137
System Operations Shared	2,539,144	1,797,936	6,336,254	221,411	10,894,745
Electric Maintenance Meter Shop	1,060,099	447,295	-	106	1,507,500
Other Delivery Services	27,546,136	17,753,626	38,170,556	45,097	83,515,415
Power Procurement	2,254,471	1,558,667	3,168,805	-	6,981,943
Management & Administration	44,065	(3,348)	-	7,972,371	8,013,088
Merchant Functions	709,640	-	-	14,804,766	15,514,406
Supply Engineering & Support	256,726	65,323	-	9,727,193	10,049,242
Internal Consulting Services	378,530	224,916	545,602	-	1,149,048
Interns	196,424	120,153	207,382	3,936	527,895
Building Services	8,276	82,562	3,929,060	107,118	4,127,016
Total	$ 129,976,126	$ 99,501,307	$ 174,891,588	$ 79,845,518	$ 484,214,539

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, 2009

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	78,743,283	96,399,563	(251,258)	174,891,588
2	Delmarva Power & Light Company	43,784,129	86,299,951	(107,954)	129,976,126
3	Atlantic City Electric	25,301,543	74,294,875	(95,111)	99,501,307
4	Conectiv Energy Supply, Inc.	19,621,924	5,681,603	(16,900)	25,286,627
5	Conectiv Delmarva Generation, Inc.	4,796,447	11,128,449	(25,158)	15,899,738
6	Pepco Energy Services, Inc.	4,282,527	9,656,596	(34,078)	13,905,045
7	Conectiv Atlantic Generation, LLC	2,910,261	4,176,667	(10,835)	7,076,093
8	Conectiv Bethlehem, LLC	1,583,483	2,244,563	(13,145)	3,814,901
9	Pepco Holdings, Inc.	1,136,131	3,258,951	(43,264)	4,351,818
10	Potomac Capital Investment Corporation	842,586	1,956,646	(23,052)	2,776,180
11	PHI Operating Services Company	796,675	1,329,406	(1,910)	2,124,171
12	Thermal Energy Limited Partnership	100,524	563,766	(3,188)	661,102
13	Conectiv Mid-Merit, LLC	1,791,382	108,302	(266)	1,899,418
14	Conectiv Thermal Systems	30,971	69,607	(487)	100,091
15	Atlantic Southern Properties	54,212	195,989	(671)	249,530
16	Conectiv Communications, Inc.	116	2,200	(5)	2,311
17	ATE Investments, Inc.	67	10,215	(155)	10,127
18	Atlantic City Electric Transition Funding, LLC	24,154	198,217	(4,552)	217,819
19	Conectiv Properties and Investments, Inc.	2,019	34,051	(51)	36,019
20	Conectiv Solutions LLC	4,124	12,654	(176)	16,602
21	Conectiv North East, LLC	138,701	8,198	(37)	146,862
22	Atlantic Generation, Inc.	318	1,799	(7)	2,110
23	DCTC-Burney, Inc.	414	57		471
24	Conectiv Services II, Inc.	21,299	63,382	(2)	84,679
25	Vineland General, Inc.	9,006			9,006
26	Vineland Limited, Inc.	346			346
27	ACE REIT, Inc.	9	62		71
28	Conectiv	25,199	4,348	(67)	29,480
29	Atlantic Thermal Operating Company	121	179,953	(559)	179,515
30	Conectiv Energy Holding Company	617	586,351	(7,301)	579,667
31	Conectiv Vineland Solar, LLC	379,665	5,885	(1)	385,549
32	Atlantic Jersey Thermal	131			131
33	Delta, LLC	5	34		39
34					
35					
36					
37					
38					
39					
40	**Total**	186,382,389	298,472,340	(640,190)	484,214,539

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)

55,741,853 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			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	-	
								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!	

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

$ 12,059,758 Input to Formula Line 21

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

57,643,767 — 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)

$ 57,643,767

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

67,972,162 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 $ 48,277,057 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	155,632		405759		11.5	1,789,768	-	4,666,229	-	149,147	-	388,852	-	
Feb	(2,116,762)		293079		10.5	(22,226,001)	-	3,077,330	-	(1,852,167)	-	256,444	-	
Mar	3,702,864		412366		9.5	35,177,208	-	3,917,477	-	2,931,434	-	326,456	-	
Apr	254,721		301512		8.5	2,165,129	-	2,562,852	-	180,427	-	213,571	-	
May	10,222,356		725662		7.5	76,667,670	-	5,442,465	-	6,388,973	-	453,539	-	
Jun	5,232,035		307117		6.5	34,008,228	-	1,996,261	-	2,834,019	-	166,355	-	
Jul	1,312,841		2194921		5.5	7,220,626	-	12,072,066	-	601,719	-	1,006,005	-	
Aug	683,628		629470		4.5	3,076,326	-	2,832,615	-	256,361	-	236,051	-	
Sep	14,547,141		-100532		3.5	50,914,994	-	(351,862)	-	4,242,916	-	(29,322)	-	
Oct	2,657,041		1064416		2.5	6,642,603	-	2,661,040	-	553,550	-	221,753	-	
Nov	3,519,414		1365487		1.5	5,279,121	-	2,048,231	-	439,927	-	170,686	-	
Dec	8,106,146		1169503		0.5	4,053,073	-	584,752	-	337,756	-	48,729	-	
Total	48,277,057	-	8,768,760	-		204,768,743	-	-	-	17,064,062	-	3,459,121	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										17,064,062	-	3,459,121	-	
Input to Line 21 of Appendix A										17,064,062	-		-	17,064,062
Input to Line 43a of Appendix A												3,459,121		3,459,121
Month In Service or Month for CWIP										7.76	#DIV/0!	7.27	#DIV/0!	

65,007,424 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			8309760		11.5	-	-	95,562,240	-	-	-	7,963,520	-	
Feb			168000		10.5	-	-	1,764,000	-	-	-	147,000	-	
Mar			2265000		9.5	-	-	21,517,500	-	-	-	1,793,125	-	
Apr			1743000		8.5	-	-	14,815,500	-	-	-	1,234,625	-	
May			1004000		7.5	-	-	7,530,000	-	-	-	627,500	-	
Jun	28,071,120		5504000		6.5	182,462,280	-	35,776,000	-	15,205,190	-	2,981,333	-	
Jul			1003000		5.5	-	-	5,516,500	-	-	-	459,708	-	
Aug	14,504,530		1003000		4.5	65,270,385	-	4,513,500	-	5,439,199	-	376,125	-	
Sep			1004000		3.5	-	-	3,514,000	-	-	-	292,833	-	
Oct			1104000		2.5	-	-	2,760,000	-	-	-	230,000	-	
Nov			1104000		1.5	-	-	1,656,000	-	-	-	138,000	-	
Dec	9,405,795		1103000		0.5	4,702,898	-	551,500	-	391,908	-	45,958	-	
Total	51,981,445	-	25,314,760	-		252,435,563	-	-	-	21,036,297	-	16,289,728	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										21,036,297	-	16,289,728	-	
72,747,232														
Input to Line 21 of Appendix A										21,036,297	-		-	21,036,297
Input to Line 43a of Appendix A												16,289,728		16,289,728
Month In Service or Month for CWIP										7.14	#DIV/0!	4.28	#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		
65,007,424	-	65,442,977	=	(435,554)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(36,296)	0.2800%	11.5	(1,169)	(37,465)
Jul	Year 1	(36,296)	0.2800%	10.5	(1,067)	(37,363)
Aug	Year 1	(36,296)	0.2800%	9.5	(965)	(37,262)
Sep	Year 1	(36,296)	0.2800%	8.5	(864)	(37,160)
Oct	Year 1	(36,296)	0.2800%	7.5	(762)	(37,058)
Nov	Year 1	(36,296)	0.2800%	6.5	(661)	(36,957)
Dec	Year 1	(36,296)	0.2800%	5.5	(559)	(36,855)
Jan	Year 2	(36,296)	0.2800%	4.5	(457)	(36,753)
Feb	Year 2	(36,296)	0.2800%	3.5	(356)	(36,652)
Mar	Year 2	(36,296)	0.2800%	2.5	(254)	(36,550)
Apr	Year 2	(36,296)	0.2800%	1.5	(152)	(36,449)
May	Year 2	(36,296)	0.2800%	0.5	(51)	(36,347)
Total		(435,554)				(442,871)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(442,871)	0.2800%	(37,581)	(406,530)
Jul	Year 2	(406,530)	0.2800%	(37,581)	(370,087)
Aug	Year 2	(370,087)	0.2800%	(37,581)	(333,542)
Sep	Year 2	(333,542)	0.2800%	(37,581)	(296,895)
Oct	Year 2	(296,895)	0.2800%	(37,581)	(260,145)
Nov	Year 2	(260,145)	0.2800%	(37,581)	(223,293)
Dec	Year 2	(223,293)	0.2800%	(37,581)	(186,337)
Jan	Year 3	(186,337)	0.2800%	(37,581)	(149,278)
Feb	Year 3	(149,278)	0.2800%	(37,581)	(112,115)
Mar	Year 3	(112,115)	0.2800%	(37,581)	(74,848)
Apr	Year 3	(74,848)	0.2800%	(37,581)	(37,476)
May	Year 3	(37,476)	0.2800%	(37,581)	0
Total with interest				(450,972)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(450,972)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	72,747,232
Revenue Requirement for Year 3		72,296,260

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

$ 72,296,260 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)

$ 72,296,260

Delmarva Power & Light Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

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

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	13.298%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	14.008%
6	C		Line B less Line A	0.7091%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.9518%

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 F June 1, 2008 and November 1, 2008 respectively.**

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		13.2984%		12.5524%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		14.3621%		13.5437%
18	Columns A, B or C from Attachment 6	Investment		25,314,760	may be weighted average of small projects	14,689,101
19	Line 18 divided by line 13	Annual Depreciation Exp		723,279		419,689
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		4.28		6.00

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending
25	Base FCR	2010	25,314,760	-	25,314,760	3,366,460	14,479,257	419,689	14,059,568
26	W Increased ROE	2010	25,314,760	-	25,314,760	3,635,730	14,479,257	419,689	14,059,568
27	Base FCR	2011	25,314,760	-	25,314,760	3,366,460	14,059,568	419,689	13,639,880
28	W Increased ROE	2011	25,314,760	-	25,314,760	3,635,730	14,059,568	419,689	13,639,880
29	Base FCR	2012	25,314,760	-	25,314,760	3,366,460	13,639,880	419,689	13,220,191
30	W Increased ROE	2012	25,314,760	-	25,314,760	3,635,730	13,639,880	419,689	13,220,191
31	Base FCR	2013	25,314,760	-	25,314,760	3,366,460	13,220,191	419,689	12,800,502
32	W Increased ROE	2013	25,314,760	-	25,314,760	3,635,730	13,220,191	419,689	12,800,502
33	Base FCR	2014	25,314,760	-	25,314,760	3,366,460	12,800,502	419,689	12,380,814
34	W Increased ROE	2014	25,314,760	-	25,314,760	3,635,730	12,800,502	419,689	12,380,814
35	Base FCR	2015	25,314,760	-	25,314,760	3,366,460	12,380,814	419,689	11,961,125
36	W Increased ROE	2015	25,314,760	-	25,314,760	3,635,730	12,380,814	419,689	11,961,125
37	Base FCR	2016	25,314,760	-	25,314,760	3,366,460	11,961,125	419,689	11,541,437
38	W Increased ROE	2016	25,314,760	-	25,314,760	3,635,730	11,961,125	419,689	11,541,437
39	Base FCR	2017	25,314,760	-	25,314,760	3,366,460	11,541,437	419,689	11,121,748
40	W Increased ROE	2017	25,314,760	-	25,314,760	3,635,730	11,541,437	419,689	11,121,748
41	Base FCR	2018	25,314,760	-	25,314,760	3,366,460	11,121,748	419,689	10,702,059
42	W Increased ROE	2018	25,314,760	-	25,314,760	3,635,730	11,121,748	419,689	10,702,059
43	Base FCR	2019	25,314,760	-	25,314,760	3,366,460	10,702,059	419,689	10,282,371
44	W Increased ROE	2019	25,314,760	-	25,314,760	3,635,730	10,702,059	419,689	10,282,371
45	Base FCR	2020	25,314,760	-	25,314,760	3,366,460	10,282,371	419,689	9,862,682
46	W Increased ROE	2020	25,314,760	-	25,314,760	3,635,730	10,282,371	419,689	9,862,682
47	Base FCR	2021	25,314,760	-	25,314,760	3,366,460	9,862,682	419,689	9,442,994
48	W Increased ROE	2021	25,314,760	-	25,314,760	3,635,730	9,862,682	419,689	9,442,994
49	Base FCR	2022	25,314,760	-	25,314,760	3,366,460	9,442,994	419,689	9,023,305
50	W Increased ROE	2022	25,314,760	-	25,314,760	3,635,730	9,442,994	419,689	9,023,305
51	Base FCR	2023	25,314,760	-	25,314,760	3,366,460	9,023,305	419,689	8,603,616
52	W Increased ROE	2023	25,314,760	-	25,314,760	3,635,730	9,023,305	419,689	8,603,616
53	Base FCR	2024	25,314,760	-	25,314,760	3,366,460	8,603,616	419,689	8,183,928
54	W Increased ROE	2024	25,314,760	-	25,314,760	3,635,730	8,603,616	419,689	8,183,928
55	Base FCR	2025	25,314,760	-	25,314,760	3,366,460	8,183,928	419,689	7,764,239
56	W Increased ROE	2025	25,314,760	-	25,314,760	3,635,730	8,183,928	419,689	7,764,239
57	Base FCR	2026	25,314,760	-	25,314,760	3,366,460	7,764,239	419,689	7,344,551
58	W Increased ROE	2026	25,314,760	-	25,314,760	3,635,730	7,764,239	419,689	7,344,551
59	Base FCR	2027	25,314,760	-	25,314,760	3,366,460	7,344,551	419,689	6,924,862
60	W Increased ROE	2027		-	-	-	7,344,551	419,689	6,924,862
61		....		....	.....	....	....	.....	.....
62		....	....	.....	.....	....	....	.....	.....
63									

FERC to become 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 Attachment 7 is

	B0494.1-4 Red Lion-Keeney				B0241.1-.2 Red Lion-Keeney				B0567 Mt.Pleasant-Townsend			
	No				No				No			
	35				35				35			
	No				No				No			
	150				150				150			
	12.5524%				12.5524%				0.132984063			
	13.5437%				13.5437%				0.143620965			
	3,099,104				2,418,717				6,414,723			
	88,546				69,106				183,278			
	6.00				6.00				6			
Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
2,184,509	3,054,831	88,546	2,966,285	460,887	2,384,164	69,106	2,315,058	359,703	6,414,723	91,639	6,323,084	932,508
2,323,872	3,054,831	88,546	2,966,285	490,290	2,384,164	69,106	2,315,058	382,650	6,414,723	91,639	6,323,084	999,766
2,131,828	2,966,285	88,546	2,877,739	449,773	2,315,058	69,106	2,245,952	351,028	6,323,084	183,278	6,139,806	999,774
2,267,031	2,966,285	88,546	2,877,739	478,298	2,315,058	69,106	2,245,952	373,291	6,323,084	183,278	6,139,806	1,065,083
2,079,146	2,877,739	88,546	2,789,194	438,658	2,245,952	69,106	2,176,845	342,354	6,139,806	183,278	5,956,529	975,401
2,210,190	2,877,739	88,546	2,789,194	466,305	2,245,952	69,106	2,176,845	363,931	6,139,806	183,278	5,956,529	1,038,760
2,026,465	2,789,194	88,546	2,700,648	427,543	2,176,845	69,106	2,107,739	333,679	5,956,529	183,278	5,773,251	951,028
2,153,349	2,789,194	88,546	2,700,648	454,313	2,176,845	69,106	2,107,739	354,572	5,956,529	183,278	5,773,251	1,012,438
1,973,784	2,700,648	88,546	2,612,102	416,429	2,107,739	69,106	2,038,633	325,005	5,773,251	183,278	5,589,973	926,655
2,096,507	2,700,648	88,546	2,612,102	442,321	2,107,739	69,106	2,038,633	345,212	5,773,251	183,278	5,589,973	986,115
1,921,103	2,612,102	88,546	2,523,556	405,314	2,038,633	69,106	1,969,527	316,330	5,589,973	183,278	5,406,695	902,282
2,039,666	2,612,102	88,546	2,523,556	430,328	2,038,633	69,106	1,969,527	335,853	5,589,973	183,278	5,406,695	959,793
1,868,422	2,523,556	88,546	2,435,010	394,199	1,969,527	69,106	1,900,421	307,656	5,406,695	183,278	5,223,417	877,909
1,982,825	2,523,556	88,546	2,435,010	418,336	1,969,527	69,106	1,900,421	326,493	5,406,695	183,278	5,223,417	933,470
1,815,740	2,435,010	88,546	2,346,464	383,085	1,900,421	69,106	1,831,314	298,981	5,223,417	183,278	5,040,140	853,536
1,925,983	2,435,010	88,546	2,346,464	406,344	1,900,421	69,106	1,831,314	317,134	5,223,417	183,278	5,040,140	907,147
1,763,059	2,346,464	88,546	2,257,919	371,970	1,831,314	69,106	1,762,208	290,306	5,040,140	183,278	4,856,862	829,163
1,869,142	2,346,464	88,546	2,257,919	394,351	1,831,314	69,106	1,762,208	307,774	5,040,140	183,278	4,856,862	880,825
1,710,378	2,257,919	88,546	2,169,373	360,855	1,762,208	69,106	1,693,102	281,632	4,856,862	183,278	4,673,584	804,790
1,812,301	2,257,919	88,546	2,169,373	382,359	1,762,208	69,106	1,693,102	298,415	4,856,862	183,278	4,673,584	854,502
1,657,697	2,169,373	88,546	2,080,827	349,741	1,693,102	69,106	1,623,996	272,957	4,673,584	183,278	4,490,306	780,417
1,755,459	2,169,373	88,546	2,080,827	370,367	1,693,102	69,106	1,623,996	289,055	4,673,584	183,278	4,490,306	828,180
1,605,016	2,080,827	88,546	1,992,281	338,626	1,623,996	69,106	1,554,890	264,283	4,490,306	183,278	4,307,028	756,044
1,698,618	2,080,827	88,546	1,992,281	358,374	1,623,996	69,106	1,554,890	279,696	4,490,306	183,278	4,307,028	801,857
1,552,334	1,992,281	88,546	1,903,735	327,511	1,554,890	69,106	1,485,783	255,608	4,307,028	183,278	4,123,751	731,671
1,641,777	1,992,281	88,546	1,903,735	346,382	1,554,890	69,106	1,485,783	270,336	4,307,028	183,278	4,123,751	775,535
1,499,653	1,903,735	88,546	1,815,189	316,397	1,485,783	69,106	1,416,677	246,934	4,123,751	183,278	3,940,473	707,298
1,584,935	1,903,735	88,546	1,815,189	334,389	1,485,783	69,106	1,416,677	260,977	4,123,751	183,278	3,940,473	749,212
1,446,972	1,815,189	88,546	1,726,644	305,282	1,416,677	69,106	1,347,571	238,259	3,940,473	183,278	3,757,195	682,925
1,528,094	1,815,189	88,546	1,726,644	322,397	1,416,677	69,106	1,347,571	251,617	3,940,473	183,278	3,757,195	722,890
1,394,291	1,726,644	88,546	1,638,098	294,167	1,347,571	69,106	1,278,465	229,585	3,757,195	183,278	3,573,917	658,552
1,471,253	1,726,644	88,546	1,638,098	310,405	1,347,571	69,106	1,278,465	242,257	3,757,195	183,278	3,573,917	696,567
1,341,610	1,638,098	88,546	1,549,552	283,053	1,278,465	69,106	1,209,359	220,910	3,573,917	183,278	3,390,639	634,179
1,414,411	1,638,098	88,546	1,549,552	298,412	1,278,465	69,106	1,209,359	232,898	3,573,917	183,278	3,390,639	670,245
1,288,928	1,549,552	88,546	1,461,006	271,938	1,209,359	69,106	1,140,252	212,236	3,390,639	183,278	3,207,362	609,806
1,357,570	1,549,552	88,546	1,461,006	286,420	1,209,359	69,106	1,140,252	223,538	3,390,639	183,278	3,207,362	643,922
....	....	....	.....	....	....	....	.....	....	....	....	.....	....
....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

s 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by FERC to become effective

B0483.1-.3 Oak Hall-Wattsville	B0320 Cool Springs
No	No
35	35
No	No
150	150
0.132984063	0.132984063
0.143620965	0.143620965
8,379,558	14,504,530
239,416	414,415
12	9

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
8,379,558	-	8,379,558	1,114,348	14,504,530	103,604	14,400,926	2,018,697	$ 10,437,112		$ 10,437,112
8,379,558	-	8,379,558	1,203,480	14,504,530	103,604	14,400,926	2,171,879	$ 11,207,668	$ 11,207,668	
8,379,558	239,416	8,140,142	1,321,925	14,400,926	414,415	13,986,511	2,274,398	$ 10,895,186		$ 10,895,186
8,379,558	239,416	8,140,142	1,408,511	14,400,926	414,415	13,986,511	2,423,171	$ 11,651,115	$ 11,651,115	
8,140,142	239,416	7,900,726	1,290,087	13,986,511	414,415	13,572,096	2,219,288	$ 10,711,393		$ 10,711,393
8,140,142	239,416	7,900,726	1,374,126	13,986,511	414,415	13,572,096	2,363,653	$ 11,452,696	$ 11,452,696	
7,900,726	239,416	7,661,310	1,258,248	13,572,096	414,415	13,157,681	2,164,177	$ 10,527,601		$ 10,527,601
7,900,726	239,416	7,661,310	1,339,741	13,572,096	414,415	13,157,681	2,304,134	$ 11,254,276	$ 11,254,276	
7,661,310	239,416	7,421,894	1,226,410	13,157,681	414,415	12,743,266	2,109,066	$ 10,343,808		$ 10,343,808
7,661,310	239,416	7,421,894	1,305,356	13,157,681	414,415	12,743,266	2,244,615	$ 11,055,856	$ 11,055,856	
7,421,894	239,416	7,182,478	1,194,571	12,743,266	414,415	12,328,851	2,053,956	$ 10,160,015		$ 10,160,015
7,421,894	239,416	7,182,478	1,270,970	12,743,266	414,415	12,328,851	2,185,097	$ 10,857,437	$ 10,857,437	
7,182,478	239,416	6,943,062	1,162,733	12,328,851	414,415	11,914,435	1,998,845	$ 9,976,223		$ 9,976,223
7,182,478	239,416	6,943,062	1,236,585	12,328,851	414,415	11,914,435	2,125,578	$ 10,659,017	$ 10,659,017	
6,943,062	239,416	6,703,646	1,130,894	11,914,435	414,415	11,500,020	1,943,735	$ 9,792,430		$ 9,792,430
6,943,062	239,416	6,703,646	1,202,200	11,914,435	414,415	11,500,020	2,066,059	$ 10,460,598	$ 10,460,598	
6,703,646	239,416	6,464,230	1,099,056	11,500,020	414,415	11,085,605	1,888,624	$ 9,608,638		$ 9,608,638
6,703,646	239,416	6,464,230	1,167,815	11,500,020	414,415	11,085,605	2,006,540	$ 10,262,178	$ 10,262,178	
6,464,230	239,416	6,224,815	1,067,217	11,085,605	414,415	10,671,190	1,833,513	$ 9,424,845		$ 9,424,845
6,464,230	239,416	6,224,815	1,133,430	11,085,605	414,415	10,671,190	1,947,022	$ 10,063,758	$ 10,063,758	
6,224,815	239,416	5,985,399	1,035,379	10,671,190	414,415	10,256,775	1,778,403	$ 9,241,053		$ 9,241,053
6,224,815	239,416	5,985,399	1,099,045	10,671,190	414,415	10,256,775	1,887,503	$ 9,865,339	$ 9,865,339	
5,985,399	239,416	5,745,983	1,003,540	10,256,775	414,415	9,842,360	1,723,292	$ 9,057,260		$ 9,057,260
5,985,399	239,416	5,745,983	1,064,660	10,256,775	414,415	9,842,360	1,827,984	$ 9,666,919	$ 9,666,919	
5,745,983	239,416	5,506,567	971,702	9,842,360	414,415	9,427,944	1,668,182	$ 8,873,468		$ 8,873,468
5,745,983	239,416	5,506,567	1,030,274	9,842,360	414,415	9,427,944	1,768,466	$ 9,468,500	$ 9,468,500	
5,506,567	239,416	5,267,151	939,863	9,427,944	414,415	9,013,529	1,613,071	$ 8,689,675		$ 8,689,675
5,506,567	239,416	5,267,151	995,889	9,427,944	414,415	9,013,529	1,708,947	$ 9,270,080	$ 9,270,080	
5,267,151	239,416	5,027,735	908,025	9,013,529	414,415	8,599,114	1,557,960	$ 8,505,883		$ 8,505,883
5,267,151	239,416	5,027,735	961,504	9,013,529	414,415	8,599,114	1,649,428	$ 9,071,660	$ 9,071,660	
5,027,735	239,416	4,788,319	876,186	8,599,114	414,415	8,184,699	1,502,850	$ 8,322,090		$ 8,322,090
5,027,735	239,416	4,788,319	927,119	8,599,114	414,415	8,184,699	1,589,910	$ 8,873,241	$ 8,873,241	
4,788,319	239,416	4,548,903	844,348	8,184,699	414,415	7,770,284	1,447,739	$ 8,138,298		$ 8,138,298
4,788,319	239,416	4,548,903	892,734	8,184,699	414,415	7,770,284	1,530,391	$ 8,674,821	$ 8,674,821	
4,548,903	239,416	4,309,487	812,509	7,770,284	414,415	7,355,869	1,392,628	$ 7,954,505		$ 7,954,505
4,548,903	239,416	4,309,487	858,349	7,770,284	414,415	7,355,869	1,470,872	$ 4,840,671	$ 4,840,671	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 186,193,239	$ 177,662,390

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4c - ACE Formula Rate Update

Attachment 4c

ATTACHMENT H-1A

Atlantic City Electric Company

Formula Rate - Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	2009
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 1,936,649
2	Total Wages Expense		p354.28b	$ 22,359,783
3	Less A&G Wages Expense		p354.27b	$ 937,023
4	Total		(Line 2 - 3)	21,422,760
5	**Wages & Salary Allocator**		(Line 1 / 4)	**9.0401%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,213,507,017
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	2,213,507,017
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 659,554,002
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 34,907,238
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)	694,461,240
14	Net Plant		(Line 8 - 13)	1,519,045,777
15	Transmission Gross Plant		(Line 29 - Line 28)	670,668,677
16	**Gross Plant Allocator**		(Line 15 / 8)	**30.2989%**
17	Transmission Net Plant		(Line 39 - Line 28)	481,006,134
18	**Net Plant Allocator**		(Line 17 / 14)	**31.6650%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 651,469,979
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	6,626,748
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**658,096,727**
23	General & Intangible		p205.5.g & p207.99.g	$ 139,067,987
24	Common Plant (Electric Only)	(Notes A & B)	p356	$ -
25	Total General & Common		(Line 23 + 24)	139,067,987
26	Wage & Salary Allocation Factor		(Line 5)	9.04015%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**12,571,950**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**782,029**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**671,450,706**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 182,095,766
31	Accumulated General Depreciation		p219.28.c 48,794,686	$
32	Accumulated Intangible Amortization		(Line 10)	34,907,238
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)	83,701,924
36	Wage & Salary Allocation Factor		(Line 5)	9.04015%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**7,566,777**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**189,662,543**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**481,788,163**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-127,041,193
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	31.67%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-127,041,193**
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	**-1,263,058**
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	10,623,329
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**10,623,329**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,040,283
48	Wage & Salary Allocation Factor		(Line 5)	9.04%
49	Total Transmission Allocated		(Line 47 * 48)	94,043
50	Transmission Materials & Supplies		p227.8c	$ 2,803,997
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**2,898,040**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	13,896,981
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**1,737,123**
	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)	**-113,045,759**
59	**Rate Base**		(Line 39 + 58)	**368,742,404**

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b	$ 9,398,722
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)	**9,398,722**
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	$ -
68	Total A&G			p323.197.b	$ 51,840,122
69	Less Property Insurance Account 924			p323.185b	$ 483,711
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$ 3,129,059
71	Less General Advertising Exp Account 930.1			p323.191b	$ 63,088
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$ -
73	Less EPRI Dues		(Note D)	p352-353	$ 99,873
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)	48,064,391
75	Wage & Salary Allocation Factor			(Line 5)	9.0401%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)	**4,345,092**
	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	$ 483,711
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	483,711
83	Net Plant Allocation Factor			(Line 18)	31.67%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)	**153,167**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**	**13,896,981**

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	**15,454,991**
87	General Depreciation			p336.10b&c	5,375,323
88	Intangible Amortization		(Note A)	p336.1d&e	48,740
89	Total			(Line 87 + 88)	5,424,063
90	Wage & Salary Allocation Factor			(Line 5)	9.0401%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)	**490,343**
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	0
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	0
95	Wage & Salary Allocation Factor			(Line 5)	9.0401%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)	**0**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**	**15,945,334**

Taxes Other than Income

98	**Taxes Other than Income**			Attachment 2	**809,389**
99	**Total Taxes Other than Income**			**(Line 98)**	**809,389**

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	65,824,409
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	21,780,263
102	**Long Term Interest**			"(Line 100 - line 101)"	44,044,146
103	**Preferred Dividends**		enter positive	p118.29c	$ 262,841
	Common Stock				
104	Proprietary Capital			p112.16c	$ 649,380,739
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)	643,166,239
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,025,488,411
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (12,788,654)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,548,604
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-391,423,411
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	622,824,950
114	Preferred Stock			p112.3c	$ 6,214,500
115	Common Stock			(Line 107)	643,166,239
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,272,205,689
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)	0.0707
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)	0.0354
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)	**0.0919**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**33,872,075**

Composite Income Taxes				
	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35.00%
129	SIT=State Income Tax Rate or Composite	(Note I)		8.99%
130	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%
132	T/ (1-T)			69.05%
	ITC Adjustment	(Note I)		
133	Amortized Investment Tax Credit	enter negative	p266.8f	$ (1,019,535)
134	T/(1-T)		(Line 132)	69.05%
135	Net Plant Allocation Factor		(Line 18)	31.6650%
136	**ITC Adjustment Allocated to Transmission**		(Line 133 * (1 + 134) * 135)	**-545,760**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 132 * 127 * (1-(123 / 126))]	**14,386,189**
138	**Total Income Taxes**		**(Line 136 + 137)**	**13,840,429**

REVENUE REQUIREMENT				
	Summary			
139	Net Property, Plant & Equipment		(Line 39)	481,788,163
140	Adjustment to Rate Base		(Line 58)	-113,045,759
141	**Rate Base**		(Line 59)	**368,742,404**
142	O&M		(Line 85)	13,896,981
143	Depreciation & Amortization		(Line 97)	15,945,334
144	Taxes Other than Income		(Line 99)	809,389
145	Investment Return		(Line 127)	33,872,075
146	Income Taxes		(Line 138)	13,840,429
147	**Gross Revenue Requirement**		**(Sum Lines 142 to 146)**	**78,364,209**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	651,469,979
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	651,469,979
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	78,364,209
153	**Adjusted Gross Revenue Requirement**		(Line 151 * 152)	**78,364,209**
	Revenue Credits & Interest on Network Credits			
154	**Revenue Credits**		Attachment 3	3,321,642
155	**Interest on Network Credits**	(Note N)	PJM Data	-
156	**Net Revenue Requirement**		**(Line 153 - 154 + 155)**	**75,042,567**
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	**75,042,567**
158	Net Transmission Plant		(Line 19 - 30)	**469,374,213**
159	Net Plant Carrying Charge		(Line 157 / 158)	**15.9878%**
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	**12.6951%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	**2.5300%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	**27,330,063**
163	Increased Return and Taxes		Attachment 4	**50,829,330**
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	**78,159,393**
165	Net Transmission Plant		(Line 19 - 30)	**469,374,213**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	**16.6518%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	**13.3591%**
168	**Net Revenue Requirement**		(Line 156)	**75,042,567**
169	True-up amount		Attachment 6	**6,204,303**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	**478,624**
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)	**82,175,494**
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	**2,707**
174	Rate ($/MW-Year)		(Line 172 / 173)	**30,361**
175	**Network Service Rate ($/MW/Year)**		**(Line 174)**	**30,361**

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	(368,847,068)	0	
ADIT-283	0	3,178,732	(6,577,523)	
ADIT-190	0	(48,741,619)	(9,787,919)	
Subtotal	0	(414,409,955)	(16,365,442)	
Wages & Salary Allocator			9.0401%	
Gross Plant Allocator		30.2989%		
ADIT	0	(125,561,733)	(1,479,460)	(127,041,193)

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 111.
Amount (1,548,604)

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

A			B	C	D	E	F	G
ADIT-190			Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
190	BAD DEBT RESERVE		5,917,061	5,917,061	-	-	-	Under the Tax Reform Act of 1986, taxpayers were required to account f 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		(245,677)	(245,677)	-	-	-	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		(174,304)				(174,304)	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual.
190	CLAIMS RESERVE		902,210				902,210	For book purposes, a deduction is taken for amounts set aside as a reserv 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			-	the disallowances of plant costs associated with ACE's investment in Unit
190	MERGER RELATED ENTRIES		4,840,658				4,840,658	/Atlantic City Electric Company merger costs deducted for tax purposes.
190	Misc Deferred Debits - Retail		-	-				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		1,180,734			1,180,734	-	Miscellaneous temporary differences that are less than $100,000 for each item. Related to all functions
190	OFFICER'S/MANAGERS DEFERRED COMP		430,462	-	-	-	430,462	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		-	-	-	-	-	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
190	ENVIRONMENTAL SITE EXPENSE		1,141,655	1,141,655	-	-	-	These deferred taxes are the result of a deduction taken for book purpos to set aside a reserve for environmental site clean-up expenses. For tax deduction is permitted until the "all events" test is met typically when economic performance has occurred. This book reserve is primarily related
190	MARK TO MARKET § 475 ADJUSTMENT		(407,837)			(407,837)	-	Pursuant to IRC Sec 475, the company is taking deduction to mark-t 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. Ret 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.
190	DEFERRED PURCHASED POWER		2,818,011	2,818,011	-	-	-	Book records amortization on Susquehanna deferred capitalized costs . F tax purposes, the amortization is added back to taxable income. Retail related.
190	PENSION PAYMENT RESERVE		27,057,844	-	-	-	27,057,844	Book records a deduction for actual SFAS 87 pension expense. A tax deduction is only allowed for actual payments into the pension trust. Affec company personnel across all functions.

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

190	SECTION 461(H) - PREPAID INSURANCE		4,051,138			4,051,138	-	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)	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
190	AMORTIZATION (LEGAL)		7,723	7,723				year incurred. For tax purposes, these costs are capital in nature and are amortized over a 30 year period. Generation related.
190	LOSS ON REACQ DEBT		(1,753,406)	(1,753,406)				over the life of the new bond issue for book purposes. Excluded here since included in Cost of Debt
190	ASBESTOS REMOVAL		1	1				full as paid . These costs were deferred and amortized for book purposes. Generation related.
190	SERP		798,534				798,534	Affects company personnel across all functions.
190	NUG BUYOUT		55,145,910	55,145,910				Generation related
190	AMORT of OPEB		(10,769,125)			(10,769,125)		OPEB, labor related and relates to all functions
190	NOL		(2,796,020)			(2,796,020)		Related to both T & D plant
190	AMA		(471,885)			(471,885)		Related to both T & D plant
190	Miscell Diff		(386,235)				(386,235)	This deferred tax balance relates to plant and results from life and method differences. Related to both T & D plant
190	Stranded Costs		(40,648,480)	(40,648,480)				All Generation related
190	Deregulation/Stranded Cost Generation Assets		(6,747,245)	(6,747,245)				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		3,420,393			3,420,393		Plant relatec
	De-regulated Deferrec		80,685,095	80,685,095				Related to generation and reta
190	SERP		(555,956)				(555,956)	Affects company personnel across all functions.
190	PENSION PAYMENT RESERVE		(44,665,532)				(44,665,532)	Affects company personnel across all functions.
190	Regulatory Liability - Demand Response Working Group		122,149				122,149	Demand response incentive program
190	Regulatory Liability - Infrastructure Improvement Surcharge		62,984			62,984		Infrastructure investment surcharge
190	NOL		3,091,228			3,091,228		Related to both T & D plant
190	AMA		2,416,492			2,416,492		Related to both T & D plant
190	NJSA		(15,274)			(15,274)		Affects copany personnel across all functions
190	Stranded Costs		(240,739)	(240,739)				All Generation related
190	Miscell Diff		7,080,554		-	-	7,080,554	This deferred tax balance relates to plant and results from life and method differences. Related to both T & D plant
190	Plant Related (Reclass)		(48,708,560)			(48,708,560)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
190	**Subtotal - p234**		**54,390,201**	**110,453,936**	**-**	**(48,741,619)**	**(7,322,116)**	
	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 fo 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**		51,924,398	110,453,936	-	(48,741,619)	(9,787,919)	

Instructions for Account 190:

ADIT
item

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 AD
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
	Plant Related		(492,809,479)	(68,293,308)		(424,516,171)	-	This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	Plant Related (Reclass)		55,669,103			55,669,103	-	This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
	Subtotal - p275		(545,558,539)	(176,711,471)	-	(368,847,068)	-	
	Less FASB 109 Above if not separately removed							
	Less FASB 106 Above if not separately removed							
282	Total		(545,558,539)	(176,711,471)	-	(368,847,068)	-	

Instructions for Account 282:
ADIT
items

2. ADIT items related only to Transmission are directly assigned to Column D

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

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

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

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADIT-283	A		B Total	C Related	D Related	E Plant	F Labor	G 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)	severed individual. For book purposes, the costs are expensed when a formal plan is
283	REGULATORY ISSUES		(1,912,208)	(1,912,208)	-	-	-	purposes. These costs were tax deductible in full as paid . Retail related
283	AMORTIZATION (LEGAL)		(6,716)	(6,716)	-	-	-	year incurred. For tax purposes, these costs are capital in nature and are amortized
283	LOSS ON REACQ DEBT		204,802	204,802	-	-	-	over the life of the new bond issue for book purposes. Excluded here since included
283	ASBESTOS REMOVAL		(2,167,583)	(2,167,583)	-	-	-	full as paid . These costs were deferred and amortized for book purposes. Generation
283	DEFERRED EXPENSE CLEARING		(1,087,778)			(1,087,778)	-	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		(4,596,476)		-	-	(4,596,476)	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
283	Stranded Costs		166,504,374	166,504,374				All Generation related
283	MISCELL RESERVE		124,443	124,443				Generation related, Environmental Reserve for BL England site,
283	PENSION PAYMENT RESERVE		-				-	Affects company personnel across all functions.
283	SERP		-				-	Affects company personnel across all functions.
283	SECTION 461(H) Prepaid		(651,031)			(651,031)		Related to both T & D plant
283	NUG BUYOUT		9,491,814	9,491,814				Generation related
283	AMORT of OPEB		5,102,539			5,102,539		OPEB, labor related and relates to all function
283	BGS Deferred Related - Retail		26,572,632	26,572,632				Retail related
283	MISC DEFERRED DEBITS		31,581	31,581				Deferred Costs for Universal Service Fund, Retail related
283	NOL		-			-		Related to both T & D plant
283	AMA		-			-		Related to both T & D plant
283	NJSA		-			-		
283	Accrued Liab - Auto		175,596				175,596	Affects copany personnel across all functions
283	Accrued Liab - Misc.		346,312			346,312		Related to T&D plant
283	Regulatory Asset - General		(379,907)				(379,907)	Regulatory liability for universal service fund
283	Regulatory Liability - Demand Response Working Group		-				-	Demand response incentive program
283	Regulatory Liability - Infrastructure Improvement Surcharge		-			-		Infrastructure investment surcharge
283	Regulatory Asset - SREC Program		(24,922)	(24,922)				Generation related - Solar Renewable EnergyCertificate Program
283	Plant Related		(195,023,097)	(75,708,826)		(119,314,271)		
283	Reclass		(3,811,947)	(3,811,947)				Related to generation
283	MISCELLANEOUS		(188,264)			(188,264)	-	Miscellaneous temporary differences that are less than $100,000 for each item. Related to all functions
283	Misc Deferred Debits - Retail		336,169	336,169				Retail related
283	DEFERRED FUEL		1,296,497	1,296,497	-	-	-	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.
283	Plant Related (Reclass)		77,908			77,908		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
283	Subtotal - p277 (Form 1-F filer: see note 6, below)		2,842,511	124,723,829	-	(116,135,539)	(5,745,778)	
283	Less FASB 109 Above if not separately removed		(119,314,271)			(119,314,271)		
	Less FASB 106 Above if not separately removed		831,745				831,745	
283	Total		121,325,037	124,723,829	-	3,178,732	(6,577,523)	

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		9,018,052	1,019,535
5	Total			9,018,052	1,019,535
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.266) for a		9,018,052	1,019,535
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)	2,193,878		
2 Personal property			
3 City License	-		
4 State Excise	-		
Total Plant Related	2,193,878	30.2989%	664,721
Labor Related		***Wages & Salary Allocator***	
5 Federal FICA & Unemployment	1,456,506		
6 Unemployment	104,241		
Total Labor Related	1,560,747	9.0401%	141,094
Other Included		***Gross Plant Allocator***	
7 Miscellaneous	11,797		
Total Other Included	11,797	30.2989%	3,574
Total Included			809,389
Excluded			
8 State Franchise tax	(93,408)		
9 TEFA	19,587,596		
10 Use & Sales Tax	(881,511)		
11 Total "Other" Taxes (included on p. 263)	22,379,099		
12 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	22,379,099		
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)		832,609
2	Total Rent Revenues	(Sum Line 1)	832,609
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 877,752
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)		1,058,766
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)		1,137,222
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		5,554
11	Gross Revenue Credits	(Sum Lines 2-10)	3,911,903
12	Less line 17g		(590,262)
13	Total Revenue Credits		3,321,642

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.	838,163
17b	Costs associated with revenues in line 17a	342,360
17c	Net Revenues (17a - 17b)	495,803
17d	50% Share of Net Revenues (17c / 2)	247,902
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)	247,902
17g	Line 17f less line 17a	(590,262)
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.	8,896,063
19	Amount offset in line 4 above	61,326,083
20	Total Account 454, 456 and 456.1	74,134,049
21	Note 4: SECA revenues booked in Account 447.	7,628,037

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)	50,829,330
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
59	Rate Base		(Line 39 + 58)	368,742,404
	Long Term Interest			
100	Long Term Interest		p117.62c through 67c	65,824,409
101	Less LTD Interest on Securitization B (Note P)		Attachment 8	21,780,263
102	**Long Term Interest**		"(Line 100 - line 101)"	44,044,146
103	**Preferred Dividends**	enter positive	p118.29c	262,841
	Common Stock			
104	Proprietary Capital		p112.16c	649,380,739
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)	643,166,239
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,025,488,411
109	Less Loss on Reacquired Debt	enter negative	p111.81.c	-12,788,654
110	Plus Gain on Reacquired Debt	enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	1,548,604
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	-391,423,411
113	Total Long Term Debt		(Sum Lines Lines 108 to 112)	622,824,950
114	Preferred Stock		p112.3c	6,214,500
115	Common Stock		(Line 107)	643,166,239
116	**Total Capitalization**		(Sum Lines 113 to 115)	1,272,205,689
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)	0.0707
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)	0.0354
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)**	**0.0969**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**35,715,787**
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	-1,019,535
134	T/(1-T)		(Line 132)	69.05%
135	Net Plant Allocation Factor		(Line 18)	31.6650%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-545,760**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		15,659,303
138	**Total Income Taxes**			**15,113,543**

Atlantic City Electric 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	$ 34,907,238	34,907,238	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	9,018,052	9,018,052	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	1,040,283	1,040,283	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	48,740	48,740	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

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	4,985,454	782,029	4,203,425	"Transmission R/W - Carll's Corner"
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	Enter	Enter	Enter	

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	2,213,507,017	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	651,469,979	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	182,095,766	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	99873	99873	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	3,129,059	0	3,129,059	Transmission related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	3,129,059	0	3,129,059	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	63,088	-	63,088	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	63,088	-	63,088	None

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
149	Excluded Transmission Facilities	(Note M)	Attachment 5	-	General Description of the Facilities
	Instructions:			Enter $	None
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process				
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, 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

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	6,832,260	9.04%	617,646	
	Plant Related	2,130,147	30.30%	645,411	
	Other		0.00%	-	
	Total Transmission Related Reserves	8,962,406		1,263,058	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			9.040%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	9.040%	-	
	Prepayments	$	54,858,453	9.040%	4,959,285	
	Prepaid Pensions if not included in Prepayments	$	62,654,335	9.040%	5,664,044	
			117,512,788		10,623,329	
						Add more lines if necessary

Extraordinary Property Loss

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

Interest on Outstanding Network Credits Cost Support

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

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits 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.

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	2,706.6	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	$ 4,776,200	$ 4,206,278	$ 11,176,729	$ 11,422,465	$ 31,581,672
Security Services Administration	531,601	350,190	993,436	240,207	2,115,434
Purchasing, Storeroom & Materials Mgt	919,078	651,941	2,487,044	92,788	4,150,851
Vehicle Resource Management	927,590	651,080	717,229	20,800	2,316,699
General Services	2,508,024	1,236,672	2,036,503	891,824	6,673,023
Building Services	1,170,573	1,002,154	2,358,359	555,940	5,087,026
Real Estate	1,126,058	996,620	336,051	38,847	2,497,576
Corporate Insurance Administration	180,103	124,022	272,694	152,806	729,625
Claims Administration	594,597	550,445	1,346,080	-	2,491,122
Regulatory Affairs	3,638,374	3,135,445	5,884,208	27,180	12,685,207
Accounts Payable Accounting Services	591,850	440,696	500,847	222,724	1,756,117
Payroll Services	410,386	246,398	627,209	97,863	1,381,856
Asset & Project Accounting Services	528,719	434,792	1,403,906	355,773	2,723,190
Investor Relations	155,445	138,572	359,753	284,773	938,543
Shareholder Services	232,179	206,012	538,394	415,127	1,391,712
Financial Reporting	836,383	744,405	1,914,097	1,493,091	4,987,976
Sarbanes-Oxley Compliance	153,467	155,750	354,939	282,860	947,016
Investment Financial Management	309,277	284,564	623,004	511,886	1,728,731
Other Financial Services	4,751,222	3,951,602	6,244,083	6,209,663	21,156,570
Insurance Premiums & Claims	2,146,823	1,567,582	3,357,127	3,069,819	10,141,351
Cost of Benefits	13,342,891	8,411,214	19,826,849	7,519,685	49,100,639
Executive Compensation Services	79,333	71,356	182,639	152,071	485,399
Other Human Resources Services	4,653,174	2,818,636	6,309,870	4,100,477	17,882,157
Legal Services	2,495,233	2,391,093	4,766,020	1,140,122	10,792,468
Audit Services	1,156,972	727,079	1,478,923	782,490	4,145,464
Special Billing	580,006	621,015	1,127,265	28,989	2,357,275
Other Customer Care	34,879,364	34,292,030	10,358,342	62	79,529,798
Marketing Services	1,346,830	970,132	1,832,720	74,530	4,224,212
Information Technology	7,180,933	4,115,177	28,620,279	5,014,635	44,931,024
PHI Corporate Contributions	11,474	10,172	26,664	20,427	68,737
Federal Government Affairs	244,765	217,449	567,270	440,610	1,470,094
Other Corporate Communications	982,347	657,377	1,508,623	656,193	3,804,540
Environmental & Safety Services	1,541,344	1,076,227	2,396,773	646,793	5,661,137
System Operations Shared	2,539,144	1,797,936	6,336,254	221,411	10,894,745
Electric Maintenance Meter Shop	1,060,099	447,295	-	106	1,507,500
Other Delivery Services	27,546,136	17,753,626	38,170,556	45,097	83,515,415
Power Procurement	2,254,471	1,558,667	3,168,805	-	6,981,943
Management & Administration	44,065	(3,348)	-	7,972,371	8,013,088
Merchant Functions	709,640	-	-	14,804,766	15,514,406
Supply Engineering & Support	256,726	65,323	-	9,727,193	10,049,242
Internal Consulting Services	378,530	224,916	545,602	-	1,149,048
Interns	196,424	120,153	207,382	3,936	527,895
Building Services	8,276	82,562	3,929,060	107,118	4,127,016
Total	$ 129,976,126	$ 99,501,307	$ 174,891,588	$ 79,845,518	$ 484,214,539

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, 2009

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	78,743,283	96,399,563	(251,258)	174,891,588
2	Delmarva Power & Light Company	43,784,129	86,299,951	(107,954)	129,976,126
3	Atlantic City Electric	25,301,543	74,294,875	(95,111)	99,501,307
4	Conectiv Energy Supply, Inc.	19,621,924	5,681,603	(16,900)	25,286,627
5	Conectiv Delmarva Generation, Inc.	4,796,447	11,128,449	(25,158)	15,899,738
6	Pepco Energy Services, Inc.	4,282,527	9,656,596	(34,078)	13,905,045
7	Conectiv Atlantic Generation, LLC	2,910,261	4,176,667	(10,835)	7,076,093
8	Conectiv Bethlehem, LLC	1,583,483	2,244,563	(13,145)	3,814,901
9	Pepco Holdings, Inc.	1,136,131	3,258,951	(43,264)	4,351,818
10	Potomac Capital Investment Corporation	842,586	1,956,646	(23,052)	2,776,180
11	PHI Operating Services Company	796,675	1,329,406	(1,910)	2,124,171
12	Thermal Energy Limited Partnership	100,524	563,766	(3,188)	661,102
13	Conectiv Mid-Merit, LLC	1,791,382	108,302	(266)	1,899,418
14	Conectiv Thermal Systems	30,971	69,607	(487)	100,091
15	Atlantic Southern Properties	54,212	195,989	(671)	249,530
16	Conectiv Communications, Inc.	116	2,200	(5)	2,311
17	ATE Investments, Inc.	67	10,215	(155)	10,127
18	Atlantic City Electric Transition Funding, LLC	24,154	198,217	(4,552)	217,819
19	Conectiv Properties and Investments, Inc.	2,019	34,051	(51)	36,019
20	Conectiv Solutions LLC	4,124	12,654	(176)	16,602
21	Conectiv North East, LLC	138,701	8,198	(37)	146,862
22	Atlantic Generation, Inc.	318	1,799	(7)	2,110
23	DCTC-Burney, Inc.	414	57		471
24	Conectiv Services II, Inc.	21,299	63,382	(2)	84,679
25	Vineland General, Inc.	9,006			9,006
26	Vineland Limited, Inc.	346			346
27	ACE REIT, Inc.	9	62		71
28	Conectiv	25,199	4,348	(67)	29,480
29	Atlantic Thermal Operating Company	121	179,953	(559)	179,515
30	Conectiv Energy Holding Company	617	586,351	(7,301)	579,667
31	Conectiv Vineland Solar, LLC	379,665	5,885	(1)	385,549
32	Atlantic Jersey Thermal	131			131
33	Delta, LLC	5	34		39
34					
35					
36					
37					
38					
39					
40	Total	186,382,389	298,472,340	(640,190)	484,214,539

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)

64,571,317 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	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	-	-	-	
								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!	

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

$ 12,676,170 Input to Formula Line 21

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

65,798,896 — 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)

$ 65,798,896

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

75,280,553 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 $ 26,437,450 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	$870,745				11.5	10,013,568	-	-	-	834,464	-	-	-	
Feb	$1,019,694				10.5	10,706,787	-	-	-	892,232	-	-	-	
Mar	$7,779				9.5	73,901	-	-	-	6,158	-	-	-	
Apr	$850,896				8.5	7,232,616	-	-	-	602,718	-	-	-	
May	($21,863)				7.5	(163,973)	-	-	-	(13,664)	-	-	-	
Jun	$3,646,013				6.5	23,699,085	-	-	-	1,974,924	-	-	-	
Jul	$8,527,126				5.5	46,899,193	-	-	-	3,908,266	-	-	-	
Aug	$126,021				4.5	567,095	-	-	-	47,258	-	-	-	
Sep	$506,924				3.5	1,774,234	-	-	-	147,853	-	-	-	
Oct	$30,359				2.5	75,898	-	-	-	6,325	-	-	-	
Nov	$5,495,982				1.5	8,243,973	-	-	-	686,998	-	-	-	
Dec	$5,377,774				0.5	2,688,887	-	-	-	224,074	-	-	-	
Total	26,437,450	-	-	-		111,811,262	-	-	-	9,317,605	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										9,317,605	-	-	-	
								Input to Line 21 of Appendix A		9,317,605	-		-	9,317,605
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		7.77	#DIV/0!	#DIV/0!	#DIV/0!	

73,458,482 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	6,759,777				10.5	70,977,659	-	-	-	5,914,805	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	1,314,356				6.5	8,543,314	-	-	-	711,943	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	8,074,133	-	-	-		79,520,973	-	-	-	6,626,748	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										6,626,748	-	-	-	
75,971,191								Input to Line 21 of Appendix A		6,626,748	-		-	6,626,748
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		2.15	#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		
73,458,482	-	67,466,306	=	5,992,176

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	499,348	0.2800%	11.5	16,079	515,427
Jul	Year 1	499,348	0.2800%	10.5	14,681	514,029
Aug	Year 1	499,348	0.2800%	9.5	13,283	512,631
Sep	Year 1	499,348	0.2800%	8.5	11,884	511,233
Oct	Year 1	499,348	0.2800%	7.5	10,486	509,834
Nov	Year 1	499,348	0.2800%	6.5	9,088	508,436
Dec	Year 1	499,348	0.2800%	5.5	7,690	507,038
Jan	Year 2	499,348	0.2800%	4.5	6,292	505,640
Feb	Year 2	499,348	0.2800%	3.5	4,894	504,242
Mar	Year 2	499,348	0.2800%	2.5	3,495	502,843
Apr	Year 2	499,348	0.2800%	1.5	2,097	501,445
May	Year 2	499,348	0.2800%	0.5	699	500,047
Total		5,992,176				6,092,845

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	6,092,845	0.2800%	517,025	5,592,880
Jul	Year 2	5,592,880	0.2800%	517,025	5,091,514
Aug	Year 2	5,091,514	0.2800%	517,025	4,588,745
Sep	Year 2	4,588,745	0.2800%	517,025	4,084,569
Oct	Year 2	4,084,569	0.2800%	517,025	3,578,980
Nov	Year 2	3,578,980	0.2800%	517,025	3,071,976
Dec	Year 2	3,071,976	0.2800%	517,025	2,563,552
Jan	Year 3	2,563,552	0.2800%	517,025	2,053,705
Feb	Year 3	2,053,705	0.2800%	517,025	1,542,430
Mar	Year 3	1,542,430	0.2800%	517,025	1,029,724
Apr	Year 3	1,029,724	0.2800%	517,025	515,582
May	Year 3	515,582	0.2800%	517,025	(0)
Total with interest				6,204,303	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		6,204,303
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	75,971,191
Revenue Requirement for Year 3		82,175,494
		212,127

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

$ 82,175,494 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)

$ 82,175,494

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

Line		Formula Line		
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	12.6951%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	13.3591%
6	C		Line B less Line A	0.6640%
7	**FCR if a CIAC**			
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.5300%

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 FER incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.**

Line		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
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

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
13,232,044	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
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....	.....	.....	....	....	.....	.....	....

r specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmissio

B0210 Orchard-Below 500kV	B0277 Cumberland Sub:2nd Xfmr
Yes	Yes
35	35
No	No
150	150
0.11181521	0.126951108
0.122178477	0.136911687
18,572,212	6,759,777
530,635	193,136
7	2

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue		Total		Incentive Charged		Revenue Credit
17,820,480	530,635	17,289,845	2,463,902	6,759,777	160,947	6,598,830	1,068,487	$	9,473,662			$	9,473,662
17,820,480	530,635	17,289,845	2,643,082	6,759,777	160,947	6,598,830	1,139,692	$	9,952,286	$	9,952,286		
17,289,845	530,635	16,759,210	2,404,569	6,598,830	193,136	6,405,693	1,006,346	$	9,246,602			$	9,246,602
17,289,845	530,635	16,759,210	2,578,249	6,598,830	193,136	6,405,693	1,070,151	$	9,710,577	$	9,710,577		
16,759,210	530,635	16,228,576	2,345,236	6,405,693	193,136	6,212,557	981,827	$	9,019,541			$	9,019,541
16,759,210	530,635	16,228,576	2,513,417	6,405,693	193,136	6,212,557	1,043,708	$	9,468,867	$	9,468,867		
16,228,576	530,635	15,697,941	2,285,903	6,212,557	193,136	6,019,420	957,309	$	8,792,481			$	8,792,481
16,228,576	530,635	15,697,941	2,448,585	6,212,557	193,136	6,019,420	1,017,265	$	9,227,158	$	9,227,158		
15,697,941	530,635	15,167,306	2,226,570	6,019,420	193,136	5,826,284	932,790	$	8,565,420			$	8,565,420
15,697,941	530,635	15,167,306	2,383,753	6,019,420	193,136	5,826,284	990,823	$	8,985,448	$	8,985,448		
15,167,306	530,635	14,636,672	2,167,237	5,826,284	193,136	5,633,148	908,271	$	8,338,359			$	8,338,359
15,167,306	530,635	14,636,672	2,318,921	5,826,284	193,136	5,633,148	964,380	$	8,743,739	$	8,743,739		
14,636,672	530,635	14,106,037	2,107,904	5,633,148	193,136	5,440,011	883,752	$	8,111,299			$	8,111,299
14,636,672	530,635	14,106,037	2,254,089	5,633,148	193,136	5,440,011	937,938	$	8,502,030	$	8,502,030		
14,106,037	530,635	13,575,403	2,048,571	5,440,011	193,136	5,246,875	859,233	$	7,884,238			$	7,884,238
14,106,037	530,635	13,575,403	2,189,257	5,440,011	193,136	5,246,875	911,495	$	8,260,320	$	8,260,320		
13,575,403	530,635	13,044,768	1,989,238	5,246,875	193,136	5,053,738	834,714	$	7,657,178			$	7,657,178
13,575,403	530,635	13,044,768	2,124,425	5,246,875	193,136	5,053,738	885,052	$	8,018,611	$	8,018,611		
13,044,768	530,635	12,514,133	1,929,905	5,053,738	193,136	4,860,602	810,195	$	7,430,117			$	7,430,117
13,044,768	530,635	12,514,133	2,059,592	5,053,738	193,136	4,860,602	858,610	$	7,776,902	$	7,776,902		
12,514,133	530,635	11,983,499	1,870,572	4,860,602	193,136	4,667,465	785,676	$	7,203,056			$	7,203,056
12,514,133	530,635	11,983,499	1,994,760	4,860,602	193,136	4,667,465	832,167	$	7,535,192	$	7,535,192		
11,983,499	530,635	11,452,864	1,811,239	4,667,465	193,136	4,474,329	761,157	$	6,975,996			$	6,975,996
11,983,499	530,635	11,452,864	1,929,928	4,667,465	193,136	4,474,329	805,724	$	7,293,483	$	7,293,483		
11,452,864	530,635	10,922,229	1,751,906	4,474,329	193,136	4,281,192	736,639	$	6,748,935			$	6,748,935
11,452,864	530,635	10,922,229	1,865,096	4,474,329	193,136	4,281,192	779,282	$	7,051,773	$	7,051,773		
10,922,229	530,635	10,391,595	1,692,573	4,281,192	193,136	4,088,056	712,120	$	6,521,875			$	6,521,875
10,922,229	530,635	10,391,595	1,800,264	4,281,192	193,136	4,088,056	752,839	$	6,810,064	$	6,810,064		
10,391,595	530,635	9,860,960	1,633,240	4,088,056	193,136	3,894,919	687,601	$	6,294,814			$	6,294,814
10,391,595	530,635	9,860,960	1,735,432	4,088,056	193,136	3,894,919	726,396	$	6,568,355	$	6,568,355		
9,860,960	530,635	9,330,326	1,573,907	3,894,919	193,136	3,701,783	663,082	$	6,067,753			$	6,067,753
9,860,960	530,635	9,330,326	1,670,600	3,894,919	193,136	3,701,783	699,954	$	6,326,645	$	6,326,645		
9,330,326	530,635	8,799,691	1,514,574	3,701,783	193,136	3,508,646	638,563	$	5,840,693			$	5,840,693
9,330,326	530,635	8,799,691	1,605,767	3,701,783	193,136	3,508,646	673,511	$	6,084,936	$	6,084,936		
8,799,691	530,635	8,269,056	1,455,241	3,508,646	193,136	3,315,510	614,044	$	5,613,632			$	5,613,632
8,799,691	530,635	8,269,056	1,540,935	3,508,646	193,136	3,315,510	647,069	$	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**	21,780,263
	Capitalization	
112	**Less LTD on Securitization Bonds**	391,423,411

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2009 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 27 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Attachment 4d - PEPCO Formula Rate Update

Attachment 4d

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	2009
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21b	$ 5,479,690
2	Total Wages Expense		p354.28b	$ 56,032,805
3	Less A&G Wages Expense		p354.27b	$ 4,131,399
4	Total		(Line 2 - 3)	51,901,406
5	**Wages & Salary Allocator**		(Line 1 / 4)	**10.5579%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 5,453,293,162
7	Common Plant In Service - Electric		(Line 24)	0
8	Total Plant In Service		(Sum Lines 6 & 7)	5,453,293,162
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 2,391,483,735
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 84,407,124
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)	2,475,890,859
14	Net Plant		(Line 8 - 13)	2,977,402,303
15	Transmission Gross Plant		(Line 29 - Line 28)	826,780,655
16	**Gross Plant Allocator**		(Line 15 / 8)	**15.1611%**
17	Transmission Net Plant		(Line 39 - Line 28)	459,067,684
18	**Net Plant Allocator**		(Line 17 / 14)	**15.4184%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 782,158,543
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	6,500,037
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**788,658,580**
23	General & Intangible		p205.5.g & p207.99.g	361,076,858
24	Common Plant (Electric Only)	(Notes A & B)	p356	0
25	Total General & Common		(Line 23 + 24)	361,076,858
26	Wage & Salary Allocation Factor		(Line 5)	10.55788%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**38,122,074**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**826,780,655**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	340,974,662
31	Accumulated General Depreciation		p219.28.c 168,847,311	
32	Accumulated Intangible Amortization		(Line 10)	84,407,124
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)	253,254,435
36	Wage & Salary Allocation Factor		(Line 5)	10.55788%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**26,738,308**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**367,712,970**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**459,067,684**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-119,946,411
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	0
42	Net Plant Allocation Factor		(Line 18)	15.42%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-119,946,411**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**	(Note B)	p216.43.b as Shown on Attachment 6	26,098,819
	Transmission O&M Reserves			
44	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**-4,706,264**
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	41,836,069
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**41,836,069**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	2,330,151
48	Wage & Salary Allocation Factor		(Line 5)	10.56%
49	Total Transmission Allocated		(Line 47 * 48)	246,015
50	Transmission Materials & Supplies		p227.8c	3,825,267
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**4,071,282**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	36,022,489
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**4,502,811**
	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)	**-48,143,695**
59	**Rate Base**		(Line 39 + 58)	**410,923,989**

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b	24,124,369
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)	**24,124,369**
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	0
68	Total A&G			p323.197.b	116,780,756
69	Less Property Insurance Account 924			p323.185b	1,064,137
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	4,156,735
71	Less General Advertising Exp Account 930.1			p323.191b	143,894
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	0
73	Less EPRI Dues		(Note D)	p352-353	275,840
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)	111,140,150
75	Wage & Salary Allocation Factor			(Line 5)	10.5579%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)	**11,734,048**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	**0**
80	Property Insurance Account 924			p323.185b	1,064,137
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	1,064,137
83	Net Plant Allocation Factor			(Line 18)	15.42%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)	**164,073**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**	**36,022,489**

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	**16,428,484**
87	General Depreciation			p336.10b&c	13,885,030
88	Intangible Amortization		(Note A)	p336.1d&e	4,872,860
89	Total			(Line 87 + 88)	18,757,890
90	Wage & Salary Allocation Factor			(Line 5)	10.5579%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)	**1,980,436**
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)	10.5579%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)	**0**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**	**18,408,920**

Taxes Other than Income

98	**Taxes Other than Income**			Attachment 2	**7,003,083**
99	**Total Taxes Other than Income**			**(Line 98)**	**7,003,083**

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	98,243,260
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	98,243,260
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,435,611,577
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)	1,433,965,210
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,563,800,000
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-35,961,561
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	216,317
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	1,528,054,756
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,433,965,210
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,962,019,966
117	Debt %	Total Long Term Debt		(Line 113 / 116)	52%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0%
119	Common %	Common Stock		(Line 115 / 116)	48%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0643
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)	0.0332
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0547
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0879**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**36,109,089**

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	-1,793,412
134	T/(1-T)			(Line 132)	67.63%
135	Net Plant Allocation Factor			(Line 18)	15.4184%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-463,536**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**15,204,140**
138	**Total Income Taxes**			**(Line 136 + 137)**	**14,740,604**
REVENUE REQUIREMENT					
	Summary				
139	Net Property, Plant & Equipment			(Line 39)	459,067,684
140	Adjustment to Rate Base			(Line 58)	-48,143,695
141	**Rate Base**			(Line 59)	**410,923,989**
142	O&M			(Line 85)	36,022,489
143	Depreciation & Amortization			(Line 97)	18,408,920
144	Taxes Other than Income			(Line 99)	7,003,083
145	Investment Return			(Line 127)	36,109,089
146	Income Taxes			(Line 138)	14,740,604
147	**Gross Revenue Requirement**			**(Sum Lines 142 to 146)**	**112,284,186**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	782,158,543
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	782,158,543
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	112,284,186
153	**Adjusted Gross Revenue Requirement**			(Line 151 * 152)	**112,284,186**
	Revenue Credits & Interest on Network Credits				
154	**Revenue Credits**			Attachment 3	5,271,065
155	**Interest on Network Credits**		(Note N)	PJM Data	-
156	**Net Revenue Requirement**			**(Line 153 - 154 + 155)**	**107,013,121**
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	**107,013,121**
158	Net Transmission Plant			(Line 19 - 30)	**441,183,881**
159	Net Plant Carrying Charge			(Line 157 / 158)	**24.2559%**
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	**20.5322%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	**9.0064%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	**56,163,428**
163	Increased Return and Taxes			Attachment 4	**54,184,546**
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	**110,347,974**
165	Net Transmission Plant			(Line 19 - 30)	**441,183,881**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	**25.0118%**
167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 163 - 86) / 165	**21.2881%**
168	**Net Revenue Requirement**			(Line 156)	**107,013,121**
169	True-up amount			Attachment 6	**6,323,176**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	**692,138**
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)	**114,028,434**
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	**6,325**
174	Rate ($/MW-Year)			(Line 172 / 173)	**18,028**
175	**Network Service Rate ($/MW/Year)**			**(Line 174)**	**18,028**

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	(727,185,796)	(9,878,020)	
ADIT-283	0	(67,907,325)	(78,456,716)	
ADIT-190	0	33,481,002	45,926,259	
Subtotal	0	(761,612,118)	(42,408,477)	
Wages & Salary Allocator			10.5579%	
Gross Plant Allocator		15.1611%		
ADIT	0	(115,468,974)	(4,477,438)	(119,946,411)

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 (216,317)

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)	10,881,973				10,881,973	For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are deducted when paid. Affects company personnel across all functions.
Additional Rental Income	0				0	Rental of General Plant and therefore allocated on labor.
D. C. Gross Receipts Tax	0	0				Retail related
Avg. Payment Plan	0	0				The average payment plan allows customers to average their electric bills on a yearly basis and make 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 when the payments received exceed the income based on the meters read basis. Retail related
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.
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	7,013,432			7,013,432		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		Under the Tax Reform Act of 1986, taxpayers were required to switch from the reserve method for bad debts to the specific write-off method. The amounts previously accumulated in a reserve were required to be included in taxable income over a four year period. The reserve method is used for book purposes. Related to all revenues.
Excess Accrued Vacation Pay	1,439,168				1,439,168	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.
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	3,561,305			3,561,305		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	23,046,449			23,046,449		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		timing differences regardless of whether the difference is normalized or flowed-through. These
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	(3,142,350)	(3,142,350)				For book purposes, the gain on the divestiture of the generating assets to be shared with customers was expensed when the gain on the sale was recorded. For tax purposes, gain to be shared is deducted when paid. Generation related
Transition Costs	0	0				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	0	0				For book purposes, these taxes were accrued when the proposed tax was enacted by the PG County Council. Since Maryland counties are prohibited from enacting any tax without the authority of the state legislature, for tax purposes they are not deductible until the tax is affirmed. Related to both T & D.
MD Adjustment	(20,318)	(20,318)				This deferred tax balance relates to a Maryland refund that was received in 2007 relating to the sale of the Pepco plant. This amount was picked up on the DC return incorrectly.
Mirant Settlement	1,930,399	1,930,399				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 liability. For tax purposes, since the funds were received, a portion of the payment was treated as currently taxable.
Health Care Plans	571,755			571,755		Additions to the reserve for health insurance payments are deducted currently for book purposes but are deducted for tax purposes when they are paid. Affects company personnel across all functions.
Severance Pay/Other Comp/Incentive Bonus	321,021				321,021	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual. Affects company personnel across all functions.
Accrued Retired Executive Compensation	0				0	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.
Prepaid Interest	(667,018)				(667,018)	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-month rule" which allows taxpayers that meet the 12-month rule to currently deduct the amount, as long as the benefits does not extend beyond 12 months. The prepaid interest relates to the Life Insurance plans, that is why this is labor related.
SERP	(1,736,485)				(1,736,485)	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.
Contribution Carryforward	849,434			849,434		PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
Capital Loss Limitation	7,221	7,221				Capital losses are limited to the amount of capital gains.
FAS 106 OPEB Adjustment	30,910,290				30,910,290	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.
Miscellaneous	1,666,258	1,666,258				See the explanation for Account 190.
Federal/State NOL	27,519,539			23,037,111	4,482,428	PHI's consolidated return is in an NOL situation, therefore, they are carried forward until such time as PHI is in a taxable income position.
AMT	2,304,153			2,009,271	294,882	AMT related to 2006/2007.

	B	C	D	E	F	G
Subtotal - p234	106,456,223	441,209	0	60,088,755	45,926,259	
Less FASB 109 Above if not separately removed	26,607,753	0	0	26,607,753		
Less FASB 106 Above if not separately removed	0		0		0	
Total	79,848,470	441,209	0	33,481,002	45,926,259	
	(1)					

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

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

Ɔeferred 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	(477,678,432)			(477,678,432)		This amount represents the difference between the tax depreciation on assets place in service after 1974 as computed pursuant to the Internal Revenue Code and the book depreciation associated with all assets.
Depreciation (BG&E)/Gain On Sale Conemaugh	0	0				Generation related
Repair Allowance	(122,022,440)			(122,022,440)		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		For tax purposes, a portion of the proceeds from the disposition of property each year is allocated to 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	(278,458)			(278,458)		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)	5,246,643			5,246,643		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		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 assets.
Control Center - Depreciation/Amort	(94,191,509)			(94,191,509)		See the explanation for Account 190.
Removal Cost Adjustment	(44,664,149)			(44,664,149)		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				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.
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		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.
Normalization Adjustment	0			0		See the explanation for Account 190
Normalization-MD Case 8162	0			0		See the explanation for Account 191
Capitalized Interest	23,782,743			23,782,743		The Tax Reform Act of 1986 eliminated the current deduction for interest incurred during construction and required that it be capitalized and depreciated over the tax life of the asset. This deferred tax is due to the differences in the way AFUDC-debt is calculated versus the way interest must be calculated for tax purposes. Related to all plant.
AFUDC Debt	(3,538,135)			(3,538,135)		For book purposes, AFUDC is capitalized and depreciated. For tax purposes, AFUDC is not recognized. Related to all plant.
Capitalized Real Estate Taxes	(23,361)			(23,361)		For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Related to all plant.
Extraordinary Gain-Nova	(8,303,806)	(8,303,806)				This deferred tax balance relates to a prior Internal Revenue Service audit related to the sale of Pepco's northern Virginia sales territory and assets located therein. Retail related
Construction Per. Interest(Net)	264,333			264,333		For tax purposes some interest was required to be capitalized related to self constructed assets. For book purposes, AFUDC is used. Related to all plant.
FAS 109 Earnings Benefit 34/35%	0			0		See the explanation for Account 190.
FAS 109 - Flowthrough Items	(33,747,220)			(33,747,220)		See the explanation for Account 190.
FAS 109 - Normalization	0			0		See the explanation for Account 190.
FAS 109 - CCRF/AFUDC Equity	(35,494,291)			(35,494,291)		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	(127,753,512)			(127,753,512)		For book purposes, certain overhead costs are capitalized and depreciated over the life of the related asset. For tax purposes, these overheads are currently deducted. Related to all plant.
EUM Assets	6,253,612	6,253,612				This deferred tax balance relates to a prior Internal Revenue Service audit related to the depreciation of Energy Use Mgt. assets. Retail related
Reduction State Taxes	0			0		Related to all plant.
MD Subtraction (Adj Gain or Loss)	0			0		from 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		audit to be depreciated for tax purposes. Related to all spare parts.
DC Consolidated Adjustment	75,745			75,745		See the explanation for Account 190.
Casualty Losses	(25,547,629)			(25,547,629)		This deferred tax balance relates to the run out of the depreciation expense related to the 1998 casualty loss claim filed with the IRS. This item was previously included in depreciation above.
Control Center - Lease Payment	92,327,449			92,327,449		For book purposes, the rental payments on the control center are expensed during the current year. For tax purposes, control center is treated as if Pepco continues to own it. The rent expense is added back to book income, the assets are depreciated and interest expense is imputed and deducted. Sale/lease back of center used for control of T & D.
CIAC	92,677,207			92,677,207		Under the Tax Reform Act of 1986, post '86 CIAC must be included in income for tax purposes. Under IRS Notice 87-51, if CIAC are not grossed up, the deferred taxes must be included in rate base in order for the Company to be in compliance with the depreciation normalization provisions of the Internal Revenue Code. Related to both T & D plant.
Connection Fees	(1,083,498)	(1,083,498)				Connection fees are considered taxable income by the Internal Revenue Service and their costs are capitalized and depreciated for tax purposes. For book purposes, connection fees are excluded from income and from the depreciable cost of the assets as a contribution in aid of construction. Retail related.
Preliminary Survey Costs	69,908	69,908				For tax purposes, survey costs are to be capitalized under 263A and depreciated.
Conservation Costs (DSM)	(11,733,934)	(11,733,934)				DSM related. Retail related.
Pension Curtailment	3,496,753	3,496,753				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.
SFAS 121 Impairment Loss	859,870	859,870				Write down of Benning/Buzzard point plant to fair market value based on the SFAS 121 impairment test for book purposes. For tax purposes, an asset can not be written down for the loss. Generation related.
Capitalized A&G	489,863			489,863		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	1,073,629			1,073,629		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Capit'd Payroll & Use Tax	1,127,624			1,127,624		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Leased Vehicles	232,441			232,441		For tax purposes leased vehicles are capitalized and depreciated. For book purposes, the vehicles are treated as leases, with a monthly lease amount being calculated. For tax purposes, a portion of the monthly lease amount needs to be added back.
Control Center - Interest Expense	(66,636,872)			(66,636,872)		See the explanation for the control center transaction in Account 190.
FAS 109 - CCRF Equity	(15,743,143)	(15,743,143)				See the explanation for Account 190.
Capitalized Pension	17,851,027			17,851,027		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	(9,878,020)				(9,878,020)	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)	(832,270,955)	(25,965,629)	0	(796,427,306)	(9,878,020)	
Less FASB 109 Above if not separately removed	(84,984,654)	(15,743,143)	0	(69,241,511)	0	
Less FASB 106 Above if not separately removed	0					
Total	(747,286,301)	(10,222,485)	0	(727,185,796)	(9,878,020)	
	1					

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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Ɔeferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT-283	Total	Gas, Prod Or Other	Only Transmission	Plant	Labor	

		Related	Related	Related	Related	Justification
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		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.
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. Retail 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
OPEB Adj DC Order #10387	0				0	This deferred tax balance reflects the difference between the tax treatment of the OPEB costs and the manner in which the DC Commission ordered these costs to be recovered from customers. Retail related.
Bk Depr on Poll Bond Int	(113,620)	(113,620)				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				Underground 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	(216,317)	(216,317)				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.
Loss on Marketable Securities	(12,835,948)	(12,835,948)				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		Legal costs related to bond financing/leasehold costs 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. Related to all functions.
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.
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	17,215,024			17,215,024		See the explanation for Account 190.
FAS 109 - Earnings Effect - Nonoperating/Other	0	0				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.
FAS 109 - Flowthrough Items	(21,991,663)			(21,991,663)		See the explanation for Account 190.
Pension Plan Contribution	(140,101,280)			(61,644,564)	(78,456,716)	The company is allowed to deduct for tax purposes all payments made to fund the General Retirement Plan per ERISA. For book purposes pension plan contributions are governed by FAS 106. This timing difference represents the excess tax payment over book. Affects company personnel across all functions.
VA GRT Adj	0	0				Retail related.
SMECO Contract Termination	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.
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	(65,354)	(65,354)				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	(1,065,168)			(1,065,168)		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.
Regulatory Assets	(5,197,592)			(5,197,592)		When a regulatory asset is established, books credits income, which for tax purposes needs to be reversed along with the associated amortization.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(164,371,918)	(13,231,239)	0	(72,683,963)	(78,456,716)	
Less FASB 109 Above if not separately removed	(4,776,639)			(4,776,639)		
Less FASB 106 Above if not separately removed	-				-	
Total	(159,595,280)	(13,231,239)	-	(67,907,325)	(78,456,716)	
	0					

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) Workshee

ADITC-255

		Item	Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			

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)	$ 6,548,712	100%	$ 6,548,712
1a	Other Personal Property Tax (excluded)	$ 24,866,874	0%	$ -
2	Capital Stock Tax		15.1611%	$ -
3	Gross Premium (insurance) Tax		15.1611%	$ -
4	PURTA		15.1611%	$ -
5	Corp License		15.1611%	$ -
			15.1611%	$ -
Total Plant Related		31,415,586	6,548,712	
Labor Related			***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & state unemployment	4,303,621		
Total Labor Related		4,303,621	10.5579%	454,371
Other Included			***Gross Plant Allocator***	
7	Miscellaneous	0		
Total Other Included		0	15.1611%	0
Total Included				7,003,083

Currently Excluded

8	Franchise	0
9	kWhTax - State Gross Receipt (Excise Tax)	104,522,064
10	Electric environmental surcharge	2,240,328
11	Universal service fee	8,459,102
12	Montgomery County Fuel	93,542,511
13	PSC assessment	7,538,536
14	Real property (State, Municipal or Local)	9,364,220
15	DC Right of Way	24,686,600
16	Use & Sales Tax	2,336,684
17	FHUT	28,301
18	DC Ballpark	16,500
19	DC Reliable Energy Trust Fund	18,434,048
20	Misc. Other	0
21	Total "Other" Taxes (included on p. 263)	306,888,101
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	306,888,101
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	$ 565,301,958
Distribution	$ 2,069,014,639
General	$ 157,155,980
Total T,D&Genl	$ 2,791,472,577
Plant ratios by Jurisdiction	
Transmission Ratio	0.20251030
Distribution ratio	0.74119110
General Ratio	0.05629859
	1.00000000
Property Taxes	$ 31,415,586
Transmission Property Tax	$ 6,361,980
Distribution Property tax	$ 23,284,953
General Property Tax	$ 1,768,653
Total check	$ 31,415,586
Allocation of General to Transmission	
General Property Tax	$ 1,768,653
Trans Labor Ratio	0.105578835
Trans General	186,732

Total Transmission Property Taxes	
Transmission	$ 6,361,980
General 186,732	$
Total Transmission Property Taxes	$ 6,548,712

Potomac Electric Power Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		10,130,450
2	Total Rent Revenues	(Sum Lines 1)	10,130,450
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 597,150
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)		1,650,050
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)	12,377,650
12	Less line 17g		(7,106,585)
13	Total Revenue Credits		5,271,065

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.	10,130,450
17b	Costs associated with revenues in line 17a	4,082,720
17c	Net Revenues (17a - 17b)	6,047,730
17d	50% Share of Net Revenues (17c / 2)	3,023,865
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	3,023,865
17g	Line 17f less line 17a	(7,106,585)
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.	39,749,634
19	Amount offset in line 4 above	94,514,308
20	Total Account 454, 456 and 456.1	146,641,592
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)	54,184,546
B	100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base		(Line 39 + 58)	410,923,989
	Long Term Interest			
100	**Long Term Interest**		p117.62c through 67c	98,243,260
101	Less LTD Interest on Securitization E (Note P)		Attachment 8	0
102	Long Term Interest		"(Line 100 - line 101)"	98,243,260
103	Preferred Dividends	enter positive	p118.29c	0
	Common Stock			
104	Proprietary Capital		p112.16c	1,435,611,577
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)	1,433,965,210
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,563,800,000
109	Less Loss on Reacquired Debt	enter negative	p111.81c	-35,961,561
110	Plus Gain on Reacquired Debt	enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	216,317
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
113	Total Long Term Debt		(Sum Lines 108 to 112)	1,528,054,756
114	Preferred Stock		p112.3c	0
115	Common Stock		(Line 107)	1,433,965,210
116	Total Capitalization		(Sum Lines 113 to 115)	2,962,019,966
117	Debt %	Total Long Term Debt	(Line 113 / 116)	52%
118	Preferred %	Preferred Stock	(Line 114 / 116)	0%
119	Common %	Common Stock	(Line 115 / 116)	48%
120	Debt Cost	Total Long Term Debt	(Line 102 / 113)	0.0643
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)	0.0332
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock	(Line 119 * 122)	0.0595
126	Total Return (R)		**(Sum Lines 123 to 125)**	**0.0927**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**38,098,443**

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	(1,793,412)
134	T/(1-T)		(Line 132)	68%
135	Net Plant Allocation Factor		(Line 18)	15.4184%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-463,536**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		16,549,639
138	**Total Income Taxes**			**16,086,103**

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	$ 84,407,124	84,407,124	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	8,237,184	8,237,184	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 2,330,151	2,330,151	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	$ 4,872,860	4,872,860	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	$ 5,453,293,162	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 782,158,543	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	340,974,662	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	117291	117291	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	$ 4,156,735	0	4,156,735	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,156,735	0	4,156,735	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	143,894	-	143,894	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)	8.1561%	8.25%	9.975%	Enter %	Enter %	Enter %	Apportioned: MD 4.585%, DC 3.5711

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	143,894	0	143,894	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					
					Or	
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			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	40,229,606	10.56%	4,247,395	
	Plant Related	3,026,616	15.16%	458,869	
	Other		0.00%	-	
	Total Transmission Related Reserves	43,256,222		4,706,264	

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			10.558%		
Pension Liabilities, if any, in Account 242		-	10.558%	-	
Prepayments 100,745,104	$		10.558%	10,636,551	
Prepaid Pensions if not included in Prepayments	$	295,509,206	10.558%	31,199,518	
		396,254,310	10.56%	41,836,069	

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	6,325.0	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)

84,889,354 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			4,978,597		11.5	-	-	57,253,869	-	-	-	4,771,156	-	
Feb			3,833,333		10.5	-	-	40,250,000	-	-	-	3,354,167	-	
Mar			3,833,333		9.5	-	-	36,416,667	-	-	-	3,034,722	-	
Apr			3,833,333		8.5	-	-	32,583,333	-	-	-	2,715,278	-	
May			3,833,333		7.5	-	-	28,750,000	-	-	-	2,395,833	-	
Jun			3,833,333		6.5	-	-	24,916,667	-	-	-	2,076,389	-	
Jul	33,558,380		3,833,333		5.5	184,571,090	-	21,083,333	-	15,380,924	-	1,756,944	-	
Aug			3,833,333		4.5	-	-	17,250,000	-	-	-	1,437,500	-	
Sep			3,833,333		3.5	-	-	13,416,667	-	-	-	1,118,056	-	
Oct			3,833,333		2.5	-	-	9,583,333	-	-	-	798,611	-	
Nov			3,833,333		1.5	-	-	5,750,000	-	-	-	479,167	-	
Dec			3,833,333		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	-	
								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!	

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

$ 15,380,924 Input to Formula Line 21

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

$ 89,310,733 — 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)

$ 89,310,733

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

103,922,602 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 $ 59,668,217 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		1,683,017		11.5	-	-	19,354,696	-	-	-	1,612,891	-	
Feb	$552,055		734,662		10.5	5,796,578	-	7,713,951	-	483,048	-	642,829	-	
Mar	($13,838)		1,993,965		9.5	(131,461)	-	18,942,668	-	(10,955)	-	1,578,556	-	
Apr	$44,311		265,889		8.5	376,644	-	2,260,057	-	31,387	-	188,338	-	
May	$491,589		277,218		7.5	3,686,918	-	2,079,135	-	307,243	-	173,261	-	
Jun	($35,796)		687,543		6.5	(232,674)	-	4,469,030	-	(19,390)	-	372,419	-	
Jul	$327,396		749,179		5.5	1,800,678	-	4,120,485	-	150,057	-	343,374	-	
Aug	($486)		1,798,470		4.5	(2,187)	-	8,093,115	-	(182)	-	674,426	-	
Sep	$44,369,439		2,152,580		3.5	155,293,037	-	7,534,030	-	12,941,086	-	627,836	-	
Oct	$1,955,959		4,123,926		2.5	4,889,898	-	10,309,815	-	407,491	-	859,151	-	
Nov	$652,668		2,862,805		1.5	979,002	-	4,294,208	-	81,584	-	357,851	-	
Dec	$11,324,920		5,846,905		0.5	5,662,460	-	2,923,453	-	471,872	-	243,621	-	
Total	59,668,217	-	23,176,159	-		178,118,891	-	-	-	14,843,241	-	7,674,553	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										14,843,241	-	7,674,553	-	
								Input to Line 21 of Appendix A		14,843,241	-		-	14,843,241
								Input to Line 43a of Appendix A				7,674,553		7,674,553
								Month In Service or Month for CWIP		9.01	#DIV/0!	8.03	#DIV/0!	

100,097,363 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			25060159		11.5	-	-	288,191,829	-	-	-	24,015,986	-	
Feb			827000		10.5	-	-	8,683,500	-	-	-	723,625	-	
Mar			794000		9.5	-	-	7,543,000	-	-	-	628,583	-	
Apr			-1341000		8.5	-	-	(11,398,500)	-	-	-	(949,875)	-	
May			616000		7.5	-	-	4,620,000	-	-	-	385,000	-	
Jun	12,000,069		616000		6.5	78,000,449	-	4,004,000	-	6,500,037	-	333,667	-	
Jul			616000		5.5	-	-	3,388,000	-	-	-	282,333	-	
Aug			616000		4.5	-	-	2,772,000	-	-	-	231,000	-	
Sep			616000		3.5	-	-	2,156,000	-	-	-	179,667	-	
Oct			716000		2.5	-	-	1,790,000	-	-	-	149,167	-	
Nov			716000		1.5	-	-	1,074,000	-	-	-	89,500	-	
Dec			724000		0.5	-	-	362,000	-	-	-	30,167	-	
Total	12,000,069	-	30,576,159	-		78,000,449	-	-	-	6,500,037	-	26,098,819	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										6,500,037	-	26,098,819	-	
107,705,258								Input to Line 21 of Appendix A		6,500,037	-		-	6,500,037
								Input to Line 43a of Appendix A				26,098,819		26,098,819
								Month In Service or Month for CWIP		5.50	#DIV/0!	1.76	#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		
100,097,363	-	93,990,378	=	6,106,985

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	508,915	0.2800%	11.5	16,387	525,302
Jul	Year 1	508,915	0.2800%	10.5	14,962	523,878
Aug	Year 1	508,915	0.2800%	9.5	13,537	522,453
Sep	Year 1	508,915	0.2800%	8.5	12,112	521,028
Oct	Year 1	508,915	0.2800%	7.5	10,687	519,603
Nov	Year 1	508,915	0.2800%	6.5	9,262	518,178
Dec	Year 1	508,915	0.2800%	5.5	7,837	516,753
Jan	Year 2	508,915	0.2800%	4.5	6,412	515,328
Feb	Year 2	508,915	0.2800%	3.5	4,987	513,903
Mar	Year 2	508,915	0.2800%	2.5	3,562	512,478
Apr	Year 2	508,915	0.2800%	1.5	2,137	511,053
May	Year 2	508,915	0.2800%	0.5	712	509,628
Total		6,106,985				6,209,582

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	6,209,582	0.2800%	526,931	5,700,038
Jul	Year 2	5,700,038	0.2800%	526,931	5,189,067
Aug	Year 2	5,189,067	0.2800%	526,931	4,676,665
Sep	Year 2	4,676,665	0.2800%	526,931	4,162,828
Oct	Year 2	4,162,828	0.2800%	526,931	3,647,552
Nov	Year 2	3,647,552	0.2800%	526,931	3,130,834
Dec	Year 2	3,130,834	0.2800%	526,931	2,612,669
Jan	Year 3	2,612,669	0.2800%	526,931	2,093,053
Feb	Year 3	2,093,053	0.2800%	526,931	1,571,983
Mar	Year 3	1,571,983	0.2800%	526,931	1,049,453
Apr	Year 3	1,049,453	0.2800%	526,931	525,460
May	Year 3	525,460	0.2800%	526,931	(0)
Total with interest				6,323,176	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		6,323,176
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	107,705,258
Revenue Requirement for Year 3		114,028,434

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

$ 114,028,434 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)

$ 114,028,434

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		
4	A	160	Net Plant Carrying Charge without Depreciation	20.5322%
5	B	167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	21.2881%
6	C		Line B less Line A	0.7559%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	9.0064%

9 **The FCR resulting from Formula in a given year is used for that year only.**

10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%,**

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		20.5322%		19.6221%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		21.6660%		20.6963%
18	Columns A, B or C from Attachment 6	Investment		30,576,159	may be weighted average of small projects	33,558,380
19	Line 18 divided by line 13	Annual Depreciation Exp		873,605		958,811
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		1.76		6.50

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
25	Base FCR	2010	30,576,159	-	30,576,159	6,277,950	33,118,925	958,811	32,160,114	7,269,315	$ 13,547,265		$ 13,547,265
26	W Increased ROE	2010	30,576,159	-	30,576,159	6,624,632	33,118,925	958,811	32,160,114	7,614,771	$ 14,239,403	$ 14,239,403	
27	Base FCR	2011	30,576,159	-	30,576,159	6,277,950	32,160,114	958,811	31,201,303	7,081,176	$ 13,359,126		$ 13,359,126
28	W Increased ROE	2011	30,576,159	-	30,576,159	6,624,632	32,160,114	958,811	31,201,303	7,416,333	$ 14,040,964	$ 14,040,964	
29	Base FCR	2012	30,576,159	-	30,576,159	6,277,950	31,201,303	958,811	30,242,492	6,893,037	$ 13,170,987		$ 13,170,987
30	W Increased ROE	2012	30,576,159	-	30,576,159	6,624,632	31,201,303	958,811	30,242,492	7,217,894	$ 13,842,526	$ 13,842,526	
31	Base FCR	2013	30,576,159	-	30,576,159	6,277,950	30,242,492	958,811	29,283,682	6,704,898	$ 12,982,847		$ 12,982,847
32	W Increased ROE	2013	30,576,159	-	30,576,159	6,624,632	30,242,492	958,811	29,283,682	7,019,455	$ 13,644,087	$ 13,644,087	
33	Base FCR	2014	30,576,159	-	30,576,159	6,277,950	29,283,682	958,811	28,324,871	6,516,758	$ 12,794,708		$ 12,794,708
34	W Increased ROE	2014	30,576,159	-	30,576,159	6,624,632	29,283,682	958,811	28,324,871	6,821,017	$ 13,445,649	$ 13,445,649	
35	Base FCR	2015	30,576,159	-	30,576,159	6,277,950	28,324,871	958,811	27,366,060	6,328,619	$ 12,606,569		$ 12,606,569
36	W Increased ROE	2015	30,576,159	-	30,576,159	6,624,632	28,324,871	958,811	27,366,060	6,622,578	$ 13,247,210	$ 13,247,210	
37	Base FCR	2016	30,576,159	-	30,576,159	6,277,950	27,366,060	958,811	26,407,249	6,140,480	$ 12,418,430		$ 12,418,430
38	W Increased ROE	2016	30,576,159	-	30,576,159	6,624,632	27,366,060	958,811	26,407,249	6,424,140	$ 13,048,772	$ 13,048,772	
39	Base FCR	2017	30,576,159	-	30,576,159	6,277,950	26,407,249	958,811	25,448,438	5,952,340	$ 12,230,290		$ 12,230,290
40	W Increased ROE	2017	30,576,159	-	30,576,159	6,624,632	26,407,249	958,811	25,448,438	6,225,701	$ 12,850,333	$ 12,850,333	
41	Base FCR	2018	30,576,159	-	30,576,159	6,277,950	25,448,438	958,811	24,489,627	5,764,201	$ 12,042,151		$ 12,042,151
42	W Increased ROE	2018	30,576,159	-	30,576,159	6,624,632	25,448,438	958,811	24,489,627	6,027,263	$ 12,651,894	$ 12,651,894	
43	Base FCR	2019	30,576,159	-	30,576,159	6,277,950	24,489,627	958,811	23,530,816	5,576,062	$ 11,854,012		$ 11,854,012
44	W Increased ROE	2019	30,576,159	-	30,576,159	6,624,632	24,489,627	958,811	23,530,816	5,828,824	$ 12,453,456	$ 12,453,456	
45	Base FCR	2020	30,576,159	-	30,576,159	6,277,950	23,530,816	958,811	22,572,006	5,387,923	$ 11,665,872		$ 11,665,872
46	W Increased ROE	2020	30,576,159	-	30,576,159	6,624,632	23,530,816	958,811	22,572,006	5,630,386	$ 12,255,017	$ 12,255,017	
47	Base FCR	2021	30,576,159	-	30,576,159	6,277,950	22,572,006	958,811	21,613,195	5,199,783	$ 11,477,733		$ 11,477,733
48	W Increased ROE	2021	30,576,159	-	30,576,159	6,624,632	22,572,006	958,811	21,613,195	5,431,947	$ 12,056,579	$ 12,056,579	
49	Base FCR	2022	30,576,159	-	30,576,159	6,277,950	21,613,195	958,811	20,654,384	5,011,644	$ 11,289,594		$ 11,289,594
50	W Increased ROE	2022	30,576,159	-	30,576,159	6,624,632	21,613,195	958,811	20,654,384	5,233,508	$ 11,858,140	$ 11,858,140	
51	Base FCR	2023	30,576,159	-	30,576,159	6,277,950	20,654,384	958,811	19,695,573	4,823,505	$ 11,101,455		$ 11,101,455
52	W Increased ROE	2023	30,576,159	-	30,576,159	6,624,632	20,654,384	958,811	19,695,573	5,035,070	$ 11,659,702	$ 11,659,702	
53	Base FCR	2024	30,576,159	-	30,576,159	6,277,950	19,695,573	958,811	18,736,762	4,635,366	$ 10,913,315		$ 10,913,315
54	W Increased ROE	2024	30,576,159	-	30,576,159	6,624,632	19,695,573	958,811	18,736,762	4,836,631	$ 11,461,263	$ 11,461,263	
55	Base FCR	2025	30,576,159	-	30,576,159	6,277,950	18,736,762	958,811	17,777,951	4,447,226	$ 10,725,176		$ 10,725,176
56	W Increased ROE	2025	30,576,159	-	30,576,159	6,624,632	18,736,762	958,811	17,777,951	4,638,193	$ 11,262,824	$ 11,262,824	
57	Base FCR	2026	30,576,159	-	30,576,159	6,277,950	17,777,951	958,811	16,819,140	4,259,087	$ 10,537,037		$ 10,537,037
58	W Increased ROE	2026	30,576,159	-	30,576,159	6,624,632	17,777,951	958,811	16,819,140	4,439,754	$ 11,064,386	$ 11,064,386	
59	Base FCR	2027	30,576,159	-	30,576,159	6,277,950	16,819,140	958,811	15,860,330	4,070,948	$ 10,348,898		$ 10,348,898
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												$ 236,515,615	$ 231,388,068

Potomac Electric Power Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4e - PPL Formula Update

Attachment 4e

ATTACHMENT H-8G

PPL Electric Utilities Corporation

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	2009 Data
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	9,082,458
2	Total Wages Expense		p354.28.b	90,520,382
3	Less A&G Wages Expense		p354.27.b	3,749,631
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	86,770,751
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**10.4672%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g	5,379,094,065
7	Accumulated Depreciation (Total Electric Plant)	(Note J)	p219.29.c	2,081,339,266
8	Accumulated Amortization	(Note A)	p200.21.c	16,949,218
9	Total Accumulated Depreciation		(Line 7 + 8)	2,098,288,484
10	Net Plant		(Line 6 - Line 9)	3,280,805,581
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 25 - Line 24)	1,253,238,499
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**23.2983%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 33 - Line 24)	738,413,638
14	**Net Plant Allocator**		(Line 13 / Line 10)	**22.5071%**
	Plant Calculations			
	Plant In Service			
15	Transmission Plant In Service	(Note B)	p207.58.g	1,181,764,806
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	15,322,650
18	**Total Transmission Plant**		(Line 15 - Line 16 + Line 17)	**1,197,087,456**
19	General		p207.99.g	497,780,433
20	Intangible		p205.5.g	38,667,760
21	Total General and Intangible Plant		(Line 19 + Line 20)	536,448,193
22	Wage & Salary Allocator		(Line 5)	10.4672%
23	**Total General and Intangible Functionalized to Transmission**		(Line 21 * Line 22)	**56,151,043**
24	**Land Held for Future Use**	(Note C) (Note P)	Attachment 5	**30,157,478**
25	**Total Plant In Rate Base**		**(Line 18 + Line 23 + Line 24)**	**1,283,395,977**
	Accumulated Depreciation			
26	Transmission Accumulated Depreciation	(Note J)	p219.25.c	**494,865,329**
27	Accumulated General Depreciation	(Note J)	p219.28.c 173,737,442	
28	Accumulated Amortization		(Line 8)	16,949,218
29	Total Accumulated Depreciation		(Line 27 + 28)	190,686,660
30	Wage & Salary Allocator		(Line 5)	10.4672%
31	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 29 * Line 30)	19,959,532
32	**Total Accumulated Depreciation**		**(Sum Lines 26 + 31)**	**514,824,861**
33	**Total Net Property, Plant & Equipment**		**(Line 25 - Line 32)**	**768,571,116**

Line	Description	Note	Source	Amount
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
34	**ADIT net of FASB 106 and 109**		Attachment 1	**-67,508,635**
	CWIP for Incentive Transmission Projects			
35	CWIP Balances for Current Rate Year	(Note H)	Attachment 6	**34,170,663**
	Prepayments			
36	Prepayments	(Note A) (Note O)	Attachment 5	**2,260,619**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	p227.16.c	2,617,108
38	Wage & Salary Allocator		(Line 5)	10.4672%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	273,938
40	Transmission Materials & Supplies		p227.8.c	11,772,128
41	**Total Materials & Supplies Allocated to Transmission**		(Line 39 + Line 40)	**12,046,066**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 70)	45,503,296
43	1/8th Rule		1/8	12.5%
44	**Total Cash Working Capital Allocated to Transmission**		(Line 42 * Line 43)	**5,687,912**
45	**Total Adjustment to Rate Base**		(Lines 34 + 35 + 36 + 41 + 44)	**-13,343,375**
46	**Rate Base**		(Line 33 + Line 45)	**755,227,740**
	Operations & Maintenance Expense			
	Transmission O&M			
47	Transmission O&M		Attachment 5	164,886,059
48	Less Account 565		Attachment 5	136,881,044
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)	**28,005,015**
	Allocated Administrative & General Expenses			
51	Total A&G		323.197b	160,377,268
52	Less: Administrative & General Expenses on Securitization Bonds	(Note O)	Attachment 8	-22,142
53	Plus: Fixed PBOP expense	(Note J)	Attachment 5	10,028,618
54	Less: Actual PBOP expense		Attachment 5	10,547,352
55	Less Property Insurance Account 924		p323.185.b	6,183,066
56	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	5,075,146
57	Less General Advertising Exp Account 930.1		p323.191.b	0
58	Less EPRI Dues	(Note D)	p352 & 353	156,459
59	Administrative & General Expenses		Sum (Lines 51 + 53) - Line 52 - Sum (Lines 54 to 58)	148,466,005
60	Wage & Salary Allocator		(Line 5)	10.4672%
61	**Administrative & General Expenses Allocated to Transmission**		(Line 59 * Line 60)	**15,540,217**
	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	8,699,771
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 924 and 930.1 - General		(Line 65 + Line 66)	8,699,771
68	Net Plant Allocator		(Line 14)	22.5071%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**1,958,065**
70	**Total Transmission O&M**		**(Lines 50 + 61 + 64 + 69)**	**45,503,296**

Depreciation & Amortization Expense

Line	Description		Note	Source	Amount
	Depreciation Expense				
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	**19,772,965**
72	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	15,657,077
73	Intangible Amortization		(Note A)	p336.1.d&e	5,730,601
74	Total			(Line 72 + Line 73)	21,387,678
75	Wage & Salary Allocator			(Line 5)	10.4672%
76	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 74 * Line 75)	**2,238,689**
77	**Total Transmission Depreciation & Amortization**			**(Lines 71 + 76)**	**22,011,654**

Taxes Other than Income Taxes

Line	Description		Note	Source	Amount
78	**Taxes Other than Income Taxes**			Attachment 2	**2,627,907**
79	**Total Taxes Other than Income Taxes**			**(Line 78)**	**2,627,907**

Return \ Capitalization Calculations

Line	Description		Note	Source	Amount
	Long Term Interest				
80	Long Term Interest			p117.62.c through 66.c	110,996,893
81	Less LTD Interest on Securitization Bonds		(Note O)	Attachment 8	0
82	**Long Term Interest**			(Line 80 - Line 81)	**110,996,893**
83	**Preferred Dividends**		enter positive	p118.29.c	**18,069,981**
	Common Stock				
84	Proprietary Capital			p112.16.c	1,894,686,318
85	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	50,604
86	Less Preferred Stock			(Line 94)	300,518,900
87	Less Account 216.1			p112.12.c	2,518,732
88	**Common Stock**			(Line 84 - 85 - 86 - 87)	**1,591,598,082**
	Capitalization				
89	Long Term Debt			p112.18.c, 19.c & 21.c	1,474,040,000
90	Less Loss on Reacquired Debt			p111.81.c	33,014,572
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)	1,441,025,428
94	Preferred Stock			p112.3.c	300,518,900
95	Common Stock			(Line 88)	1,591,598,082
96	**Total Capitalization**			(Sum Lines 93 to 95)	**3,333,142,410**
97	Debt %	Total Long Term Debt		(Line 93 / Line 96)	43.2%
98	Preferred %	Preferred Stock		(Line 94 / Line 96)	9.0%
99	Common %	Common Stock		(Line 95 / Line 96)	47.8%
100	Debt Cost	Total Long Term Debt		(Line 82 / Line 93)	0.0770
101	Preferred Cost	Preferred Stock		(Line 83 / Line 94)	0.0601
102	Common Cost	Common Stock	(Note J)	Fixed	0.1168
103	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * Line 100)	0.0333
104	Weighted Cost of Preferred	Preferred Stock		(Line 98 * Line 101)	0.0054
105	Weighted Cost of Common	Common Stock		(Line 99 * Line 102)	0.0558
106	**Rate of Return on Rate Base (ROR)**			(Sum Lines 103 to 105)	**0.0945**
107	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 106)**	**71,365,299**

Composite Income Taxes				
	Income Tax Rates			
108	FIT=Federal Income Tax Rate	(Note I)		35.00%
109	SIT=State Income Tax Rate or Composite			9.99%
110	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
111	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%
112	T / (1-T)			70.92%
	ITC Adjustment			
113	Amortized Investment Tax Credit - Transmission Related		Attachment 5	-548,000
114	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 113 * (1 / (1 - Line 111))	**-936,648**
115	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 112 * Line 107 * (1- (Line 103 / Line 106))]	**32,776,563**
116	**Total Income Taxes**		**(Line 114 + Line 115)**	**31,839,915**
Revenue Requirement				
	Summary			
117	Net Property, Plant & Equipment		(Line 33)	768,571,116
118	Total Adjustment to Rate Base		(Line 45)	-13,343,375
119	Rate Base		(Line 46)	755,227,740
120	Total Transmission O&M		(Line 70)	45,503,296
121	Total Transmission Depreciation & Amortization		(Line 77)	22,011,654
122	Taxes Other than Income		(Line 79)	2,627,907
123	Investment Return		(Line 107)	71,365,299
124	Income Taxes		(Line 116)	31,839,915
125	**Gross Revenue Requirement**		**(Sum Lines 120 to 124)**	**173,348,071**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Transmission Plant In Service		(Line 15)	1,181,764,806
127	Excluded Transmission Facilities	(Note M)	Attachment 5	0
128	Included Transmission Facilities		(Line 126 - Line 127)	1,181,764,806
129	Inclusion Ratio		(Line 128 / Line 126)	100.00%
130	Gross Revenue Requirement		(Line 125)	173,348,071
131	**Adjusted Gross Revenue Requirement**		(Line 129 * Line 130)	**173,348,071**
	Revenue Credits			
132	**Revenue Credits**		Attachment 3	**12,952,766**
133	**Net Revenue Requirement**		**(Line 131 - Line 132)**	**160,395,305**
	Net Plant Carrying Charge			
134	Gross Revenue Requirement		(Line 130)	**173,348,071**
135	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**736,392,790**
136	Net Plant Carrying Charge		(Line 134 / Line 135)	**23.5402%**
137	Net Plant Carrying Charge without Depreciation		(Line 134 - Line 71) / Line 135	**20.8551%**
138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 134 - Line 71 - Line 107 - Line 116) / Line 135	**6.8401%**
	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)	**70,142,857**
140	Increased Return and Taxes		Attachment 4	**109,369,082**
141	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 139 + Line 140)	**179,511,939**
142	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**736,392,790**
143	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 141 / Line 142)	**24.3772%**
144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 141 - Line 71) / Line 142	**21.6921%**
145	**Net Revenue Requirement**		(Line 133)	**160,395,305**
146	True-up amount		Attachment 6	**17,485,975**
147	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**-**
148	**Net Zonal Revenue Requirement**		(Line 145 + 146 + 147)	**177,881,280**
	Network Zonal Service Rate			
149	1 CP Peak	(Note L)	PJM Data	**7,608.7**
150	Rate ($/MW-Year)		(Line 148 / 149)	**$ 23,379**
151	**Network Service Rate ($/MW/Year)**		**(Line 150)**	**$ 23,379**

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.

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	(80,195,198)	0	(39,481,993)		From Acct. 282 total, below
ADIT-283	(2,059,865)	(13,698,900)	(559,255)		From Acct. 283 total, below
ADIT-190	21,519,517	0	4,789,504		From Acct. 190 total, below
Subtotal	(60,735,546)	(13,698,900)	(35,251,744)		Sum lines 1 through 3
Wages & Salary Allocator			10.4672%		
Net Plant Allocator		22.5071%			
ADIT	(60,735,546)	(3,083,223)	(3,689,866)	(67,508,635)	Sum Cols. D, E, F; Enter as negative Appendix A, line 42.
	row 4	row 5 * row 4	row 5 * row 4		

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

A *ADIT-190*	B *Total*	C *Gas, Prod, Dist Or Other Related*	D *Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Account 190						
Accumulated Deferred Investment Tax Credits (Non-Transmission)	2,444,430	2,444,430				Basis difference between book plant and tax plant basis related to investment tax credits on distribution property
Accumulated Deferred Investment Tax Credits (Transmission)	885,499		885,499			Basis difference between book plant and tax plant basis related to investment tax credits on transmissi property
Regulatory Liability - Income Taxes Related to ITC (Non-Tx)	1,733,614	1,733,614				Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on distribution property
Regulatory Liability - Income Taxes Related to ITC (Tx)	628,005		628,005			Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on transmission property
Contributions in Aid of Construction (Non-Tx)	76,958,862	76,958,862				Distribution related income that is taxable for tax return purposes, but recorded as a reduction to plant book purposes.
Contributions in Aid of Construction (Tx-related)	21,519,517		21,519,517			Transmission related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Pensions and Post-Retirement	135,988,567	135,988,567				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes
Bad Debts	8,806,999	8,806,999				Retail related book expense not deductible for tax return purposes
Vacation Pay	4,416,009				4,416,009	Book expense not deductible for tax return purposes - labor related to all functions
Taxes Other Than Income Taxes	6,799,918	6,799,918				Book expense not deductible for tax return purposes - retail related gross receipts and sales & use taxes
RAR Adjustments	(5,134,054)	(5,134,054)				Distribution related IRS audit adjustments
Workers Compensation	297,856				297,856	Book expense not deductible for tax return purposes - labor related to all functions
Obsolete Inventory	443,729	443,729				Distribution related book expense not deductible for tax return purposes
Deferred Intercompany Transactions	(47,643)	(47,643)				Retail related income recorded for book purposes not includable in taxable income - related to receivables factoring
Deferred Compensation	75,639				75,639	Book expense not deductible for tax return purposes - labor related to all functions
Restructuring Consumer Expense	(69)	(69)				Retail related book expense not deductible for tax return purposes
Environmental Liability	813,175	813,175				Distribution related book expense for manufactured gas plants not deductible for tax return purposes
Post Employment Liabilities	3,238,216	3,238,216				Book expense not deductible for tax return purposes
Book Contingencies	348,545	348,545				Distribution related book expense not deductible for tax return purposes.
TSC over/undercollections	16,054,242	16,054,242				Retail related book expense not deductible for tax return purposes
Interest on TSC over/undercollections	375,441	375,441				Retail related income recorded for book purposes not includable in taxable income
Purta Tax Surcharge	4,166,639	4,166,639				Distribution related book expense not deductible for tax return purposes.
Restructuring write-off - CTC	7,483,918	7,483,918				Retail related income recorded for book purposes not includable in taxable income
Subtotal - p234	288,297,054	260,474,529	23,033,021	0	4,789,504	
Less FASB 109 Above if not separately removed	5,691,548	4,178,044	1,513,504			
Less FASB 106 Above if not separately removed	4,677,692	4,677,692				
Total	277,927,814	251,618,793	21,519,517	0	4,789,504	

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)	(431,404,708)	(431,404,708)				Deductions for distribution related tax depreciation in excess of book depreciation at federal rate
ACRS/MACRS Property (Transmission)	(65,388,357)		(65,388,357)			Deductions for transmission related tax depreciation in excess of book depreciation at federal rate
ACRS/MACRS Property (General Plant)	(45,367,893)				(45,367,893)	Deductions for general plant related tax depreciation in excess of book depreciation at federal rate
FAS109 regulatory assets/liabilities related to plant	(153,355,389)	(153,355,389)				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)	(129,548,199)	(129,548,199)				Basis difference between distribution related book plant and tax plant basis at federal & state rates
Basis adjustments between book and tax plant (Tx - related)	(14,555,139)		(14,555,139)			Basis difference between transmission related book plant and tax plant basis at federal & state rates
Basis adjustments between book and tax plant (General Plant)	5,885,900				5,885,900	Basis difference between book plant and tax plant basis at federal & state rates
RAR adjustments related to plant (Non-Tx)	(2,447,673)	(2,447,673)				IRS audit adjustments related to distribution plant
RAR adjustments related to plant (Tx - related)	(251,702)		(251,702)			IRS audit adjustments related to transmission plant
Subtotal - p275	(836,433,160)	(716,755,969)	(80,195,198)	0	(39,481,993)	
Less FASB 109 Above if not separately removed	(153,355,389)	(153,355,389)				
Less FASB 106 Above if not separately removed	0					
Total	(683,077,771)	(563,400,580)	(80,195,198)	0	(39,481,993)	

Instructions for Account 282:

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

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

PPL Electric Utilities Corporation

A	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod, Dist Or Other Related*	*Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Account 283						
Reacquired debt costs	(13,698,900)			(13,698,900)		Plant related expense deferred for book purposes and deducted for tax purposes
FAS 109 regulatory assets/liabilities	(108,940,186)	(108,940,186)				Asset recorded for regulatory purposes related to book and tax basis plant and non-plant differences
Pension and post-retirement	109,129	109,129				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes
Ice storms	(3,778,976)	(3,778,976)				Distribution related expense deferred for book purposes and deducted for tax purposes
RAR Adjustments	(7,972,246)	(7,972,246)				Distribution related IRS audit adjustments
Deferred intercompany gain - trademark sale	(955,034)	(955,034)				Income recorded for book purposes not includable in taxable income
Receivables Factoring	(2,754,036)	(2,754,036)				Retail related income recorded for book purposes not includable in taxable income
Unrealized gains/losses	(35,888)	(35,888)				Equity adjustment for book purposes not includable in taxable income
Rate case expenses	(232,889)	(232,889)				Retail related expense deferred for book purposes and deducted for tax purposes
FAS158 Regulatory Asset	(95,167,827)	(95,167,827)				Asset recorded for regulatory purposes for FAS 158 pension and post-retirement costs
Company Car Elimination Bonus	(51,452)	(51,452)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Prepaid Insurance	(1,174,730)	(1,174,730)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Transmission Rate Base over/undercollection	(2,059,865)		(2,059,865)			Transmission related book expense not deductible for tax return purposes
Default Service Plan Regulatory Asset	(572,283)	(572,283)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Conservation Program Regulatory Asset	(1,087,277)	(1,087,277)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Smart Meter Technology Regulatory Asset	(19,227)	(19,227)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Clearing Accounts	(559,255)				(559,255)	Expense deferred for book purposes and deducted for tax purposes.
STAS adjustment	(258,920)	(258,920)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Subtotal - p277	(239,209,862)	(222,891,842)	(2,059,865)	(13,698,900)	(559,255)	
Less FASB 109 Above if not separately removed	(108,940,186)	(108,940,186)				
Less FASB 106 Above if not separately removed	109,129	109,129				
Total	(130,378,805)	(114,060,785)	(2,059,865)	(13,698,900)	(559,255)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

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

PPL Electric Utilities Corporation

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	Page 263 Col (i)	Allocator	Allocated Amount
	Plant Related		**Net Plant Allocator**	
1	Real Property (State, Municipal or Local)	761,458		
2	PURTA	4,967,215		
3				
4				
5				
6				
7				
8	**Total Plant Related**	5,728,673	22.5071%	1,289,357
	Labor Related		**Wages & Salary Allocator**	
9	Federal FICA	6,464,469		
10	Federal Unemployment	69,696		
11	State Unemployment	224,907		
12				
13				
14	**Total Labor Related**	6,759,072	10.4672%	707,485
	Other Included		**Net Plant Allocator**	
15	PA Capital Stock Tax	2,808,849		
16	Local Franchise & Liscense Tax	250		
17	PA Capital Stock Tax on Securitization Bonds (Source: Attachment 8)	(5,248)		
18				
19	**Total Other Included**	2,803,851	22.5071%	631,065
20	**Total Included (Lines 8 + 14 + 19)**	15,291,596		2,627,907
	Currently Excluded			
21	Gross Receipts	186,382,738		
22	Sales and Use	(929,053)		
23	1997 PURTA Settlement	(10,041,667)		
24				
25				
26				
27				
28	**Subtotal, Excluded**	175,412,018		
29	**Total, Included and Excluded (Line 20 + Line 28)**	190,703,614		
30	**Total Other Taxes from p114.14.c less Tax on Securitization Bonds**	190,703,614		
31	Difference (Line 29 - Line 30)	-		

Criteria for Allocation:

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

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

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

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

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

PPL Electric Utilities Corporation

Attachment 3 - Revenue Credit Worksheet

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related		1,021,666
	Account 456 - Other Electric Revenues (Note 1)		
2	Transmission for Others (Note 3)		-
3	Schedule 12 Revenues (Note 3)		4,711,764
4	Schedule 1A		2,582,922
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)		2,274,569
7	Professional Services provided to others		579,281
8	Facilities Charges including Interconnection Agreements (Note 2)		1,782,564
9	Gross Revenue Credits	(Sum Lines 1-10)	12,952,766
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	109,369,082
B	100 Basis Point increase in ROE			1.00%
	Return Calculation			
			Appendix A Line or Source Reference	
1	**Rate Base**		(Attachment A Line 46)	755,227,740
	Long Term Interest			
2	Long Term Interest		(Attachment A Line 80)	110,996,893
3	Less LTD Interest on Securitization Bonds		Attachment 8	-
4	Long Term Interest		(Line 2 - Line 3)	110,996,893
5	**Preferred Dividends**	enter positive	p118.29.c	18,069,981
	Common Stock			
6	Proprietary Capital		p112.16.c	1,894,686,318
7	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	50,604
8	Less Preferred Stock		(Attachment A Line 86)	300,518,900
9	Less Account 216.1		p112.12.c	2,518,732
10	Common Stock		(Line 6 - 7 - 8 - 9)	1,591,598,082
	Capitalization			
11	Long Term Debt		p112.18.c, 19.c & 21.c	1,474,040,000
12	Less Loss on Reacquired Debt		p111.81.c	33,014,572
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)	1,441,025,428
16	Preferred Stock		p112.3.c	300,518,900
17	Common Stock		(Line 10)	1,591,598,082
18	Total Capitalization		(Sum Lines 15 to 17)	3,333,142,410
19	Debt %	Total Long Term Debt	(Line 15 / Line 18)	43.2%
20	Preferred %	Preferred Stock	(Line 16 / Line 18)	9.0%
21	Common %	Common Stock	(Line 17 / Line 18)	47.8%
22	Debt Cost	Total Long Term Debt	(Line 4 / Line 15)	0.0770
23	Preferred Cost	Preferred Stock	(Line 5 / Line 16)	0.0601
24	Common Cost	Common Stock	Fixed	0.1268
25	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 19 * Line 22)	0.0333
26	Weighted Cost of Preferred	Preferred Stock	(Line 20 * Line 23)	0.0054
27	Weighted Cost of Common	Common Stock	(Line 21 * Line 24)	0.0605
28	**Rate of Return on Rate Base (ROR)**		(Sum Lines 25 to 27)	**0.0993**
29	**Investment Return = Rate Base * Rate of Return**		**(Line 1 * Line 28)**	**74,971,563**
	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	(548,000)
37	**ITC Adjust. Allocated to Trans. - Grossed Up**		(Line 36 * (1 / (1 - Line 33))	**-936,648**
38	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		35,334,168
39	**Total Income Taxes**			**34,397,519**

ITC Adjustment

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
113	**Amortized Investment Tax Credit**	Company Records	-1,858,013	-548,000	-1,310,013	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 &	33,615,133	25,894,257	4,263,221	3,457,655	
			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
					25,894,257	4,263,221		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	10,547,352			Current year actual PBOP expense
65	Property Insurance Account 924	p323.185.b	6,183,066	2,516,705	8,699,771	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	5,075,146	0	5,075,146	

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	-		-	-

Excluded Plant Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
127	Excluded Transmission Facilities	(Note M)		**General Description of the Facilities**
	Instructions:		**Enter $**	
1	Remove all investment below 69 kV or generator step-up transformers included in transmission plant in service that are not a result of the RTEP process		**0**	**None**
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher, as well as below 69 kV, the following formula will be used:	**Example**	**Or Enter $**	
A	Total investment in substation	1,000,000		
B	Identifiable investment in Transmission (provide workpaper	500,000		
C	Identifiable investment in Distribution (provide workpapers)	400,000		
D	Amount to be excluded (A x (C / (B + C)))	444,444		
				Add more lines if necessary

Prepayments and Prepaid Pension Asset

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Prepayments on Securitization Bonds Adjustment	POLR and Retail Related Adjustment	Prepayments	W&S Allocator	Functionalized to TX	Description of the Prepayments
36	**Prepayments**									
	Prepayments	(Note A) (Note O)	Form 1 -- p111.57.c	24,023,866	0	2,426,674	21,597,192	10.4672%	2,260,619	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	169,611,401	4,725,342	164,886,059	Adjustment for Ancillary Services p321.88b and p321.92b.
48	Less Account 565	p.321.96.b	136,881,044	0	136,881,044	**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	**7,608.7**	

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 2004	Year 2 2005	Year 3 2006	Year 4 2007	Year 5 2008	Total	5 - Year Amortization
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	18,086,370							
	Transmission Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	1,686,595	1,923,848	1,490,638	2,065,421	1,843,165	1,109,904	8,432,976	1,686,595
	Total Transmission Depreciation Expense Including Amortization of Limited Term I	(Note J)	Company Records	19,772,965							
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	15,399,964							
	General Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	257,113	489,561	36,146	2,853,554	-1,106,726	-986,970	1,285,565	257,113
	Total General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	15,657,077							

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)

$ 131,953,494 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 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	(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.)					5,534,456		12					66,413,472	
Jan	1,721,241	1,321	32,622		950,127		11.5	19,794,272	15,192	375,153	-	10,926,461	-
Feb	(300,718)	504	32,183		1,181,951		10.5	(3,157,539)	5,292	337,922	-	12,410,486	-
Mar	820,437	163	5,921		1,570,489		9.5	7,794,152	1,549	56,250	-	14,919,646	-
Apr	930,076		74,445		1,830,075		8.5	7,905,646	-	632,783	-	15,555,638	-
May	1,021,920	106,006	114,869		1,734,600		7.5	7,664,400	795,045	861,518	-	13,009,500	-
Jun	12,962,358		126,355		2,148,646		6.5	84,255,327	-	821,308	-	13,966,199	-
Jul	456,089		126,355		2,668,378		5.5	2,508,490	-	694,953	-	14,676,079	-
Aug	520,125		120,612		2,090,125		4.5	2,340,563	-	542,754	-	9,405,563	-
Sep	1,772,409		120,612		2,069,147		3.5	6,203,432	-	422,142	-	7,242,015	-
Oct	1,508,620		36,691		2,110,983		2.5	3,771,550	-	91,728	-	5,277,458	-
Nov	4,892,313		19,460		1,802,601		1.5	7,338,470	-	29,190	-	2,703,902	-
Dec	8,998,480		21,509		2,111,246		0.5	4,499,240	-	10,755	-	1,055,623	-
Total	35,303,350	107,994	831,634	-	27,802,824	-		150,918,000	817,077	4,876,452	-	187,562,038	-

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

Input to Line 17 of Appendix A
Input to Line 35 of Appendix A
Month In Service or Month for CWIP

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

$ 135,271,777 — 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

$ 135,271,777 — 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)

$ 135,271,777

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 — $ 35,454,907 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 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	(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.)					5,608,097		12					67,297,164	
Jan	1,721,241	1,321	32,622		950,128		11.5	19,794,271	15,188	375,153	-	10,926,472	-
Feb	(144,116)	504	32,183		1,181,950		10.5	(1,513,221)	5,293	337,922	-	12,410,475	-
Mar	767,117	163	4,651		1,571,761		9.5	7,287,610	1,545	44,185	-	14,931,730	-
Apr	641,847	380	16,580		1,601,025		8.5	5,455,696	3,227	140,930	-	13,608,713	-
May	3,000,697	168	32,024		2,819,726		7.5	22,505,230	1,263	240,180	-	21,147,945	-
Jun	4,542,245	0	37,139		1,958,266		6.5	29,524,595	-	241,404	-	12,728,729	-
Jul	7,558,751	-640	28,617		2,067,943		5.5	41,573,132	(3,518)	157,394	-	11,373,687	-
Aug	593,844	0	51,356		1,552,513		4.5	2,672,300	-	231,102	-	6,986,309	-
Sep	2,928,721	0	35,552		1,712,081		3.5	10,250,522	-	124,432	-	5,992,284	-
Oct	2,602,013	0	37,253		1,681,697		2.5	6,505,032	-	93,133	-	4,204,243	-
Nov	8,078,089	0	34,468		1,322,068		1.5	12,117,134	-	51,702	-	1,983,102	-
Dec	3,162,577	-15	52,623		1,676,383		0.5	1,581,289	(8)	26,312	-	838,192	-
Total	35,453,026	1,881	395,068	-	25,703,638	-		157,753,590	22,991	2,063,846	-	184,429,042	-

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

Input to Line 17 of Appendix A
Input to Line 35 of Appendix A
Month In Service or Month for CWIP

$ 152,159,902 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		
152,159,902	-	135,271,777	=	16,888,125

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of the Current Yr — 0.2800%

Month	Yr	1/12 of Step 8 (See Note #1)	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	1,407,344	0.2800%	11.5	45,316	1,452,660
Jul	Year 1	1,407,344	0.2800%	10.5	41,376	1,448,720
Aug	Year 1	1,407,344	0.2800%	9.5	37,435	1,444,779
Sep	Year 1	1,407,344	0.2800%	8.5	33,495	1,440,839
Oct	Year 1	1,407,344	0.2800%	7.5	29,554	1,436,898
Nov	Year 1	1,407,344	0.2800%	6.5	25,614	1,432,957
Dec	Year 1	1,407,344	0.2800%	5.5	21,673	1,429,017
Jan	Year 2	1,407,344	0.2800%	4.5	17,733	1,425,076
Feb	Year 2	1,407,344	0.2800%	3.5	13,792	1,421,136
Mar	Year 2	1,407,344	0.2800%	2.5	9,851	1,417,195
Apr	Year 2	1,407,344	0.2800%	1.5	5,911	1,413,255
May	Year 2	1,407,344	0.2800%	0.5	1,970	1,409,314
Total		16,888,125				17,171,846

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	17,171,846	0.2800%	1,457,165	15,762,762
Jul	Year 2	15,762,762	0.2800%	1,457,165	14,349,733
Aug	Year 2	14,349,733	0.2800%	1,457,165	12,932,748
Sep	Year 2	12,932,748	0.2800%	1,457,165	11,511,795
Oct	Year 2	11,511,795	0.2800%	1,457,165	10,086,864
Nov	Year 2	10,086,864	0.2800%	1,457,165	8,657,942
Dec	Year 2	8,657,942	0.2800%	1,457,165	7,225,020
Jan	Year 3	7,225,020	0.2800%	1,457,165	5,788,085
Feb	Year 3	5,788,085	0.2800%	1,457,165	4,347,127
Mar	Year 3	4,347,127	0.2800%	1,457,165	2,902,135
Apr	Year 3	2,902,135	0.2800%	1,457,165	1,453,096
May	Year 3	1,453,096	0.2800%	1,457,165	(0)
Total with interest				17,485,975	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		17,485,975
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$	-
Revenue Requirement for Year 3		17,485,975

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	(C) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(D) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(F) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(G) Weighting	(H) Other Plant In Service Amount (A x G)	(I) 0 Amount (B x G) 0	(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.)			395,068		25,703,638		12			4,740,816		308,443,656	
Jan	934,689		52,662		1,012,913		11.5	10,748,924	-	605,613	-	11,648,500	-
Feb	1,377,045		108,808		748,032		10.5	14,458,976	-	1,142,484	-	7,854,336	-
Mar	1,309,997		104,055		927,878		9.5	12,444,975	-	988,523	-	8,814,841	-
Apr	355,110		84,496		1,058,325		8.5	3,018,432	-	718,216	-	8,995,763	-
May	3,085,919		72,279		1,141,985		7.5	23,144,392	-	542,095	-	8,564,890	-
Jun	5,706,826		281,847		1,348,287		6.5	37,094,368	-	1,832,004	-	8,763,865	-
Jul	7,974,811		64,972		1,314,019		5.5	43,861,462	-	357,348	-	7,227,105	-
Aug	589,184		482,036		2,277,626		4.5	2,651,329	-	2,169,160	-	10,249,317	-
Sep	355,110		215,668		1,646,630		3.5	1,242,884	-	754,836	-	5,763,206	-
Oct	1,166,639		443,181		1,575,859		2.5	2,916,596	-	1,107,953	-	3,939,646	-
Nov	14,475,343		224,182		2,680,318		1.5	21,713,014	-	336,273	-	4,020,477	-
Dec	21,152,889		76,941		857,137		0.5	10,576,444	-	38,471	-	428,568	-
Total	58,483,561	-	2,606,195	-	42,292,647	-		183,871,796	-	15,333,791	-	394,714,169	-

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

Input to Line 17 of Appendix A
Input to Line 35 of Appendix A
Month In Service or Month for CWIP

10 May Year 3 Post results of Step 9 on PJM web site
$ 160,395,305 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)
$ 160,395,305

(N) Other Plant In Service (H / 12)	(O) Juniata Wavetrap (I / 12) (b0171.2)	(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
				5,534,456		
1,649,523	1,266	31,263	-	910,538	-	
(263,128)	441	28,160	-	1,034,207	-	
649,513	129	4,687	-	1,243,304	-	
658,804	-	52,732	-	1,296,303	-	
638,700	66,254	71,793	-	1,084,125	-	
7,021,277	-	68,442	-	1,163,850	-	
209,041	-	57,913	-	1,223,007	-	
195,047	-	45,230	-	783,797	-	
516,953	-	35,179	-	603,501	-	
314,296	-	7,644	-	439,788	-	
611,539	-	2,433	-	225,325	-	
374,937	-	896	-	87,969	-	
12,576,500	68,090	406,371	-	15,630,170	-	-
12,576,500	68,090		-		-	12,644,590
		406,371		15,630,170		16,036,541
7.73	4.43	6.14	-	5.25	-	

(N) Other Plant In Service (H / 12)	(O) Juniata Wavetrap (I / 12) (b0171.2)	(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
				5,608,097		
1,649,523	1,266	31,263	-	910,539	-	
(126,102)	441	28,160	-	1,034,206	-	
607,301	129	3,682	-	1,244,311	-	
454,641	269	11,744	-	1,134,059	-	
1,875,436	105	20,015	-	1,762,329	-	
2,460,383	-	20,117	-	1,060,727	-	
3,464,428	(293)	13,116	-	947,807	-	
222,692	-	19,259	-	582,192	-	
854,210	-	10,369	-	499,357	-	
542,086	-	7,761	-	350,354	-	
1,009,761	-	4,309	-	165,259	-	
131,774	(1)	2,193	-	69,849	-	
13,146,132	1,916	171,987	-	15,369,087	-	
13,146,132	1,916		-		-	13,148,048
		171,987		15,369,087		15,541,074
7.55	(0.22)	6.78	-	4.82	-	

(N)	(O)	(P)	(Q)	(R)	(S)	
Other Plant In Service	0	Susq-Rose CWIP	Susq-Rose PIS	Susq-Rose CWIP	Susq-Rose PIS	Total
(H / 12)	(I / 12)	(J / 12)	(K / 12)	(L / 12)	(M / 12)	
	0	< 500kV (b0487.1)	< 500kV (b0487.1)	>= 500kV (b0487)	>= 500kV (b0487)	
		395,068		25,703,638		
895,744	-	50,468	-	970,708	-	
1,204,915	-	95,207	-	654,528	-	
1,037,081	-	82,377	-	734,570	-	
251,536	-	59,851	-	749,647	-	
1,928,699	-	45,175	-	713,741	-	
3,091,197	-	152,667	-	730,322	-	
3,655,122	-	29,779	-	602,259	-	
220,944	-	180,763	-	854,110	-	
103,574	-	62,903	-	480,267	-	
243,050	-	92,329	-	328,304	-	
1,809,418	-	28,023	-	335,040	-	
881,370	-	3,206	-	35,714	-	
15,322,650	-	1,277,816	-	32,892,847	-	
15,322,650	-		-		-	15,322,650
		1,277,816		32,892,847		34,170,663
8.86	-	6.12	-	2.67	-	

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	137	Net Plant Carrying Charge without Depreciation	20.8551%
4	B	144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	21.6921%
5	C		Line B less Line A	0.8370%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.8401%

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
10										
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	11.68% ROE		20.8551%	20.8551%	20.8551%	20.8551%	20.8551%	20.8551%	20.8551%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		21.9013%	21.9013%	20.8551%	20.8551%	20.8551%	21.9013%	21.9013%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified	Investment		42,292,647		86,626	62,067	123,504	2,606,195	
18	Line 17 divided by line 12	Annual Depreciation Exp		1,006,968	-	2,063	1,478	2,941	62,052	-
19	Month in which project is placed in service (e.g. Jan=1)	Month In Service or Month for CWIP		2.67		(0.22)	6.78	1.00	6.12	

Line		Invest Yr	Susquehanna - Roseland CWIP (b0487) >= 500kV Beginning	Depreciation	Ending	Revenue	Susquehanna - Roseland PIS (b0487) >= 500kV Beginning	Depreciation	Ending	Revenue	Hosensack Wavetrap (b0171.2) Beginning	Depreciation	Ending	Revenue
20		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	5,534,456	-	5,534,456	433,646	-	-	-	-	86,626	1,454	85,172	12,921
22	W Increased ROE	2008	5,534,456	-	5,534,456	453,742	-	-	-	-	86,626	1,454	85,172	12,921
23	W 11.68 % ROE	2009	25,703,638	-	25,703,638	3,744,759	-	-	-	-	85,172	2,063	83,109	19,836
24	W Increased ROE	2009	25,703,638	-	25,703,638	3,928,397	-	-	-	-	85,172	2,063	83,109	19,836
25	W 11.68 % ROE	2010	42,292,647	-	42,292,647	7,594,834	-	-	-	-	83,109	2,063	81,047	18,965
26	W Increased ROE	2010	42,292,647	-	42,292,647	7,975,865	-	-	-	-	83,109	2,063	81,047	18,965
27	W 11.68 % ROE	2011		-	-	-	-	-	-	-	-	-	-	-
28	W Increased ROE	2011		-	-	-	-	-	-	-	-	-	-	-
29	W 11.68 % ROE	2012		-	-	-	-	-	-	-	-	-	-	-
30	W Increased ROE	2012		-	-	-	-	-	-	-	-	-	-	-
31	W 11.68 % ROE	2013		-	-	-	-	-	-	-	-	-	-	-
32	W Increased ROE	2013		-	-	-	-	-	-	-	-	-	-	-
33	W 11.68 % ROE	2014		-	-	-	-	-	-	-	-	-	-	-
34	W Increased ROE	2014		-	-	-	-	-	-	-	-	-	-	-
35	W 11.68 % ROE	2015		-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015		-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016		-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016		-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017		-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017		-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018		-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018		-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019		-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019		-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020		-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020		-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021		-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021		-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022		-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022		-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023		-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023		-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024		-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024		-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025		-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025		-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026		-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026		-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027		-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027		-	-	-	-	-	-	-	-	-	-	-
61		....					....	-	.....	....	....	....	.....	....
62		....					....	.....	.....	....	....	.....	.....	....

Line	Alburtis Wavetrap (b0172.1) Beginning	Depreciation	Ending	Revenue	Juniata Wavetrap (b0284.2) Beginning	Depreciation	Ending	Revenue	Susquehanna - Roseland CWIP (b0487.1) < 500kV Beginning	Depreciation	Ending	Revenue
21	62,067	991	61,076	8,811	-	-	-	-	-	-	-	-
22	62,067	991	61,076	8,811	-	-	-	-	-	-	-	-
23	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723	395,068	-	395,068	43,820
24	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723	395,068	-	395,068	45,969
25	59,598	1,478	58,121	13,599	120,563	2,941	117,623	27,471	2,606,195	-	2,606,195	311,783
26	59,598	1,478	58,121	13,599	120,563	2,941	117,623	27,471	2,606,195	-	2,606,195	327,425
27	-	-	-	-	-	-	-	-	-	-	-	-
28	-	-	-	-	-	-	-	-	-	-	-	-
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
31	-	-	-	-	-	-	-	-	-	-	-	-
32	-	-	-	-	-	-	-	-	-	-	-	-
33	-	-	-	-	-	-	-	-	-	-	-	-
34	-	-	-	-	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-	-	-	-	-
36	-	-	-	-	-	-	-	-	-	-	-	-
37	-	-	-	-	-	-	-	-	-	-	-	-
38	-	-	-	-	-	-	-	-	-	-	-	-
39	-	-	-	-	-	-	-	-	-	-	-	-
40	-	-	-	-	-	-	-	-	-	-	-	-
41	-	-	-	-	-	-	-	-	-	-	-	-
42	-	-	-	-	-	-	-	-	-	-	-	-
43	-	-	-	-	-	-	-	-	-	-	-	-
44	-	-	-	-	-	-	-	-	-	-	-	-
45	-	-	-	-	-	-	-	-	-	-	-	-
46	-	-	-	-	-	-	-	-	-	-	-	-
47	-	-	-	-	-	-	-	-	-	-	-	-
48	-	-	-	-	-	-	-	-	-	-	-	-
49	-	-	-	-	-	-	-	-	-	-	-	-
50	-	-	-	-	-	-	-	-	-	-	-	-
51	-	-	-	-	-	-	-	-	-	-	-	-
52	-	-	-	-	-	-	-	-	-	-	-	-
53	-	-	-	-	-	-	-	-	-	-	-	-
54	-	-	-	-	-	-	-	-	-	-	-	-
55	-	-	-	-	-	-	-	-	-	-	-	-
56	-	-	-	-	-	-	-	-	-	-	-	-
57	-	-	-	-	-	-	-	-	-	-	-	-
58	-	-	-	-	-	-	-	-	-	-	-	-
59	-	-	-	-	-	-	-	-	-	-	-	-
60	-	-	-	-	-	-	-	-	-	-	-	-
61	....	....	.....	....	....	....	.....	....	....	....	.....	....
62	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

Line	Susquehanna - Roseland PIS (b0487.1) < 500kV Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
21	-	-	-	-	$ 455,377		$ 455,377
22	-	-	-	-	$ 475,473	$ 475,473	
23	-	-	-	-	$ 3,851,361		$ 3,851,361
24	-	-	-	-	$ 4,037,148	$ 4,037,148	
25	-	-	-	-	$ 7,966,651		$ 7,966,651
26	-	-	-	-	$ 8,363,325	$ 8,363,325	
27	-	-	-	-	$ -		$ -
28	-	-	-	-	$ -	$ -	
29	-	-	-	-	$ -		$ -
30	-	-	-	-	$ -	$ -	
31	-	-	-	-	$ -		$ -
32	-	-	-	-	$ -	$ -	
33	-	-	-	-	$ -		$ -
34	-	-	-	-	$ -	$ -	
35	-	-	-	-	$ -		$ -
36	-	-	-	-	$ -	$ -	
37	-	-	-	-	$ -		$ -
38	-	-	-	-	$ -	$ -	
39	-	-	-	-	$ -		$ -
40	-	-	-	-	$ -	$ -	
41	-	-	-	-	$ -		$ -
42	-	-	-	-	$ -	$ -	
43	-	-	-	-	$ -		$ -
44	-	-	-	-	$ -	$ -	
45	-	-	-	-	$ -		$ -
46	-	-	-	-	$ -	$ -	
47	-	-	-	-	$ -		$ -
48	-	-	-	-	$ -	$ -	
49	-	-	-	-	$ -		$ -
50	-	-	-	-	$ -	$ -	
51	-	-	-	-	$ -		$ -
52	-	-	-	-	$ -	$ -	
53	-	-	-	-	$ -		$ -
54	-	-	-	-	$ -	$ -	
55	-	-	-	-	$ -		$ -
56	-	-	-	-	$ -	$ -	
57	-	-	-	-	$ -		$ -
58	-	-	-	-	$ -	$ -	
59	-	-	-	-	$ -		$ -
60	-	-	-	-	$ -	$ -	
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**	(22,142)	(See FM 1, note to page 114, line 4)
	Taxes Other Than Income		
78	**Less Taxes Other Than Income on Securitization Bonds**	5,248	(See FM 1, note to page 114, line 14)
	Long Term Interest		
81	**Less LTD Interest on Securitization Bonds**	0	(See FM 1, note to page 114, lines 62 + 63)
	Capitalization		
92	**Less LTD on Securitization Bonds**	0	(See FM 1, note to page 112, line 18)

Calculation of the above Securitization Adjustments

The amounts above are associated with transition bonds issued to securitize the recovery of retail stranded costs, pursuant to an Order entered by the Pennsylvania Public Utility Commission on May 21, 1999 at Docket No. R-00994637, in accordance with Pennsylvania's Electric Generation Customer Choice and Competition Act.

PPL Electric Utilities Corporation

Attachment 9 - Depreciation Rates

(A) Number	(B) Plant Type	(C) Estimated Life	(D) Mortality Curve	(E) Current Age	(F) Remaining Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	Transmission									
350.4	Land Rights	70	S4	26.8	43.20	2.4074	75,345,822	35,125,432	40,220,390	968,257
352	Structures and Improvements	55	R4	21.8	33.20	3.1637	31,572,760	14,831,790	16,740,970	529,640
353	Station Equipment	47	R1	12.0	35.00	2.9343	424,289,654	162,310,590	261,979,064	7,687,129
354	Towers and Fixtures	65	R3	16.8	48.20	2.0940	303,171,235	118,412,354	184,758,881	3,868,834
354.2	Towers and Fixtures - Clearing Land and Rights of Way	70	R4	25.7	44.30	2.6290	11,739,902	6,271,301	5,468,601	143,771
355	Poles and Fixtures	55	R1.5	14.3	40.70	2.4119	96,302,004	37,509,174	58,792,830	1,418,001
355.2	Poles and Fixtures - Clearing Land and Rights of Way	70	R4	22.5	47.50	2.2118	7,345,535	3,641,739	3,703,796	81,920
356	Overhead Conductors and Devices	55	R3	19.5	35.50	3.2171	197,633,671	108,814,995	88,818,676	2,857,418
357	Underground Conduit	50	R4	17.5	32.50	2.3716	6,161,364	1,815,474	4,345,890	103,066
358	Underground Conductors and Devices	40	R3	11.3	28.70	3.3544	16,499,821	6,677,830	9,821,991	329,466
359	Roads and Trails	70	R4	26.2	43.80	2.4520	6,578,494	2,546,353	4,032,141	98,870
	General									
389.4	Land Rights	65	R4	38.5	26.50	3.2110	4,399	1,190	3,209	103
390.2	Structures and Improvements - Buildings	55	S0	35.6	19.40	2.2468	266,011,880	63,926,007	202,085,873	4,540,550
390.21	Structures and Improvements - Leaseholds	10	NA		9.50	-	741,658	70,355	671,303	0
390.4	Structures and Improvements - Air Conditioning	30	R2	8.9	21.10	5.1365	28,026,976	11,687,220	16,339,756	839,290
391.2	Office Furniture and Equipment - Furniture	20	NA		10.60	5.1833	19,305,963	7,581,007	11,724,956	1,000,684
391.4	Office Furniture and Equipment - Mechanical Equipment	15	NA		11.20	6.8581	1,922,578	329,592	1,592,986	131,853
391.6	Office Furniture and Equipment - Computer Equipment - General	5	NA		3.50	19.9507	568,012	84,336	483,676	113,323
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System	7	NA		-	14.2800	38,155,394	38,155,394	0	0
392.1	Transportation Equipment - 5 Years	5	R4	1.6	3.40	30.9700	2,615,383	1,193,235	1,422,148	440,439
392.2	Transportation Equipment - 8 Years	8	S3	2.6	5.40	25.9091	14,635,814	6,547,631	8,088,183	2,095,573
392.3	Transportation Equipment - 10 Years	11	R2.5	4.9	6.10	7.9363	60,053,651	21,596,984	38,456,667	3,052,024
392.4	Transportation Equipment - Trailers	16	L1	(0.1)	16.10	8.1622	4,923,640	1,004,633	3,919,007	319,876
392.5	Transportation Equipment - 15 Years	14	L2	4.2	9.80	10.2644	2,863,975	618,211	2,245,764	230,513
392.6	Transportation Equipment - 20 Years	18	L1.5	4.4	13.60	9.1598	766,939	99,361	667,578	61,149
393	Store Equipment	25	NA		9.20	4.3634	2,911,704	1,135,979	1,775,725	127,050
394	Tools, Shop and Garage Equipment - Distribution Line Crews	20	NA		10.50	5.7031	5,568,679	1,507,410	4,061,269	317,586
394.2	Tools, Shop and Garage Equipment - Tools	20	NA		11.10	7.0416	293,480	55,029	238,451	20,666
394.4	Tools, Shop and Garage Equipment - Construction Department	20	NA		6.80	5.5823	2,379,751	1,127,492	1,252,259	132,845
394.6	Tools, Shop and Garage Equipment - Other	20	NA		12.10	4.5391	13,707,920	4,490,919	9,217,001	622,222
394.8	Tools, Shop and Garage Equipment - Garage Tools Support	20	NA		4.10	5.3775	6,658,049	4,870,653	1,787,396	358,034
395	Laboratory Equipment	20	NA		13.20	4.4212	3,366,563	1,204,196	2,162,367	148,842
396	Power Operated Equipment	15	NA		10.70	10.2926	1,505,479	572,149	933,330	154,953
397	Communication Equipment	15	NA		9.70	5.5347	10,668,306	8,150,786	2,517,520	590,462
398	Miscellaneous Equipment	20	NA		6.20	5.9234	1,720,768	604,249	1,116,519	101,928
	Intangible									
303.2	Intangible Computer Software	5	NA		3.90	20.00	37,009,288	15,368,056	21,641,232	5,438,660
303.4	Other Amortized Property	15	NA		2.40	6.67	1,035,137	896,213	138,924	291,941

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance.
2 Column (E) is based on the Estimated Life in Column (C) less the Remaining Life in Column (F) for those accounts for which using a Mortality Curve is identified.
3 Column (F) is the average remaining life of the assets in the account based on their vintage.
4 Column (G) is the depreciation rate from the Mortality Curve specified based on data in Columns (C) and (D).
5 Columns (H) and (I) are the depreciable gross plant investment and accumulated depreciation in the account or subaccount.
6 Column (J) is the depreciable net plant in the account or subaccount.
7 Column (K) is Column (G) multiplied by Column (J) for those accounts that have an identified Mortality Curve.
8 Each year, PPL Electric will provide a copy of the annual report submitted to the PA PUC that shows the calculation of the depreciation rates and expenses derived from Columns (C) and (D).
9 Every 5 years, PPL Electric will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.
10 Column (K) for Accounts Nos. 303.2 and 303.4 are calculated using individual asset depreciation and, therefore, are not derived values.
11 Column (K) for Account No. 392.3 is net of capitalized depreciation expense. See the applicable note in FERC Form No. 1.
12 For those General Plant accounts that do not have Mortality Curves as indicated by "NA" in Column (D), additional detail is provided in Attachment 9 - Supplemental General Plant Depreciation Details.

PPL Electric Utilities Corporation

Attachment 9 - Supplemental
General Plant Depreciation Details

(A) Number	(B) Plant Type	(C) Estimated Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	General						
390.21	Structures and Improvements - Leaseholds - Net Method	10	-	741,658	70,355	671,303	0
391.2	Office Furniture and Equipment - Furniture - Gross Method	20	4.9030	12,273,097	2,478,521	9,794,577	601,744
391.2	Office Furniture and Equipment - Furniture - Net Method	20	20.6664	7,032,866	5,102,486	1,930,379	398,940
				19,305,963	7,581,007	11,724,956	1,000,684
391.4	Office Furniture and Equipment - Mechanical Equipment - Gross Method	15	6.6661	1,831,581	271,720	1,559,861	122,096
391.4	Office Furniture and Equipment - Mechanical Equipment - Net Method	15	29.4545	90,997	57,871	33,125	9,757
				1,922,578	329,592	1,592,986	131,853
391.6	Office Furniture and Equipment - Computer Equipment - General- Gross Method	5	19.9507	568,012	84,336	483,676	113,323
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System- Gross Method	7	14.2800	38,155,394	38,155,394	0	0
393	Store Equipment - Gross Method	25	3.9374	1,270,821	257,574	1,013,247	50,037
393	Store Equipment - Net Method	25	10.1003	1,640,883	878,405	762,478	77,013
				2,911,704	1,135,979	1,775,725	127,050
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Gross Method	20	5.0000	2,375,017	356,993	2,018,024	118,751
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Net Method	20	9.7314	3,193,662	1,150,417	2,043,245	198,835
				5,568,679	1,507,410	4,061,269	317,586
394.2	Tools, Shop and Garage Equipment - Tools - Gross Method	20	5.0000	133,692	9,050	124,642	6,685
394.2	Tools, Shop and Garage Equipment - Tools - Net Method	20	12.2848	159,788	45,979	113,809	13,981
				293,480	55,029	238,451	20,666
394.4	Tools, Shop and Garage Equipment - Construction Department - Gross Method	20	5.5758	2,371,800	1,125,527	1,246,273	132,246
394.4	Tools, Shop and Garage Equipment - Construction Department - Net Method	20	10.0007	7,951	1,965	5,986	599
				2,379,751	1,127,492	1,252,259	132,845
394.6	Tools, Shop and Garage Equipment - Gross Method	20	4.1007	9,794,027	1,601,703	8,192,324	401,620
394.6	Tools, Shop and Garage Equipment - Net Method	20	21.5289	3,913,893	2,889,215	1,024,678	220,602
				13,707,920	4,490,919	9,217,002	622,222
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Gross Method	20	3.9602	475,760	23,313	452,447	18,841
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Net Method	20	25.4087	6,182,289	4,847,340	1,334,949	339,193
				6,658,049	4,870,653	1,787,396	358,034
395	Laboratory Equipment - Gross Method	20	4.3288	1,177,059	190,453	986,607	50,953
395	Laboratory Equipment - Net Method	20	8.3256	2,189,504	1,013,743	1,175,760	97,889
				3,366,563	1,204,196	2,162,367	148,842
396	Power Operated Equipment - Gross Method	15	6.6667	478,248	125,265	352,983	31,883
396	Power Operated Equipment - Net Method	15	21.2061	1,027,231	446,883	580,348	123,069
				1,505,479	572,149	933,330	154,953
397	Communication Equipment - Gross Method	15	5.2410	9,987,727	7,957,652	2,030,075	523,461
397	Communication Equipment - Net Method	15	13.7454	680,579	193,133	487,446	67,001
				10,668,306	8,150,786	2,517,520	590,462
398	Miscellaneous Equipment - Gross Method	20	4.7155	374,159	94,003	280,156	17,644
398	Miscellaneous Equipment - Net Method	20	10.0775	1,346,609	510,246	836,363	84,284
				1,720,768	604,249	1,116,519	101,928

Notes:

1 This schedule shows additional detail for those General Plant accounts that do not have a Mortality Curve. The calculation of Depreciation Expense by the Gross Plant Method (i.e., Column (G) multiplied by Column (H)) and the Net Plant Method (i.e., Column (G) multiplied by Column (J)) is shown separately for the assets in each account subject to each such method. Assets purchased new are depreciated using the Gross Plant Method. Assets purchased used are depreciated using the Net Plant Method (i.e., over their remaining economic life).

Attachment 4f - AEP East Formula Rate
Summary Update

Formula Rate Update for AEP East Operating Companies in PJM

To be Effective July 1, 2010 through June 30, 2011
Docket No ER08-1329

Pursuant to PJM OATT Attachment H-14A (Formula Rate Implementation Protocols), AEP has calculated its Annual Transmission Revenue Requirements (ATRR) to produce the "Annual Update" for the Rate Year beginning July 1, 2010 through June 30, 2011. All the files pertaining to the Annual Update are to be posted on the PJM website in PDF format. The first file provides the ATRR and rates for Network transmission service and Scheduling System Control and Dispatch Service (Schedule 1A), and the annual transmission revenue requirement for RTEP projects (Schedule 12). An informational filing will also be submitted to the FERC.

AEP network service rate will decrease effective July 1, 2010 from $24,550.54 per MW per year to $22,558.81 per MW per year with the AEP annual revenue requirement decreasing from $599,570,841 to $550,929,037.

The AEP Schedule 1A rate will increase from $0.0771 per MWh to $.1019 per MWh.

An annual revenue requirement of $6,230,866 for three RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b0504 (Hanging Rock) of $1,399,436
2. b0318 (Amos 765/138 kV Transformer) of $2,672,729
3. b0839 (Twin Branch) of $2,158,701